2.5 EXHIBIT 2: RATE BASE

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2.5 EXHIBIT 2: RATE BASE

2.5.1 RATE BASE

2.5.1.1 OVERVIEW

The rate base for the purpose of calculating the revenue requirement used in this Application follows Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued on July 18, 2014 (the "Filing Requirements"). In accordance with the Filing Requirements, Guelph Hydro has calculated the rate base for the 2016 Test Year based on the average of the opening and closing balances of gross fixed assets and accumulated depreciation, plus a working capital allowance based on 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The 2016 rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting, and administration expenses.

Since its last Cost of Service application for 2012 rates, Guelph Hydro has not applied for, nor received, any Incremental Capital Module ("ICM") adjustments.

Guelph Hydro adopted IFRS January 1, 2011 for financial reporting. For rate setting purposes, Guelph Hydro has filed 2012 to 2016 information using modified IFRS.

Guelph Hydro has provided its rate base calculations for the years 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and 2016 Test Year in Table 2-1 below. Guelph Hydro has calculated its 2016 rate base as $162,960,102.

Table 2-1
Summary of Rate Base

Description	2012 Actual Year MIFRS	2013 Actual Year MIFRS	2014 Actual Year MIFRS	2015 Bridge Year MIFRS	2016 Test Year MIFRS
Opening Balance Gross Fixed Assets	$122,576,198	$131,947,307	$138,073,015	$146,798,079	$164,161,260 *
Closing Balance Gross Fixed Assets	$131,947,307	$138,073,015	$146,798,079	$163,560,606	$174,943,260
Average Gross Fixed Assets	$127,261,753	$135,010,161	$142,435,547	$155,179,343	$169,552,260
Opening Balance Accumulated Depreciation	($9,690,632)	($15,060,711)	($20,601,182)	($26,338,513)	($32,544,287)
Closing Balance Accumulated Depreciation	($15,060,711)	($20,601,182)	($26,338,513)	($32,325,338)	($38,846,473)
Average Accumulated Depreciation	($12,375,672)	($17,830,946)	($23,469,847)	($29,331,925)	($35,695,380)
Average Net Fixed Assets	$114,886,081	$117,179,214	$118,965,700	$125,847,417	$133,856,880
Working Capital	$164,758,517	$182,851,859	$197,135,779	$222,319,897	$223,870,940
Working Capital Allowance - 2012 to 2015 at 15%; 2016 at 13%	$24,713,778	$27,427,779	$29,570,367	$33,347,985	$29,103,222
Rate Base	$139,599,859	$144,606,993	$148,536,067	$159,195,402	$162,960,102

***Note:** Inclusion of the Zigbee Chip in 2016 Opening Gross Fixed Assets balance explains the deviation from 2015 Closing Gross Fixed Assets balance.

RATE BASE VARIANCE ANALYSIS

Guelph Hydro has calculated the materiality threshold of its 2016 distribution revenue requirement to be $172,000 for 2016 in accordance with Chapter 2 of the Filing Requirements issued on July 18, 2014:

0.5% x $34,319,428 distribution revenue requirement = $171,597

Guelph Hydro rounded up the materiality threshold to $172,000.

The following Table 2-2 sets out Guelph Hydro's rate base and working capital calculations for 2012 Board-approved and 2012 Actual, 2013 Actual, 2014 Actual, 2015 Bridge Year and 2016 Test Year, and the following variances:

Table 2-2
Rate Base Variances

Rate Base:

Description			2012 Approved		2012 Actual Year	Variance 2012 Actual to 2012 Approved	2013 Actual Year	Variance 2013 Actual to 2012 Actual	2014 Actual	Variance 2014 Actual to 2013 Actual	2015 Bridge Year	Variance 2015 Bridge to 2014 Actual	2016 Test Year	Variance 2016 Test to 2015 Bridge
Gross Fixed Assets (Average)			177,044,156		$127,261,753	($49,782,403)	$135,010,161	**$7,748,408**	$142,435,547	**$7,425,386**	$155,179,343	**$12,743,796**	$169,552,260	**$14,372,917**
Accumulated Depreciation (Average)			$62,545,027		$12,375,672	($50,169,356)	$17,830,946	**$5,455,275**	$23,469,847	**$5,638,901**	$29,331,925	**$5,862,078**	$35,695,380	**$6,363,455**
Net Book Value			114,499,128		$114,886,081	**$386,953**	$117,179,214	**$2,293,133**	$118,965,700	**$1,786,485**	$125,847,417	**$6,881,718**	$133,856,880	**$8,009,463**
Average Net Book Value			$114,499,128		$114,886,081	**$386,953**	$117,179,214	**$2,293,133**	$118,965,700	**$1,786,485**	$125,847,417	**$6,881,718**	$133,856,880	**$8,009,463**
Working Capital			$167,747,105		$164,758,517	($2,988,588)	$182,851,859	**$18,093,341**	$197,135,779	**$14,283,921**	$222,319,897	**$25,184,118**	$223,870,940	**$1,551,043**
Working Capital Allowance			$25,177,591		$24,713,778	($463,813)	$27,427,779	**$2,714,001**	$29,570,367	**$2,142,588**	$33,347,985	**$3,777,618**	$29,103,222	($4,244,762)
Rate Base			$139,676,719		$139,599,859	($76,860)	$144,606,993	**$5,007,135**	$148,536,067	**$3,929,074**	$159,195,402	**$10,659,335**	$162,960,102	**$3,764,700**

Table 2-3

Rate Base Variances

	2012 Variance from 2012 Approved	2013 Variance from 2012 Actual	2014 Variance from 2013 Actual	2015 Variance from 2014 Actual	2016 Variance from 2015 Bridge
Net Book Value					
Δ Average Net Book Value	$386,953	$2,293,133	$1,786,485	$6,881,718	$8,009,463
Working Capital Allowance	**($448,288)**	**$2,714,001**	**$2,142,588**	**$3,777,618**	**($4,244,762)**
Δ Cost of Power	($303,949)	$2,429,308	$2,318,342	$3,602,256	($4,076,059)
Δ Operations	($27,657)	$40,980	$77,560	$42,038	($26,268)
Δ Maintenance	($49,074)	$78,006	($88,361)	$41,907	($14,076)
Δ Billing & Collecting	$16,245	($25,294)	($65,153)	($77,777)	$21,560
Δ Community Relations	($35,950)	$3,539	$8,494	($867)	($3,540)
Δ Administration & General Expense	($56,122)	$185,090	($80,038)	$179,020	($145,005)
Δ Property Taxes	$73,853	($2,056)	($22,662)	$384	($5,959)
Less Adjustment for fully allocated depreciation	($65,634)	$4,428.23	($5,593)	($9,343)	$4,584.05
Total Rate Base Variance	**($61,335)**	**$5,007,135**	**$3,929,074**	**$10,659,335**	**$3,764,700**

In order to present a detailed explanation of the annual change in Guelph Hydro's rate base from the 2012 Board-approved rate base to the 2016 Test Year rate base, the narrative below splits Guelph Hydro's Average Net Book Value into four components:

- Average gross fixed asset additions
- Average customer contributions
- Average depreciation expense
- Average disposals

As a result of this split, some of the figures presented in the ensuing narrative will not tie directly to the Rate Base variances presented in Table 2-2 above; however, the sum of these components matches precisely with the overall annual variances in rate base that is shown in Table 2-2.

Variance of 2012 Actual versus 2012 Board-Approved Rate Base

The variance between the 2012 Actual and the 2012 Board-approved Rate Base was ($61,335). Guelph Hydro has identified one main driver to explain the variance: a lower Working Capital due to lower than estimated Cost of Power.

For an explanation of the changes in the Working Capital and Working Capital Allowance please see Table 2-4 Cost of Power Analysis.

Variance of 2013 Actual versus 2012 Actual Rate Base:

The variance of the 2013 actual rate base from the 2012 actual rate base was $5,007,135. The main drivers that explain the variance were:

1. A higher Average Net Book Value of assets of $2,293,133 as a result of increased average capital spending in 2012 and 2013 of $10,947,199, offset by average customer contributions of $2,975,044, and an average depreciation expense of $5,562,159. The remaining variance was a result of an average net disposal value of $116,866 (for more details, please see Exhibit 2, Tab 2, Schedule 2, 2.5.2.2 Required Information); and
2. An increase in working capital and the working capital allowance due to an increase in cost of power of $16,195,386; the increase in cost of power reflects higher average market prices and global adjustment (the average price variance for power was of $8.39/MWh).

Table 2-4 below presents the 2012 Board-approved Cost of Power and Working Capital Allowance related to Cost of Power compared to the 2012 Actual Cost of Power and Working Capital Allowance related to Cost of Power. Additionally, Table 2-4 includes the 2012 to 2016 year-over-year variances of Cost of Power and Working Capital Allowance related to Cost of Power.

Table 2-4 Cost of Power Variances Analysis

Description	2012 Approved	2012 Actual Year	Variance 2012 Actual to 2012 Approved	2013 Actual Year	Variance 2013 Actual to 2012 Actual	2014 Actual	Variance 2014 Actual to 2013 Actual	2015 Bridge Year	Variance 2015 Bridge to 2014 Actual	2016 Test Year	Variance 2016 Test to 2015 Bridge
Power Purchased	$123,988,132	$124,161,545	**$173,413**	$139,182,565	**$15,021,020**	$152,921,778	**$13,739,213**	$174,009,223	**$21,087,445**	$174,966,575	**$957,352**
Charges -WMS	$8,897,272	$8,869,474	**($27,798)**	$9,076,762	**$207,288**	$7,505,379	**($1,571,383)**	$7,956,787	**$451,409**	$8,001,928	**$45,141**
Chares -Network	$10,159,839	$10,380,125	**$220,286**	$10,971,289	**$591,164**	$11,627,831	**$656,542**	$12,914,428	**$1,286,597**	$12,387,008	**($527,420)**
Charges -CN	$8,218,645	$8,048,714	**($169,931)**	$8,170,261	**$121,547**	$8,365,845	**$195,584**	$9,399,740	**$1,033,895**	$9,417,712	**$17,972**
Rural Rate Assistance Expense	$2,224,318	$0	**($2,224,318)**	$0	**$0**	$2,229,533	**$2,229,533**	$2,350,869	**$121,336**	$2,364,206	**$13,337**
LV Charges	$36,400	$38,417	**$2,018**	$16,659	**($21,758)**	$16,627	**($32)**	$28,848	**$12,221**	$28,848	**$0**
SME Charge			**$0**	$276,125	**$276,125**	$482,279	**$206,154**	$504,416	**$22,138**	$515,169	**$10,752**
Cost of Power	$153,524,605	$151,498,276	($2,026,329)	$167,693,661	$16,195,386	$183,149,271	$15,455,610	$207,164,311	$24,015,040	$207,681,446	$517,134

Cost of Power - in Working Capital Allowance - Variances Analysis

Description	2012 Approved	2012 Actual Year	Variance 2012 Actual to 2012 Approved	2013 Actual Year	Variance 2013 Actual to 2012 Actual	2014 Actual	Variance 2014 Actual to 2013 Actual	2015 Bridge Year	Variance 2015 Bridge to 2014 Actual	2016 Test Year	Variance 2016 Test to 2015 Bridge
Power Purchased	$18,598,219.76	$18,624,231.75	**$26,011.99**	$20,877,384.80	**$2,253,153.04**	$22,938,266.68	**$2,060,881.89**	$26,101,383.42	**$3,163,116.74**	$22,745,655	**-$3,355,729**
Charges -WMS	$1,334,590.75	$1,330,421.09	**($4,169.66)**	$1,361,514.23	**$31,093.14**	$1,125,806.80	**($235,707.43)**	$1,193,518.08	**$67,711.28**	$1,040,251	**-$153,267**
Chares -Network	$1,523,975.83	$1,557,018.78	**$33,042.95**	$1,645,693.36	**$88,674.58**	$1,744,174.63	**$98,481.27**	$1,937,164.21	**$192,989.58**	$1,610,311	**-$326,853**
Charges -CN	$1,232,796.72	$1,207,307.12	**($25,489.60)**	$1,225,539.19	**$18,232.07**	$1,254,876.80	**$29,337.61**	$1,409,961.01	**$155,084.21**	$1,224,303	**-$185,658**
Rural Rate Assistance Expense	$333,647.69	$0.00	**($333,647.69)**	$0.00	**$0.00**	$334,429.92	**$334,429.92**	$352,630.34	**$18,200.42**	$307,347	**-$45,284**
LV Charges	$5,459.97	$5,762.61	**$302.65**	$2,498.90	**($3,263.71)**	$2,494.03	**($4.86)**	$4,327.18	**$1,833.15**	$3,750	**-$577**
SME Charge	$0.00	$0.00	**$0.00**	$41,418.72	**$41,419**	$72,341.83	**$30,923**	$75,662.47	**$3,321**	$66,972	**-$8,691**
Cost of Power	$23,028,690.72	$22,724,741.35	**($303,949.37)**	$25,154,049.19	**$2,429,307.84**	$27,472,390.69	**$2,318,341.50**	$31,074,646.70	**$3,602,256.01**	$26,998,588	**-$4,076,059**

Consumption	2012 Approved	2012 Actual Year	Variance 2012 Actual to 2012 Approved	2013 Actual Year	Variance 2013 Actual to 2012 Actual	2014 Actual	Variance 2014 Actual to 2013 Actual	2015 Bridge Year	Variance 2015 Bridge to 2014 Actual	2016 Test Year	Variance 2016 Test to 2015 Bridge
kWh	1,676,018,424	1,700,966,689	**24,948,265**	1,710,129,645	**9,162,956**	1,731,366,637	**21,236,992**	1,770,599,158	**39,232,521**	1,780,523,469	**9,924,311**
kW	2,575,397	2,613,255	**37,858**	2,530,260	**-82,995**	2,567,537	**37,277**	2,738,192	**170,655**	2,754,592	**16,401**
Price Variance - Power $/MWh	$73.98	$72.99	-$0.98	$81.39	$8.39	$88.32	$6.94	$98.28	$9.95	$98.27	-$0.01

Variance of 2014 Actual Rate Base over the 2013 Actual Rate Base:

The 2014 actual rate base was $3,929,074 higher than the 2013 actual rate base. The main explanatory drivers of the variance were:

1. An Increase in the average Net Book Value ("NBV") of distribution assets of $1,786,485. The total variance was a result of increased average capital spending over the last two years of $10,296,568 offset by average customer contributions of $2,820,856 and an average depreciation expense of $5,659,282. The remaining variance was a result of an average net disposal value of $29,945. For more details, please see Exhibit 2, Tab 2, Schedule 2, 2.5.2.2 Required Information.
2. A $2,142,588 increase in the Working Capital Allowance due to an increase in the Cost of Power (please see Table 2-4 Cost of Power Variance Analysis).

Variance of the 2015 Bridge Year Rate Base over the 2014 Actual Rate Base:

The 2015 Bridge Year rate base is estimated to be $10,659,335 higher than the 2014 actual rate base. The main drivers explaining the variance are:

1. An increase in the average NBV of distribution assets of $6,881,718. The total variance results from higher average capital spending over 2014 and estimated for 2015 of $15,376,257 offset by average customer contributions of $2,714,612 and an average depreciation expense of $5,779,927. (For more details, please see Exhibit 2, Tab 2, Schedule 2, 2.5.2.2 Required Information), and
2. A $3,777,618 increase in the Working Capital Allowance is due to an increase in the Cost of Power (please see Table 2-4 Cost of Power Variance Analysis).

Variance of the 2016 Test Year Rate Base over the 2015 Bridge Year Rate Base:

The 2016 Test Year rate base is $3,764,700 higher than the 2015 Bridge Year rate base. The main driver that explains the variance is:

1. An increase in the average NBV of distribution assets of $8,009,463. Total variance was a result of increased average capital spending estimated for 2015 and 2016 of $16,874,763, offset by average customer contributions of $3,102,500 and an average depreciation expense of $6,144,506. The remaining variance results from an adjustment made to the opening gross cost of $600,654 and opening accumulated depreciation of $218,949 to reflect the net book value of Guelph Hydro's investment in the Zigbee chip ($381,705) as part of the initial transition to the smart meters in 2010. (For more details, please see Exhibit 2, Tab 2, Schedule 2, 2.5.2.2 Required Information).

FIXED ASSET CONTINUITY SCHEDULES

Opening and closing balances of gross assets and accumulated depreciation correspond to the fixed asset continuity statements. The net book value balances, excluding construction work in progress, are the balances included in the rate base calculation.

Guelph Hydro has completed the requirement of Appendix 2-BA in Tables 2-5 through 2-9.

Table 2-5

Appendix 2-BA

Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2012**

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 251,106	$ 240,878	-$ 160,780	$ 331,204	$ -	-$ 42,153	$ -	-$ 42,153	$ 289,051
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 4,416,883	$ -	$ -	$ 4,416,883	$ -	$ -	$ -	$ -	$ 4,416,883
47	1808	Buildings	$ 15,996,406	$ -	$ -	$ 15,996,406	-$ 741,063	-$ 553,814	$ -	-$ 1,294,877	$ 14,701,529
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,999,565	$ 1,596,026	$ -	$ 15,595,591	-$ 355,034	-$ 377,319	$ -	-$ 732,353	$ 14,863,238
47	1820	Distribution Station Equipment <50 kV	$ 1,635,880	$ 15,874	$ -	$ 1,651,754	-$ 91,205	-$ 46,132	$ -	-$ 137,337	$ 1,514,417
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 15,891,244	$ 1,188,239	$ -	$ 17,079,483	-$ 913,235	-$ 475,644	$ -	-$ 1,388,879	$ 15,690,604
47	1835	Overhead Conductors & Devices	$ 12,384,018	$ 763,811	$ -	$ 13,147,829	-$ 622,725	-$ 323,157	$ -	-$ 945,882	$ 12,201,947
47	1840	Underground Conduit	$ 28,828,682	$ 3,403,796	$ -	$ 32,232,478	-$ 1,895,391	-$ 1,022,119	$ -	-$ 2,917,510	$ 29,314,967
47	1845	Underground Conductors & Devices	$ 26,624,500	$ 2,071,993	$ -	$ 28,696,493	-$ 1,906,421	-$ 1,016,017	$ -	-$ 2,922,438	$ 25,774,055
47	1850	Line Transformers	$ 12,175,860	$ 874,211	$ -	$ 13,050,071	-$ 881,540	-$ 461,908	$ -	-$ 1,343,448	$ 11,706,623
47	1855	Services (Overhead & Underground)	$ 5,091,588	$ 487,637	$ -	$ 5,579,225	-$ 524,577	-$ 272,642	$ -	-$ 797,219	$ 4,782,006
47	1860	Meters	$ 13,929,040	$ 577,883	$ -	$ 14,506,923	-$ 1,684,279	-$ 745,600	$ -	-$ 2,429,880	$ 12,077,043
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 588,464	$ 43,060	$ -	$ 631,524	-$ 36,580	-$ 99,938	$ -	-$ 136,518	$ 495,006
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,380,469	$ 155,368	$ -	$ 1,535,837	-$ 678,809	-$ 307,477	$ -	-$ 986,286	$ 549,551
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 1,879,998	$ 468,956	-$ 21,761	$ 2,327,192	-$ 283,606	-$ 359,296	$ 8,705	-$ 634,197	$ 1,692,995
8	1935	Stores Equipment	$ 54	$ 0	$ -	$ 54	-$ 54	$ -	$ -	-$ 54	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 524,649	$ 76,475	$ -	$ 601,124	-$ 157,148	-$ 78,266	$ -	-$ 235,414	$ 365,710
8	1945	Measurement & Testing Equipment	$ 2,974	$ -	$ -	$ 2,974	-$ 2,974	$ -	$ -	-$ 2,974	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 214,353	$ -	$ -	$ 214,353	-$ 197,271	-$ 8,016	$ -	-$ 205,286	$ 9,066
47	1970	Load Management Controls Customer Premises	$ 136,371	$ -	$ -	$ 136,371	-$ 21,676	-$ 11,001	$ -	-$ 32,677	$ 103,694
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 666,966	$ 270,043	$ -	$ 937,009	-$ 227,665	-$ 120,675	$ -	-$ 348,340	$ 588,669
47	1985	Miscellaneous Fixed Assets	$ 6,157	$ -	$ -	$ 6,157	$ -	$ -	$ -	$ -	$ 6,157
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 34,049,426	-$ 2,680,601	$ -	-$ 36,730,027	$ 1,530,672	$ 942,443	$ -	$ 2,473,115	-$ 34,256,911
	2070	Other Utility Plant	$ 398	$ -	$ -	$ 398	-$ 51	-$ 51	$ -	-$ 103	$ 295
						$ -				$ -	$ -
		Sub-Total before Work in Process	**$ 122,576,198**	**$ 9,553,649**	**-$ 182,541**	**$ 131,947,307**	**-$ 9,690,632**	**-$ 5,378,783**	**$ 8,705**	**-$ 15,060,711**	**$ 116,886,596**
	2055	Work in Process - Non-Distribution assets	$ 75,202	$ 129,274	-$ 75,202	$ 129,274	$ -			$ -	$ 129,274
	2055	Work in Process - Distribution system	$ 1,616,000	$ 1,061,348	-$ 1,616,000	$ 1,061,348	$ -			$ -	$ 1,061,348
	2055	Work in Process - AFUDC	$ -	$ -	$ -	$ -	$ -			$ -	$ -
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 124,267,400**	**$ 10,744,272**	**-$ 1,873,743**	**$ 133,137,929**	**-$ 9,690,632**	**-$ 5,378,783**	**$ 8,705**	**-$ 15,060,711**	**$ 118,077,218**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,378,783**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 359,296
Stores Equipment	-$ 78,266
Net Depreciation	-$ 4,941,221

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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Table 2-6

Appendix 2-BA

Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2013**

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 331,204	$ 115,795	$ -	$ 446,999	-$ 42,153	-$ 77,820	$ -	-$ 119,973	$ 327,026
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 4,416,883	$ -	-$ 37,500	$ 4,379,383	$ -	$ -	$ -	$ -	$ 4,379,383
47	1808	Buildings	$ 15,996,406	$ 97,634	$ -	$ 16,094,040	-$ 1,294,877	-$ 689,636	$ -	-$ 1,984,513	$ 14,109,528
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 15,595,591	$ 537,200	$ -	$ 16,132,792	-$ 732,353	-$ 404,718	$ -	-$ 1,137,071	$ 14,995,721
47	1820	Distribution Station Equipment <50 kV	$ 1,651,754	$ 436	$ -	$ 1,652,190	-$ 137,337	-$ 46,802	$ -	-$ 184,139	$ 1,468,051
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 17,079,483	$ 1,511,855	$ -	$ 18,591,337	-$ 1,388,879	-$ 440,420	$ -	-$ 1,829,299	$ 16,762,039
47	1835	Overhead Conductors & Devices	$ 13,147,829	$ 735,098	$ -	$ 13,882,928	-$ 945,882	-$ 287,501	$ -	-$ 1,233,384	$ 12,649,544
47	1840	Underground Conduit	$ 32,232,478	$ 2,462,016	-$ 7,991	$ 34,686,503	-$ 2,917,510	-$ 1,063,265	$ -	-$ 3,980,776	$ 30,705,728
47	1845	Underground Conductors & Devices	$ 28,696,493	$ 927,654	$ -	$ 29,624,147	-$ 2,922,438	-$ 1,060,562	$ -	-$ 3,983,000	$ 25,641,147
47	1850	Line Transformers	$ 13,050,071	$ 809,578	$ -	$ 13,859,650	-$ 1,343,448	-$ 480,179	$ -	-$ 1,823,627	$ 12,036,023
47	1855	Services (Overhead & Underground)	$ 5,579,225	$ 736,174	$ -	$ 6,315,399	-$ 797,219	-$ 252,847	$ -	-$ 1,050,066	$ 5,265,334
47	1860	Meters	$ 14,506,923	$ 466,243	$ -	$ 14,973,165	-$ 2,429,880	-$ 850,890	$ -	-$ 3,280,770	$ 11,692,396
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 631,524	$ 50,495	$ -	$ 682,019	-$ 136,518	-$ 137,756	$ -	-$ 274,275	$ 407,744
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,535,837	$ 415,592	-$ 830	$ 1,950,599	-$ 986,286	-$ 313,976	$ 83	-$ 1,300,178	$ 650,421
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 2,327,192	$ 461,583	-$ 218,635	$ 2,570,140	-$ 634,197	-$ 329,882	$ 204,979	-$ 759,101	$ 1,811,039
8	1935	Stores Equipment	$ 54	$ -	$ -	$ 54	-$ 54	$ -	$ -	-$ 54	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 601,124	$ 79,477	$ -	$ 680,602	-$ 235,414	-$ 78,159	$ -	-$ 313,573	$ 367,029
8	1945	Measurement & Testing Equipment	$ 2,974	$ -	$ -	$ 2,974	-$ 2,974	$ -	$ -	-$ 2,974	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 214,353	$ -	$ -	$ 214,353	-$ 205,286	-$ 8,016	$ -	-$ 213,302	$ 1,050
47	1970	Load Management Controls Customer Premises	$ 136,371	$ -	$ -	$ 136,371	-$ 32,677	-$ 11,261	$ -	-$ 43,938	$ 92,434
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 937,009	$ 253,319	$ -	$ 1,190,328	-$ 348,340	-$ 239,702	$ -	-$ 588,042	$ 602,286
47	1985	Miscellaneous Fixed Assets	$ 6,157	$ -	$ -	$ 6,157	$ -	$ -	$ -	$ -	$ 6,157
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 36,730,027	-$ 3,269,487	$ -	-$ 39,999,514	$ 2,473,115	$ 1,027,857	$ -	$ 3,500,973	-$ 36,498,541
	2070	Other Utility Plant	$ 398	$ -	$ -	$ 398	-$ 103	$ -	$ -	-$ 103	$ 295
						$ -				$ -	$ -
		Sub-Total before Work in Process	**$ 131,947,307**	**$ 6,390,664**	**-$ 264,956**	**$ 138,073,015**	**-$ 15,060,711**	**-$ 5,745,533**	**$ 205,062**	**-$ 20,601,182**	**$ 117,471,833**
	2055	Work in Process - Non-Distribution assets	$ 129,274	$ -	$ -	$ 129,274	$ -			$ -	$ 129,274
	2055	Work in Process - Distribution system	$ 1,061,348	$ 2,867,303	-$ 1,061,348	$ 2,867,303	$ -			$ -	$ 2,867,303
	2055	Work in Process - AFUDC	$ -	$ 114,128	$ -	$ 114,128	$ -			$ -	$ 114,128
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 133,137,929**	**$ 9,372,095**	**-$ 1,326,304**	**$ 141,183,720**	**-$ 15,060,711**	**-$ 5,745,533**	**$ 205,062**	**-$ 20,601,182**	**$ 120,582,538**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,745,533**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 329,882
Stores Equipment	-$ 78,159
Net Depreciation	-$ 5,337,492

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.

2 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.

Table 2-7

Appendix 2-BA

Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2014**

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 446,999	$ 166,819	$ -	$ 613,818	-$ 119,973	-$ 106,082	$ -	-$ 226,055	$ 387,763
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 4,379,383	$ -	$ -	$ 4,379,383	$ -	$ -	$ -	$ -	$ 4,379,383
47	1808	Buildings	$ 16,094,040	$ 483,568	$ -	$ 16,577,608	-$ 1,984,513	-$ 700,204	$ -	-$ 2,684,716	$ 13,892,892
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 16,132,792	-$ 312,119	$ -	$ 15,820,672	-$ 1,137,071	-$ 403,630	$ -	-$ 1,540,701	$ 14,279,971
47	1820	Distribution Station Equipment <50 kV	$ 1,652,190	$ 15,874	$ -	$ 1,668,064	-$ 184,139	-$ 47,069	$ -	-$ 231,208	$ 1,436,856
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,591,337	$ 1,428,993	$ -	$ 20,020,330	-$ 1,829,299	-$ 482,021	$ -	-$ 2,311,319	$ 17,709,011
47	1835	Overhead Conductors & Devices	$ 13,882,928	$ 772,741	$ -	$ 14,655,669	-$ 1,233,384	-$ 301,132	$ -	-$ 1,534,516	$ 13,121,153
47	1840	Underground Conduit	$ 34,686,503	$ 2,269,156	$ -	$ 36,955,660	-$ 3,980,776	-$ 777,402	$ -	-$ 4,758,178	$ 32,197,482
47	1845	Underground Conductors & Devices	$ 29,624,147	$ 2,938,193	$ -	$ 32,562,340	-$ 3,983,000	-$ 1,108,798	$ -	-$ 5,091,798	$ 27,470,542
47	1850	Line Transformers	$ 13,859,650	$ 1,271,201	$ -	$ 15,130,851	-$ 1,823,627	-$ 496,016	$ -	-$ 2,319,643	$ 12,811,207
47	1855	Services (Overhead & Underground)	$ 6,315,399	$ 327,407	$ -	$ 6,642,807	-$ 1,050,066	-$ 269,861	$ -	-$ 1,319,926	$ 5,322,880
47	1860	Meters	$ 14,973,165	$ 144,003	$ -	$ 15,117,169	-$ 3,280,770	-$ 869,286	$ -	-$ 4,150,056	$ 10,967,113
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 682,019	$ 104,225	$ -	$ 786,244	-$ 274,275	-$ 144,068	$ -	-$ 418,342	$ 367,901
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,950,599	$ 475,939	$ -	$ 2,426,538	-$ 1,300,178	-$ 282,597	$ -	-$ 1,582,775	$ 843,763
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 2,570,140	$ 437,499	$ 167,720	$ 3,175,359	-$ 759,101	-$ 364,079	-$ 167,720	-$ 1,290,900	$ 1,884,460
8	1935	Stores Equipment	$ 54	$ -	$ -	$ 54	-$ 54	$ -	$ -	-$ 54	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 680,602	$ 85,754	-$ 3,418	$ 762,938	-$ 313,573	-$ 81,245	$ 3,418	-$ 391,400	$ 371,538
8	1945	Measurement & Testing Equipment	$ 2,974	$ -	$ -	$ 2,974	-$ 2,974	$ -	$ -	-$ 2,974	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 214,353	$ -	$ -	$ 214,353	-$ 213,302	-$ 1,050	$ -	-$ 214,352	$ 1
47	1970	Load Management Controls Customer Premises	$ 136,371	$ -	$ -	$ 136,371	-$ 43,938	-$ 10,796	$ -	-$ 54,734	$ 81,637
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,190,328	$ 323,733	$ -	$ 1,514,061	-$ 588,042	-$ 208,643	$ -	-$ 796,685	$ 717,376
47	1985	Miscellaneous Fixed Assets	$ 6,157	$ -	$ -	$ 6,157	$ -	-$ 6,157	$ -	-$ 6,157	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 39,999,514	-$ 2,372,224	$ -	-$ 42,371,738	$ 3,500,973	$ 1,087,158	$ -	$ 4,588,130	-$ 37,783,608
	2070	Other Utility Plant	$ 398	$ -	$ -	$ 398	-$ 103	-$ 51	$ -	-$ 154	$ 244
						$ -				$ -	$ -
		Sub-Total before Work in Process	**$ 138,073,015**	**$ 8,560,763**	**$ 164,302**	**$ 146,798,080**	**-$ 20,601,182**	**-$ 5,573,029**	**-$ 164,302**	**-$ 26,338,513**	**$ 120,459,567**
	2055	Work in Process - Non-Distribution assets	$ 129,274	$ 588,175	-$ 111,815	$ 605,634	$ -			$ -	$ 605,634
	2055	Work in Process - Distribution system	$ 2,867,303	$ 4,551,893	-$ 2,867,303	$ 4,551,893	$ -			$ -	$ 4,551,893
	2055	Work in Process - AFUDC	$ 114,128	$ 123,528	-$ 114,128	$ 123,528	$ -			$ -	$ 123,528
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 141,183,720**	**$ 13,824,358**	**-$ 2,928,944**	**$ 152,079,134**	**-$ 20,601,182**	**-$ 5,573,029**	**-$ 164,302**	**-$ 26,338,513**	**$ 125,740,622**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,573,029**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 364,079
Stores Equipment	-$ 81,245
Net Depreciation	-$ 5,127,705

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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Table 2-8

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)	$ 613,818	$ 522,302	$ -	$ 1,136,120	-$ 226,055	-$ 174,994	$ -	-$ 401,049	$ 735,071
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 4,379,383	$ -	$ -	$ 4,379,383	$ -	$ -	$ -	$ -	$ 4,379,383
47	1808	Buildings	$ 16,577,608	$ 755,000	$ -	$ 17,332,608	-$ 2,684,716	-$ 717,345	$ -	-$ 3,402,062	$ 13,930,547
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 15,820,672	$ 2,232,000	$ -	$ 18,052,672	-$ 1,540,701	-$ 431,530	$ -	-$ 1,972,231	$ 16,080,441
47	1820	Distribution Station Equipment <50 kV	$ 1,668,064	$ -	$ -	$ 1,668,064	-$ 231,208	-$ 47,330	$ -	-$ 278,538	$ 1,389,526
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,020,330	$ 2,850,291	$ -	$ 22,870,621	-$ 2,311,319	-$ 524,048	$ -	-$ 2,835,367	$ 20,035,254
47	1835	Overhead Conductors & Devices	$ 14,655,669	$ 1,385,877	$ -	$ 16,041,546	-$ 1,534,516	-$ 320,748	$ -	-$ 1,855,264	$ 14,186,282
47	1840	Underground Conduit	$ 36,955,660	$ 4,641,626	$ -	$ 41,597,286	-$ 4,758,178	-$ 845,596	$ -	-$ 5,603,773	$ 35,993,512
47	1845	Underground Conductors & Devices	$ 32,562,340	$ 1,748,902	$ -	$ 34,311,242	-$ 5,091,798	-$ 1,161,789	$ -	-$ 6,253,587	$ 28,057,655
47	1850	Line Transformers	$ 15,130,851	$ 1,526,293	$ -	$ 16,657,144	-$ 2,319,643	-$ 525,413	$ -	-$ 2,845,057	$ 13,812,087
47	1855	Services (Overhead & Underground)	$ 6,642,807	$ 1,387,904	$ -	$ 8,030,711	-$ 1,319,926	-$ 297,439	$ -	-$ 1,617,365	$ 6,413,345
47	1860	Meters	$ 15,117,169	$ 1,010,000	$ -	$ 16,127,169	-$ 4,150,056	-$ 903,549	$ -	-$ 5,053,605	$ 11,073,564
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 786,244	$ 58,000	$ -	$ 844,244	-$ 418,342	-$ 151,756	$ -	-$ 570,098	$ 274,145
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 2,426,538	$ 680,000	$ -	$ 3,106,538	-$ 1,582,775	-$ 336,411	$ -	-$ 1,919,187	$ 1,187,351
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 3,175,359	$ 739,332	$ -	$ 3,914,691	-$ 1,290,900	-$ 424,706	$ -	-$ 1,715,606	$ 2,199,086
8	1935	Stores Equipment	$ 54	$ -	$ -	$ 54	-$ 54	$ -	$ -	-$ 54	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 762,938	$ 64,000	$ -	$ 826,938	-$ 391,400	-$ 82,903	$ -	-$ 474,303	$ 352,635
8	1945	Measurement & Testing Equipment	$ 2,974	$ -	$ -	$ 2,974	-$ 2,974	$ -	$ -	-$ 2,974	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 214,353	$ -	$ -	$ 214,353	-$ 214,352	$ -	$ -	-$ 214,352	$ 1
47	1970	Load Management Controls Customer Premises	$ 136,371	$ -	$ -	$ 136,371	-$ 54,734	-$ 10,437	$ -	-$ 65,171	$ 71,200
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,514,061	$ 218,000	$ -	$ 1,732,061	-$ 796,685	-$ 196,722	$ -	-$ 993,407	$ 738,655
47	1985	Miscellaneous Fixed Assets	$ 6,157	$ -	$ -	$ 6,157	-$ 6,157	$ -	$ -	-$ 6,157	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 42,371,738	-$ 3,057,000	$ -	-$ 45,428,738	$ 4,588,130	$ 1,165,942	$ -	$ 5,754,072	-$ 39,674,666
	2070	Other Utility Plant	$ 398	$ -	$ -	$ 398	-$ 154	-$ 51	$ -	-$ 205	$ 193
						$ -				$ -	$ -
		Sub-Total before Work in Process	**$ 146,798,080**	**$ 16,762,527**	**$ -**	**$ 163,560,606**	**-$ 26,338,513**	**-$ 5,986,825**	**$ -**	**-$ 32,325,338**	**$ 131,235,268**
	2055	Work in Process - Non-Distribution assets	$ 605,634	$ -	-$ 605,634	-$ 0	$ -			$ -	-$ 0
	2055	Work in Process - Distribution system	$ 4,551,893	$ 1,200,000	-$ 4,551,893	$ 1,200,000	$ -			$ -	$ 1,200,000
	2055	Work in Process - AFUDC	$ 123,528	$ 96,959	-$ 123,528	$ 96,959	$ -			$ -	$ 96,959
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 152,079,134**	**$ 18,059,486**	**-$ 5,281,055**	**$ 164,857,565**	**-$ 26,338,513**	**-$ 5,986,825**	**$ -**	**-$ 32,325,338**	**$ 132,532,227**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,986,825**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 424,706
Stores Equipment	-$ 82,903
Net Depreciation	-$ 5,479,217

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.

2 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.

Table 2-9

Appendix 2-BA

Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2016**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,136,120	$ 93,000	$ -	$ 1,229,120	-$ 401,049	-$ 218,459	$ -	-$ 619,508	$ 609,612
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 4,379,383	$ -	$ -	$ 4,379,383	$ -	$ -	$ -	$ -	$ 4,379,383
47	1808	Buildings	$ 17,332,608	$ 804,000	$ -	$ 18,136,608	-$ 3,402,062	-$ 739,102	$ -	-$ 4,141,164	$ 13,995,445
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 18,052,672	$ 599,000	$ -	$ 18,651,672	-$ 1,972,231	-$ 466,918	$ -	-$ 2,439,149	$ 16,212,524
47	1820	Distribution Station Equipment <50 kV	$ 1,668,064	$ -	$ -	$ 1,668,064	-$ 278,538	-$ 47,330	$ -	-$ 325,868	$ 1,342,195
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,870,621	$ 2,209,145	$ -	$ 25,079,766	-$ 2,835,367	-$ 574,117	$ -	-$ 3,409,484	$ 21,670,282
47	1835	Overhead Conductors & Devices	$ 16,041,546	$ 1,074,137	$ -	$ 17,115,683	-$ 1,855,264	-$ 343,375	$ -	-$ 2,198,639	$ 14,917,044
47	1840	Underground Conduit	$ 41,597,286	$ 3,597,537	$ -	$ 45,194,823	-$ 5,603,773	-$ 927,392	$ -	-$ 6,531,165	$ 38,663,658
47	1845	Underground Conductors & Devices	$ 34,311,242	$ 1,355,503	$ -	$ 35,666,745	-$ 6,253,587	-$ 1,199,753	$ -	-$ 7,453,340	$ 28,213,405
47	1850	Line Transformers	$ 16,657,144	$ 1,182,968	$ -	$ 17,840,112	-$ 2,845,057	-$ 554,612	$ -	-$ 3,399,669	$ 14,440,443
47	1855	Services (Overhead & Underground)	$ 8,030,711	$ 1,075,710	$ -	$ 9,106,421	-$ 1,617,365	-$ 337,371	$ -	-$ 1,954,737	$ 7,151,684
47	1860	Meters (1)	$ 16,727,823	$ 415,000	$ -	$ 17,142,823	-$ 5,272,554	-$ 970,309	$ -	-$ 6,242,863	$ 10,899,960
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 844,244	$ 163,000	$ -	$ 1,007,244	-$ 570,098	-$ 57,747	$ -	-$ 627,845	$ 379,399
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,106,538	$ 497,000	$ -	$ 3,603,538	-$ 1,919,187	-$ 398,404	$ -	-$ 2,317,591	$ 1,285,947
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 3,914,691	$ 573,000	$ -	$ 4,487,691	-$ 1,715,606	-$ 464,989	$ -	-$ 2,180,594	$ 2,307,097
8	1935	Stores Equipment	$ 54	$ -	$ -	$ 54	-$ 54	$ -	$ -	-$ 54	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 826,938	$ 66,000	$ -	$ 892,938	-$ 474,303	-$ 85,452	$ -	-$ 559,755	$ 333,183
8	1945	Measurement & Testing Equipment	$ 2,974	$ -	$ -	$ 2,974	-$ 2,974	$ -	$ -	-$ 2,974	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 214,353	$ -	$ -	$ 214,353	-$ 214,352	$ -	$ -	-$ 214,352	$ 1
47	1970	Load Management Controls Customer Premises	$ 136,371	$ -	$ -	$ 136,371	-$ 65,171	-$ 10,336	$ -	-$ 75,507	$ 60,864
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 1,732,061	$ 225,000	$ -	$ 1,957,061	-$ 993,407	-$ 153,405	$ -	-$ 1,146,812	$ 810,250
47	1985	Miscellaneous Fixed Assets	$ 6,157	$ -	$ -	$ 6,157	-$ 6,157	$ -	$ -	-$ 6,157	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 45,428,738	-$ 3,148,000	$ -	-$ 48,576,738	$ 5,754,072	$ 1,246,935	$ -	$ 7,001,008	-$ 41,575,731
	2070	Other Utility Plant	$ 398	$ -	$ -	$ 398	-$ 205	-$ 51	$ -	-$ 256	$ 142
						$ -				$ -	$ -
		Sub-Total before Work in Process	**$ 164,161,260**	**$ 10,782,000**	**$ -**	**$ 174,943,260**	**-$ 32,544,287**	**-$ 6,302,186**	**$ -**	**-$ 38,846,473**	**$ 136,096,787**
	2055	Work in Process - Non-Distribution assets	-$ 0	$ -	$ -	-$ 0	$ -			$ -	-$ 0
	2055	Work in Process - Distribution system	$ 1,200,000	$ 1,200,000	-$ 1,200,000	$ 1,200,000	$ -			$ -	$ 1,200,000
	2055	Work in Process - AFUDC	$ 96,959	$ 39,577	-$ 96,959	$ 39,577	$ -			$ -	$ 39,577
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 165,458,219**	**$ 12,021,577**	**-$ 1,296,959**	**$ 176,182,837**	**-$ 32,544,287**	**-$ 6,302,186**	**$ -**	**-$ 38,846,473**	**$ 137,336,364**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 6,302,186**			

Note (1) The opening balance is the 2015 closing balance adjusted for Zigbee chip costs of $600,654

Note (1) The opening balance is the 2015 closing balance adjusted for Zigbee chip depreciation of $218,949

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 464,989
Stores Equipment	-$ 85,452
Net Depreciation	-$ 5,751,746

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.

FIXED ASSET CONTINUITY SCHEDULE VARIANCE ANALYSIS

December 31, 2012 - Fixed Asset Continuity Schedule

Gross capital assets increased by $9,553,649, net of capital contributions, and mainly resulted from Guelph Hydro's continued investment in its distribution system in the amount of $8,568,911. Based on the deemed useful lives of Guelph Hydro's assets, the total depreciation value for 2012 was calculated to be $5,378,783.

December 31, 2013 - Fixed Asset Continuity Schedule

Gross capital assets increased by $6,390,664, net of capital contributions. The increase mainly reflects Guelph Hydro's continued investment in distribution system assets in the amount of $5,170,086 for construction projects that were completed and put into service in the year. As at year end 2013, Guelph Hydro also had an increased number of projects that were not yet in use and, as a result, the balance of construction work in progress increased by $1,805,955. Based on the deemed useful lives of Guelph Hydro's assets, the total depreciation value for 2013 was calculated to be $5,745,533.

December 31, 2014 - Fixed Asset Continuity Schedule

In 2014, Gross capital assets were increased by $8,560,763, net of capital contributions, which was primarily due to Guelph Hydro's continued investment in its distribution system of $6,806,959 for construction projects that were completed and put in use during 2014. As at year-end, Guelph Hydro's construction work in progress (CWIP) balance increased to account for projects that were not placed into service. This led to a further increase in CWIP of $1,684,590 to a balance of $4,551,893. In 2014, Guelph Hydro retained Kinectrics to review its current asset base to validate the deemed useful lives of its assets for depreciation purposes for 2014 and for the 2015 Bridge Year and the 2016 Test Year. Guelph Hydro calculated a total depreciation value for 2014 to be $5,573,029.

December 31, 2015 - Fixed Asset Continuity Schedule

In 2015, Gross capital assets are forecast to increase by $16,762,527, net of capital contributions, which again mainly reflects Guelph Hydro's continued investment in its distribution system of $13,943,893 for construction projects that are expected to be completed and put into service in the year. $4,551,893 of the above-noted balance relates to expenditures made in 2014 but which expenditures remained in the company's CWIP as at December 31, 2014. As at year-end 2015, Guelph Hydro estimates an increase in the number of projects that will be placed into service, and as a result, Guelph Hydro's CWIP balance is forecast to decrease by $3,351,893. Based on the deemed useful lives of the company's assets, Guelph Hydro has calculated a total depreciation value for 2015 to be $5,986,825.

December 31, 2016 - Fixed Asset Continuity Schedule

For the 2016 Test Year, Guelph Hydro is forecasting its Gross capital assets to increase by $10,782,000, net of capital contributions. The increase relates mainly to Guelph Hydro's continued investment in its distribution system of $8,586,000 for construction projects that are expected to be completed and put into service in 2016. As at year-end 2016, Guelph Hydro is forecasting a CWIP balance that is largely unchanged from 2015. Based on the deemed useful lives of its assets, Guelph Hydro calculated a total depreciation value for 2016 to be $6,302,186.

2.5.1.2 GROSS ASSETS – PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

NBV has been used as the basis for setting opening rate base values. To establish the continuity of historical costs, the statement of opening value for regulated net book value includes gross capital cost and accumulated depreciation, and further breaks out amounts as necessary to support the regulatory accounting requirements.

Guelph Hydro has adhered to IFRS capitalization accounting requirements for financial reporting purposes and MIFRS for rate setting and regulatory reporting purposes since January 1, 2011.

Customer contributions received for PP&E

For regulatory reporting and rate setting purposes, customer contributions are treated not as deferred revenue, as required under IFRS, but instead these amounts are included as an offset to rate base, and amortized to income over the life of the facilities to which they relate. The amortization expense for customer contributions has been treated as an offset against Guelph Hydro's depreciation expense. Because IFRS requires Guelph Hydro to treat customer contributions as deferred revenue for non-regulatory reporting, these amounts are not subject to the half-year rule when amortizing them as other income. Consequently, Guelph Hydro does not use the half-year rule for regulatory reporting and rate-setting purposes when calculating the amortization of customer contributions.

Guelph Hydro confirms that the amortization period of customer contributions is adjusted on an ongoing basis to remain consistent with the useful lives of the asset category to which they relate.

Asset reclassifications from PPE to intangible assets

For 2015 and 2016 Guelph Hydro has included intangible assets (e.g., computer software and land rights) in rate base and the associated amortization expense in depreciation expense for determining revenue requirement.

Asset retirement obligations and gains/losses on disposition of assets

Guelph Hydro has not recognized any asset retirement obligations because it had no retirement obligations, therefore it has not accounted for any gains or losses on disposition of assets.

Treatment of asset impairment

Guelph Hydro has not recorded any asset impairment loss.

GROSS ASSET ANALYSIS BY FUNCTION

Land & Building

In 2014, Guelph Hydro was required to invest $483,568 to re-roof a large part of its head office building at 395 Southgate Drive due to significant leaking and to help prepare the building for a second-story addition that is planned for 2015 – 2016.

In 2015 and 2016, Guelph Hydro plans to extend the 2nd floor of 395 Southgate Drive in order to better manage the increase in FTEs that are expected as part of Guelph Hydro's growth plan. The projected costs of the expansion are $755,000 in 2015 and $804,000 in 2016.

Distribution System

The largest component of this category is Guelph Hydro's newly built transformer station, Arlen MTS. In 2013, the final stage of the project was completed and the last of the related work orders were closed. This resulted in capital additions of $537,200. In 2014, Guelph Hydro determined that $312,119 of the 2013 increase to capital additions was inappropriate, and this resulted in a decrease to this asset category to reflect the correction. In 2015, Guelph Hydro has scheduled a complete rebuild of its Distribution Station in Rockwood which is estimated to cost $2,232,000 and is planning to undertake an additional investment in the Arlen Station in 2016.

Poles and Wires, Line Transformers and Service and Meters

In order to ensure that the City of Guelph and the Village of Rockwood have a dependable and safe distribution infrastructure, Guelph Hydro continuously invests in poles and wires, line transformers and meters. For a detailed explanation relating to this capital investment program see the DSP in this Exhibit, Appendix 2-A.

IT Assets

In 2011-2012, Guelph Hydro considered replacing its current Enterprise Resource Planning (ERP) system. After lengthy discussions with its current ERP software provider, Guelph Hydro determined that it would be more prudent and cost-effective to upgrade its existing ERP system. As a result, Guelph Hydro first invested in upgrading its hardware (i.e., servers, backup system and phone system) which resulted in capital additions of $415,592 in 2013 and $475,939 in 2014. Concurrently, Guelph Hydro invested in important pieces of software to fill in specific gaps in its ERP system (a document management system at a cost of $115,795 in 2013, and an electronic time keeping system at a cost of $166,819 in 2014) and to introduce efficiencies in the company's day-to-day operations. In 2015, Guelph Hydro projects to capitalize the major ERP upgrade that has been in development for the previous 12-18 months; this will result in software-related increases to capital of $522,302. Guelph Hydro's computer

hardware infrastructure will continue to be financially supported to ensure that all information systems operate in a stable, secure and reliable manner. Guelph Hydro estimates that it will need to invest $680,000 in 2015 and $497,000 in 2016 on this initiative.

Equipment

The main two components of this category are Guelph Hydro's fleet and its tools and equipment. Guelph Hydro maintains a consistent investment in these areas to ensure that it is able to provide its operating crews with the necessary tools so that work can be carried out safely, reliably and efficiently. The company's investment in its fleet, tools and equipment over the last 3 years has been $545,431 (2012), $541,060 (2013) and $523,253 (2014). Guelph Hydro projects to continue this same investment philosophy to ensure that the quality of equipment available for its operating staff remains at a high standard. To this end, Guelph Hydro plans to spend $803,332 in 2015 and $639,000 in 2016. The 2015 investment is higher due to the planned acquisition of 2 large bucket trucks.

Other General Assets

The primary component of this asset category is SCADA equipment. Similar to its other asset categories, Guelph Hydro maintains a consistent level of investment in order to operate its business as efficiently and effectively as possible. Guelph Hydro's capitalized expenditures on SCADA equipment for the last 3 years have been $270,043 (2012), $253,319 (2013) and $323,733 (2014). Guelph Hydro projects to continue this level of spending in this asset category by investing $218,000 in SCADA in 2015 and $225,000 in 2016.

Contributions and Grants

With the City of Guelph and the Village of Rockwood growing at a steady pace, Guelph Hydro receives steady capital contributions on an annual basis relating to distribution

system expansion. Over the last 3 years Guelph Hydro received $2,680,601 (2012), 3,269,487 (2013) and 2,372,224 (2014). Guelph Hydro capital contribution projections are $3,057,000 in 2015 and $3,148,000 in 2016.

Table 2-10: Breakdown by Function

Gross Asset Summary

Gross Assets	2012 Approved	2012 Actual	2013 Actual	2014 Actual	2015 BridgeYear	2016 Test Year
Land and Buildings	22,720,488	20,413,289	20,473,423	20,956,991	21,711,991	22,515,991
Distribution System	11,692,064	17,247,345	17,784,981	17,488,736	19,720,736	20,319,736
Poles and Wires	129,043,433	91,156,283	96,784,915	104,193,999	114,820,695	123,057,017
Line Transformers	20,298,244	13,050,071	13,859,650	15,130,851	16,657,144	17,840,112
Services and Meters	22,480,935	20,086,148	21,288,564	21,759,975	24,157,879	26,249,243
IT Assets	5,163,806	1,867,041	2,397,598	3,040,356	4,242,658	4,832,658
Equipment	8,916,014	3,777,222	4,150,142	4,941,922	5,803,254	6,605,254
Other General Assets	1,409,933	1,079,936	1,333,255	1,656,988	1,874,988	2,099,988
Contributions and Grants	(40,339,111)	(36,730,027)	(39,999,514)	(42,371,738)	(45,428,738)	(48,576,738)
Total	**181,385,806**	**131,947,307**	**138,073,015**	**146,798,079**	**163,560,606**	**174,943,260**

TEST YEAR PLANT ITEM DESCRIPTIONS

Table 2-11 below provides a detailed breakdown by major plant account for each functionalized plant item. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2016 Test Year.

Table 2-11: Detailed Breakdown by Major Plant Account for Each Functionalized Plant Item

Description		2012 Approved ($)		2012 Actual ($)	Variance from 2012 Approved	2013 Actual ($)	Variance from 2012 Actual	2014 Actual ($)	Variance from 2013 Actual	2015 Bridge ($)	Variance from 2014 Actual	2016 Test ($)	Variance from 2015 Bridge
Land and Buildings													
1805-Land		2,641,987		4,416,883	1,774,896	4,379,383	(37,500)	4,379,383	0	4,379,383	0	4,379,383	0
1806-Land Rights		0		0	0	0	0	0	0	0	0	0	0
1808-Buildings and Fixtures		20,078,502		15,996,406	(4,082,096)	16,094,040	97,634	16,577,608	483,568	17,332,608	755,000	18,136,608	804,000
1905-Land		0		0	0	0	0	0	0	0	0	0	0
1906-Land Rights		0		0	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements		0		0	0	0	0	0	0	0	0	0	0
Sub-Total-Land and Buildings	**0**	**22,720,488**	**0**	**20,413,289**	**(2,307,199)**	**20,473,423**	**60,134**	**20,956,991**	**483,568**	**21,711,991**	**755,000**	**22,515,991**	**804,000**
Distribution System													
TS Primary Above 50									0		0		0
1815-Transformer Station Equipment - Normally Primary above 50 kV		9,983,177		15,595,591	5,612,414	16,132,792	537,200	15,820,672	(312,119)	18,052,672	2,232,000	18,651,672	599,000
Sub-Total-TS Primary Above 50	**0**	**9,983,177**	**0**	**15,595,591**	**5,612,414**	**16,132,792**	**537,200**	**15,820,672**	**(312,119)**	**18,052,672**	**2,232,000**	**18,651,672**	**599,000**
1820-Distribution Station Equipment-Normally Primary below 50 kV		1,708,887		1,651,754	(57,133)	1,652,190	436	1,668,064	15,874	1,668,064	0	1,668,064	0
Sub-Total-DS	**0**	**1,708,887**		**1,651,754**	**(57,133)**	**1,652,190**	**436**	**1,668,064**	**15,874**	**1,668,064**	**0**	**1,668,064**	**0**
Poles and Wires													
1830-Poles, Towers and Fixtures		25,057,333		17,079,483	(7,977,850)	18,591,337	1,511,855	20,020,330	1,428,993	22,870,621	2,850,291	25,079,766	2,209,145
1835-Overhead Conductors and Devices		20,468,828		13,147,829	(7,320,998)	13,882,928	735,098	14,655,669	772,741	16,041,546	1,385,877	17,115,683	1,074,137
1840-Underground Conduit		42,725,238		32,232,478	(10,492,760)	34,686,503	2,454,026	36,955,660	2,269,156	41,597,286	4,641,626	45,194,823	3,597,537
1845-Underground Conductors and Devices		40,792,034		28,696,493	(12,095,541)	29,624,147	927,654	32,562,340	2,938,193	34,311,242	1,748,902	35,666,745	1,355,503
Sub-Total-Poles and Wires	**0**	**129,043,433**	**0**	**91,156,283**	**(37,887,150)**	**96,784,915**	**5,628,633**	**104,193,999**	**7,409,083**	**114,820,695**	**10,626,696**	**123,057,017**	**8,236,322**
Line Transformers													
1850-Line Transformers		20,298,244		13,050,071	(7,248,173)	13,859,650	809,578	15,130,851	1,271,201	16,657,144	1,526,293	17,840,112	1,182,968
Sub-Total-Line Transformers	**0**	**20,298,244**		**13,050,071**	**(7,248,173)**	**13,859,650**	**809,578**	**15,130,851**	**1,271,201**	**16,657,144**	**1,526,293**	**17,840,112**	**1,182,968**
Services and Meters													
1855-Services		7,731,481		5,579,225	(2,152,256)	6,315,399	736,174	6,642,807	327,407	8,030,711	1,387,904	9,106,421	1,075,710
1860-Meters		14,749,454		14,506,923	(242,532)	14,973,165	466,243	15,117,168	144,003	16,127,168	1,010,000	17,142,822	1,015,654
					0		0		0		0		0
Sub-Total-Services and Meters	**0**	**22,480,935**	**0**	**20,086,148**	**(2,394,787)**	**21,288,564**	**1,202,417**	**21,759,975**	**471,410**	**24,157,879**	**2,397,904**	**26,249,243**	**2,091,364**

Description		2012 Approved ($)		2012 Actual ($)	Variance from 2012 Approved	2013 Actual ($)	Variance from 2012 Actual	2014 Actual ($)	Variance from 2013 Actual	2015 Bridge ($)	Variance from 2014 Actual		2016 Test ($)	Variance from 2015 Bridge
IT Assets														
1920-Computer Equipment - Hardware		4,049,349		1,535,837	(2,513,512)	1,950,599	414,763	2,426,538	475,939	3,106,538	680,000		3,603,538	497,000
1921-Computer Equipment					0		0		0		0			0
1611 - Intangible Assets - Computer Software				331,204	331,204	446,999	115,795	613,818	166,819	1,136,120	522,302		1,229,120	93,000
1925-Computer Software		1,114,457		0	(1,114,457)	0	0	0	0	0	0		0	0
Sub-Total-IT Assets	**0**	**5,163,806**		**1,867,041**	**(3,296,765)**	**2,397,598**	**530,558**	**3,040,356**	**642,758**	**4,242,658**	**1,202,302**		**4,832,658**	**590,000**
Equipment														
1915-Office Furniture and Equipment		1,221,843		631,524	(590,319)	682,019	50,495	786,244	104,225	844,244	58,000		1,007,244	163,000
1930-Transportation Equipment		3,816,072		2,327,192	(1,488,879)	2,570,140	242,948	3,175,359	605,219	3,914,691	739,332		4,487,691	573,000
1935-Stores Equipment		96,338		54	(96,284)	54	0	54	0	54	0		54	0
1940-Tools, Shop and Garage Equipment		1,168,006		601,124	(566,881)	680,602	79,477	762,938	82,336	826,938	64,000		892,938	66,000
Equipment		14,872		2,974	(11,898)	2,974	0	2,974	0	2,974	0		2,974	0
1950-Power Operated Equipment		0		0	0	0	0	0	0		0		0	0
1955-Communication Equipment		0		0	0	0	0	0	0	0	0		0	0
1960-Miscellaneous Equipment		2,598,884		214,353	(2,384,531)	214,353	0	214,353	0	214,353	0		214,353	0
Sub-Total-Equipment	**0**	**8,916,014**		**3,777,222**	**(5,138,793)**	**4,150,142**	**372,920**	**4,941,922**	**791,780**	**5,803,254**	**861,332**		**6,605,254**	**802,000**
Other General Assets														
1825-Storage Battery Equipment		0		0	0	0	0	0	0	0	0		0	0
1970-Load Management Controls - Customer Premises		314,982		136,371	(178,610)	136,371	0	136,371	0	136,371	0		136,371	0
1975-Load Management Controls - Utility Premises		0		0	0	0	0	0	0	0	0		0	0
1980-System Supervisory Equipment		1,088,022		937,009	(151,013)	1,190,328	253,319	1,514,061	323,733	1,732,061	218,000		1,957,061	225,000
1985-Sentinel Lighting Rentals		6,158		6,157	(1)	6,157	0	6,157	0	6,157	0		6,157	0
1995-Contributions and Grants - Credit		(40,339,111)		(36,730,027)	3,609,084	(39,999,514)	(3,269,487)	(42,371,738)	(2,372,224)	(45,428,738)	(3,057,000)		(48,576,738)	(3,148,000)
Sub-Total-Other General Assets	**0**	**(38,929,949)**		**(35,650,489)**	**3,279,460**	**(38,666,657)**	**(3,016,168)**	**(40,715,148)**	**(2,048,491)**	**(43,554,148)**	**(2,839,000)**	**0**	**(46,477,148)**	**(2,923,000)**
Other Plant														
2070-Other Utility Plant		771		398	(373)	398	0	398	0	398	0		398	0
Sub-Total-Other Distribution Assets	0	771		398	(373)	398	0	398	0	398	0		398	0
GROSS ASSET TOTAL	**0**	**181,385,806**		**131,947,307**	**(49,438,499)**	**138,073,015**	**6,125,708**	**146,798,079**	**8,725,065**	**163,560,606**	**16,762,527**		**174,943,260**	**11,382,654**

YEAR OVER YEAR VARIANCE ANALYSIS OF PLANT ITEMS

In reviewing the variance of ($49,438,499) between the 2012 Approved and 2012 Actual balances, it is evident that capital spending was significantly lower than was estimated and approved. The primary reason for this decrease is due to Guelph Hydro's election to restate the gross capital costs of its Property, Plant and Equipment to reflect its carrying costs or net book values when adopting IFRS accounting standards. As a result, effective January 1, 2010, Guelph Hydro's gross capital asset value decreased from $141,595,382 to $91,854,087. The decrease of $49,741,295 was the accumulated depreciation at that date. Under IFRS these carrying values were then used to calculate depreciation on a go-forward basis based on the appropriate estimated useful lives remaining for each asset category.

Land & Building

The variance between the 2012 Actual and the 2012 Approved balance of ($2,307,199) was primarily due to the above-noted restatement when Guelph Hydro adopted IFRS. The reduction relating to buildings and fixtures was $2,205,191. Within the asset category, various land servicing costs were included as building costs instead of land costs. As a result, the actual land balance was higher by $1,774,896 relative to the 2012 approved value to reflect the true cost of the land after all the services were completed; building costs were lower by a similar amount. The reason for the variances of ($483,568) in 2014, ($755,000) in 2015, and ($804,000) in 2016 are as outlined above relating to the reconstruction of the roof and building expansion at Guelph Hydro's primary place of business 395 Southgate Drive, Guelph.

Distribution System

The variance of $5,612,414 between the 2012 Actual and the 2012 Approved balance was primarily due to higher spending on the Arlen MTS compared to what was initially projected. It was determined that it would be more economical to build a station that has the capability for expansion in the future which was not part of the initial specifications

(For further details, please see Exhibit 1, Tab 2, Schedule 4, Additional Cost of Arlen TS).

The variances in 2013 of $537,200, 2014 of ($312,119), 2015 of $2,232,000, and 2016 of $599,000 are outlined above.

Poles and Wires, Line Transformers and Services and Meters

As noted above, a detailed analysis of these asset categories are outlined in the DSP in this Exhibit, Appendix 2-A. The total variance of ($47,530,110) between the 2012 Actual and the 2012 Approved balance resulted from the net impact of the IFRS restatement process as described above. The breakdown is as follows:

- Poles and Wires had a variance of ($37,887,150) of which ($37,199,177) resulted from the IFRS carrying value restatement.
- Line Transformers had a variance of ($7,248,173) of which ($6,328,035) resulted from the IFRS carrying value restatement.
- Service and Meters had a variance of ($2,394,787) of which ($3,392,681) resulted from the IFRS carrying value restatement.

IT Assets

There were two contributing factors to the variance of ($3,296,765) between the 2012 Actual and the 2012 Approved balance. First, ($1,410,016) of the variance resulted from the impact of the IFRS restatement described. Second, ($1,114,457) resulted from Guelph Hydro's decision not to replace its current ERP system, and commit to upgrading its current system instead to ensure that the technology met Guelph Hydro's needs on go-forward basis. For further information regarding the variances for years 2013 – 2016 see the IT Assets note above.

Equipment

The total variance of ($5,138,793) between the 2012 Actual and the 2012 Approved balance was primarily due to the IFRS restatement process as described above. The breakdown is as follows:

- Office Furniture & Equipment had a variance of ($590,319) of which ($658,628) resulted from the IFRS carrying value restatement.
- Transportation Equipment had a variance of ($1,488,879) of which ($1,403,167) resulted from the IFRS carrying value restatement.
- Tools, shop and garage equipment had a variance of ($566,881) of which ($535,192) resulted from the IFRS carrying value restatement.
- Stores equipment had a variance of ($96,284) of which ($96,284) resulted from the IFRS carrying value restatement.
- Miscellaneous equipment had a variance of ($2,384,531) of which ($2,118,596.36) resulted from the IFRS carrying value restatement.
- Measuring and testing equipment had a variance of ($11,898) of which ($11,898) resulted from the IFRS carrying value restatement.

Other General Assets

The total variance of $3,279,460 between the 2012 Actual and the 2012 Approved balance was primarily due to the IFRS restatement process as described above. The breakdown is as follows:

- Load management controls had a variance of ($178,610) of which ($178,610) resulted from the IFRS carrying value restatement.
- System supervisory equipment had a variance of ($151,013) of which ($70,392) resulted from the IFRS carrying value restatement.

- Contributions and grants had a variance of $3,609,084 of which $6,255,174 resulted from the IFRS carrying value restatement. There was also an offsetting variance that resulted from the difference in customer contributions approved in Guelph Hydro's 2012 rate filing of $8,544,464 for 2010-2012 compared to the $11,190,555 that was actually received in 2012.

INCREMENTAL CAPITAL MODULE ADJUSTMENTS

Guelph Hydro did not apply for incremental capital adjustments in the IRM period following the 2012 Cost of Service application.

ACCUMULATED DEPRECIATION

Guelph Hydro does not have a depreciation policy; the paragraph below describes Guelph Hydro's depreciation practice once assets are capitalized; the capitalization and overhead policy has been provided in Appendix 2-A of this Exhibit.

Guelph Hydro recognizes depreciation on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction-in-progress assets are not amortized until construction of a project is complete and the project placed into service.

Guelph Hydro uses the half-year rule for calculating depreciation and the typical useful lives of assets developed by Kinectrics in the March 24, 2010 *Useful Life of Assets* study as included in its 2012 COS Application (EB-2011-0123), Tab 2, Schedule 10, Appendix A, and agreed upon in the Board-approved Settlement filed on December 2, 2011 (Issue 2.4 page 23, and issue 4.3 page 33) to calculate depreciation for its fiscal years 2012 and 2013. In 2014, Guelph Hydro engaged Kinectrics to review its useful lives, as required under IFRS, which resulted in an updated report dated April 23rd, 2015; Kinectrics Inc., Report No: K-418636-RA-001-R00 (the "Kinectrics Report").

Please see the Kinectrics Report in Appendix K of the DSP. Guelph Hydro used these useful lives to calculate depreciation for the years 2014-2016.

Details of Guelph Hydro's depreciation by account number are provided in Appendix 2-CB to 2-CE Depreciation and Amortization Expense, by year, in Tables 2-12 to 2-16.

Further information on Guelph Hydro's depreciation expenses and continuity schedules are provided in Tables 4-73 to 4-77 in Exhibit 4, Tab 4, 2.7.4 Depreciation, Amortization and Depletion.

VARIANCE ANALYSIS FOR ACCUMULATED DEPRECIATION

Guelph Hydro has presented its accumulated depreciation variance analysis above the materiality threshold of $172,000 in Tables 2-12 to 2-16 (Appendix 2-CB to 2-CE Depreciation and Amortization Expense) above.

RECONCILIATION OF CONTINUITY STATEMENTS TO CALCULATED DEPRECIATION EXPENSES

As outlined in Table 2-12 (2012 Depreciation and Amortization Expense), when comparing Guelph Hydro's depreciation expense that is stated in its continuity schedule ($5,378,783) to the amount calculated in the depreciation expense schedule ($4,733,041); there was an overall variance of $645,742 for fiscal year 2012.

This variance was primarily due to depreciation being calculated on the opening capital assets owned by Guelph Hydro as of January 1st, 2012. The main contributing factor to the difference in depreciation for this block of assets arises from IFRS requiring a "componentization" of major asset class and depreciation to be recorded for each component. To comply with the IFRS requirement, Guelph Hydro began tracking and depreciating each asset account by major components to derive the net book value of these major components. This change in methodology from the transition to IFRS

resulted in the assets' new capitalized cost, over their estimated useful life. The depreciation expense schedule used a weighted average useful life for the entire asset account which leads to an average depreciation value as opposed to an exact depreciation value for the account based on individual components. The variance is greater when the asset account has a wide range of estimated useful lives for its components.

Specifically, Account 1808 Buildings and Fixtures, had a variance of $130,408. The main component contributing to this difference was the depreciation of Guelph Hydro's head office building's HVAC system. The net book value as at January 1, 2012 was $1,852,727 with a remaining estimated useful life of 11.5 years. As a result, the annual depreciation was determined to be $159,783 per annum. Guelph Hydro has also determined that the estimated weighted average useful lives of the other major components in this asset class is 36.03 years. As a result, the annual depreciation for this HVAC system using the weighted average method is $51,422; a variance of $108,312 per year.

USoA Account 1845, Underground Conductors and Devices, was the second asset account that contributed $112,451 to the above noted total variance. This variance was mainly due to a longer average useful life of the asset class as a whole prior to the switch to IFRS. With the switch to IFRS and the associated componentization of this asset class, it was determined that many of the components had significantly shorter useful lives than before, which led to these components being depreciated faster.

Table 2-12
Appendix 2-CB
Depreciation and Amortization Expense

Guelph Hydro adopted IFRS on January 1, 2011

Year 2012 MIFRS

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 251,106	$ 240,878	5.00	5.00	20.00%	$ 50,221	$ 24,088	$ 74,309	$ 42,153	$ 32,156	$ 48,176		$ 98,397
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 4,416,883	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 15,255,343	$ -	36.03	50.00	2.00%	$ 423,407	$ -	$ 423,407	$ 553,814	-$ 130,408	$ -		$ 423,407
1810	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 13,644,531	$ 1,596,026	39.89	39.31	2.54%	$ 342,054	$ 20,301	$ 362,354	$ 377,319	-$ 14,964	$ 40,601		$ 382,655
1820	Distribution Station Equipment <50 kV	$ 1,544,675	$ 15,874	35.00	40.00	2.50%	$ 44,134	$ 198	$ 44,332	$ 46,132	-$ 1,800	$ 397		$ 44,530
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 14,978,009	$ 1,188,239	39.08	50.00	2.00%	$ 383,265	$ 11,882	$ 395,148	$ 475,644	-$ 80,497	$ 23,765	$ 1,010	$ 406,020
1835	Overhead Conductors & Devices	$ 11,761,293	$ 763,811	45.33	53.00	1.89%	$ 259,459	$ 7,206	$ 266,665	$ 323,157	-$ 56,492	$ 14,412	$ 55	$ 273,815
1840	Underground Conduit	$ 26,933,291	$ 3,403,796	30.58	40.00	2.50%	$ 880,749	$ 42,547	$ 923,296	$ 1,022,119	-$ 98,823	$ 85,095	$ 527	$ 965,317
1845	Underground Conductors & Devices	$ 24,718,079	$ 2,071,993	28.22	37.96	2.63%	$ 875,906	$ 27,292	$ 903,198	$ 1,016,017	-$ 112,819	$ 54,584	$ 369	$ 930,121
1850	Line Transformers	$ 11,294,320	$ 874,211	29.00	39.82	2.51%	$ 389,459	$ 10,977	$ 400,436	$ 461,908	-$ 61,472	$ 21,954	$ 1,854	$ 409,559
1855	Services (Overhead & Underground)	$ 4,567,011	$ 487,637	22.34	30.00	3.33%	$ 204,432	$ 8,127	$ 212,559	$ 272,642	-$ 60,083	$ 16,255		$ 220,687
1860	Meters	$ 12,244,761	$ 577,883	18.57	21.15	4.73%	$ 659,384	$ 13,662	$ 673,046	$ 745,600	-$ 72,555	$ 27,323	-$ 181,088	$ 867,795
1860	Meters (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1905	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 551,884	$ 43,060	4.87	10.00	10.00%	$ 113,323	$ 2,153	$ 115,476	$ 99,938	$ 15,538	$ 4,306	$ 6,261	$ 111,368
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 701,660	$ 155,368	2.82	5.00	20.00%	$ 248,815	$ 15,537	$ 264,352	$ 307,477	-$ 43,124	$ 31,074	$ 60,164	$ 219,725
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 1,596,392	$ 468,956	6.54	9.50	10.53%	$ 244,097	$ 24,682	$ 268,779	$ 359,296	-$ 90,518	$ 49,364	$ 50,626	$ 242,835
1935	Stores Equipment	$ 0	$ 0			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 367,501	$ 76,475	6.02	10.00	10.00%	$ 61,047	$ 3,824	$ 64,870	$ 78,266	-$ 13,396	$ 7,648	$ 3,997	$ 64,697
1945	Measurement & Testing Equipment	$ 0	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ 17,082	$ -	2.18		0.00%	$ 7,836	$ -	$ 7,836	$ 8,016	-$ 180	$ -		$ 7,836
1970	Load Management Controls Customer Premises	$ 114,695	$ -	11.26		0.00%	$ 10,186	$ -	$ 10,186	$ 11,001	-$ 815	$ -	$ 533	$ 9,653
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 439,301	$ 270,043	3.19	5.00	20.00%	$ 137,712	$ 27,004	$ 164,716	$ 120,675	$ 44,041	$ 54,009		$ 191,720
1985	Miscellaneous Fixed Assets	$ 6,157	$ -	3.00		0.00%	$ 2,052	$ -	$ 2,052	$ -	$ 2,052	$ -		$ 2,052
1990	Other Tangible Property	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 32,518,754	-$ 2,680,601	40.16	39.08	2.56%	-$ 809,730	-$ 34,296	-$ 844,026	-$ 942,443	$ 98,417	-$ 68,593		-$ 878,323
2070	Other Utility Plant	$ 347	$ -	7.00		0.00%	$ 50	$ -	$ 50	$ 51	-$ 2	$ -		$ 50
	Total	**$ 112,885,566**	**$ 9,553,649**				**$ 4,527,858**	**$ 205,183**	**$ 4,733,041**	**$ 5,378,783**	**-$ 645,742**	**$ 410,367**	**-$ 55,692**	**$ 4,993,917**

Notes:

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

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

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with the Board's regulatory accounting policies. The capitalization and depreciation expense accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors ("APH").

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2012 additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1, 2012, the effective date of the changes in policies, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as of January 1, 2012. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

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

As outlined in Table 2-13 (2013 Depreciation and Amortization Expense), there was an overall variance of $589,155 for fiscal year 2013 when comparing Guelph Hydro's depreciation expense of ($5,745,533) stated in the continuity schedule to the amount calculated in the depreciation expense ($5,156,378).

Similar to the analysis above for 2012, the chart below shows this variance was primarily due to the depreciation expense on the opening capital assets owned by Guelph Hydro as of January 1st, 2012. As with the variance explanation for 2012, Guelph Hydro's detailed componentized depreciation process from the switch to IFRS versus the weighted average method used to calculate the depreciation expense schedule for Guelph Hydro's pre-2012 owned assets was the primary reason for the variance. Once again the main asset categories that contributed to the variance was USoA 1808 — Buildings and Fixtures and USoA 1845 — Underground Conductors and Devices. The variance for USoA 1808 was higher in 2013 compared to 2012 due to the HVAC system in Guelph Hydro's head office building having only 7 years of useful life remaining as opposed to the previously assumed 11.5 years. This increased the variance on this component to $190,435 compared to the $108,312 that existed in 2012.

Table 2-13

Appendix 2-CC
Depreciation and Amortization Expense
Guelph Hydro adopted IFRS on January 1, 2011

2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 115,795	5.00	20.00%	$ 109,976	$ 77,820	$ 32,156	$ 23,159		$ 121,556
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 97,634	50.00	2.00%	$ 424,383	$ 689,636	-$ 265,253	$ 1,953		$ 425,359
1810	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 537,200	40.00	2.50%	$ 389,370	$ 404,718	-$ 15,348	$ 13,430		$ 396,085
1820	Distribution Station Equipment <50 kV	$ 436	40.00	2.50%	$ 44,536	$ 46,802	-$ 2,266	$ 11		$ 44,541
1825	Storage Battery Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 1,511,855	50.00	2.00%	$ 421,139	$ 440,420	-$ 19,281	$ 30,237		$ 436,257
1835	Overhead Conductors & Devices	$ 735,098	55.12	1.81%	$ 280,484	$ 287,501	-$ 7,018	$ 13,336		$ 287,152
1840	Underground Conduit	$ 2,462,016	40.00	2.50%	$ 996,092	$ 1,063,265	-$ 67,173	$ 61,550		$ 1,026,867
1845	Underground Conductors & Devices	$ 927,654	36.73	2.72%	$ 942,749	$ 1,060,562	-$ 117,813	$ 25,256	$ 3,310	$ 952,067
1850	Line Transformers	$ 809,578	39.97	2.50%	$ 419,686	$ 480,179	-$ 60,492	$ 20,255	$ 1,543	$ 428,271
1855	Services (Overhead & Underground)	$ 736,174	31.65	3.16%	$ 232,317	$ 252,847	-$ 20,530	$ 23,260		$ 243,946
1860	Meters	$ 466,243	17.04	5.87%	$ 881,476	$ 850,890	$ 30,586	$ 27,362		$ 895,157
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 50,495	10.00	10.00%	$ 113,893	$ 137,756	-$ 23,863	$ 5,049	$ 1,425	$ 114,993
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 415,592	5.00	20.00%	$ 261,284	$ 313,976	-$ 52,692	$ 83,118	$ 120,719	$ 182,125
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 461,583	8.02	12.47%	$ 271,612	$ 329,882	-$ 58,270	$ 57,554	$ 26,530	$ 273,859
1935	Stores Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 79,477	10.00	10.00%	$ 68,671	$ 78,159	-$ 9,487	$ 7,948	$ 5,175	$ 67,470
1945	Measurement & Testing Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		0.00%	$ 7,836	$ 8,016	-$ 180	$ -	$ 6,966	$ 870
1970	Load Management Controls Customer Premises	$ -		0.00%	$ 9,653	$ 11,261	-$ 1,607	$ -	$ 464	$ 9,189
1975	Load Management Controls Utility Premises	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 253,319	15.03	6.65%	$ 200,148	$ 239,702	-$ 39,554	$ 16,854	$ 60,856	$ 147,718
1985	Miscellaneous Fixed Assets	$ -		0.00%	$ 2,052	$ -	$ 2,052	$ -		$ 2,052
1990	Other Tangible Property	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 3,269,487	38.28	2.61%	-$ 921,027	-$ 1,027,857	$ 106,830	-$ 85,410		-$ 963,732
2070	Other Utility Plant	$ -		0.00%	$ 50	$ -	$ 50	$ -		$ 50
	Total	**$ 6,390,664**			**$ 5,156,378**	**$ 5,745,533**	**-$ 589,155**	**$ 324,923**	**$ 226,988**	**$ 5,091,852**

Notes:

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

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

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

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

As outlined in Table 2-14 below (2014 Depreciation and Amortization Expense), when comparing Guelph Hydro's depreciation expense included in its Continuity Schedule ($5,573,029) to the amount calculated in the depreciation expense schedule ($5,292,257), there was an overall variance of $280,772 for fiscal year 2014.

Similar to the analysis above for the prior years, the Table below shows that this variance was primarily due to the amount of depreciation expense calculated on the opening capital assets owned by Guelph Hydro as of January 1st, 2012. As in 2012, Guelph Hydro's detailed componentized depreciation process versus the weighted average method used by the depreciation expense schedule for Guelph Hydro's pre-2012 owned assets was the primary reason for the variance. In 2014, as with the two previous years, USoA 1808 — Buildings and Fixtures and USoA 1845 — Underground Conductors and Devices were the main asset categories that contributed to the variance in this account.

As stated previously, Guelph Hydro engaged Kinectrics to review the useful lives of its distribution assets. Based on Kinectrics' review, some of the major components of asset account 1840, Underground Conduit, had a change in their useful lives. For some components, the useful lives of the assets were extended; in some cases by 10 years and in other cases 15. As a result, Guelph Hydro adjusted its annual depreciation to a lower amount than was stated previously, which led to a lower overall depreciation expense relative to the depreciation expense calculated for Guelph Hydro's pre-2012 asset base. The impact of this change in useful lives on the depreciation expense variance of USoA 1840 was a decrease of $240,753, and was the primary reason that the overall variance for all of Guelph Hydro's depreciation expense on PP&E decreased from approximately $600,000 in 2012 and 2013 to $281,000 in 2014.

Table 2-14

Appendix 2-CD
Depreciation and Amortization Expense

Guelph Hydro adopted IFRS on January 1, 2011

2014 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 166,819	5.00	20.00%	$ 138,238	$ 106,082	$ 32,156	$ 33,364		$ 154,920
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 483,568	25.41	3.94%	$ 434,875	$ 700,204	-$ 265,329	$ 19,031		$ 444,390
1810	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	-$ 312,119	40.00	2.50%	$ 392,183	$ 403,630	-$ 11,447	-$ 7,803		$ 388,282
1820	Distribution Station Equipment <50 kV	$ 15,874	30.46	3.28%	$ 44,802	$ 47,069	-$ 2,267	$ 521		$ 45,062
1825	Storage Battery Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 1,428,993	49.82	2.01%	$ 450,599	$ 482,021	-$ 31,422	$ 28,683		$ 464,940
1835	Overhead Conductors & Devices	$ 772,741	56.93	1.76%	$ 293,939	$ 301,132	-$ 7,193	$ 13,574		$ 300,725
1840	Underground Conduit	$ 2,269,156	50.30	1.99%	$ 1,049,423	$ 777,402	$ 272,021	$ 45,112		$ 1,071,980
1845	Underground Conductors & Devices	$ 2,938,193	38.40	2.60%	$ 990,324	$ 1,108,798	-$ 118,473	$ 76,515	$ 9,621	$ 1,018,961
1850	Line Transformers	$ 1,271,201	41.61	2.40%	$ 443,546	$ 496,016	-$ 52,471	$ 30,550	$ 4,766	$ 454,055
1855	Services (Overhead & Underground)	$ 327,407	34.13	2.93%	$ 248,743	$ 269,861	-$ 21,118	$ 9,593		$ 253,539
1860	Meters	$ 144,003	18.71	5.34%	$ 899,005	$ 869,286	$ 29,719	$ 7,697	$ 36,313	$ 866,541
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 104,225	10.00	10.00%	$ 120,204	$ 144,068	-$ 23,864	$ 10,422	$ 423	$ 124,993
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 475,939	5.00	20.00%	$ 229,719	$ 282,597	-$ 52,878	$ 95,188	$ 61,779	$ 215,533
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 437,499	8.02	12.47%	$ 301,134	$ 364,079	-$ 62,945	$ 54,551	$ 8,358	$ 320,052
1935	Stores Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 85,754	10.00	10.00%	$ 71,758	$ 81,245	-$ 9,488	$ 8,575	$ 5,831	$ 70,215
1945	Measurement & Testing Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		0.00%	$ 870	$ 1,050	-$ 180	$ -	$ 1,050	-$ 180
1970	Load Management Controls Customer Premises	$ -		0.00%	$ 9,189	$ 10,796	-$ 1,607	$ -	$ 359	$ 8,830
1975	Load Management Controls Utility Premises	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 323,733	9.74	10.27%	$ 164,337	$ 208,643	-$ 44,306	$ 33,238	$ 44,187	$ 136,769
1985	Miscellaneous Fixed Assets	$ -		0.00%	$ 2,052	$ 6,157	-$ 4,105	$ -	$ 6,157	-$ 4,105
1990	Other Tangible Property	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 2,372,224	40.90	2.44%	-$ 992,733	-$ 1,087,158	$ 94,425	-$ 58,001		-$ 1,021,733
2070	Other Utility Plant	$ -		0.00%	$ 50	$ 51	-$ 1	$ -		$ 50
	Total	**$ 8,560,763**			**$ 5,292,257**	**$ 5,573,029**	**-$ 280,772**	**$ 400,811**	**$ 178,843**	**$ 5,313,819**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)				$ -					
	Total Depreciation Expense				**$ 5,292,257**					

Notes:

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

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

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

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

As outlined in Table 2-15 (2015 Depreciation and Amortization Expense), when comparing Guelph Hydro's depreciation expense included in its Continuity Schedule ($5,986,825) to the amount calculated in the depreciation expense schedule ($5,688,131); there is an overall variance of $298,694 for fiscal year 2015.

Similar to the analysis above for the prior years, the chart below shows this variance is primarily due to depreciation being calculated on the opening capital assets owned by Guelph Hydro as of January 1st, 2012. As in 2012, Guelph Hydro's detailed componentized depreciation process arising from the switch to IFRS versus the weighted average method used by the depreciation expense schedule for Guelph Hydro's pre-2012 owned assets pre-IFRS is the primary reason for the variance. In 2015, as in the previous years, the main asset categories that are contributing to the variance are USoA 1808 — Buildings and Fixtures and USoA 1845 — Underground Conductors and Devices. Depreciation expense for these two accounts is higher than the depreciation expense calculated before the switch to IFRs, but the higher depreciation expense for these accounts is offset by lower depreciation expense for USoA 1840 — Underground Conduit.

Table 2-15

Appendix 2-CE
Depreciation and Amortization Expense

Guelph Hydro adopted IFRS on January 1, 2011

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2014 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2015 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 522,302	5.00	20.00%	$ 207,150	$ 174,994	$ 32,156	$ 104,460		$ 259,380
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 755,000	50.00	2.00%	$ 451,940	$ 717,345	-$ 265,405	$ 15,100		$ 459,490
1810	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 2,232,000	40.00	2.50%	$ 416,182	$ 431,530	-$ 15,348	$ 55,800		$ 444,082
1820	Distribution Station Equipment <50 kV	$ -		0.00%	$ 45,062	$ 47,330	-$ 2,268	$ -		$ 45,062
1825	Storage Battery Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 2,850,291	50.00	2.00%	$ 493,443	$ 524,048	-$ 30,605	$ 57,006	$ 525	$ 521,421
1835	Overhead Conductors & Devices	$ 1,385,877	55.12	1.81%	$ 313,297	$ 320,748	-$ 7,451	$ 25,143		$ 325,868
1840	Underground Conduit	$ 4,641,626	50.22	1.99%	$ 1,118,193	$ 845,596	$ 272,597	$ 92,426	$ 270	$ 1,164,135
1845	Underground Conductors & Devices	$ 1,748,902	36.73	2.72%	$ 1,042,769	$ 1,161,789	-$ 119,021	$ 47,615	$ 5,069	$ 1,061,508
1850	Line Transformers	$ 1,526,293	40.99	2.44%	$ 472,673	$ 525,413	-$ 52,740	$ 37,236	$ 4,064	$ 487,227
1855	Services (Overhead & Underground)	$ 1,387,904	31.65	3.16%	$ 275,467	$ 297,439	-$ 21,972	$ 43,855		$ 297,394
1860	Meters	$ 1,010,000	11.14	8.98%	$ 911,873	$ 903,549	$ 8,324	$ 90,664	$ 53,042	$ 904,163
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 58,000	10.00	10.00%	$ 127,893	$ 151,756	-$ 23,863	$ 5,800	$ 105,059	$ 25,733
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 680,000	5.00	20.00%	$ 283,533	$ 336,411	-$ 52,878	$ 136,000	$ 55,147	$ 296,386
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 739,332	8.48	11.79%	$ 363,644	$ 424,706	-$ 61,062	$ 87,185	$ 30,584	$ 376,653
1935	Stores Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 64,000	10.00	10.00%	$ 73,415	$ 82,903	-$ 9,488	$ 6,400	$ 3,951	$ 72,664
1945	Measurement & Testing Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		0.00%	-$ 180	$ -	-$ 180	$ -		-$ 180
1970	Load Management Controls Customer Premises	$ -		0.00%	$ 8,830	$ 10,437	-$ 1,607	$ -	$ 101	$ 8,729
1975	Load Management Controls Utility Premises	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 218,000	10.00	10.00%	$ 147,669	$ 196,722	-$ 49,053	$ 21,800	$ 65,467	$ 93,102
1985	Miscellaneous Fixed Assets	$ -		0.00%	-$ 4,105	$ -	-$ 4,105	$ -		-$ 4,105
1990	Other Tangible Property	$ -		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 3,057,000	39.26	2.55%	-$ 1,060,666	-$ 1,165,942	$ 105,276	-$ 77,866		-$ 1,099,598
2070	Other Utility Plant	$ -		0.00%	$ 50	$ 51	-$ 1	$ -		$ 50
	Total	**$ 16,762,527**			**$ 5,688,131**	**$ 5,986,825**	**-$ 298,694**	**$ 748,625**	**$ 323,280**	**$ 5,739,164**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)									
	Total Depreciation expense to be included in the test year revenue requirement				**$ 5,688,131**					

Notes:

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

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

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

As outlined in Table 2-16 (Depreciation and Amortization Expense), when comparing Guelph Hydro's depreciation expense included in its Continuity Schedule ($6,302,186) to the amount calculated in the depreciation expense schedule ($5,960,636); there is an overall variance of $341,550 for fiscal year 2016.

Similar to the analysis above for the prior years, the chart below shows this variance is primarily due to depreciation being calculated on the opening capital assets owned by Guelph Hydro as of January 1st, 2012. As in 2012, Guelph Hydro's detailed componentized depreciation process arising from the switch to IFRS versus the weighted average method used by the depreciation expense schedule for Guelph Hydro's pre-2012 owned assets pre-IFRS is the primary reason for the variance. In 2016, as in previous years, the main asset categories that are contributing to the variance are USoA 1808 — Buildings and Fixtures and USoA 1845 — Underground Conductors and Devices. Higher depreciation expense for these two accounts is offset by lower depreciation expense for USoA 1840 — Underground Conduit.

Table 2-16

Appendix 2-CE
Depreciation and Amortization Expense

Guelph Hydro adopted IFRS on January 1, 2011

2016 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2016 Depreciation Expense [1] (h)=2015 Full Year Depreciation + ((d)*0.5)/(f)	2016 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 93,000	5.00	20.00%	**$ 268,680**	$ 218,459	**$ 50,221**
1612	Land Rights (Formally known as Account 1906)			0.00%	**$ -**		**$ -**
1805	Land	$ -		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 804,000	32.28	3.10%	**$ 471,944**	$ 739,102	**-$ 267,158**
1810	Leasehold Improvements	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 599,000	40.00	2.50%	**$ 451,569**	$ 466,918	**-$ 15,348**
1820	Distribution Station Equipment <50 kV	$ -		0.00%	**$ 45,062**	$ 47,330	**-$ 2,268**
1825	Storage Battery Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 2,209,145	50.00	2.00%	**$ 543,513**	$ 574,117	**-$ 30,605**
1835	Overhead Conductors & Devices	$ 1,074,137	55.12	1.81%	**$ 335,612**	$ 343,375	**-$ 7,764**
1840	Underground Conduit	$ 3,597,537	50.22	1.99%	**$ 1,199,953**	$ 927,392	**$ 272,561**
1845	Underground Conductors & Devices	$ 1,355,503	36.73	2.72%	**$ 1,079,960**	$ 1,199,753	**-$ 119,793**
1850	Line Transformers	$ 1,182,968	40.99	2.44%	**$ 501,657**	$ 554,612	**-$ 52,955**
1855	Services (Overhead & Underground)	$ 1,075,710	31.65	3.16%	**$ 314,389**	$ 337,371	**-$ 22,982**
1860	Meters	$ 415,000	16.16	6.19%	**$ 917,003**	$ 970,309	**-$ 53,306**
1860	Meters (Smart Meters)			0.00%	**$ -**		**$ -**
1905	Land	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -		0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 163,000	10.00	10.00%	**$ 33,883**	$ 57,747	**-$ 23,863**
1915	Office Furniture & Equipment (5 years)			0.00%	**$ -**		**$ -**
1920	Computer Equipment - Hardware	$ 497,000	5.00	20.00%	**$ 346,086**	$ 398,404	**-$ 52,318**
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	**$ -**		**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	**$ -**		**$ -**
1930	Transportation Equipment	$ 573,000	9.69	10.32%	**$ 406,206**	$ 464,989	**-$ 58,783**
1935	Stores Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 66,000	10.00	10.00%	**$ 75,964**	$ 85,452	**-$ 9,488**
1945	Measurement & Testing Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)			0.00%	**$ -**		**$ -**
1960	Miscellaneous Equipment	$ -		0.00%	**-$ 180**	$ -	**-$ 180**
1970	Load Management Controls Customer Premises	$ -		0.00%	**$ 8,729**	$ 10,336	**-$ 1,607**
1975	Load Management Controls Utility Premises	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 225,000	10.00	10.00%	**$ 104,352**	$ 153,405	**-$ 49,053**
1985	Miscellaneous Fixed Assets	$ -		0.00%	**-$ 4,105**	$ -	**-$ 4,105**
1990	Other Tangible Property	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,148,000	39.26	2.55%	**-$ 1,139,690**	-$ 1,246,935	**$ 107,245**
2070	Other Utility Plant	$ -		0.00%	**$ 50**	$ 51	**-$ 1**
	Total	**$ 10,782,000**			**$ 5,960,636**	**$ 6,302,186**	**-$ 341,550**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				**$ 5,960,636**		

Notes:

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

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

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

2.5.1.3 ALLOWANCE FOR WORKING CAPITAL

As outlined in the Filing Requirements, in its letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters respecting the options established in the June 22, 2011 Cost of Service Filing Requirements for the calculation of the allowance for working capital for the 2013 rate year. The Board noted that distributors could take one of the two approaches for the calculation of their allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study.

Guelph Hydro has taken the 13% allowance approach for the 2016 Test Year in this Application, in accordance with the Filing Requirements. Based on this approach, Guelph Hydro's working capital allowance is forecast to be $29,103,222 for 2016. A summary of Working Capital is presented in Table 2-17 below:

Table 2-17
Summary of Working Capital

Description	2012 Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Cost of Power	153,524,605	151,498,276	167,693,661	183,149,271	207,164,311	207,681,446
Operations	4,003,069	3,818,692	4,091,889	4,608,958	4,889,213	5,439,342
Maintenance	1,850,075	1,522,912	2,042,953	1,453,878	1,733,255	1,891,630
Billing & Collecting	2,684,296	2,792,596	2,623,970	2,189,614	1,671,102	2,094,042
Community Relations	271,158	31,494	55,086	111,711	105,928	94,998
Administration & General Expense	5,413,903	5,039,759	6,273,693	5,740,105	6,933,569	6,884,849
Property Taxes	0	492,351	478,647	327,567	330,126	335,074
Less: Adjustment for fully allocated depreciation		437,562	408,041	445,324	507,608	550,440
Working Capital	167,747,105	164,758,517	182,851,859	197,135,779	222,319,897	223,870,940

Guelph Hydro has provided its calculations by account for each of 2012 Actual, 2013 Actual, 2014 Actual, the 2015 Bridge Year and the 2016 Test Year in Table 2-18 on the following pages.

Guelph Hydro has provided a spreadsheet setting out Guelph Hydro's Cost of Power calculations in Tables 2-19 and 2-20.

Table 2-18

Working Capital Calculation by Account

Working Capital Allowance by Account

Expense Description	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Actual	Allowance for Working Capital	2015 Bridge	Allowance for Working Capital	2016 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		13%
Operation										
5005-Operation Supervision and Engineering	2,820,397	423,060	1,930,250	289,538	2,185,551	327,833	2,515,563	377,334	2,882,698	374,751
5010-Load Dispatching	75,953	11,393	83,192	12,479	182,687	27,403	117,450	17,618	126,450	16,439
5012-Station Buildings and Fixtures Expense	20,787	3,118	20,992	3,149	23,150	3,473	23,256	3,488	24,650	3,204
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	19,416	2,912	27,125	4,069	59,353	8,903	45,500	6,825	63,000	8,190
5020-Overhead Distribution Lines and Feeders - Operation Labour	20,119	3,018	19,369	2,905	9,702	1,455	22,500	3,375	23,000	2,990
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	15,088	2,263	61,663	9,249	58,223	8,733	59,742	8,961	72,447	9,418
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	0	0	0	0	0	0	0	0	0	0
5040-Underground Distribution Lines and Feeders - Operation Labour	250,066	37,510	243,639	36,546	282,212	42,332	257,000	38,550	257,000	33,410
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	11,313	1,697	6,335	950	5,790	869	7,510	1,127	7,520	978
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	0	0	0	0	0	0	0	0	0	0
5065-Meter Expense	-190,533	(28,580)	182,940	27,441	295,964	44,395	250,000	37,500	255,000	33,150
5070-Customer Premises - Operation Labour	0	0	0	0	0	0	0	0	0	0
5075-Customer Premises - Materials and Expenses	0	0	0	0	0	0	0	0	0	0
5085-Miscellaneous Distribution Expense	766,684	115,003	1,514,782	227,217	1,504,638	225,696	1,581,192	237,179	1,718,077	223,350
5095-Overhead Distribution Lines and Feeders - Rental Paid	9,402	1,410	1,602	240	1,688	253	9,500	1,425	9,500	1,235
Sub-Total	**3,818,692**	**572,804**	**4,091,889**	**613,783**	**4,608,958**	**691,344**	**4,889,213**	**733,382**	**5,439,342**	**707,114**

Working Capital Calculation by Account: Table 2-18 Continued

Expense Description	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge	Allowance for Working Capital	2015 Test	Allowance for Working Capital	2016 Test	Allowance for Working Capital
Maintenance										
5105-Maintenance Supervision and Engineering	0	0	0	0	0	0	0	0	0	0
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	1,199	180	51,475	7,721	4,284	643	3,000	450	5,000	650
5120-Maintenance of Poles, Towers and Fixtures	45,401	6,810	52,814	7,922	74,056	11,108	50,000	7,500	52,000	6,760
5125-Maintenance of Overhead Conductors and Devices	335,832	50,375	618,945	92,842	221,387	33,208	375,000	56,250	465,000	60,450
5130-Maintenance of Overhead Services	267,564	40,135	326,335	48,950	280,877	42,132	300,000	45,000	325,000	42,250
5135-Overhead Distribution Lines and Feeders - Right of Way	211,348	31,702	149,360	22,404	205,298	30,795	212,500	31,875	226,870	29,493
5145-Maintenance of Underground Conduit	143,283	21,493	247,841	37,176	144,038	21,606	215,000	32,250	225,000	29,250
5150-Maintenance of Underground Conductors and Devices	167,563	25,134	243,356	36,503	158,213	23,732	126,255	18,938	126,260	16,414
5155-Maintenance of Underground Services	150,483	22,572	165,035	24,755	301,615	45,242	170,000	25,500	170,000	22,100
5160-Maintenance of Line Transformers	199,218	29,883	187,366	28,105	61,854	9,278	274,500	41,175	289,500	37,635
5175-Maintenance of Meters	1,021	153	427	64	2,258	339	7,000	1,050	7,000	910
Sub-Total	**1,522,912**	**228,437**	**2,042,953**	**306,443**	**1,453,878**	**218,082**	**1,733,255**	**259,988**	**1,891,630**	**245,912**

Working Capital Calculation by Account: Table 2-18 Continued

Expense Description	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge	Allowance for Working Capital	2015 Bridge	Allowance for Working Capital	2016 Test	Allowance for Working Capital
Billing and Collections										
5305-Supervision	745,807	111,871	523,139	78,471	593,713	89,057	13,639	2,046	18,179	2,363
5310-Meter Reading Expense	336,788	50,518	355,323	53,298	142,302	21,345	230,426	34,564	237,198	30,836
5315-Customer Billing	1,578,185	236,728	1,461,160	219,174	1,264,515	189,677	931,946	139,792	1,272,585	165,436
5320-Collecting	0	0	0	0	0	0	286,283	42,942	357,160	46,431
5325-Collecting- Cash Over and Short	3,158	474	3,805	571	1,635	245	3,808	571	3,919	510
5330-Collection Charges	67,136	10,070	52,487	7,873	50,633	7,595	55,000	8,250	55,000	7,150
5335-Bad Debt Expense	60,709	9,106	226,402	33,960	134,933	20,240	150,000	22,500	150,000	19,500
5340-Miscellaneous Customer Accounts Expenses	812	122	1,653	248	1,883	282	0	0	0	0
Sub-Total	**2,792,596**	**418,889**	**2,623,970**	**393,595**	**2,189,614**	**328,442**	**1,671,102**	**250,665**	**2,094,042**	**272,225**
Community Relations										
5405-Supervision	0	0	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	4,924	739	3,610	542	7,217	1,083	0	0	10,000	1,300
5415-Energy Conservation	3,482	522	5,142	771	72,315	10,847	50,928	7,639	44,998	5,850
5420-Community Safety Program	0	0	0	0	0	0	0	0	0	0
5425- Miscelaneous Customer Service and Informational Expenses	23,088	3,463	24,403	3,660	30,404	4,561	55,000	8,250	40,000	5,200
5515-Advertising Expense	0	0	21,930	3,290	1,775	266	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0	0
Sub-Total	**31,494**	**4,724**	**55,086**	**8,263**	**111,711**	**16,757**	**105,928**	**15,889**	**94,998**	**12,350**

Working Capital Calculation by Account: Table 2-18 Continued

Expense Description	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Actual	Allowance for Working Capital	2015 Bridge	Allowance for Working Capital	2016 Test	Allowance for Working Capital
Administrative and General Expenses										
5605-Executive Salaries and Expenses	142,242	21,336	163,404	24,511	132,933	19,940	206,564	30,985	209,445	27,228
5610-Management Salaries and Expenses	2,344,071	351,611	2,417,919	362,688	2,577,949	386,692	2,816,515	422,477	2,868,043	372,846
5615-General Administrative Salaries and Expenses	199,801	29,970	231,833	34,775	207,550	31,133	185,815	27,872	190,562	24,773
5620-Office Supplies and Expenses	540,065	81,010	351,937	52,791	380,635	57,095	323,150	48,473	329,980	42,897
5625-Administrative Expense Transferred Credit	(808,272)	(121,241)	330,307	49,546	(667,418)	(100,113)	(684,458)	(102,669)	(679,452)	(88,329)
5630-Outside Services Employed	368,868	55,330	244,519	36,678	244,009	36,601	442,500	66,375	259,900	33,787
5635-Property Insurance	132,766	19,915	129,822	19,473	51,197	7,679	164,700	24,705	167,900	21,827
5640-Injuries and Damages	82,099	12,315	99,375	14,906	106,627	15,994	0	0	0	0
5645-Employee Pensions and Benefits	888,615	133,292	655,968	98,395	792,950	118,942	1,611,412	241,712	1,670,304	217,139
5647-Employees Sick Leave	69,048	10,357	50,680	7,602	60,164	9,025	63,808	9,571	60,539	7,870
5655-Regulatory Expenses	171,040	25,656	156,173	23,426	151,817	22,773	245,100	36,765	218,900	28,457
5660-General Advertising Expenses	71,865	10,780	69,399	10,410	33,120	4,968	84,000	12,600	85,000	11,050
5665-Miscellaneous General Expenses	233,219	34,983	828,047	124,207	828,245	124,237	808,848	121,327	809,149	105,189
5670-Rent	0	0	0	0	0	0	0	0	0	0
5675-Maintenance of General Plant	573,332	86,000	513,310	76,997	761,484	114,223	633,615	95,042	653,580	84,965
5680-Electrical Safety Authority Fees	0	0	0	0	0	0	0	0	0	0
5695-OM&A Contra Account	0	0	0	0	0	0	0	0	0	0
6205 - LEAP	31,000	4,650	31,000	4,650	78,843	11,827	32,000	4,800	41,000	5,330
Sub-Total	**5,039,759**	**755,964**	**6,273,693**	**941,054**	**5,740,105**	**861,016**	**6,933,569**	**1,040,035**	**6,884,849**	**895,030**

Working Capital Calculation by Account: Table 2-18 Continued

Expense Description	2012 Actual	Allowance for Working Capital	2013 Actual	Allowance for Working Capital	2014 Bridge	Allowance for Working Capital	2015 Bridge	Allowance for Working Capital	2016 Test	Allowance for Working Capital
Taxes Other Than Income Taxes										
6105-Property Taxes	54,789	8,218	70,607	10,591	-117,758	(17,664)	-177,482	(26,622)	-215,366	(27,998)
Sub-Total	**54,789**	**8,218**	**70,607**	**10,591**	**(117,758)**	**(17,664)**	**(177,482)**	**(26,622)**	**(215,366)**	**(27,998)**
Cost of Power										
4705 - Power Purchased	64,679,722	9,701,958	72,076,652	10,811,498	89,516,871	13,427,531	77,617,609	11,642,641	77,938,038	10,131,945
4707- Charges - Global Adjustment	59,481,823	8,922,273	67,105,913	10,065,887	63,404,907	9,510,736	96,391,614	14,458,742	97,028,537	12,613,710
4708-Charges-WMS	8,869,474	1,330,421	9,076,762	1,361,514	7,505,379	1,125,807	7,956,787	1,193,518	8,001,928	1,040,251
4710-Cost of Power Adjustments	0	0	0	0	0	0	0	0	0	0
4712-Charges-One-Time	0	0	0	0	0	0	0	0	0	0
4714-Charges-NW	10,380,125	1,557,019	10,971,289	1,645,693	11,627,831	1,744,175	12,914,428	1,937,164	12,387,008	1,610,311
4716-Charges-CN	8,048,714	1,207,307	8,170,261	1,225,539	8,365,845	1,254,877	9,399,740	1,409,961	9,417,712	1,224,303
4730-Rural Rate Assistance	0	0	0	0	2,229,533	334,430	2,350,869	352,630	2,364,206	307,347
4750-LV Charges	38,417	5,763	16,659	2,499	16,627	2,494	28,848	4,327	28,848	3,750
4751- Charges - Smart Metering Entity Charge	0	0	276,125	41,419	482,279	72,342	504,416	75,662	515,169	66,972
Sub-Total	**151,498,276**	**22,724,741**	**167,693,661**	**25,154,049**	**183,149,271**	**27,472,391**	**207,164,311**	**31,074,647**	**207,681,446**	**26,998,588**
TOTAL WORKING CAPITAL ALLOWANCE	**164,758,517**	**24,713,778**	**182,851,859**	**27,427,779**	**197,135,779**	**29,570,367**	**222,319,897**	**33,347,985**	**223,870,940**	**29,103,222**

COST OF POWER CALCULATION

Cost of Power projections were calculated based upon the 2015 and 2016 load forecast and the proposed loss factor of 1.0260.

Electricity costs were calculated using the Regulated Price Plan ("RPP") commodity price for RPP customers (as indicated in the RPP Price Report November 1, 2014 to October 31, 2015 as issued by the OEB on October 16, 2014) and the Wholesale Electricity Market Price for non-RPP customers (as indicated in the Ontario Wholesale Electricity Market Price Forecast presented to the OEB by Navigant Consulting on October 8, 2014).

The RPP and non-RPP forecast consumption was calculated based on the actual 2014 data reported in RRR in February 2015.

The 2015 rates for the Retail Transmission Network charge and Retail Transmission Connection charge, Wholesale Market Service rate and Debt Retirement Charge are all set out as approved in Guelph Hydro's 2015 IRM rate application (EB-2014-0077). The 2016 rates for the Retail Transmission Network charge and Retail Transmission Connection charge, Wholesale Market Service rate, Debt Retirement Charge and SSS Administration fee are based on the proposed rates for the 2016 Test Year.

Low Voltage Charges

Guelph Hydro is an embedded distributor to Hydro One Networks Inc. ("Hydro One") and as such incurs costs for low voltage ("LV") services. The LV costs for 2015 and 2016 are projected to be $28,848. The 2016 Low Voltage forecast is based on actual volumes for the period January 2012 to December 2014 and the most recently approved Hydro One rates effective January 1, 2015.

Table 2-19

2015 COST OF POWER FORECAST CALCULATION:

Electricity - Commodity			**Bridge Year**				**%**		**RPP and Non-RPP Cost of Power**	
Class per Load Forecast	**2015 Forecasted Metered kWhs**	**2015 Loss Factor**	**Forecasted kWhs adjusted by DLF**	**RPP Prices**	**HOEP**	**Global Adjustment**	**RPP**	**Non-RPP**	**RPP $**	**Non-RPP $**
Residential	379,756,990	1.0260	389,628,987	$0.09496	$0.02064	$0.07488	93.95%	6.05%	$34,762,257	$2,250,103
GS<50kW	149,811,070	1.0260	153,705,493	$0.09496	$0.02064	$0.07488	83.45%	16.55%	$12,180,315	$2,429,803
GS 50kW to 999kW	401,416,721	1.0260	411,851,774	$0.09496	$0.02064	$0.07488	8.05%	91.95%	$3,149,120	$36,172,390
GS 1000kW to 4999kW	545,824,692	1.0260	560,013,712	$0.09496	$0.02064	$0.07488	0.00%	100.00%	$0	$53,492,510
Large Use	282,116,008	1.0260	289,449,773	$0.09496	$0.02064	$0.07488	0.00%	100.00%	$0	$27,648,242
Unmetered Scattered Load	1,788,381	1.0260	1,834,871	$0.09496	$0.02064	$0.07488	0.00%	0.67%	$0	$1,179
Sentinel Lighting	21,782	1.0260	22,348	$0.09496	$0.02064	$0.07488	89.95%	10.05%	$1,909	$215
Street Lighting	9,863,513	1.0260	10,119,921	$0.09496	$0.02064	$0.07488	99.33%	100.00%	$954,525	$966,655
TOTAL	**1,770,599,158**		**1,816,626,878**						$51,048,126	$122,961,097

Transmission - Network		**Volume**	**2015**			
Class per Load Forecast		**Metric**	**Bridge Year**			
Residential		kWh	389,628,987	$0.0078	$3,033,374	
GS<50kW		kWh	153,705,493	$0.0071	$1,096,921	
GS 50kW to 999kW		kW	1,047,058	$3.0882	$3,233,523	*include WMP forecast
GS 1000kW to 4999kW		kW	1,157,642	$3.0882	$3,575,030	
Large Use		kW	506,086	$3.7293	$1,887,345	
Unmetered Scattered Load		kWh	1,834,871	$0.0071	$13,095	
Sentinel Lighting		kW	61	$2.2795	$139	
Street Lighting		kW	27,346	$2.7427	$75,001	
TOTAL					**$12,914,428**	

Transmission - Connection		**Volume**	**2015**			
Class per Load Forecast		**Metric**	**Bridge Year**			
Residential		kWh	389,628,987	$0.0058	$2,260,803	
GS<50kW		kWh	153,705,493	$0.0051	$790,902	
GS 50kW to 999kW		kW	1,047,058	$2.2318	$2,336,823	*include WMP forecast
GS 1000kW to 4999kW		kW	1,157,642	$2.2318	$2,583,625	
Large Use		kW	506,086	$2.6949	$1,363,850	
Unmetered Scattered Load		kWh	1,834,871	$0.0051	$9,441	
Sentinel Lighting		kW	61	$1.6471	$101	
Street Lighting		kW	27,346	$1.9818	$54,194	
TOTAL					**$9,399,740**	

Wholesale Market Service			**2015**			
Class per Load Forecast			**Bridge Year**			
Residential		kWh	389,628,987	$0.0044	$1,714,368	
GS<50kW		kWh	153,705,493	$0.0044	$676,304	
GS 50kW to 999kW		kWh	403,585,620	$0.0044	$1,775,777	
GS 1000kW to 4999kW		kWh	560,013,712	$0.0044	$2,464,060	*Excludes WMP forecast
Large Use		kWh	289,449,773	$0.0044	$1,273,579	
Unmetered Scattered Load		kWh	1,834,871	$0.0044	$8,073	
Sentinel Lighting		kWh	22,348	$0.0044	$98	
Street Lighting		kWh	10,119,921	$0.0044	$44,528	
TOTAL			**1,808,360,724**		**$7,956,787**	

Rural Rate Assistance			**2015**			
Class per Load Forecast			**Bridge Year**			
Residential		kWh	389,628,987	$0.0013	$506,518	
GS<50kW		kWh	153,705,493	$0.0013	$199,817	
GS 50kW to 999kW		kWh	403,585,620	$0.0013	$524,661	*Excludes WMP forecast
GS 1000kW to 4999kW		kWh	560,013,712	$0.0013	$728,018	
Large Use		kWh	289,449,773	$0.0013	$376,285	
Unmetered Scattered Load		kWh	1,834,871	$0.0013	$2,385	
Sentinel Lighting		kWh	22,348	$0.0013	$29	
Street Lighting		kWh	10,119,921	$0.0013	$13,156	
TOTAL			**1,808,360,724**		**$2,350,869**	

2015	**Bridge Year**
4705-Power Purchased	$174,009,223
4708-Charges-WMS	$7,956,787
4714-Charges-NW	$12,914,428
4716-Charges-CN	$9,399,740
4730-Rural Rate Assistance	$2,350,869
4750-Low Voltage	$28,848
4751 - SME	504,416
TOTAL	**207,164,311**

Table 2-20

2016 COST OF POWER FORECAST CALCULATION:

Electricity - Commodity		2016	Test year				%		RPP and Non-RPP Cost of Power		
Class per Load Forecast	**2016 Forecasted Metered kWhs**	**Proposed Loss Factor**	**Kwhs adjusted by DLF**	**RPP Prices**	**HOEP**	**Global Adjustment**	**RPP**	**Non-RPP**	**RPP $**	**Non-RPP $**	**Total Cost Of Power**
Residential	381,586,775	1.0260	391,506,338	0.09496	0.02064	$0.07488	93.95%	6.05%	$34,929,752	$2,260,945	$37,190,697
GS<50kW	150,174,015	1.0260	154,077,873	0.09496	0.02064	$0.07488	83.45%	16.55%	$12,209,824	$2,435,690	$14,645,514
GS 50kW to 999kW	397,678,750	1.0260	408,016,633	0.09496	0.02064	$0.07488	8.05%	91.95%	$3,119,796	$35,835,555	$38,955,351
GS 1000kW to 4999kW	563,100,354	1.0260	577,738,464	0.09496	0.02064	$0.07488	0.00%	100.00%	$0	$55,185,578	$55,185,578
Large Use	276,633,108	1.0260	283,824,341	0.09496	0.02064	$0.07488	0.00%	100.00%	$0	$27,110,901	$27,110,901
Unmetered Scattered Load	1,700,939	1.0260	1,745,156	0.09496	0.02064	$0.07488	0.00%	0.67%	$0	$1,121	$1,121
Sentinel Lighting	21,457	1.0260	22,015	0.09496	0.02064	$0.07488	89.95%	10.05%	$1,880	$211	$2,092
Street Lighting	9,628,070	1.0260	9,878,357	0.09496	0.02064	$0.07488	99.33%	100.00%	$931,740	$943,581	$1,875,321
TOTAL	**1,780,523,469**		**1,826,809,177**						$51,192,993	$123,773,582	**$174,966,575**

Transmission - Network		Volume	2016		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	391,506,338	$0.0074	$2,909,721
GS<50kW		kWh	154,077,873	$0.0068	$1,049,698
GS 50kW to 999kW		kW	1,037,307	$2.9481	$3,058,094
GS 1000kW to 4999kW		kW	1,194,282	$2.9481	$3,520,872
Large Use		kW	496,250	$3.5601	$1,766,712
Unmetered Scattered Load		kWh	1,745,156	$0.0068	$11,889
Sentinel Lighting		kW	60	$2.1761	$131
Street Lighting		kW	26,693	$2.6183	$69,889
TOTAL					**$12,387,008**

Transmission - Connection		Volume	2016		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	391,506,338	$0.0058	$2,265,301
GS<50kW		kWh	154,077,873	$0.0051	$790,587
GS 50kW to 999kW		kW	1,037,307	$2.2255	$2,308,546
GS 1000kW to 4999kW		kW	1,194,282	$2.2255	$2,657,895
Large Use		kW	496,250	$2.6873	$1,333,579
Unmetered Scattered Load		kWh	1,745,156	$0.0051	$8,955
Sentinel Lighting		kW	60	$1.6425	$99
Street Lighting		kW	26,693	$1.9762	$52,751
TOTAL					**$9,417,712**

Wholesale Market Service			2016			
Class per Load Forecast			**Test Year**			
Residential		kWh	391,506,338	$0.0044	$1,722,628	
GS<50kW		kWh	154,077,873	$0.0044	$677,943	
GS 50kW to 999kW		kWh	399,827,453	$0.0044	$1,759,241	*Excludes WMP forecast
GS 1000kW to 4999kW		kWh	577,738,464	$0.0044	$2,542,049	
Large Use		kWh	283,824,341	$0.0044	$1,248,827	
Unmetered Scattered Load		kWh	1,745,156	$0.0044	$7,679	
Sentinel Lighting		kWh	22,015	$0.0044	$97	
Street Lighting		kWh	9,878,357	$0.0044	$43,465	
TOTAL			**1,818,619,997**		**$8,001,928**	

Rural Rate Assistance			2016			
Class per Load Forecast			**Test Year**			
Residential		kWh	391,506,338	$0.0013	$508,958	
GS<50kW		kWh	154,077,873	$0.0013	$200,301	
GS 50kW to 999kW		kWh	399,827,453	$0.0013	$519,776	*Excludes WMP forecast
GS 1000kW to 4999kW		kWh	577,738,464	$0.0013	$751,060	
Large Use		kWh	283,824,341	$0.0013	$368,972	
Unmetered Scattered Load		kWh	1,745,156	$0.0013	$2,269	
Sentinel Lighting		kWh	22,015	$0.0013	$29	
Street Lighting		kWh	9,878,357	$0.0013	$12,842	
TOTAL			**1,818,619,997**		**$2,364,206**	

2016	**Test Year**
4705-Power Purchased	$174,966,575
4708-Charges-WMS	$8,001,928
4714-Charges-NW	$12,387,008
4716-Charges-CN	$9,417,712
4730-Rural Rate Assistance	$2,364,206
4750-Low Voltage	$28,848
4751 - SME	515,169
TOTAL	**207,681,446**

2.5.1.4 TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

The OEB approved Guelph Hydro's recovery of costs associated with stranded meters in its 2012 Cost of Service proceedings (EB-2011-0123). Accordingly, Guelph Hydro is not seeking recovery of stranded meter costs in this application.

Since stranded meter costs were recovered in a Cost of Service filing, Guelph Hydro has not filed Appendix 2-S Stranded Meter Treatment.

2.5.2 CAPITAL EXPENDITURES

In this Exhibit, Guelph Hydro has included the following sections which provide information from the Distribution System Plan (DSP) as outlined in Chapter 5 of Filing Requirements and Appendix 2-A of this Exhibit.

1) Planning;
2) Required Information;
3) Capitalization Policy;
4) Capitalization of Overhead;
5) Costs of Eligible Investments for Distributors;
6) New Policy Options for the Funding of Capital;
7) Addition of ICM Assets to Rate Base; and
8) Service Quality Performance.

2.5.2.1 PLANNING

The Board's RRFE is designed to support the cost-effective planning and operation of the distribution network and that of LDC distribution systems. The RRFE takes an integrated approach to planning in order to facilitate prioritization and pacing of capital expenditures. Guelph Hydro has filed its DSP in accordance with Chapter 5 Filing Requirements in Appendix 2-A of this Exhibit.

REGIONAL PLANNING

Guelph Hydro has been an active partner with Kitchener-Wilmot Hydro, Cambridge and North Dumfries Hydro, Waterloo North Hydro and Hydro One, collectively participating with IESO to address regional supply issues; specifically regarding constraints on bulk supply systems, and studying reliability contingencies and upgrades. This has

materialized with the approval and execution of GATR (Guelph Area Transmission Reinforcement), which is the first stage of an overall 25-year plan for the region. The cost for the GATR project is socialized, rather than being attributed directly to the connected communities by way of higher distribution rates through LDC capital plans or higher municipal taxes.

Guelph Hydro maintains a regular dialogue with its municipal counterparts in the City of Guelph and Village of Rockwood to understand and anticipate growth in each community which it serves, and to be aware of changes to land zoning for infill properties and green field sites, such as industrial land development in its south service area of Guelph. Also factored with its supply planning, is the impact of Guelph's Community Energy Initiative, which is a blueprint for mapping self-sufficiency by displacing grid supply resources with energy conservation programs and embedded generation. This initiative aims to reduce the impact of growth and the effect of per capita carbon footprint.

Guelph Hydro has included in its planning horizon a plan to better utilize existing transmission connected resources by investing in distribution plant and thereby shifting new load from stations that would need considerable investment to stations that have existing capacity. This is described in Guelph Hydro's DSP evidence presented in this Exhibit, Appendix 2-A.

Guelph Hydro's service areas are surrounded by Hydro One. In one example which demonstrates regional partners working well together, Hydro One has agreed that the electrical supply for a new school in the Village of Rockwood will be supplied by Guelph Hydro even though it is within Hydro One's service area, due to the fact that Hydro One's distribution plant was further away. A service amendment was granted. This decision was made because it made economic and logistic sense for all parties involved.

No load transfer customers exist between Guelph Hydro and any other utility.

PLANNING HORIZON

The RRFE Report indicated that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles.

Guelph Hydro has taken an integrated approach for investment planning on Guelph Hydro's distribution system. All investments pertaining to the following have been planned and optimized together:

- System renewal and expansion;
- Renewable generation connections;
- Customer connections and regulatory requirements;
- System growth and planning criteria;
- General plant in support of daily operations;
- Smart grid development and implementation; and
- Regionally planned infrastructure.

This allows Guelph Hydro to develop a DSP that allocates its resources in an optimal way to achieve cost-effective planning over the planning horizon.

The DSP covers a planning horizon of five years starting in the test year, which is 2016 in the case of this filing (2016-2020).

Employing this longer term approach requires Guelph Hydro to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing Guelph Hydro's ability to plan ahead and respond to the evolving needs of customers in a timely manner, while managing and leveling the impacts of these expenditures on consumer rates to maintain affordability of its service.

For further information regarding Guelph Hydro's capital expenditures planning, please refer to Guelph Hydro's DSP found in Appendix 2-A of this Exhibit.

2.5.2.2 REQUIRED INFORMATION

Guelph Hydro has completed Appendix 2-AB Capital Expenditure Summary presenting four historical years, the 2015 Bridge Year and five planned years of capital expenditures. This is the first year for which Guelph Hydro has filed a DSP, therefore historical "Plan" amounts and variance analysis are not required. Guelph Hydro has made its best efforts to categorize historical projects into the DSP categories (System Access, System Renewal, System Service, and General Plant).

Appendix 2-AB Capital Expenditure Summary is presented in Table 2-21 below.

Table 2-21

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
			%			%			%			%			%					
System Access	N/A	6,574,742	--	N/A	5,018,365	--	N/A	4,229,054	--	N/A	4,886,595	--	N/A	5,846,937	--	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	N/A	1,648,262	--	N/A	2,536,522	--	N/A	2,830,493	--	N/A	3,726,430	--	N/A	3,960,130	--	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	N/A	16,898,611	--	N/A	3,139,974	--	N/A	3,185,982	--	N/A	2,250,748	--	N/A	3,842,621	--	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	N/A	1,052,721	--	N/A	984,738	--	N/A	1,220,577	--	N/A	2,359,438	--	N/A	2,212,704	--	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	-	26,174,335	--	-	11,679,598	--	-	11,466,106	--	-	13,223,211	--	-	15,862,392	--	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305
System O&M	-	5,379,426	--	-	5,619,519	--	-	6,425,264	--	-	6,784,094	--	-	7,186,934	--	7,856,913	7,966,910	8,078,446	8,191,545	8,306,226

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 are full year actual results
2015 Bridge Year is a forecast, no "actual results are included.

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

The following information provides a brief outline of the outputs of the asset management and capital expenditure planning process that have affected capital expenditures in each of the four main major categories and overall allocation of the capital budget. The overall allocation of the capital budget amongst major categories for the Test year and Forecast period can be seen in Chart 2-1 and Chart 2-2 below.

Chart 2-1: 2016 Capital Expenditures by Category

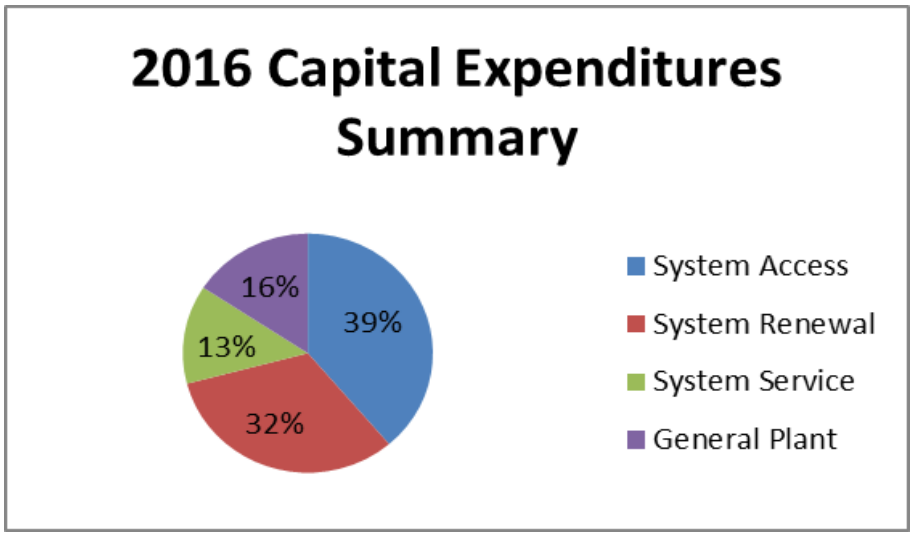
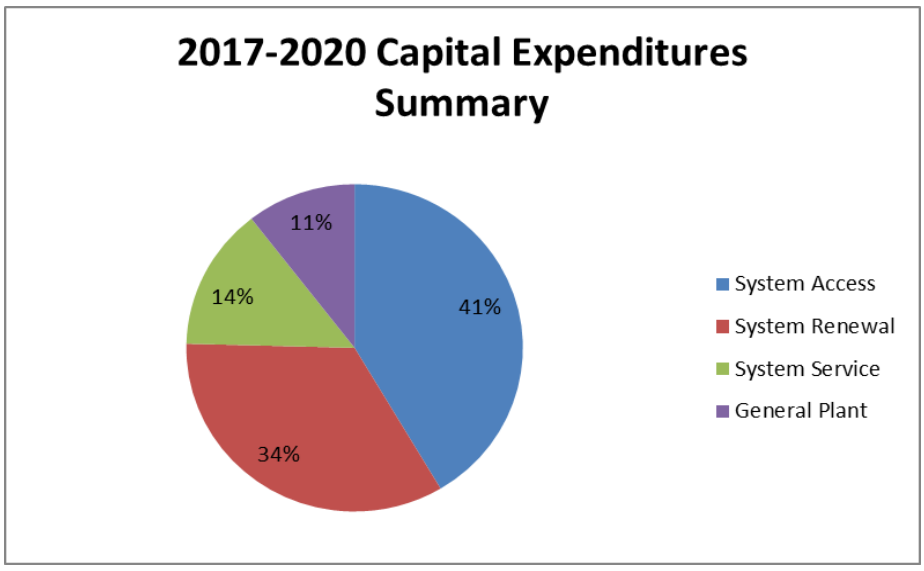


Chart 2-2: 2017 to 2020 Capital Expenditures by Category



System Access Investments

System Access investments account for the highest portion of the capital expenditures for the Test Year and Forecast Period averaging 40% of total capital budget. These expenditures are an integral part of the distribution system and the most challenging to plan as they include a number of outside influences that have contributions to the overall investment. A number of outputs resulting from asset management and capital expenditure process contribute to the outcome of the investment in System Access and have affected the overall capital expenditures:

- Consultation with municipal officials to understand future projects requiring relocation of distribution system assets in support of System Access investments. This process assists in shaping the overall allocation of investment required to support relocations resulting from projects on municipal right of ways.
- The outcome of the City of Guelph Development Priorities Plan assists in forecasting capital expenditures for residential developments in support of System Access investments.
- Consultation with existing customers, specifically industrial and large use customers, to gain perspective to current and future electrical needs to help plan the system accordingly in support of System Access investments.

System Renewal Investments

System renewal investments contribute the remaining bulk of the overall capital expenditures averaging approximately 33% of the investments for the forecast period. Expenditures within the renewal sector are highly dependent on the condition of distribution system assets and play a crucial role in the overall sustainment of the distribution system. The asset management process on the renewal of assets is managed based on the foundation of the Asset Condition Assessment on distribution system assets. This information in turn acts as an input into the Guelph Hydro system

renewal project prioritization process described in the Distribution System Plan in Appendix 2-A of this Exhibit.

System Service Investments

System Service Investments account for approximately 14% of the overall allocation of the capital budget and consist of expenditures related to the installation of a current limiting reactor ("CLR") as well as feeder projects to support the capacity within certain areas of the City of Guelph. System forecasting showed that the requirement for additional capacity was not needed by future load growth however on a feeder level, a different analysis performed and system reconfigurations are being done and will be required to transition load to where it is needed.

General Plant Investments

General plant expenditures account for a small portion of the overall allocation of capital investment averaging approximately 16% for the test year and approximately 11% for the forecast period. Expenditures in general plant relate to modifications, replacements or additions to assets that are not part of its distribution system, including land and buildings, tools and equipment, fleet and electronic devices, and software used to support day-to-day business and operations activities. A number of key outputs related to the asset management and capital planning process contribute to the capital expenditures for non-distribution system items in general plant. Assessments completed on IT infrastructure and the operations fleet of vehicles play a major role in determining the expenditure requirements for these given areas.

For more detail, please refer to Guelph Hydro's DSP in Appendix 2-A of this Exhibit.

SUMMARY OF CAPITAL PROJECTS

Table 2-22 (Chapter 2 Appendix 2-AA) below presents a summary of all gross capital expenditures by program and project where the total of the program or project exceeds the materiality threshold of $172,000 for the historical period 2011-2014 and the 2015 Bridge Year and 2016 Test Year.

Table 2-22: Appendix 2-AA Capital Projects

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
SYSTEM ACCESS						
Apartment, Commercial, Industrial Customer Connections (CACI)	600,858	546,155	544,823	1,035,517	628,053	646,894
Meter Installations (CMEG)	162,476	121,866	-30,003	-19,038	485,000	415,000
- Meters & Metering	224,735	237,712	381,702	302,009	0	0
- Smart Metering	897,505	176,751	7,918	0	0	0
- Spec S/C burden - WMP's at TS's	58,230	30,819	63,283	106,927	0	0
- SSN AMI Hardware Upgrades	0	0	0	0	525,000	0
Distribution System Modifications / Expansions for Customers (CMOD)	181,659	68,172	75,760	-10,230	761,407	784,249
- MacLennan Street @ Wheeler Court	0	0	0	173,036	0	0
- Customer, 75 Southgate Dr	1,966,781	7,576	0	0	0	0
- Customer - 63 Independence Place	0	0	0	800,104	0	0
System Relocations Property Development (CREL)	63,951	4,747	109,517	-18,795	1,262,023	1,299,884
- Carden St, Wyndham to MacDonell	203,008	703	0	0	0	0
- Hanlon Parkway at Laird Road Intersection	56,698	1,199,729	60,094	0	0	0
- Laird Road and Southgate Drive Intersection	0	0	180,697	0	0	0
- Norfolk St, Woolwich Intersection	265,969	32,664	0	0	0	0
- Speedvale Ave E, Stevenson Rd N to Sherwood	0	40,687	369,640	0	0	0
- Victoria Road South - Arkell Rd to MacAlister Blvd	0	329,165	36,740	0	0	0
- Wellington St W - Gordon St UG	0	0	0	269,437	0	0
- Wellington St W - Wellington to Gordon UG	0	0	0	925,914	0	0
- Wyndham St S, Farquhar to Wellington	56,639	120,347	3,776	0	0	0
Expansions for New Residential Subdivions (CRES)	485,186	566,058	521,164	135,031	1,401,224	1,443,261
- Arkell Meadows Subdivision	0	0	35	192,395	0	0
- Chillico Glen, Phase 2 Subdivision	243,563	2,650	0	0	0	0
- Chillico Run Subdivision	0	0	0	189,741	0	0
- Cityview Heights, Ph 2, Cityview & Oakes	0	103,413	110,233	0	0	0
- Grangehill, Phase 7A	0	27,207	356,092	-74,688	0	0
- Kortright East, Phase 3 A Subdivision	0	0	0	378,588	0	0
- Morningcrest, Ph 2C, Couling Cr	0	193,183	50,112	0	0	0
- Noble Ridge Estates, Phase 1 - Rockwood	0	158,831	465,671	0	0	0
- Northern Heights, Phase 5	0	325	139,219	40,735	0	0
- Watson Creek, Phase 3	67,663	358,266	162	0	0	0
New Residential Service Connections (CSER)	410,079	311,801	348,477	216,128	231,994	238,954
Expansions for New Residential Townhouse Subdivions (CTH)	513,372	373,985	111,539	190,009	552,236	568,803
- Lakeview Place Townhomes, 15 Carere Cres	116,367	5,553	30,424	40,804	0	0
- Westminister Woods East, Phase 5	0	0	291,981	12,971	0	0
SYSTEM ACCESS Sub-Total	6,574,742	5,018,365	4,229,054	4,886,595	5,846,937	5,397,045

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
SYSTEM RENEWAL						
Distribution System Replacment (CREP)	569,065	527,883	950,686	1,443,423	168,117	770,741
- 21 Woodlawn Rd E Reconstruction	0	0	171,694	121,583	0	0
- 295 Water Street Single Phase Ug W/ Secondary Ug Cable	0	0	0	0	0	448,000
- Acorn Pl and Chestnut Pl Rehabilitation	0	0	178,115	0	0	0
- Alice St, Arthur S to Stevenson S	246,589	209,017	3,174	0	0	0
- Alma St N / Plymouth Crt	0	0	0	0	0	218,000
- Alma St N/Julia Dr/Drew St	0	0	0	0	0	216,000
- Arrow Rd	0	0	0	0	0	432,000
- Campbell TS Easement, Dawson Rd to Edinburgh Rd	226,030	0	0	0	0	0
- Damaged or Deteriorated Poles	292,502	303,400	90,218	237,767	0	0
- Dawson Rd – U/G	0	0	0	0	369,000	0
- Deerfield Pl Pole Trans	0	0	0	0	174,000	0
- Edinburgh Rd N - Speedvale to Woodlawn Rd W	169,642	122,580	69,881	0	0	0
- Fife (Wellington To Gateway)	0	0	0	0	0	173,000
- Hands Dr, Latenda Pl, Dimson Ave Rehab	0	0	125,114	479,310	0	0
- Imperial Rd N North Of Paisley	0	0	0	0	351,000	0
- Imperial Rd S / Samantha Crt	0	0	0	0	0	247,000
- Lewis Road Reconstruction	0	2,670	315,868	240,172	0	0
- Macdonell St Carden To Woolwich	0	0	0	0	300,000	0
- Nicklin Road Reconstruction	0	195,481	0	0	0	0
- Paisley St West Of Norfolk	0	0	0	0	261,000	0
- Parkwood Gardens, Phase 3 Rehab	0	1,084,440	-2,386	0	0	0
- Elmira Rd South	0	0	0	0	0	388,000
- Sherwood Dr Rehabilitation	0	0	567,424	0	0	0
- Speedvale Ave W - At Kathleen	0	0	0	0	245,000	0
- Victoria Road North - Islington Ave to Speed River	0	0	0	579,897	0	0
- Western Ave Reconstruction	0	0	209,181	0	0	0
- Westgate Dr/Lonsdale Dr/ Edinburgh Rd N [Oh]	0	0	0	0	0	285,000
- Willow Rd At Applewood	0	0	0	0	278,000	0
-8 &16 Wilsonview Ave Vault Replacement	0	0	0	301,969	0	0
- Rickson Ave UG Rehab	0	0	0	0	1,508,000	0
- Keats UG Rehab	0	0	0	0	0	986,000
Distribution System Transformer replacement upgrades (CTRU)	144,433	91,051	151,523	322,307	306,013	315,193
SYSTEM RENEWAL Sub-Total	1,648,262	2,536,522	2,830,493	3,726,430	3,960,130	4,478,934

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
SYSTEM SERVICE						
Distribution System Feeder Infrastrucutre (CFDR)	270,231	115,835	42,765	348,005	1,527	94,833
- Campbell TS, Campbell Rd, Massey Rd, Elmira Rd N	0	0	1,881,150	237,224	0	0
- Clair Road - Crawley to Southgate - Composite Pole Line	200,916	31,096	-5,582	0	0	0
- Crawley Road, South of Clair Rd at MTS#1	197,659	0	0	0	0	0
- Edinburgh Rd N (Bristol To Foster)	0	0	0	0	400,000	0
- Edinburgh Rd N / Sultan St	0	0	0	0	0	176,000
- Edinburgh Road South - From Cedar to Bristol Street	0	0	0	1,146,385	0	0
- External Ground Grid, Hanlon Rd - Kortright to Maltby	164,989	0	0	0	0	0
- Feeder to Clairfields	0	0	0	0	300,000	0
- Hanlon Creek Business Park, Phase 1B, Part 1	267,848	8,947	0	0	0	0
- Hanlon Creek Business Park, Phase 1B, Part 2	9,680	181,547	0	0	0	0
- Hanlon Creek Business Park, Phase 2	386	639,614	42,024	0	0	0
- Poppy Drive, Phase 1B	0	203,347	4,309	0	0	0
- Rockwood - Harris St	0	15,245	268,354	0	0	0
- Waterloo Ave	0	0	0	0	442,000	0
- New 5M53 - Cedar St (Edinburgh To Maple)	0	0	0	0	0	500,000
- Edinburgh Rd S (Municipal To Bristol - West Side)	0	0	0	0	0	407,000
- Customer, 75 Southgate Dr	530,780	16,779	0	0	0	0
SCADA Infrastructure (CSC)	86,503	124,910	69,317	-14,053	218,360	224,911
SCADA Master - Web Console/HW Upgrades	147,716	98,614	98,213	0	0	0
SCADA Master	0	24,478	0	188,343	0	0
SCADA / Remotely Operated Switches (CSW)	119,131	78,394	241,920	289,419	248,784	256,248
Transformer Stations & Distribution Stations (CTS/CDS)	26,723	5,140	207,720	55,426	181,950	49,408
- ARLEN MTS	14,876,047	1,596,028	335,790	0	0	0
- Rockwood MS#1 Reconstruction	0	0	0	0	1,250,000	0
- Arlen MTS - Series Reactor	0	0	0	0	800,000	150,000
SYSTEM SERVICE Sub-Total	16,898,611	3,139,974	3,185,982	2,250,748	3,842,621	1,858,400
GENERAL PLANT						
Building / Fixtures	32,636	0	97,634	483,568	254,500	154,135
Building Addition	0	0	0	0	500,000	650,000
Office Equipment / Graphics	25,249	43,060	50,495	104,225	58,350	163,100
Fleet / Rolling Stock	402,093	218,798	461,583	318,503	200	272,886
2012 Terex C-5052	0	250,158	0	0	0	0
Replace Double Bucket (T8)	0	0	0	0	350,000	0
New Single Bucket (42')	0	0	0	0	206,000	0
Replace Single Bucket (T9)	0	0	0	0	0	300,000
LineChamp Material Handler	0	0	0	302,328	0	0
IT Capital	284,128	155,368	331,387	660,217	460,000	470,000
Corporate Voice System	0	0	200,000	0	0	0
D & R Electronics	240,878	0	0	0	0	0
Comp Software	0	240,878	0	0	0	0
Servers	0	0	0	0	100,000	100,000
3-IBM I series Servers	0	0	0	0	220,000	20,000
Lansa Software	0	0	0	404,843	0	0
Major Tools	67,738	76,475	79,477	85,754	63,654	65,564
Sub-Total	1,052,721	984,738	1,220,577	2,359,438	2,212,704	2,195,685
Miscellaneous						
Total	**26,174,335**	**11,679,598**	**11,466,106**	**13,223,211**	**15,862,392**	**13,930,063**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*						
Total	**26,174,335**	**11,679,598**	**11,466,106**	**13,223,211**	**15,862,392**	**13,930,063**

CAPITAL EXPENDITURES VARIANCE ANALYSIS

An overall summary of gross capital expenditures from 2011-2016 by DSP categories is shown in Table 2-23 below outlining year-to-year variances at both the category and program level.

Table 2-23: Capital Projects Variances

	2011 Vs 2012			2012 Vs 2013			2013 Vs 2014			2014 Vs 2015			2015 Vs 2016			2016 Vs 2017			2017-2020 Trending			
Programs	**2011 (Previous Bridge Year)**	**2012 (Previous Test Year)**	**Variance from 2011 Actual**	**2012 (Previous Test Year)**	**2013**	**Variance from 2012 Actual**	**2013**	**2014**	**Variance from 2013 Actual**	**2014**	**2015 Bridge Year**	**Variance from 2014 Actual**	**2015 Bridge Year**	**2016 Test Year**	**Variance from 2015 Budget**	**2016 Test Year**	**2017**	**Variance from 2016 Budget**	**2017**	**2018**	**2019**	**2020**
	Actual	**Actual**	**Variance**	**Actual**	**Actual**	**Variance**	**Actual**	**Actual**	**Variance**	**Actual**	**Budget**	**Variance**	**Budget**	**Budget**	**Variance**	**Budget**	**Plan**	**Variance**	**Plan**	**Plan**	**Plan**	**Plan**
System Access																						
Apartment, Commercial, Industrial Customer Connections (CACI)	600,858	546,155	-54,703	546,155	544,823	-1,332	544,823	1,035,517	490,694	1,035,517	628,053	-407,464	628,053	646,894	18,842	646,894	666,301	19,407	666,301	686,290	706,879	728,085
Meter Installations (CMEG)	1,342,946	567,148	-775,798	567,148	422,899	-144,249	422,899	389,899	-33,000	389,899	1,010,000	620,101	1,010,000	415,000	-595,000	415,000	365,000	-50,000	365,000	385,000	385,000	375,000
Distribution System Modifications / Expansions for Customers (CMOD)	2,148,440	75,748	-2,072,692	75,748	75,760	12	75,760	962,910	887,150	962,910	761,407	-201,503	761,407	784,249	22,842	784,249	807,777	23,527	807,777	832,010	856,970	882,679
System Relocations Property Development (CREL)	646,265	1,728,042	1,081,777	1,728,042	760,464	-967,578	760,464	1,176,556	416,093	1,176,556	1,262,023	85,467	1,262,023	1,299,884	37,861	1,299,884	1,338,881	38,997	1,338,881	1,379,047	1,420,418	1,463,031
Expansions for New Residential Subdivisions (CRES)	796,412	1,409,933	613,521	1,409,933	1,642,688	232,755	1,642,688	861,802	-780,885	861,802	1,401,224	539,422	1,401,224	1,443,261	42,037	1,443,261	1,486,559	43,298	1,486,559	1,531,156	1,577,090	1,624,403
New Residential Service Connections (CSER)	410,079	311,801	-98,278	311,801	348,477	36,676	348,477	216,128	-132,349	216,128	231,994	15,866	231,994	238,954	6,960	238,954	246,123	7,169	246,123	253,506	261,112	268,945
Expansions for New Residential Subdivisions (CTH)	629,739	379,538	-250,201	379,538	433,944	54,406	433,944	243,783	-190,161	243,783	552,236	308,452	552,236	568,803	16,567	568,803	585,867	17,064	585,867	603,443	621,546	640,192
Sub-Total	**6,574,742**	**5,018,365**	**-1,556,377**	**5,018,365**	**4,229,054**	**-789,311**	**4,229,054**	**4,886,595**	**657,542**	**4,886,595**	**5,846,937**	**960,341**	**5,846,937**	**5,397,045**	**-449,892**	**5,397,045**	**5,496,506**	**99,461**	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**
Miscellaneous Projects (under Materiality threshold)																						
Total System Access	**6,574,742**	**5,018,365**	**-1,556,377**	**5,018,365**	**4,229,054**	**-789,311**	**4,229,054**	**4,886,595**	**657,542**	**4,886,595**	**5,846,937**	**960,341**	**5,846,937**	**5,397,045**	**-449,892**	**5,397,045**	**5,496,506**	**99,461**	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**
System Renewal																						
Distribution System Replacement (CREP)	1,503,828	2,445,471	941,643	2,445,471	2,678,970	233,499	2,678,970	3,404,122	725,152	3,404,122	3,654,117	249,995	3,654,117	4,163,741	509,624	4,163,741	4,288,653	124,912	4,288,653	4,417,312	4,549,832	4,686,327
Distribution System Transformer replacement upgrades (CTRU)	144,433	91,051	-53,382	91,051	151,523	60,472	151,523	322,307	170,784	322,307	306,013	-16,294	306,013	315,193	9,180	315,193	324,649	9,456	324,649	334,389	344,420	354,753
Sub-Total	**1,648,262**	**2,536,522**	**888,260**	**2,536,522**	**2,830,493**	**293,971**	**2,830,493**	**3,726,430**	**895,937**	**3,726,430**	**3,960,130**	**233,700**	**3,960,130**	**4,478,934**	**518,804**	**4,478,934**	**4,613,302**	**134,368**	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**
Miscellaneous Projects (under Materiality threshold)																						
Total System Renewal	**1,648,262**	**2,536,522**	**888,260**	**2,536,522**	**2,830,493**	**293,971**	**2,830,493**	**3,726,430**	**895,937**	**3,726,430**	**3,960,130**	**233,700**	**3,960,130**	**4,478,934**	**518,804**	**4,478,934**	**4,613,302**	**134,368**	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**
System Service																						
Distribution System Feeder Infrastrucutre (CFDR)	1,642,489	1,212,410	-430,079	1,212,410	2,233,021	1,020,611	2,233,021	1,731,614	-501,406	1,731,614	1,143,527	-588,087	1,143,527	1,177,833	34,306	1,177,833	1,213,168	35,335	1,213,168	1,249,563	1,287,050	1,325,661
SCADA Infrastructure (CSC)	234,219	248,002	13,783	248,002	167,530	-80,472	167,530	174,290	6,759	174,290	218,360	44,070	218,360	224,911	6,551	224,911	231,658	6,747	231,658	238,608	245,766	253,139
SCADA / Remotely Operated Switches (CSW)	119,131	78,394	-40,737	78,394	241,920	163,526	241,920	289,419	47,498	289,419	248,784	-40,635	248,784	256,248	7,464	256,248	263,935	7,687	263,935	271,853	280,009	288,409
Transformer Stations & Distribution Stations (CTS/CDS)	14,902,770	1,601,168	-13,301,602	1,601,168	543,510	-1,057,658	543,510	55,426	-488,085	55,426	2,231,950	2,176,524	2,231,950	199,409	-2,032,542	199,409	205,391	5,982	205,391	211,552	217,899	224,436
Sub-Total	**16,898,611**	**3,139,974**	**-13,758,637**	**3,139,974**	**3,185,982**	**46,008**	**3,185,982**	**2,250,748**	**-935,233**	**2,250,748**	**3,842,621**	**1,591,873**	**3,842,621**	**1,858,400**	**-1,984,221**	**1,858,400**	**1,914,152**	**55,752**	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**
Miscellaneous Projects (under Materiality threshold)																						
Total System Service	**16,898,611**	**3,139,974**	**-13,758,637**	**3,139,974**	**3,185,982**	**46,008**	**3,185,982**	**2,250,748**	**-935,233**	**2,250,748**	**3,842,621**	**1,591,873**	**3,842,621**	**1,858,400**	**-1,984,221**	**1,858,400**	**1,914,152**	**55,752**	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**
General Plant																						
Building / Fixtures	32,636	0	-32,636	0	97,634	97,634	97,634	483,568	385,934	483,568	754,500	270,932	754,500	804,135	49,635	804,135	163,909	-640,226	163,909	168,826	173,891	179,108
Office Equipment / Graphics	25,249	43,060	17,812	43,060	50,495	7,434	50,495	104,225	53,730	104,225	58,350	-45,875	58,350	163,100	104,750	163,100	64,993	-98,107	64,993	66,943	68,951	71,020
Fleet / Rolling Stock	402,093	468,956	66,863	468,956	461,583	-7,372	461,583	620,831	159,248	620,831	556,200	-64,631	556,200	572,886	16,686	572,886	590,073	17,187	590,073	607,775	626,008	644,788
IT Capital	525,006	396,246	-128,760	396,246	531,387	135,141	531,387	1,065,060	533,673	1,065,060	780,000	-285,060	780,000	590,000	-190,000	590,000	545,000	-45,000	545,000	561,350	578,191	595,536
Major Tools	67,738	76,475	8,737	76,475	79,477	3,002	79,477	85,754	6,277	85,754	63,654	-22,100	63,654	65,564	1,910	65,564	67,531	1,967	67,531	69,556	71,643	73,792
Sub-Total	**1,052,721**	**984,738**	**-67,984**	**984,738**	**1,220,577**	**235,840**	**1,220,577**	**2,359,438**	**1,138,861**	**2,359,438**	**2,212,704**	**-146,734**	**2,212,704**	**2,195,685**	**-17,019**	**2,195,685**	**1,431,505**	**-764,179**	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**
Miscellaneous Projects (under Materiality threshold)																						
Total General Plant	**1,052,721**	**984,738**	**-67,984**	**984,738**	**1,220,577**	**235,840**	**1,220,577**	**2,359,438**	**1,138,861**	**2,359,438**	**2,212,704**	**-146,734**	**2,212,704**	**2,195,685**	**-17,019**	**2,195,685**	**1,431,505**	**-764,179**	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**
				0																		
Total all Categories	**26,174,335**	**11,679,598**	**-14,494,737**	**11,679,598**	**11,466,106**	**-213,493**	**11,466,106**	**13,223,211**	**1,757,105**	**13,223,211**	**15,862,392**	**2,639,180**	**15,862,392**	**13,930,063**	**-1,932,328**	**13,930,063**	**13,455,465**	**-474,598**	**13,455,465**	**13,868,179**	**14,272,674**	**14,679,305**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*	**0**	**0**	**0**	**0**	**0**	**0**																
Total	**26,174,335**	**11,679,598**	**-14,494,737**	**11,679,598**	**11,466,106**	**-213,493**	**11,466,106**	**13,223,211**	**1,757,105**	**13,223,211**	**15,862,392**	**2,639,180**	**15,862,392**	**13,930,063**	**-1,932,328**	**13,930,063**	**13,455,465**	**-474,598**	**13,455,465**	**13,868,179**	**14,272,674**	**14,679,305**

In Table 2-24 below, Guelph Hydro presents the capital expenditure variance analysis above the materiality threshold of $172,000.

2011 Actual Vs 2012 Actual Capital Expenditure Variances

Table 2-24: 2011 vs. 2012 Capital Expenditure Variances

CATEGORY	2011 Actual Vs 2012 Actual		
	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
System Access	6,574,742	5,018,365	-1,556,377
System Renewal	1,648,262	2,536,522	888,260
System Service	16,898,611	3,139,974	-13,758,637
General Plant	1,052,721	984,738	-67,984
TOTAL EXPENDITURE	26,174,335	11,679,598	-14,494,737

2011 vs. 2012 System Access

The major factors explaining the variance within the System Access category were:

- A significant decrease in projects from 2011 to 2012 related to distribution system expansions for new customers of $2,072,692.
- A significant decrease within the metering program from 2011 to 2012, primarily resulted from the decrease in 2012 smart meter program capital expenditures.
- Distribution system relocations increased by $1,082,000 due to increased activity by municipal land and provincial land owners.
- The total capital expenditure for system expansion and servicing new residential developments decreased by $265,000 from 2011 to 2012 due to decreased residential development activity.

The majority of capital expenditures contained within the System Access category. with the exception of metering, are recovered through capital contributions.

Table 2-25: 2011 vs. 2012 System Access Variances

	2011 Vs 2012		
Programs	**2011 (Previous Bridge Year)**	**2012 (Previous Test Year)**	**Variance from 2011 Actual**
	Actual	**Actual**	**Variance**
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	600,858	546,155	-54,703
Meter Installations (CMEG)	1,342,946	567,148	-775,798
Distribution System Modifications / Expansions for Customers (CMOD)	2,148,440	75,748	-2,072,692
System Relocations Property Development (CREL)	646,265	1,728,042	1,081,777
Expansions for New Residential Subdivisions (CRES)	796,412	1,409,933	613,521
New Residential Service Connections (CSER)	410,079	311,801	-98,278
Expansions for New Residential Subdivisions (CTH)	629,739	379,538	-250,201
Sub-Total	**6,574,742**	**5,018,365**	**-1,556,377**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**6,574,742**	**5,018,365**	**-1,556,377**

2011 vs. 2012 System Renewal

This variance is primarily due to an underground rehabilitation project in the Parkwood Gardens subdivision at which obsolete and poor condition pole transformers were removed from the system and replaced with new pad mounted transformers and new underground distribution and service cable.

Table 2-26: 2011 vs. 2012 System Renewal Variances

	2011 Vs 2012		
Programs	**2011 (Previous Bridge Year)**	**2012 (Previous Test Year)**	**Variance from 2011 Actual**
	Actual	**Actual**	**Variance**
System Renewal			
Distribution System Replacement (CREP)	1,503,828	2,445,471	941,643
Distribution System Transformer replacement upgrades (CTRU)	144,433	91,051	-53,382
Sub-Total	**1,648,262**	**2,536,522**	**888,260**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**1,648,262**	**2,536,522**	**888,260**

2011 vs. 2012 System Service

The most significant driver explaining the variance within the System Service category was due to the significant decrease in capital expenditures related to the Arlen Municipal Transformer Station (MTS) after 2011. This MTS project was started in 2009 with an in-service date of early 2012. A significant amount of costs were contained within 2011 and only final project closing expenditures carried over to the 2012 fiscal year. The variance was also due to a decrease in distribution system feeder infrastructure as a result of the construction of Arlen MTS.

Table 2-27: 2011 vs. 2012 System Service Variances

Programs	2011 Vs 2012		
	2011 (Previous Bridge Year)	2012 (Previous Test Year)	Variance from 2011 Actual
	Actual	Actual	Variance
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,642,489	1,212,410	-430,079
SCADA Infrastructure (CSC)	234,219	248,002	13,783
SCADA / Remotely Operated Switches (CSW)	119,131	78,394	-40,737
Transformer Stations & Distribution Stations (CTS/CDS)	14,902,770	1,601,168	-13,301,602
Sub-Total	**16,898,611**	**3,139,974**	**-13,758,637**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**16,898,611**	**3,139,974**	**-13,758,637**

2011 vs. 2012 General Plant

The variance is below the materiality threshold and therefore deemed immaterial.

Table 2-28: 2011 vs. 2012 General Plant Variances

Programs	2011 Vs 2012		
	2011 (Previous Bridge Year)	2012 (Previous Test Year)	Variance from 2011 Actual
	Actual	Actual	Variance
General Plant			
Building / Fixtures	32,636	0	-32,636
Office Equipment / Graphics	25,249	43,060	17,812
Fleet / Rolling Stock	402,093	468,956	66,863
IT Capital	525,006	396,246	-128,760
Major Tools	67,738	76,475	8,737
Sub-Total	**1,052,721**	**984,738**	**-67,984**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**1,052,721**	**984,738**	**-67,984**

2012 Actual Vs 2013 Actual Capital Expenditure Variances

Table 2-29: 2012 vs. 2013 Capital Expenditure Variances

CATEGORY	2012 Actual Vs 2013 Actual		
	2012	2013	Variance from 2012 Actual
	Actual	Actual	Variance
System Access	5,018,365	4,229,054	-789,311
System Renewal	2,536,522	2,830,493	293,971
System Service	3,139,974	3,185,982	46,008
General Plant	984,738	1,220,577	235,840
TOTAL EXPENDITURE	11,679,598	11,466,106	-213,493

2012 vs. 2013 System Access

The main drivers behind the variances within the System Access category are the decrease in projects related to distribution system relocations to accommodate work from municipal and provincial land owners' infrastructure projects. This activity accounted for ($967,578) of the variance. Conversely, an increase in expansion projects for servicing new residential developments increased by $323,837.

The majority of capital expenditures contained in the System Access category with the exception of metering, are capital costs recovered through capital contributions.

Table 2-30: 2012 vs. 2013 System Access Variances

	2012 Vs 2013		
Programs	**2012 (Previous Test Year)**	**2013**	**Variance from 2012 Actual**
	Actual	**Actual**	**Variance**
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	546,155	544,823	-1,332
Meter Installations (CMEG)	567,148	422,899	-144,249
Distribution System Modifications / Expansions for Customers (CMOD)	75,748	75,760	12
System Relocations Property Development (CREL)	1,728,042	760,464	-967,578
Expansions for New Residential Subdivisions (CRES)	1,409,933	1,642,688	232,755
New Residential Service Connections (CSER)	311,801	348,477	36,676
Expansions for New Residential Subdivisions (CTH)	379,538	433,944	54,406
Sub-Total	**5,018,365**	**4,229,054**	**-789,311**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**5,018,365**	**4,229,054**	**-789,311**

2012 vs. 2013 System Renewal

The variance within the System Renewal category is a result of a slight increase in capital expenditures related to the removal of pole transformers from the distribution system as compared to spending the previous year on the same type of program.

Table 2-31: 2012 vs. 2013 System Renewal Variances

	2012 Vs 2013		
Programs	**2012 (Previous Test Year)**	**2013**	**Variance from 2012 Actual**
	Actual	**Actual**	**Variance**
System Renewal			
Distribution System Replacement (CREP)	2,445,471	2,678,970	233,499
Distribution System Transformer replacement upgrades (CTRU)	91,051	151,523	60,472
Sub-Total	**2,536,522**	**2,830,493**	**293,971**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**2,536,522**	**2,830,493**	**293,971**

2012 vs. 2013 System Service

The overall variance within the System Service category is below the materiality threshold, however, specific variances within the category of $1,020,611 and ($1,057,658) are related to distribution system feeder infrastructure and transformer and distribution stations, respectively. A significant portion of the variance within the distribution system feeder infrastructure program is a result of the Campbell Road underground feeder project, which was implemented to provide additional capacity to the North West region of Guelph. The variance within the Transformer and Distribution station program was a result of the completion of the Arlen MTS project.

Table 2-32: 2012 vs. 2013 System Service Variances

Programs	2012 Vs 2013		
	2012 (Previous Test Year)	2013	Variance from 2012 Actual
	Actual	Actual	Variance
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,212,410	2,233,021	1,020,611
SCADA Infrastructure (CSC)	248,002	167,530	-80,472
SCADA / Remotely Operated Switches (CSW)	78,394	241,920	163,526
Transformer Stations & Distribution Stations (CTS/CDS)	1,601,168	543,510	-1,057,658
Sub-Total	**3,139,974**	**3,185,982**	**46,008**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**3,139,974**	**3,185,982**	**46,008**

2012 vs. 2013 General Plant

Overall capital expenditures are consistent in the General Plant category for the 2012 and 2013 years, with the primary variance contained in IT capital, which was a result of the corporate voice system at a cost of $200,000.

Table 2-33: 2012 vs. 2013 General Plant Variances

Programs	2012 Vs 2013		
	2012 (Previous Test Year)	2013	Variance from 2012 Actual
	Actual	Actual	Variance
General Plant			
Building / Fixtures	0	97,634	97,634
Office Equipment / Graphics	43,060	50,495	7,434
Fleet / Rolling Stock	468,956	461,583	-7,372
IT Capital	396,246	531,387	135,141
Major Tools	76,475	79,477	3,002
Sub-Total	**984,738**	**1,220,577**	**235,840**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**984,738**	**1,220,577**	**235,840**

2013 Actual Vs 2014 Actual Capital Expenditure Variances

Table 2-34: 2013 vs. 2014 Capital Expenditure Variances

	2013 Actual Vs 2014 Actual		
CATEGORY	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
System Access	4,229,054	4,886,595	657,542
System Renewal	2,830,493	3,726,430	895,937
System Service	3,185,982	2,250,748	-935,233
General Plant	1,220,577	2,359,438	1,138,861
TOTAL EXPENDITURE	11,466,106	13,223,211	1,757,105

2013 vs. 2014 System Access

The variance in the 2013 and 2014 System Access work is associated with the following:

- Apartment, Commercial and Industrial Customer Connections increase by $490,694 due to the increase in customer-related servicing projects;
- System Modifications to accommodate customers increased by $887,150 due specifically to a single project for a large industrial customer; and
- Asset relocations due to City of Guelph projects increased by $416,093 due to the City of Guelph road reconstruction work on Wellington and Gordon Streets.

The overall spending in the residential development servicing sector decreased by $1,103,395 as a result of decrease in the number of projects in 2014. Work in this area was very slow in the beginning of the year due to the late winter in 2013 which caused projects to be delayed.

Table 2-35: 2013 vs. 2014 System Access Variances

	2013 Vs 2014		
Programs	**2013**	**2014**	**Variance from 2013 Actual**
	Actual	**Actual**	**Variance**
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	544,823	1,035,517	490,694
Meter Installations (CMEG)	422,899	389,899	-33,000
Distribution System Modifications / Expansions for Customers (CMOD)	75,760	962,910	887,150
System Relocations Property Development (CREL)	760,464	1,176,556	416,093
Expansions for New Residential Subdivisions (CRES)	1,642,688	861,802	-780,885
New Residential Service Connections (CSER)	348,477	216,128	-132,349
Expansions for New Residential Subdivisions (CTH)	433,944	243,783	-190,161
Sub-Total	**4,229,054**	**4,886,595**	**657,542**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**4,229,054**	**4,886,595**	**657,542**

2013 vs. 2014 System Renewal

The main contributors to the variance in capital expenditures for System Renewal projects between 2013 and 2014 can be linked to differences in spending on the major sustainment programs as a result of outcomes from the ACA. A comparison on specific programs with respect to asset replacements concluded the following variances:

- Concrete Distribution Poles $213,399
- OH Pole Line Rebuilds $546,638
- Pole-Trans Rehabilitation ($421,977)
- Replacement of Damaged Equipment $157,513
- UG Structures $277,736
- Distribution Transformer Replacement $181,990

Table 2-36: 2013 vs. 2014 System Renewal Variances

	2013 Vs 2014		
Programs	**2013**	**2014**	**Variance from 2013 Actual**
	Actual	**Actual**	**Variance**
System Renewal			
Distribution System Replacement (CREP)	2,678,970	3,404,122	725,152
Distribution System Transformer replacement upgrades (CTRU)	151,523	322,307	170,784
Sub-Total	**2,830,493**	**3,726,430**	**895,937**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**2,830,493**	**3,726,430**	**895,937**

2013 vs. 2014 System Service

The contributing factor to the variance in spending on distribution system feeder infrastructure was due to the types of projects implemented between the years. 2013 saw capital expenditures in the distribution feeders area spent on the addition of an underground feeder system to accommodate additional load growth in the North West portion of the City of Guelph. In 2014, the major feeder project was the reconstruction of an overhead pole line to increase capacity as part of the 2013 project. Within the Stations program, a variance of ($488,085) was a result of the finalization of projects related to the construction of Arlen MTS in 2013. 2014 capital expenditures of $90,967 are considered to be consistent with future expenditures related to transformer and distribution stations.

Table 2-37: 2013 vs. 2014 System Service Variances

Programs	2013 Vs 2014		
	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	2,233,021	1,731,614	-501,406
SCADA Infrastructure (CSC)	167,530	174,290	6,759
SCADA / Remotely Operated Switches (CSW)	241,920	289,419	47,498
Transformer Stations & Distribution Stations (CTS/CDS)	543,510	55,426	-488,085
Sub-Total	**3,185,982**	**2,250,748**	**-935,233**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**3,185,982**	**2,250,748**	**-935,233**

2013 vs. 2014 General Plant

Major variances in spending within the General Plant sector between 2013 and 2014 can be accounted for based on the following factors:

- Replacement of the administration building roof due to age and condition $473,479
- Purchase of Lansa IT software $404,843

Table 2-38: 2013 vs. 2014 General Plant Variances

Programs	2013 Vs 2014		
	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
General Plant			
Building / Fixtures	97,634	483,568	385,934
Office Equipment / Graphics	50,495	104,225	53,730
Fleet / Rolling Stock	461,583	620,831	159,248
IT Capital	531,387	1,065,060	533,673
Major Tools	79,477	85,754	6,277
Sub-Total	**1,220,577**	**2,359,438**	**1,138,861**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**1,220,577**	**2,359,438**	**1,138,861**

2014 Actual Vs 2015 Forecast Capital Expenditure Variances

Table 2-39: 2014 vs. 2015 Capital Expenditure Variances

	2014 Actual Vs 2015 Forecast		
CATEGORY	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
System Access	4,886,595	5,846,937	960,341
System Renewal	3,726,430	3,960,130	233,700
System Service	2,250,748	3,842,621	1,591,873
General Plant	2,359,438	2,212,704	-146,734
TOTAL EXPENDITURE	13,223,211	15,862,392	2,639,180

2014 vs. 2015 System Access

The variance in the 2014 actuals to the 2015 budget for System Access work is associated with the following:

- Apartment, Commercial and Industrial Customer Connections is scheduled to decrease by $407,464 due an expected decrease in projects related to customer servicing. 2014 capital expenditures in this area were considered to be an anomaly based on the historic spending range of $546,155 in 2012 and $600,858 in 2011.
- System modifications to accommodate customers is planned to decrease slightly in comparison to 2014 due to a forecasted decline in projects.
- Combined capital expenditures in the residential development servicing sector is slated to increase as a result of projects that were scheduled to begin in 2014 but were delayed to 2015.
- Metering includes a significant increase related to a major Smart Metering Advanced Metering Infrastructure (AMI) back-office system hardware upgrade budgeted at $525,000 in 2015. The existing hardware has reached its service

life, and its replacement will be sized to accommodate anticipated future growth over the next five years.

Table 2-40: 2014 vs. 2015 System Access Variances

Programs	2014 Vs 2015		
	2014	2015 Bridge Year	Variance from 2014 Actual
	Actual	Budget	Variance
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	1,035,517	628,053	-407,464
Meter Installations (CMEG)	389,899	1,010,000	620,101
Distribution System Modifications / Expansions for Customers (CMOD)	962,910	761,407	-201,503
System Relocations Property Development (CREL)	1,176,556	1,262,023	85,467
Expansions for New Residential Subdivisions (CRES)	861,802	1,401,224	539,422
New Residential Service Connections (CSER)	216,128	231,994	15,866
Expansions for New Residential Subdivisions (CTH)	243,783	552,236	308,452
Sub-Total	**4,886,595**	**5,846,937**	**960,341**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**4,886,595**	**5,846,937**	**960,341**

2014 vs. 2015 System Renewal

Minor variations in the types of projects within the renewal of assets category are the contributing factor for the difference in capital expenditures between 2014 and 2015. Planned expenditures for 2015 are consistent with 2014 capital replacement projects.

Table 2-41: 2014 vs. 2015 System Renewal Variances

Programs	2014 Vs 2015		
	2014	2015 Bridge Year	Variance from 2014 Actual
	Actual	Budget	Variance
System Renewal			
Distribution System Replacement (CREP)	3,404,122	3,654,117	249,995
Distribution System Transformer replacement upgrades (CTRU)	322,307	306,013	-16,294
Sub-Total	**3,726,430**	**3,960,130**	**233,700**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**3,726,430**	**3,960,130**	**233,700**

2014 vs. 2015 System Service

The variance within the System Service category can be attributed to a decrease in capital expenditures related to distribution system feeder infrastructure of ($588,087) and an increase in spending to projects related to transformer and distribution stations. The large variance in feeder infrastructure was a result of a single project in 2014 related to the rebuilding and capacity increase of a multi-circuit pole line on Edinburgh Road South from Cedar TS to Bristol Street. The variances within the stations category are a result of the rebuild of Rockwood MS1 and the addition of a series reactor at Arlen MTS to mitigate high fault levels.

Table 2-42: 2014 vs. 2015 System Service Variances

Programs	2014 Vs 2015		
	2014	2015 Bridge Year	Variance from 2014 Actual
	Actual	Budget	Variance
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,731,614	1,143,527	-588,087
SCADA Infrastructure (CSC)	174,290	218,360	44,070
SCADA / Remotely Operated Switches (CSW)	289,419	248,784	-40,635
Transformer Stations & Distribution Stations (CTS/CDS)	55,426	2,231,950	2,176,524
Sub-Total	**2,250,748**	**3,842,621**	**1,591,873**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**2,250,748**	**3,842,621**	**1,591,873**

2014 vs. 2015 General Plant

The variance in costs between 2014 and 2015 within the General Plant category can be attributed to the following:

- Building roof ($473,289)
- Administration Building addition $500,000

The variances in expenditures for the IT capital are a result of the 2014 Lansa IT software purchase. Capital expenditures in all remaining programs in the General Plant category are uniform with previous years and fall below the material threshold.

Table 2-43: 2014 vs. 2015 General Plant Variances

Programs	2014 Vs 2015		
	2014	2015 Bridge Year	Variance from 2014 Actual
	Actual	Budget	Variance
General Plant			
Building / Fixtures	483,568	754,500	270,932
Office Equipment / Graphics	104,225	58,350	-45,875
Fleet / Rolling Stock	620,831	556,200	-64,631
IT Capital	1,065,060	780,000	-285,060
Major Tools	85,754	63,654	-22,100
Sub-Total	**2,359,438**	**2,212,704**	**-146,734**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**2,359,438**	**2,212,704**	**-146,734**

2015 Forecast Vs 2016 Forecast Capital Expenditure Variances

Table 2-44: 2015 vs. 2016 Capital Expenditure Variances

	2015 Forecast Vs 2016 Forecast		
CATEGORY	2015	2016 Test Year	Variance from 2015 Budget
	Budget	Budget	Variance
System Access	5,846,937	5,397,045	-449,892
System Renewal	3,960,130	4,478,934	518,804
System Service	3,842,621	1,858,400	-1,984,221
General Plant	2,212,704	2,195,685	-17,019
TOTAL EXPENDITURE	15,862,392	13,930,063	-1,932,328

2015 vs. 2016 System Access

The primary variance within this category is the result of a decrease in capital expenditures in the metering program due to a $525,000 upgrade project completed in 2015 on the Smart Meter back-office hardware.

Table 2-45: 2015 vs. 2016 System Access Variances

	2015 Vs 2016		
Programs	**2015 Bridge Year**	**2016 Test Year**	**Variance from 2015 Budget**
	Budget	**Budget**	**Variance**
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	628,053	646,894	18,842
Meter Installations (CMEG)	1,010,000	415,000	-595,000
Distribution System Modifications / Expansions for Customers (CMOD)	761,407	784,249	22,842
System Relocations Property Development (CREL)	1,262,023	1,299,884	37,861
Expansions for New Residential Subdivisions (CRES)	1,401,224	1,443,261	42,037
New Residential Service Connections (CSER)	231,994	238,954	6,960
Expansions for New Residential Subdivisions (CTH)	552,236	568,803	16,567
Sub-Total	**5,846,937**	**5,397,045**	**-449,892**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**5,846,937**	**5,397,045**	**-449,892**

2015 vs. 2016 System Renewal

The variance in spending can be attributed to an increase in capital expenditures in order to address the need to increase the replacement of asset targets related to the replacement of overhead infrastructure as a result of the conclusions set out in the 2014 ACA.

Table 2-46: 2015 vs. 2016 System Renewal Variances

Programs	2015 Vs 2016		
	2015 Bridge Year	2016 Test Year	Variance from 2015 Budget
	Budget	Budget	Variance
System Renewal			
Distribution System Replacement (CREP)	3,654,117	4,163,741	509,624
Distribution System Transformer replacement upgrades (CTRU)	306,013	315,193	9,180
Sub-Total	**3,960,130**	**4,478,934**	**518,804**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**3,960,130**	**4,478,934**	**518,804**

2015 vs. 2016 System Service

The primary variance is a result of a the capital expenditures related to the construction and rebuilding of Rockwood MS#1 in 2015 which accounts for $1,250,000, as well as the Arlen MTS reactor project scheduled to be in service in 2016, which resulted in a variance of $650,000.

Table 2-47: 2015 vs. 2016 System Service Variances

Programs	2015 Vs 2016		
	2015 Bridge Year	2016 Test Year	Variance from 2015 Budget
	Budget	Budget	Variance
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,143,527	1,177,833	34,306
SCADA Infrastructure (CSC)	218,360	224,911	6,551
SCADA / Remotely Operated Switches (CSW)	248,784	256,248	7,464
Transformer Stations & Distribution Stations (CTS/CDS)	2,231,950	199,409	-2,032,542
Sub-Total	**3,842,621**	**1,858,400**	**-1,984,221**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**3,842,621**	**1,858,400**	**-1,984,221**

2015 vs. 2016 General Plant

Planned expenditures for 2015 and 2016 are very consistent and the overall General Plant variance falls below the materiality threshold and is deemed to be immaterial.

Table 2-48: 2015 vs. 2016 General Plant Variances

	2015 Vs 2016		
Programs	**2015 Bridge Year**	**2016 Test Year**	**Variance from 2015 Budget**
	Budget	**Budget**	**Variance**
General Plant			
Building / Fixtures	754,500	804,135	49,635
Office Equipment / Graphics	58,350	163,100	104,750
Fleet / Rolling Stock	556,200	572,886	16,686
IT Capital	780,000	590,000	-190,000
Major Tools	63,654	65,564	1,910
Sub-Total	**2,212,704**	**2,195,685**	**-17,019**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**2,212,704**	**2,195,685**	**-17,019**

2016 Forecast Vs 2017 Forecast Capital Expenditure Variances

Table 2-49: 2016 vs. 2017 Capital Expenditure Variances

CATEGORY	2016 Forecast Vs 2017 Forecast		
	2016 Test Year	2017	Variance from 2016 Budget
	Budget	Budget	Variance
System Access	5,397,045	5,496,506	99,461
System Renewal	4,478,934	4,613,302	134,368
System Service	1,858,400	1,914,152	55,752
General Plant	2,195,685	1,431,505	-764,179
TOTAL EXPENDITURE	13,930,063	13,455,465	-474,598

2016 vs. 2017 System Access

Planned expenditures for 2016 and 2017 are consistent which results in a variance that falls below the materiality threshold.

Table 2-50: 2016 vs. 2017 System Access Variances

Programs	2016 Vs 2017		
	2016 Test Year	2017	Variance from 2016 Budget
	Budget	Plan	Variance
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	646,894	666,301	19,407
Meter Installations (CMEG)	415,000	365,000	-50,000
Distribution System Modifications / Expansions for Customers (CMOD)	784,249	807,777	23,527
System Relocations Property Development (CREL)	1,299,884	1,338,881	38,997
Expansions for New Residential Subdivisions (CRES)	1,443,261	1,486,559	43,298
New Residential Service Connections (CSER)	238,954	246,123	7,169
Expansions for New Residential Subdivisions (CTH)	568,803	585,867	17,064
Sub-Total	**5,397,045**	**5,496,506**	**99,461**
Miscellaneous Projects (under Materiality threshold)			
Total System Access	**5,397,045**	**5,496,506**	**99,461**

2016 vs. 2017 System Renewal

Planned expenditures for 2016 and 2017 are consistent which results in a variance that falls below the materiality threshold.

Table 2-51: 2016 vs. 2017 System Renewal Variances

Programs	2016 Vs 2017		
	2016 Test Year	2017	Variance from 2016 Budget
	Budget	Plan	Variance
System Renewal			
Distribution System Replacement (CREP)	4,163,741	4,288,653	124,912
Distribution System Transformer replacement upgrades (CTRU)	315,193	324,649	9,456
Sub-Total	**4,478,934**	**4,613,302**	**134,368**
Miscellaneous Projects (under Materiality threshold)			
Total System Renewal	**4,478,934**	**4,613,302**	**134,368**

2016 vs. 2017 System Service

Planned expenditures for 2016 and 2017 are consistent which results in a variance that falls below the materiality threshold.

Table 2-52: 2016 vs. 2017 System Service Variances

	2016 Vs 2017		
Programs	**2016 Test Year**	**2017**	**Variance from 2016 Budget**
	Budget	**Plan**	**Variance**
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,177,833	1,213,168	35,335
SCADA Infrastructure (CSC)	224,911	231,658	6,747
SCADA / Remotely Operated Switches (CSW)	256,248	263,935	7,687
Transformer Stations & Distribution Stations (CTS/CDS)	199,409	205,391	5,982
Sub-Total	**1,858,400**	**1,914,152**	**55,752**
Miscellaneous Projects (under Materiality threshold)			
Total System Service	**1,858,400**	**1,914,152**	**55,752**

2016 vs. 2017 General Plant

The overall spending variance of ($764,179) within the General Plant category is mainly attributed to the decrease in capital expenditures related to the administration building addition project. This project is planned to be completed in 2016 and as a result GHESI does not expect any further expenditures related to this project beyond 2016.

Table 2-53: 2016 vs. 2017 General Plant Variances

Programs	2016 Vs 2017		
	2016 Test Year	2017	Variance from 2016 Budget
	Budget	Plan	Variance
General Plant			
Building / Fixtures	804,135	163,909	-640,226
Office Equipment / Graphics	163,100	64,993	-98,107
Fleet / Rolling Stock	572,886	590,073	17,187
IT Capital	590,000	545,000	-45,000
Major Tools	65,564	67,531	1,967
Sub-Total	**2,195,685**	**1,431,505**	**-764,179**
Miscellaneous Projects (under Materiality threshold)			
Total General Plant	**2,195,685**	**1,431,505**	**-764,179**

2017-2020 Forecast Capital Expenditure Variances Trending Analysis

Overall trending from 2017 – 2020 between categories is very consistent with an average increase rate of approximately 2.3% with minor year-to-year increases planned for inflation.

Table 2-54

	2017 - 2020 Trending			
CATEGORY	2017	2018	2019	2020
	Plan	Plan	Plan	Plan
System Access	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	4,613,302	4,751,701	4,894,252	5,041,080
System Service	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	13,455,465	13,868,179	14,272,674	14,679,305

2017 to 2020 System Access

Year-over-year average variances for this capital expenditure category over the 2017-2020 period exhibit a consistent trend with an increase of approximately 2.25%. The effect is an increase of $125,000 and is below the materiality threshold and deemed immaterial.

Table 2-55

	2017-2020 Trending			
Programs	**2017**	**2018**	**2019**	**2020**
	Plan	**Plan**	**Plan**	**Plan**
System Access				
Apartment, Commercial, Industrial Customer Connections (CACI)	666,301	686,290	706,879	728,085
Meter Installations (CMEG)	365,000	385,000	385,000	375,000
Distribution System Modifications / Expansions for Customers (CMOD)	807,777	832,010	856,970	882,679
System Relocations Property Development (CREL)	1,338,881	1,379,047	1,420,418	1,463,031
Expansions for New Residential Subdivisions (CRES)	1,486,559	1,531,156	1,577,090	1,624,403
New Residential Service Connections (CSER)	246,123	253,506	261,112	268,945
Expansions for New Residential Subdivisions (CTH)	585,867	603,443	621,546	640,192
Sub-Total	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**
Miscellaneous Projects (under Materiality threshold)				
Total System Access	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**

2017 to 2020 System Renewal

The year-over-year average variance over the 2017-2020 period shows a consistent trend with an increase of about 2.32%. The effect is an increase of $107,000 and is below the materiality threshold and deemed immaterial.

Table 2-56

	2017-2020 Trending			
Programs	**2017**	**2018**	**2019**	**2020**
	Plan	**Plan**	**Plan**	**Plan**
System Renewal				
Distribution System Replacement (CREP)	4,288,653	4,417,312	4,549,832	4,686,327
Distribution System Transformer replacement upgrades (CTRU)	324,649	334,389	344,420	354,753
Sub-Total	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**
Miscellaneous Projects (under Materiality threshold)				
Total System Renewal	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**

2017 to 2020 System Service

The year-over-year average variance over the 2017-2020 period exhibits a consistent trend with an increase of about 2.32%. The effect is an increase of $44,300 and is below the materiality threshold and deemed immaterial.

Table 2-57

	2017-2020 Trending			
Programs	**2017**	**2018**	**2019**	**2020**
	Plan	**Plan**	**Plan**	**Plan**
System Service				
Distribution System Feeder Infrastrucutre (CFDR)	1,213,168	1,249,563	1,287,050	1,325,661
SCADA Infrastructure (CSC)	231,658	238,608	245,766	253,139
SCADA / Remotely Operated Switches (CSW)	263,935	271,853	280,009	288,409
Transformer Stations & Distribution Stations (CTS/CDS)	205,391	211,552	217,899	224,436
Sub-Total	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**
Miscellaneous Projects (under Materiality threshold)				
Total System Service	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**

2017 to 2020 General Plant

The year-over-year average variance over the 2017-2020 period exhibits a consistent trend with an increase of about 1.52%. The effect is an increase of $21,750 which is below the materiality threshold and deemed immaterial.

Table 2-58

Programs	2017-2020 Trending			
	2017	2018	2019	2020
	Plan	Plan	Plan	Plan
General Plant				
Building / Fixtures	163,909	168,826	173,891	179,108
Office Equipment / Graphics	64,993	66,943	68,951	71,020
Fleet / Rolling Stock	590,073	607,775	626,008	644,788
IT Capital	545,000	561,350	578,191	595,536
Major Tools	67,531	69,556	71,643	73,792
Sub-Total	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**
Miscellaneous Projects (under Materiality threshold)				
Total General Plant	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**

2012 Board-Approved vs. 2012 Actual Capital Expenditure Analysis

A summary, by material capital project, of 2012 actual project costs compared to 2012 Board-approved projects is shown in the following section. An explanation of the material variances is as follows.

2012 Board-Approved vs. 2012 Actual - System Access – $497,272

Apartment, Commercial, Industrial and Customer Connections - ($24,160)

The overall variance for projects related to connection of apartment, commercial and industrial customers was below the materiality threshold and is deemed immaterial.

Meter Installations – (57,852)

The overall variance related to GHESI's metering activities is below the materiality threshold and deemed immaterial.

Distribution System Modifications / Expansions for Customers – ($285,159)

The variance for this activity can be attributed to a decrease in projects related to expansions or modifications to the distribution system to accommodate customer connections. The planned budget for this type of work is based mainly on two factors: historical trends and current information from customers for upcoming projects. Due to the nature of this work which is outside of GHESI's control, projects did not materialize from the customer's perspective.

System Relocations Property Development – $763,010

The variance for this activity can be mainly attributed to a single project in which the relocation of distribution facilities were required for the MTO due to the installation of a highway overpass in the south end of the City of Guelph. The project started in 2011 and went into service in 2013 with the majority of expenditures taking place in 2012. Due to the nature of this project and the ownership of lands where GHESI's

distribution system was installed, over 90% of the costs for this project were recovered through capital contributions from the land owner. This project required a signification portion of overhead facilities to be relocated underground and also included a bore under the highway to accommodate underground feeder cables.

Expansions for New Residential Subdivisions – ($53,466)

The overall variance related to the expansion of distribution system facilities to accommodate new residential subdivisions fell below the materiality threshold and is deemed immaterial.

Residential Service Connections – $71,873

The overall variance for the service connections to residential customers is below the materiality threshold and deemed immaterial.

Expansions for New Residential Townhouse Subdivisions – $83,026

The overall variance related to the expansion for distribution system facilities to accommodate new residential townhouse subdivisions is below the materiality threshold and deemed immaterial.

Table 2-59

2012 Actual vs. 2012 Approved System Access Variances

Projects	2012 (Previous Test Year)	2012 - OEB Board Approved	2012 - Variance
	Actual	Approved	Variance
Reporting Basis	IFRS	IFRS	IFRS
System Access			
Apartment, Commercial, Industrial Customer Connections (CACI)	546,155	570,315	-24,160
Meter Installations (CMEG)	567,148	625,000	-57,852
- Meters & Metering**	237,712		
- SMART METERING**	176,751		
Distribution System Modifications / Expansions for Customers (CMOD)	75,748	360,907	-285,159
System Relocations Property Development (CREL)	1,728,042	965,032	763,010
- Hanlon Parkway at Laird Road Intersection**	1,199,729		
- Victoria Road South - Arkell Rd to MacAlister Blvd**	329,165		
Expansions for New Residential Subdivions (CRES)	1,409,933	1,463,399	-53,466
- Morningcrest, Ph 2C, Couling Cr**	193,183		
- Noble Ridge Estates, Phase 1 - Rockwood**	158,831		
- Watson Creek, Phase 3**	358,266		
New Residential Service Connections (CSER)	311,801	239,928	71,873
Expansions for New Residential Townhouse Subdivions (CTH)	379,538	296,512	83,026
Sub-Total	**5,018,365**	**4,521,093**	**497,272**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**
Total System Access	**5,018,365**	**4,521,093**	**497,272**

2012 Board-Approved vs. 2012 Actual - System Renewal – ($267,822)

Distribution System Replacement – ($135,662)

The overall variance for the renewal of distribution system facilities is below the materiality threshold and deemed immaterial.

Distribution System Transformer replacement upgrades – ($132,160)

The overall variance for the replacement and upgrade of distribution system transformation is below the materiality threshold and deemed immaterial.

Table 2-60

2012 Actual vs. 2012 Approved System Renewal Variances

Projects	2012 (Previous Test Year)	2012 - OEB Board Approved	2012 - Variance
	Actual	Approved	Variance
Reporting Basis	**IFRS**	**IFRS**	**IFRS**
System Renewal			
Distribution System Replacment (CREP)	2,445,471	2,581,133	-135,662
- Alice St, Arthur S to Stevenson S**	209,017		
- Damaged or Deteriorated Poles**	303,400	182,000	
- Nicklin Road Reconstruction**	195,481		
- Parkwood Gardens, Phase 3 Rehab**	1,084,440		
- Sherwood Dr Rehabilitation**		300,000	
Distribution System Transformer replacement upgrades (CTRU)	91,051	223,211	-132,160
Sub-Total	**2,536,522**	**2,804,344**	**-267,822**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**
Total System Renewal	**2,536,522**	**2,804,344**	**-267,822**

2012 Board-Approved vs. 2012 Actual - System Service - $312,116

The variance of $312,116 for activities within the System Service category can be mainly attributed to lower actual capital expenditures related to distribution system feeder infrastructure than was budgeted, as well as an increase in spending for the Arlen MTS. The Maltby Road - Gordon to Crawley and Gordon St - Clair to Maltby projects that were proposed to take place in 2012 were removed from the capital plan due to a lack of progress on the development of lands requiring electricity supply in that area. Both Hanlon Creek Business Park phase projects were not planned to move forward in 2012, but as a result of an accelerated development schedule by the City of Guelph and land owners, distribution system facilities were required to be built and put in service. The following provides a breakdown of variances within the System Service category:

- Distribution System Feeder Infrastructure - ($1,244,158)
- SCADA Infrastructure - $48,002
- SCADA / Remotely Operated Switches – ($82,162)
- Transformer Stations & Distribution Stations - $1,601,168

Table 2-61

2012 Actual vs. 2012 Approved System Service Variances

Projects	2012 (Previous Test Year)	2012 - OEB Board Approved	2012 - Variance
	Actual	Approved	Variance
Reporting Basis	IFRS	IFRS	IFRS
System Service			
Distribution System Feeder Infrastrucutre (CFDR)	1,212,410	2,456,568	-1,244,158
- Hanlon Creek Business Park, Phase 1B, Part 2**	181,547	0	
- Hanlon Creek Business Park, Phase 2**	639,614	0	
- Poppy Drive, Phase 1B **	203,347	0	
- Maltby Road Gordon to Crawley**	0	530,000	
- Gordon St Clair to Maltby**	0	440,000	
- York Road - Railway to Watson**	0	636,000	
SCADA Infrastructure (CSC)	248,002	200,000	48,002
SCADA / Remotely Operated Switches (CSW)	78,394	171,290	-92,896
Transformer Stations & Distribution Stations (CTS/CDS)	1,601,168	0	1,601,168
- ARLEN MTS**	1,596,028		
Sub-Total	**3,139,974**	**2,827,857**	**312,116**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**
Total System Service	**3,139,974**	**2,827,857**	**312,116**

2012 Board-Approved vs. 2012 Actual - General Plant - ($200,450)

The overall variance within the General Plant category of ($200,450) can be attributed to the minor variances contained within several cost centres, listed below. Individually each variance falls below GHESI's materiality threshold. The overall category variance can be related to a decrease in capital expenditures on GHESI's administration building and IT infrastructure. GHESI's normal budget and spending on capital for building related items was approximately $32,000 in 2011 and $97,000 in

2013, however in 2012 there was no necessity to complete any major building related projects. Capital expenditures related to IT infrastructure in 2012 were slightly lower than budgeted and approved amounts. The variances can be attributed to a project related to disaster recovery that was postponed to 2013, as well as a change in project scope related to IT items for the GHESI administration building Boardroom. The following is a breakdown of variances within General Plant:

- Building / Fixtures – ($82,688)
- Office Equipment / Graphics – ($9,440)
- Fleet / Rolling Stock – ($16,044)
- IT Capital – ($103,754)
- Major Tools – $11,475

Table 2-62

2012 Actual vs. 2012 Approved General Plant Variances

Projects	2012 (Previous Test Year)	2012 - OEB Board Approved	2012 - Variance
	Actual	Approved	Variance
Reporting Basis	IFRS	IFRS	IFRS
General Plant			
Building / Fixtures	0	82,688	-82,688
Office Equipment / Graphics	43,060	52,500	-9,440
Fleet / Rolling Stock	468,956	485,000	-16,044
- 2012 Terex C-5052 **	250,158		
IT Capital	396,246	500,000	-103,754
- Comp Software**	240,878		
Major Tools	76,475	65,000	11,475
Sub-Total	**984,738**	**1,185,188**	**-200,450**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**
Total General Plant	**984,738**	**1,185,188**	**-200,450**
Total all Categories	**11,679,598**	**11,338,482**	**341,116**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*			
Total	**11,679,598**	**11,338,482**	**341,116**

PROJECTS WITH LIFE CYCLE GREATER THAN ONE YEAR

Guelph Hydro's accounting policy is to include projects in fixed assets when they are completed and put into service. Capital projects which are not yet completed are included in CWIP. Capital projects with a life cycle greater than one year will be carried over from one year to the next in CWIP. Once completed, expenditures are removed from CWIP and capitalized to fixed assets, at which point they begin depreciating.

Treatment of Cost of Funds

Guelph Hydro's accounting policy is to capitalize borrowing costs based on its average CWIP balance over the fiscal year. This capitalized interest is then added to CWIP and is allocated to each of the distribution system asset categories based on the total unitized costs that result as the CWIP projects are completed and put into service. Guelph Hydro uses the weighted average of the quarterly prescribed interest rates posted by the OEB when calculating its year end Allowance for Borrowed Funds Used During Construction "AFUDC" balance.

COMPONENTS OF OTHER CAPITAL EXPENDITURES – NON DISTRIBUTION

Other GHESI capital expenditures that are included in the non-distribution system activity category include a 10kW solar PV microFIT project located on the roof of the switchgear and P&C building at the Guelph Hydro-owned Arlen MTS. This project was commissioned and put into service in 2013 at a cost of $45,578. This project reconciles to the total capital budget. Details regarding the expenditures can be found below.

Table 2-63

		2012	2013	2014	2015	2016
2075	Non-Utility Property Owned or Under Capital Lease (Gross Cost)	0.00	45,577.55	45,577.55	45,577.55	45,577.55
2180	Accumulated Amortization of Non-Utility Property	0.00	(1,321.75)	(3,964.75)	(6,607.75)	(9,250.75)
	Non-Utility Property Owned or Under Capital Lease (NBV)	0.00	44,255.80	41,612.80	38,969.80	36,326.80

2.5.2.3 CAPITALIZATION POLICY

Guelph Hydro has not changed its capitalization policy since the last rebasing application for 2012 rates (EB-2011-0123) (please see the capitalization and depreciation policy in this Exhibit, Appendix 2-B).

Capitalization of Expenses - Overview

Effective January 1, 2011, Guelph Hydro adopted accounting policies that are compliant with International Financial Reporting Standards ("IFRS"). With respect to capitalization of certain expenses, Guelph Hydro follows the guidance provided by IAS 16.16, whereby capital cost includes the following:

- Purchase price, including duties and non-refundable taxes and excluding trade discounts and rebates
- All expenditures directly attributable to bringing the asset to a working condition for its "intended use"
    - Directly attributable need not be incremental or external
    - Capable of being operated in the manner intended by management
- Cost of the obligation of its dismantlement, removal or restoration
- PP&E include expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour, third party subcontracting and other costs directly attributable to bringing the asset to a working condition for its intended use.
- Expenditures that create a physical betterment or improvement of an asset will be capitalized.

Guidelines for Capitalization

Capital Assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are defined as assets that lack physical substance. They include computer software.

Betterment - a "betterment" is a cost which enhances the service potential of a capital asset and/or increases its value, and is therefore capitalized. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value.

Repairs - a repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and are charged to an operating account.

Capitalization by Component

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which: a) are significant in relation to the total cost of the item and b) have different depreciation methods or useful life.

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually

significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service.

- Guelph Hydro has used the Typical Useful Life provided in the Kinectrics Report as its basis for assigning the estimated service life to assets. As required under IFRS, Guelph Hydro reviews the useful lives assigned to each major component on an ongoing basis and in 2014 engaged Kinectrics to review its distribution assets and provide Guelph Hydro with the most up to date assessment of the condition of its assets and a recommendation as to its remaining useful life. Based on these recommendations, Guelph Hydro made the necessary adjustments to its depreciation calculations so that they reflect the most up to date useful lives for fiscal years 2014 – 2016. Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. In the first year of service, depreciation is calculated using the ½ year rule. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated.

Overhead Policy

Guelph Hydro's overhead policy was reviewed by its external auditors during its transition period back in 2011 and during each year-end audit since the transition to ensure that Guelph Hydro's policy remains to be IFRS compliant.

In 2011, Guelph Hydro reviewed and changed its overhead policy, including the capitalization component, to follow a more direct allocation of costs as required under IFRS. Guelph Hydro does not capitalize general administrative costs related to Administration, HR, Regulatory Affairs, Information Systems Technology, Billing and Collections or Finance.

In addition to Guelph Hydro's direct labour costs are those costs that are generally considered labour 'burden'. Guelph Hydro's burden costs include vacation, statutory holidays, sick time, CPP, EI, OMERS contributions, health care and other employee benefits. Burden rates are forecasted by employee classification (i.e. Line Construction, maintenance, metering etc.) and are set-up in Guelph Hydro's costing system accordingly. Through the timesheet process, employees track their hours by work order which designates whether the work is expensed or capitalized. Labour costs are then directly charged to specific project by employee based on the work executed in the field. The labour burden is then added to the project costs based on the direct labour cost the employee charges to the project.

The overhead policy also addresses what Guelph Hydro considers as the two main cost centres that directly impact its capital projects; fleet costs and the Engineering department. Costs of these departments are allocated to the departments that are served – Lines, Substations and Metering – and directly impact construction activities.

Fleet Costs - these costs include the costs associated with maintaining Guelph Hydro's fleet of pick-up trucks, bucket trucks with aerial devices, and trailers. These costs include fuel, repairs, parts, insurance, depreciation and all other items of expense necessary to keep the fleet in service. A fleet burden rate is reviewed on an annual basis for the fleet as a whole and costs are allocated to the capital projects based on labour costs of the Line Construction and Inspection staff as well as the Operations and Metering staff that were charged to these same capital projects. This fleet burden process estimates the run time of the fleet as to whether they were used for capital work

or maintenance and operational work which allows us to allocate the fleet costs accordingly.

Engineering - the Engineering department follows a similar methodology for the calculation of overheads that is used for Guelph Hydro's fleet costs in order to accurately make a determination of what can be directly attributable to capital and therefore included in the capital costs of a project. Based on actual labour costs charged to capital projects throughout the year by Line Construction, Inspection, Operations and Metering, engineering costs are allocated to these same projects. Burden rates are reviewed annually and are set based on the Engineering departments approved operating budget as well as Guelph Hydro's capital plan for the year. This review outlines the total direct labour time required to meet the capital plan and ensures the capital recovery is appropriate to cover the estimated costs associated with the engineering time required.

Once the overhead rates are determined, the costs are charged to the capital projects based on the direct labour hours charged to the projects by the departments outlined above through the timesheet process by work order. As a result, for every labour dollar allocated to a capital project by an employee through the timesheet process, an engineering burden amount is also directly attributed to the specific project as part of Guelph Hydro's costing process. For example, when a line crew is working on a specific job, the hours worked on the job are processed through payroll and then the work order costing system then multiplies those hours by the overhead rate to attach the cost directly to the job. This costing system is tracked and maintained by the engineering department and is continuously reconciled to the actual costs been tracked in the financial system.

As part of the transition to IFRS, Guelph Hydro took the position that costs related to both Inventory and purchasing as well as facility costs were not going to be part of the capitalization process through its burden rates. As a result, any costs related to these functions have been treated as OM&A costs and expensed annually.

The Capitalization and Overhead Policy is presented in Appendix 2-B of this Exhibit.

2.5.2.4 CAPITALIZATION OF OVERHEAD

Guelph Hydro has completed Appendix 2-D Overhead Expense showing a breakdown of OM&A before capitalization and capitalized OM&A. In the 2016 Test Year, Guelph Hydro anticipates that 5.94% of OM&A costs will be capitalized.

Please see Appendix 2-D below in Table 2-64.

BURDEN RATES

The table below summarizes the historical and forecasted overhead rates related to the capitalization of costs on self-constructed assets. Guelph Hydro changes its burden rates periodically to reflect actual costs or changed circumstances.

Guelph Hydro has three types of overhead costs that are capitalized; (i) Engineering; (ii) Fleet; and (iii) payroll benefits. Guelph Hydro applies burden rates to the actual labour costs charged to the capital projects by the employees in their direct labour departments (Lines Construction, Inspection, Maintenance and Metering).

As described previously, Guelph Hydro does not allocate any indirect costs associated with Finance, Human Resources, Information Systems Technology, Regulatory Affairs, Billing and Collections or the Administration department.

Table 2-64

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	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year
Fleet	$ 705,622	$ 839,340	$ 893,338	$ 945,355	$ 870,972
Engineering	$ 1,759,320	$ 1,423,964	$ 1,587,859	$ 1,517,638	$ 1,546,053
System Operations and Maintenance	$ 5,036,183	$ 5,887,542	$ 5,608,387	$ 6,625,382	$ 7,270,862
Stores	$ 252,805	$ 334,617	$ 328,841	$ 383,910	$ 394,322
General Administration Expenses	$ 1,230,872	$ 2,559,408	$ 1,659,615	$ 1,527,570	$ 1,543,820
Human Resources, including Retirement benefil and performance plan	$ 1,526,708	$ 1,532,409	$ 1,571,978	$ 1,923,235	$ 1,824,994
Accounting	$ 521,122	$ 591,101	$ 581,806	$ 860,979	$ 908,459
Regulatory Affairs	$ 232,035	$ 241,630	$ 267,470	$ 406,856	$ 343,128
Community Relations	$ 118,611	$ 131,746	$ 132,876	$ 149,000	$ 114,000
Billing & Collections	$ 2,804,273	$ 2,634,342	$ 2,680,998	$ 2,308,541	$ 2,746,655
Total OM&A Before Capitalization (B)	$ 14,187,551	$ 16,176,100	$ 15,313,168	$ 16,648,466	$ 17,563,264

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	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
Fleet	$ 538,363	$ 620,624	$ 688,403	$ 736,272	$ 648,397	Y	Directly attributable to total labour costs charged to capital
Engineering	$ 443,734	$ 467,885	$ 520,500	$ 579,126	$ 510,007	Y	Directly attributable to total labour costs charged to capital
Total Capitalized OM&A (A)	$ 982,098	$ 1,088,509	$ 1,208,902	$ 1,315,397	$ 1,158,404		

% of Capitalized OM&A (=A/B)	6%	6%	7%	7%	6%		

Guelph Hydro's burden rates are reviewed and compared to actual costs annually. During the time period 2012 – 2014, the rates were not required to be adjusted as the costs calculated through the burden rate system provided a reasonable estimate of the related actual costs.

Table 2-65: Burden Rates

Description		2012-2014 Actual Costs	2015 Bridge	2016 Test
Engineering Burden				
	100% Total labour costs (1)	15%	15%	15%
add	50% Total overtime costs (1)	15%	15%	15%
add	100% 3rd Party Sub-contractors	9%	9%	9%
Fleet Burden				
	100% Total labour costs (2)	65%	65%	65%
add	50% Total overtime costs (2)	65%	65%	65%
add	100% Total labour costs (3)	35%	35%	35%
add	50% Total overtime costs (3)	35%	35%	35%
Payroll Burden				
	100% Total labour costs (4)	110%	110%	110%
add	50% Total overtime costs (4)	110%	110%	110%
add	100% Total labour costs (5)	50%	50%	50%
add	50% Total overtime costs (5)	50%	50%	50%

(1) Labour Costs for all direct labour departments allocating time to the capital project through the payroll system (Line construction, inspection, operations and metering)

(2) Labour costs relating to the Line construction and inspection departments allocating time to the capital project through the payroll system

(3) Labour costs relating to the operations and metering departments allocating time to the capital project through the payroll system

(4) Labour costs relating to the line construction, operations and metering departments allocating time to the capital project through the payroll system

(5) Labour costs relating to the inspection department allocating time to the capital project through the payroll system.

2.5.2.5 COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

Section 2.5.2.5 of the Filing Requirements contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in section 79.1 of the *Ontario Energy Board Act, 1998* (the "Act") and Regulation 330/09 (O. Reg. 330/09)[1] made under the Act.

Costs incurred by a distributor, in accordance with cost responsibility rules in the OEB's Distribution System Code for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system, are considered to be eligible investments for the purpose of provincial rate recovery under s. 79.1of the Act.[2]

REG CONNECTIONS

There is significant renewable generation activity across Guelph Hydro's distribution system. As of December 31, 2014, Guelph Hydro had connected 309 renewable generation projects with a total nameplate capacity of 8.537 MW. Guelph Hydro expects to connect an estimated 360 additional renewable energy generation facilities over the 2015 to 2020 rate period, with a corresponding capacity of 8 MW. Therefore, by the end of 2020, the utility anticipates to have almost 660 renewable generation facilities with a corresponding capacity of approximately 16 MW connected to its distribution system.

Guelph Hydro does not expect any capital expenditures related to renewable energy generation in its Distribution System Plan. There are no additional OM&A costs related to renewable generation as Guelph Hydro is able to process both microFIT and FIT applications utilizing existing employees. Therefore, Guelph Hydro does not require

[1] O. Reg. 330/09.
[2] O. Reg. 330/09, at s. 1(2).

recovering costs incurred to make eligible investments as described in section 79.1 of the Act and O.Reg. 330/09 under the Act.

Because Guelph Hydro does not expect any capital expenditures related to renewable energy generation, Guelph Hydro has not filed Appendix 2-FA to 2-FC.

2.5.2.6 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

HALF YEAR RULE: D_1-FACTOR

On June 20, 2014, the Board issued a letter related to the *Proposal for New Policy Options for the Funding of Capital Investments* (EB-2014-0219). The Board proposed an adjustment mechanism referred to as the D_1- factor. The purpose of this mechanism is to eliminate the effect of the half-year rule on test year capital additions for the intervening years between rebasing applications (i.e., during the subsequent IR term) by adjusting for the incremental revenue requirement (depreciation expense plus return on capital and associated taxes/PILs) of the test year capital additions. This is proposed to be accomplished through an adjustment (to be referred to as the D_1-factor) to the price cap formula in the first IR application subsequent to the Cost of Service application that resulted in rebased rates. The half-year rule would still apply for the test year.

The current approach for capital investments that go into service in the test year allows only one-half of the revenue requirement to go into rates. However, in an extended IR regime (from 3 years to now 5 years), the half-year rule does not work well since it distorts revenues and cash flows. The absence of the other half of the revenue requirement impact for test year assets persists throughout the IR term, and the sustainment or replacement capital is not fully funded during the IR term by depreciation expense. Therefore, the Board developed the D_1-factor to recover the impact of the half year rule.

The D_1-factor is the ratio of the incremental revenue requirement to adjust for full year impact and represents the other half of the revenue requirement impact for test year additions. The D_1-factor is to be applied as an adjustment to the Price Cap IR formula.

Adjusted Price Cap IR Formula for first year Price Cap IR only:

$$P_{t+1} = P_t \times (1 + (IPI - 0 - stretch_factor \pm Z + D_1))$$

In order to mitigate the effects of the half-year rule on distribution revenue in the years following the rebasing year, Guelph Hydro is requesting that the D_1-factor adjustment be applied to its distribution rates in the first Price Cap IR application following this rebasing application. Guelph Hydro has calculated its D_1-factor to be 2.13%, which is below the acceptable adjustment of 3%. Table 2-66 below presents the calculation of Guelph Hydro's D_1-factor.

Table 2-66

2016

D_1-factor Calculation

Cost of Service Test Year Capital Additions				Gross Book Value	$	10,782,000	Appendix 2-BA	
Depreciation Expense on Cost of Service Test Year Capital Additions								
Depreciation Expense on Cost of Service Test Year Capital Additions				Full Year	App. 2-CE/2-CI, cell I57			
				Half Year	Estimate based on 2-CE/2-CI or 2-CJ			
Incremental Depreciation Expense on Test Year Capital Additions							$ 254,371	(a)
Average Net Book Value of Cost of Service Test Year Capital Additions					$	10,782,000		
Cost of Capital Parameters and Calculations								
	Capital Share		**Rate**				**Return on Capital**	
Equity	40%	RRWF, Sheet 3, Cell U57	9.30%	RRWF, Sheet 3, Cell U64	$	4,312,800	$ 401,090	
Preferred Shares	0%	RRWF, Sheet 3, Cell U58	0%	RRWF, Sheet 3, Cell U65	$	-	$ -	
Long-term Debt	56%	RRWF, Sheet 3, Cell U55	5.18%	RRWF, Sheet 3, Cell U62	$	6,037,920	$ 312,528	
Short-term Debt	4%	RRWF, Sheet 3, Cell U56	2.16%	RRWF, Sheet 3, Cell U63	$	431,280	$ 9,316	
	100%	**WACC** (Weighted Average Cost of Capital)	6.71%	Total Return on Capital	$	10,782,000	$ 722,934	(b)
Taxes/PILs Calculation								
Aggregate Corporate Tax Rate			25.47%	Sum of RRWF, Sheet 3, cells E49 and E50				
Taxes/PILs expense based on return on equity portion of capital					$	102,172		
Grossed-up taxes/PILs expense							$ 137,095	(c)
					Sub-total		$ 860,030	(d) = (b) + (c)
					1/2 Year Impact		$ 430,015	(e) = (d) /2
D_1 -Factor								
Numerator	Sum of Cells O29 and O31						$ 684,386	(f) = (a) + (e)
Denominator	Base Revenue Requirement			RRWF, Sheet 8, Cell N29			$ 32,112,227	(g)
Data from KWHI, EB-2013-0147, final evidence, RRWF, etc. (reflects Board Decision and DRO)					D_1	=	2.13%	(h) = (f) / (g)

Advanced Capital Module

In the Report of the Board, *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) dated September 18, 2014, the Board-approved the Advanced Capital Module (ACM), a new funding mechanism which would

enable reviews during a Cost of Service application for the need and prudence of any proposed incremental capital module funding requests for discrete projects that are part of a distributor's DSP, and that are planned to come into service during the IRM period.

Guelph Hydro does not plan any discrete capital expenditures above ACM threshold and therefore it is not applying for an advanced capital module in this Application.

2.5.2.7 ADDITION OF ICM ASSETS TO RATE BASE

Guelph Hydro did not apply for an ICM in the IRM period following its 2012 Cost of Service. Therefore, Guelph Hydro is not requesting ICM capital asset amounts to be incorporated into its rate base.

Account 1508 Other Regulatory Assets, Sub-accounts, Incremental Capital

Guelph Hydro disposed the account 1508 Other Regulatory Assets, Sub-accounts, Incremental Capital (Expenditures, Depreciation Expenses, Accumulated Depreciation, and Incremental Capital Expenditures) in its 2012 Cost of Service Application (EB-2011-0123).

2.5.2.8 SERVICE QUALITY AND RELIABILITY PERFORMANCE

Reported Electricity Service Quality Requirements ("ESQRs")

With the exception of two occurrences in 2014 in which a high volume of locate requests and a change in locate contractors impacted Guelph Hydro's ability to meet its targets for scheduling and meeting appointments, Guelph Hydro has consistently exceeded the OEB's Reported Electricity Service Quality Requirements ("ESQRs") and, as set out in Table 2-67 through 2-78 below, has targeted to maintain its performance at levels equal to or above the OEB's standards in 2015 and 2016. Guelph Hydro has also completed and presented Appendix 2-G: System Quality Indicators in this section, in Table 2-83.

"Guelph Hydro is ranked in the top 10% in Canada for system reliability. This has an important impact on Guelph's prosperity and quality of life – when you think of all the customers who rely on the service, from industrial to commercial customers to homeowners and families." – Former Mayor Karen Farbridge (September 2014)

GUELPH HYDRO'S SERVICE QUALITY INDICATORS
ANNUAL AVERAGE PERFORMANCE

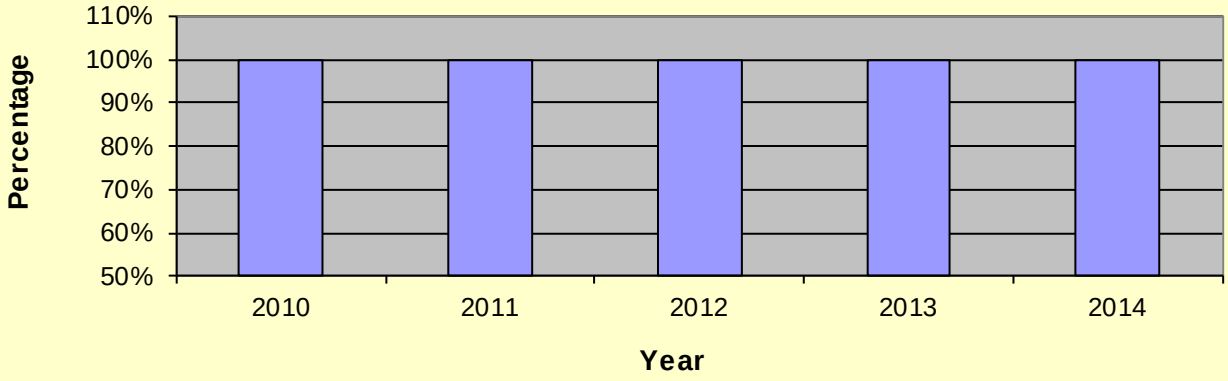
Table 2-67:
Connection of New Services - Low Voltage (<750 V)

OEB Approved Standard: 90% of the time

Actual									Target	
2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
100%	100%	100%	100%	99.80%	99.90%	100%	100%	100%	100%	100%

Annual Percentage of New Low Voltage Services Connected within Five Days

As a minimum performance standard for the connection of new universal services,new low voltage (<750 volts) services must be connected within 5 business days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time. The connection of new services indicator measures the percentage of requests that are met within the required minimum performance standard.



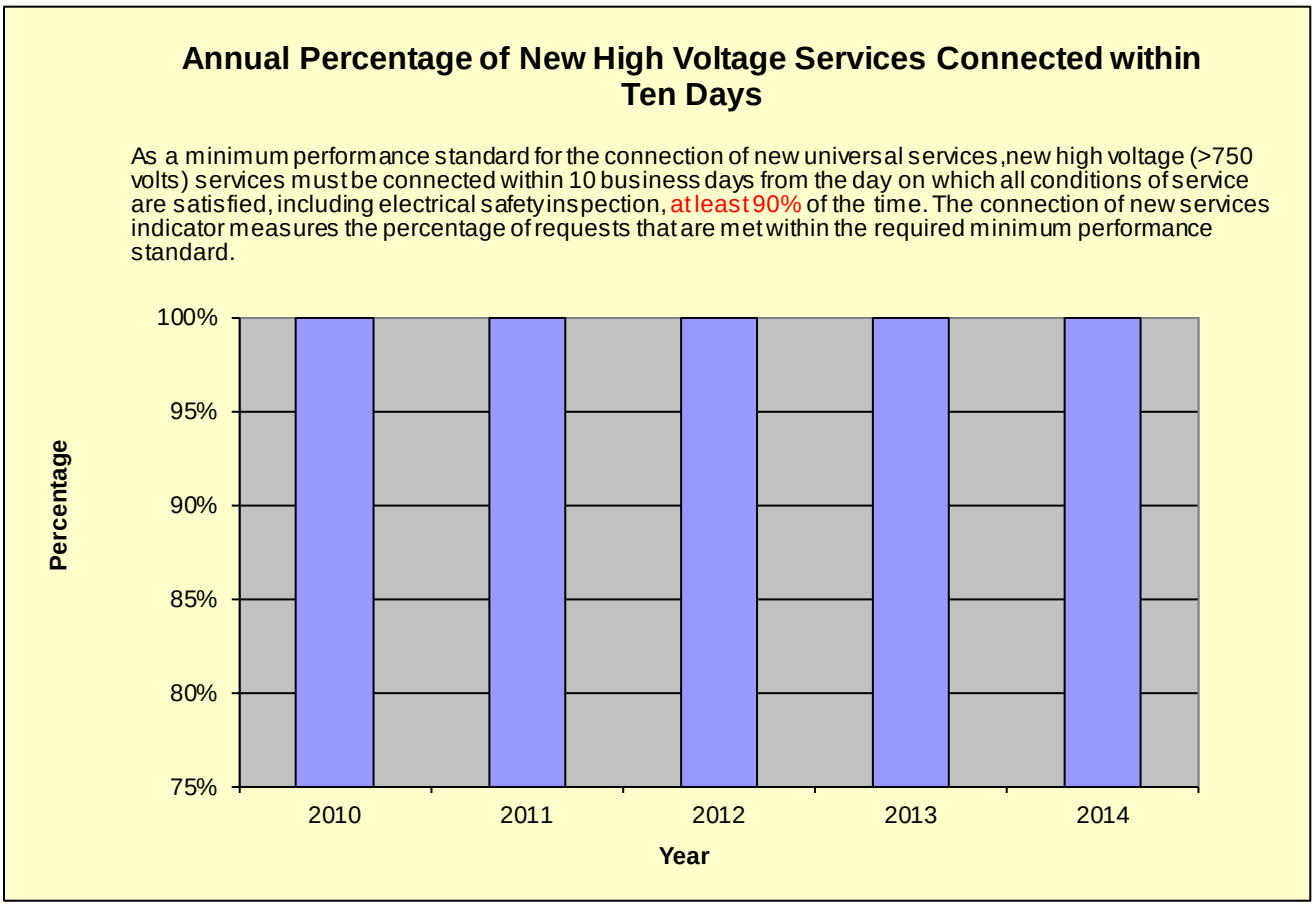
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Table 2-68:
Connection of New Services – High Voltage (>=750 V)

OEB Approved Standard: 90% of the time

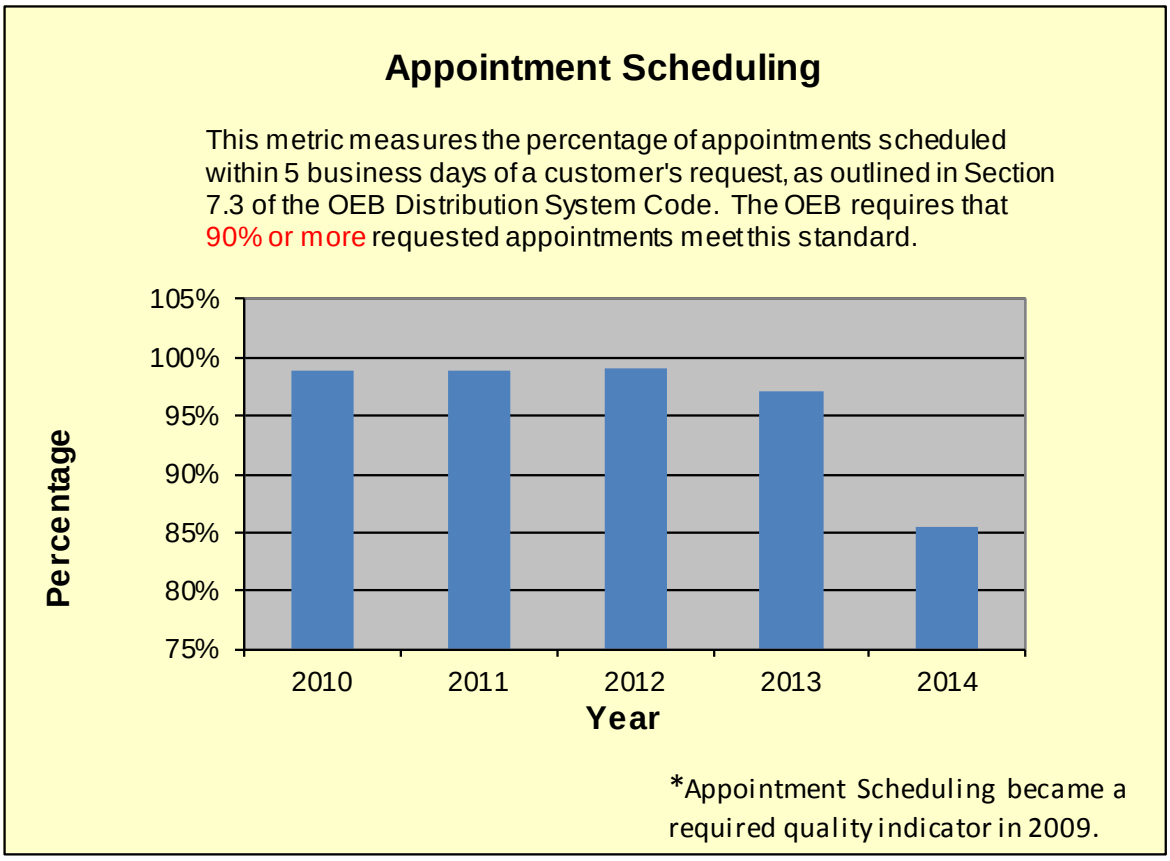
Actual									Target	
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%



2
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Table 2-69:
Appointment Scheduling
OEB Approved Standard: 90% of the time

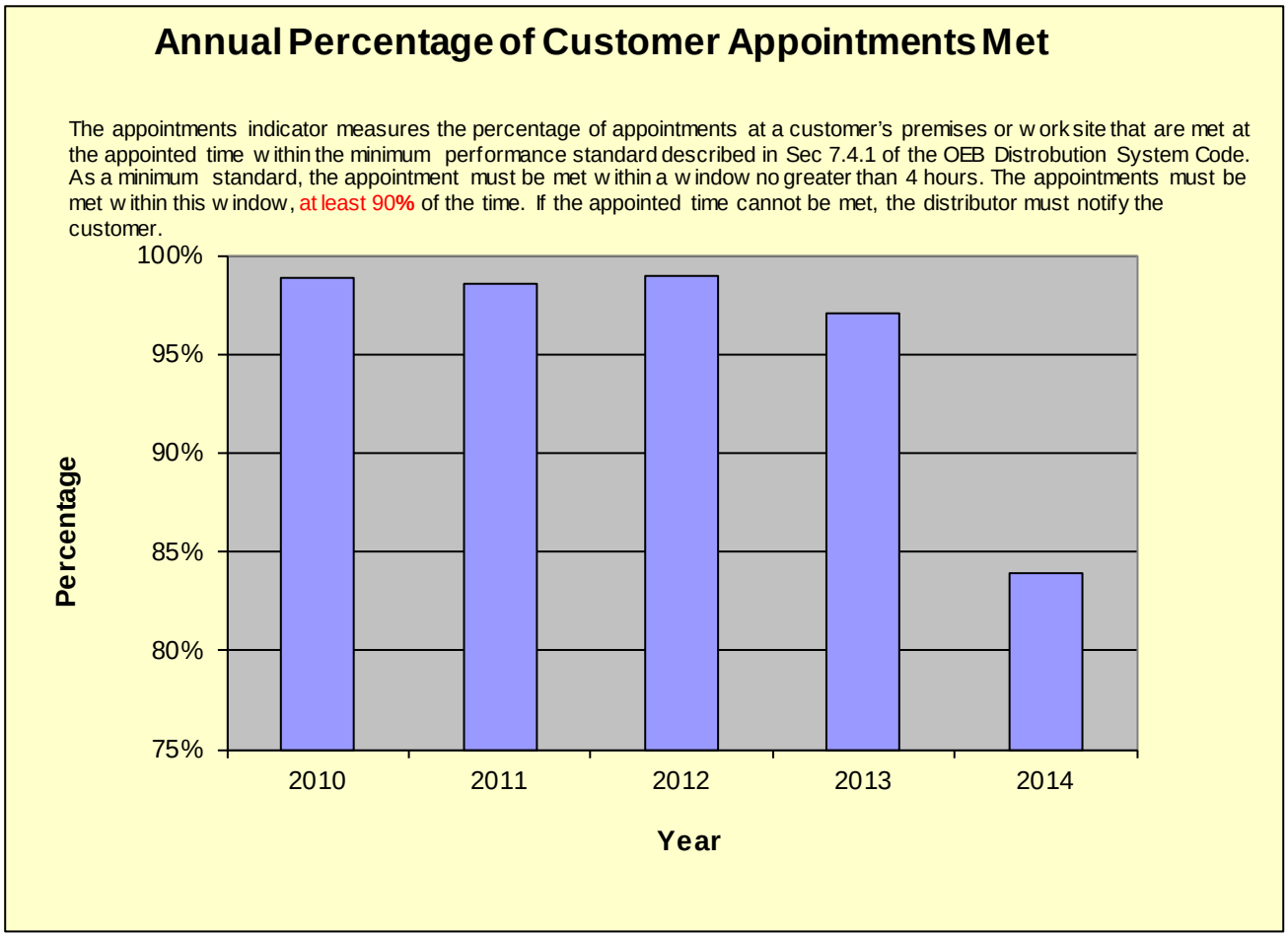
Actual						Target	
2009	2010	2011	2012	2013	2014	2015	2016
100%	98.90%	98.90%	99.00%	97.00%	85.40%	99%	99%



In 2014 Guelph Hydro experienced lower than expected appointments scheduled within 5 business days of a customer's request. Guelph Hydro was transitioning to a new locate contractor beginning in the month of April, and simultaneously received an uncharacteristically large volume of locate requests, which further added to the challenge of scheduling appointments. Guelph Hydro resolved the issue and exceeded the minimum standards for the latter half of 2014.

Table 2-70:
Appointments Met
OEB Approved Standard: 90% of the time

Actual									Target	
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100%	100%	100%	96.50%	98.90%	98.60%	99.00%	97.10%	83.9%	99%	99%



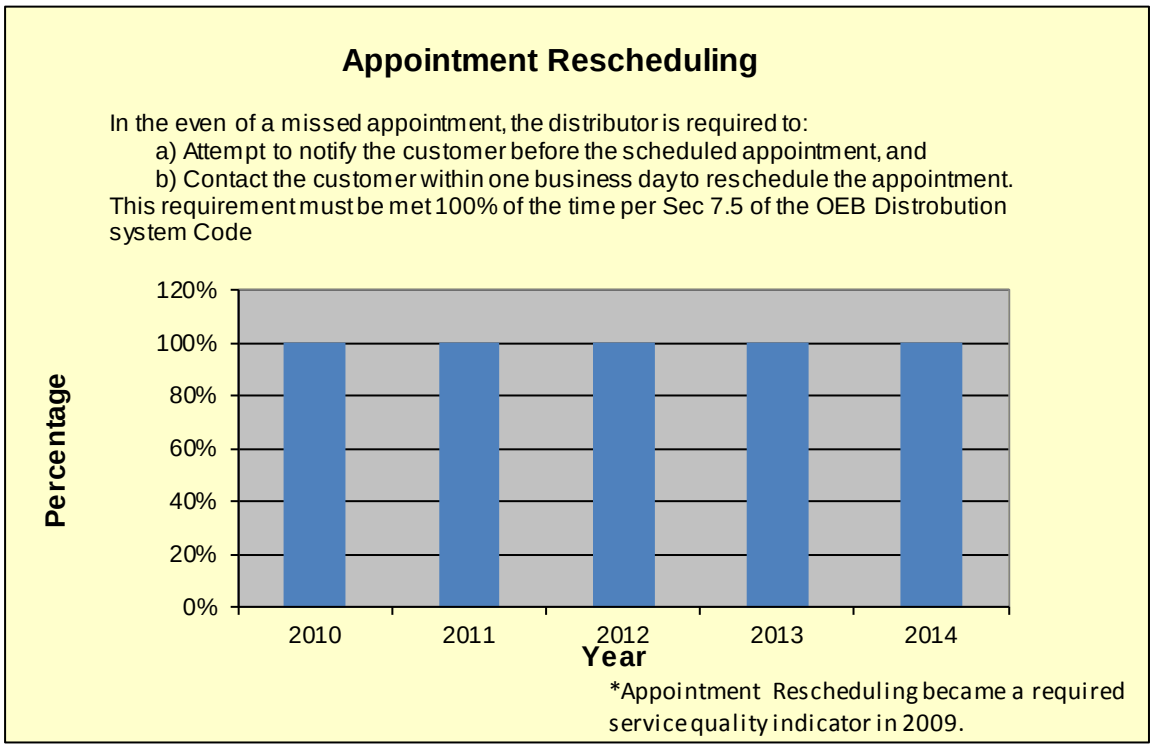
In 2014, Guelph Hydro experienced a lower than expected result in scheduled appointments met on time as it related to underground locates due to the larger than normal volume of locate requests that were received in April to May of 2014. Guelph Hydro experienced an increase of over 30% of locates requests within the month of May 2014, which proposed a challenge to the Guelph Hydro contractors completing the

scheduled locates within the 5 day allowance. Along with the increase in locate requests, Guelph Hydro was also transitioning to a new locate contractor beginning in the month of April which further added to the challenges and lower than average response time Issues with this metric were promptly resolved by Guelph Hydro's efforts and transition to new locate contractor. Specifically, Guelph Hydro met on a regular basis with its locate contractor to work through any issues and continually monitored performance. Guelph Hydro will continue to monitor the metric and consider the need to act accordingly to meet the requirement.

Table 2-71:
Rescheduling a Missed Appointment

OEB Approved Standard: 100% of the time

Actual						Target	
2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
100%	100%	100%	100%	100%	100.0%	100%	100%



Guelph Hydro's customer service quality in the historical period has been consistently beyond the industry target. Although Guelph Hydro's 2012 telephone accessibility results of 80% are well above the industry target of 65%, Guelph Hydro acknowledged a 2012 reduction in performance when compared to previous years. This issue was addressed with the implementation of an IVR system.

1

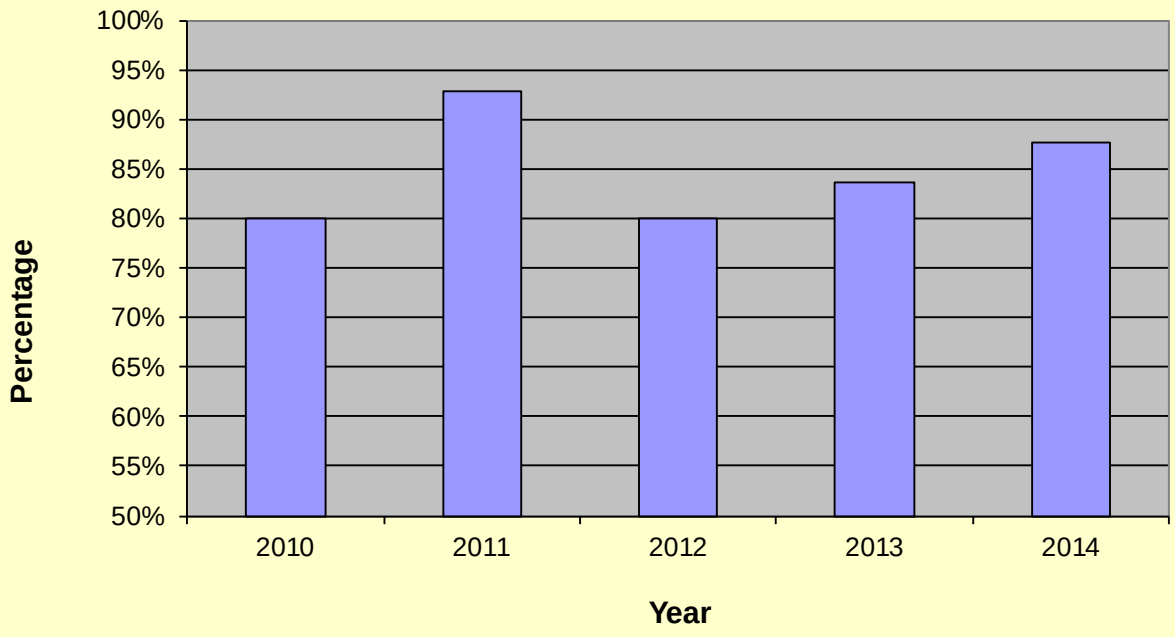
Table 2-72:
Annual Phone Calls Percentage Met

OEB Approved Standard: 65% of the time

Actual %									Target %	
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
63.58%	80.70%	81.60%	*70.60%	80.00%	92.90%	80.00%	83.70%	87.70%	88%	90%

Annual Percentage of Telephone Calls Answered within 30 Seconds

Qualified incoming calls to the distributor's customer care telephone number must be answered within a 30 second time period. This service quality requirement must be met at least 65% of the time annualy. For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the .first ring



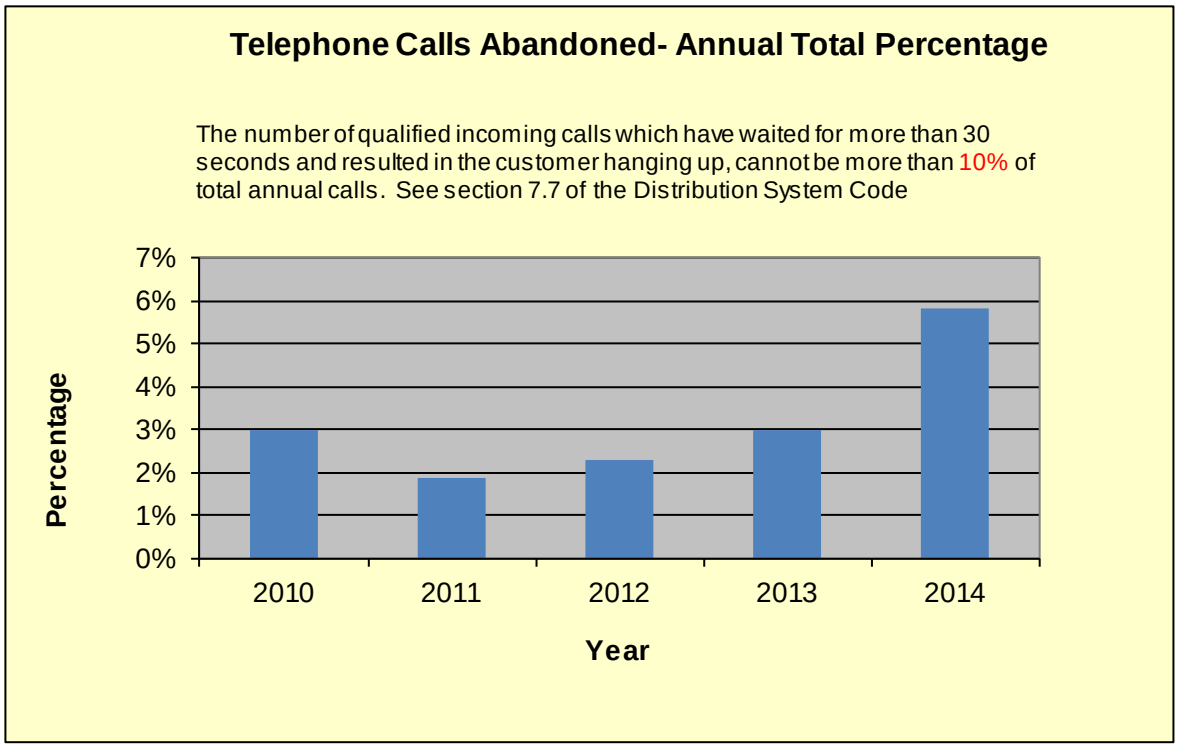
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Table 2-73:
Telephone Call Abandon Rate

OEB Approved Standard: 10% or less

Actual %						Target %	
2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
0.00%	3.00%	1.90%	2.30%	3.00%	5.80%	2%	1.5%



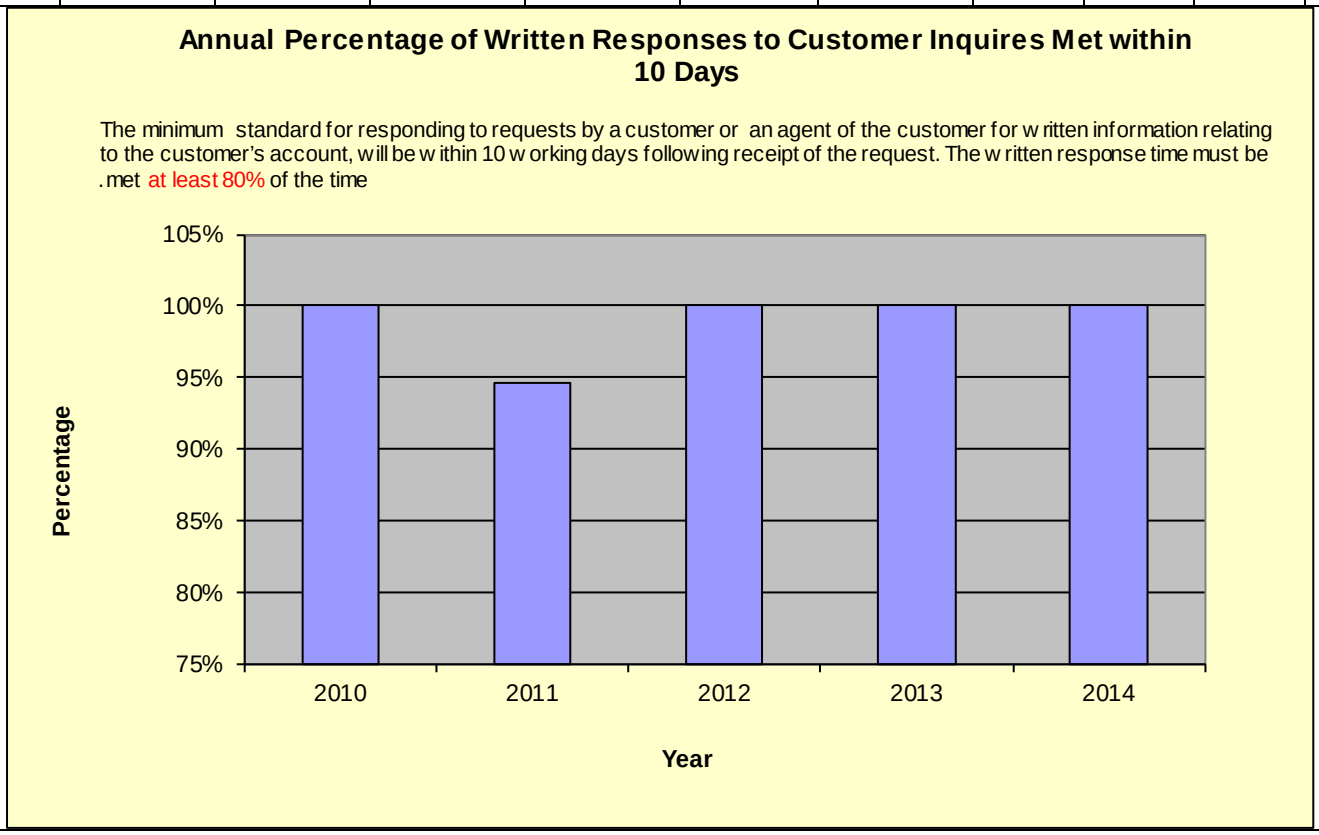
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Table 2-74:
Written Responses to Enquires

OEB Approved Standard: within 10 days at least 80% of the time

Actual %									Target %	
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100.00%	100.00%	100.00%	100.00%	100.00%	94.70%	100.00%	100%	100%	100%	100%



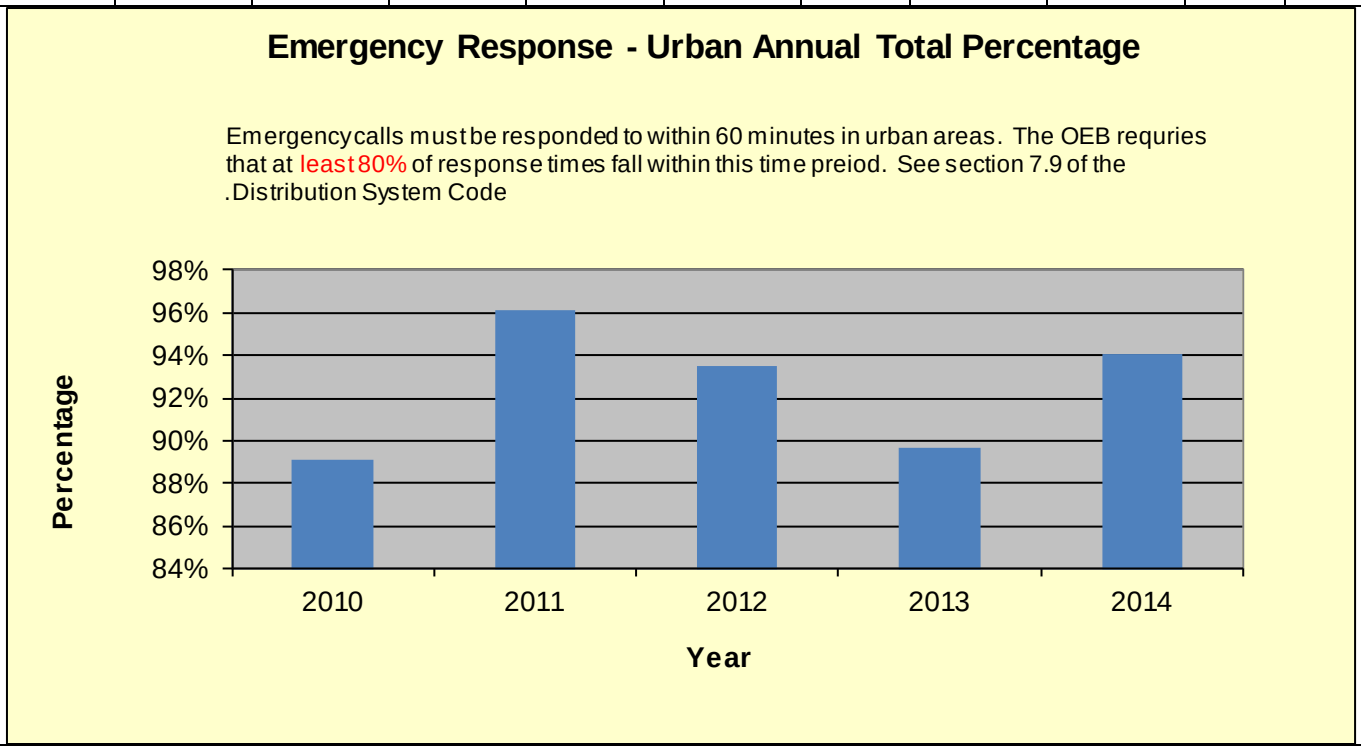
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Table 2-75:
Emergency Response Urban Annual

OEB Approved Standard: 80% of the time

Actual %									Target %	
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
89.63%	86.40%	93.90%	90.20%	89.10%	96.10%	93.50	89.70%	94.00%	94%	94%



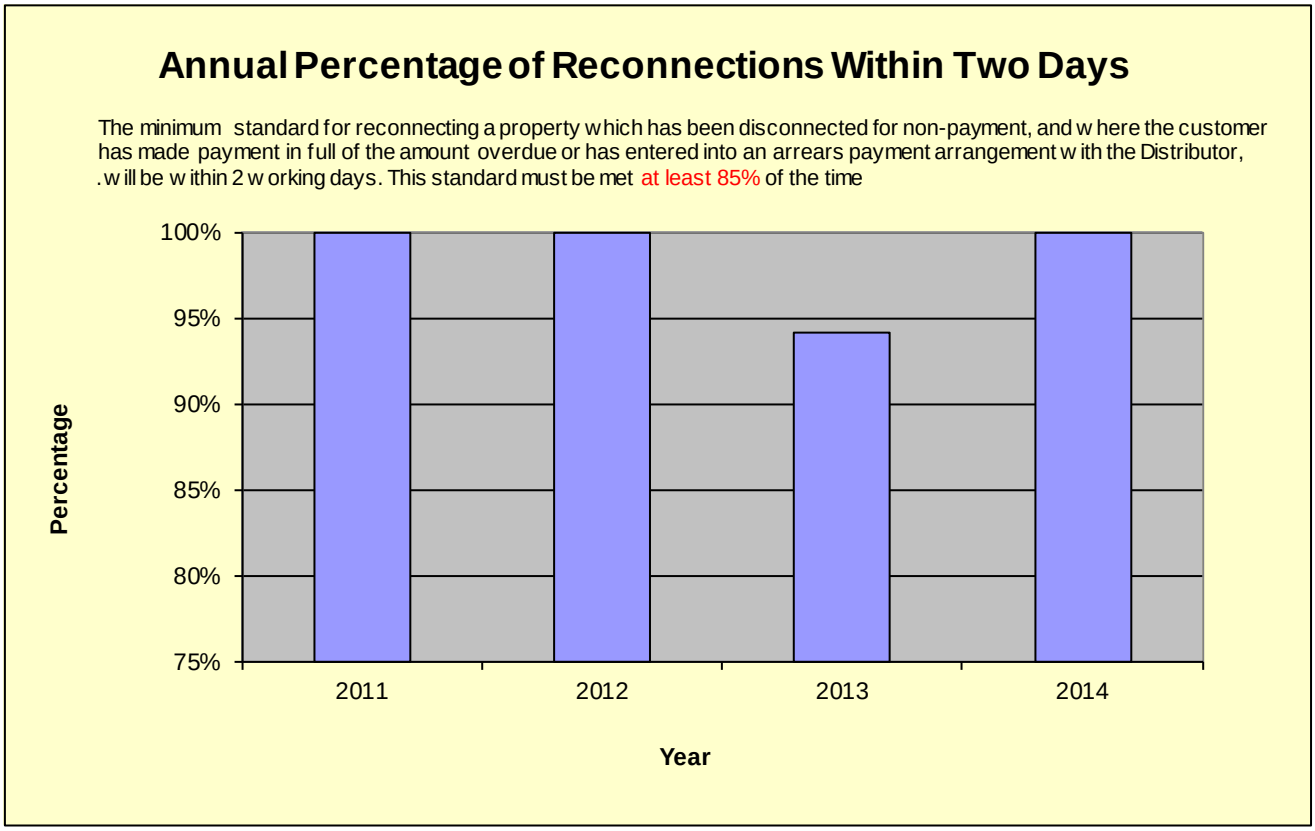
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Table 2-76:
Reconnection Performance Standard

OEB Approved Standard: 85% of the time

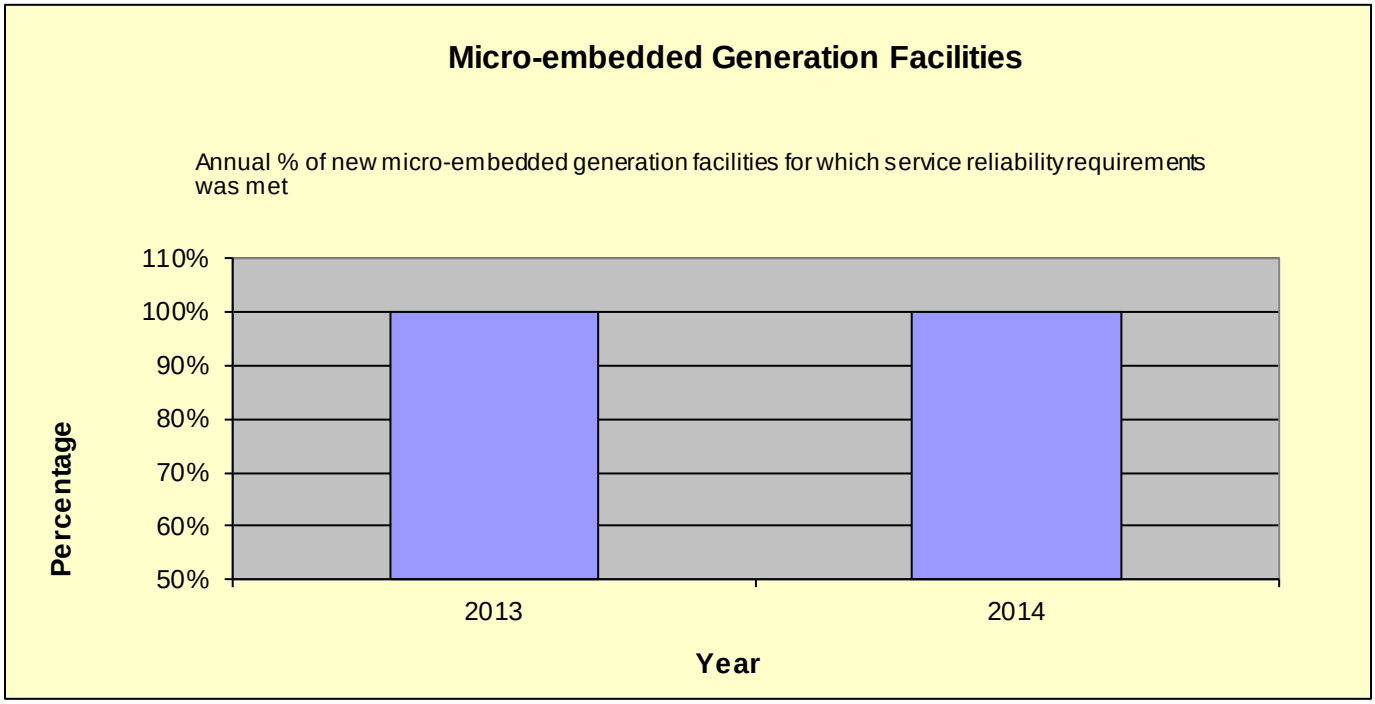
Actual %				Target %	
2011	**2012**	**2013**	**2014**	**2015**	**2016**
100%	100%	94.10%	100%	100%	100%



2

1

Table 2-77: Micro-embedded Generation Facilities			
OEB Approved Standard:			
Actual %		**Target %**	
2013	**2014**	**2015**	**2016**
100%	100%	100%	100%



2

SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) for the last five completed years.

Guelph Hydro tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index). Table 2-78 below shows actual results for the past 5 years.

Table 2-78: Service Reliability Indices

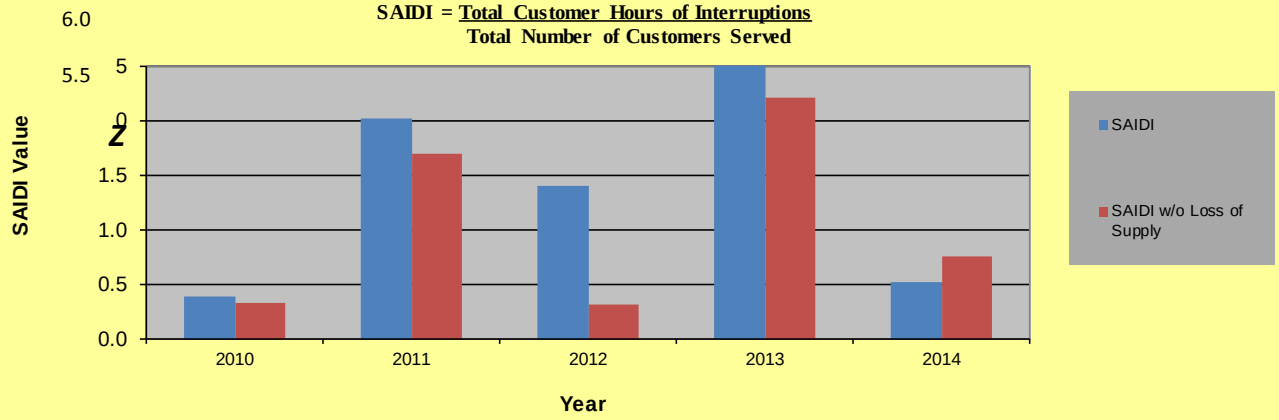
Reliability Indicator		Year				
		2010	2011	2012	2013	2014
System Average Interruption Duration Index (SAIDI)	All outages	0.39	2.02	1.41	3.41	0.52
	Excluding Loss of Supply	0.33	1.70	0.31	2.21	0.75
System Average Interruption Frequency Index (SAIFI)	All outages	1.27	2.45	2.53	4.01	1.05
	Excluding Loss of Supply	0.75	1.51	1.49	3.36	1.24
Customer Average Interruption Duration (CAIDI)	All outages	0.31	0.83	0.56	0.85	0.49
	Excluding Loss of Supply	0.45	1.12	0.21	0.66	0.61

Table 2-79

System Average Interruption Duration Index (SAIDI)

SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year, on average. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

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



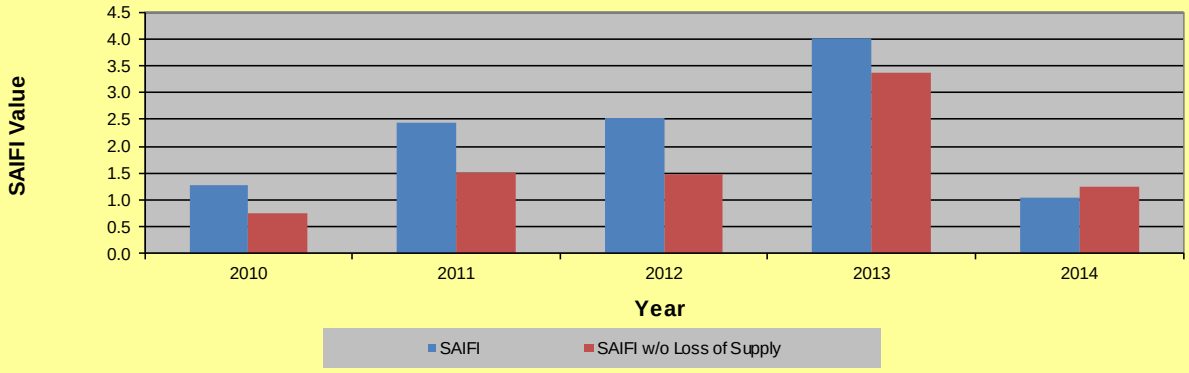
*Loss of Supply (Code 2 Outages), as defined by the Board, includes a loss of supply where customer interruptions are caused due to problems in the bulk electricity supply system (Hydro One).

Table 2-80

System Average Interruption Frequency Index (SAIFI)

SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as, the number of interruptions normalized per customer served, and it is expressed as follows:

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



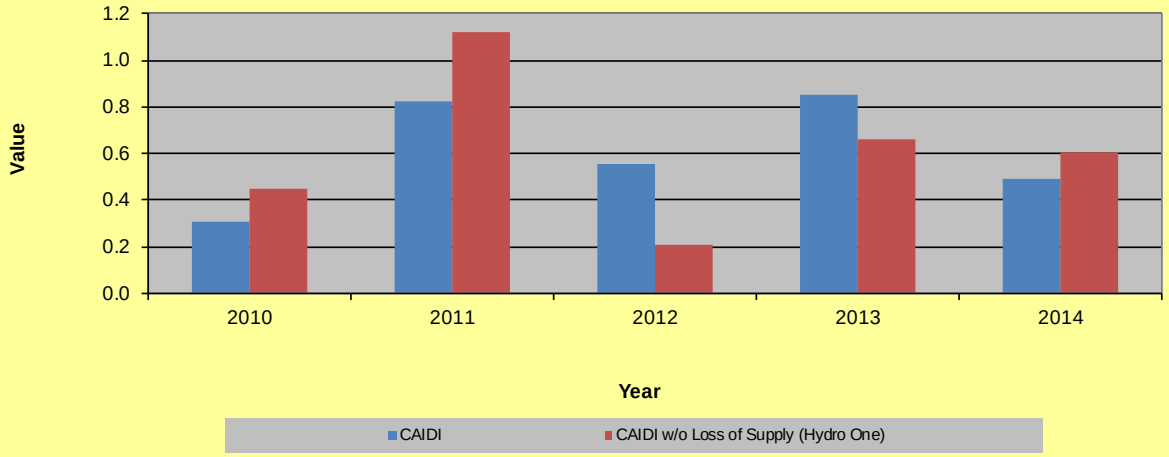
*Code 2 Outages, as defined by the Board, include a loss of supply where customer interruptions are caused due to problems in the bulk electricity supply system (Hydro One).

Table 2-81

Customer Average Interruption Duration Index (CAIDI)

CAIDI is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the average duration of interruptions in the year, and is expressed as follows:

CAIDI = System Average Interruption Duration Index (SAIDI) / System Average Interruption Frequency Index (SAIFI)



*Code 2 Outages, as defined by the Board, include a loss of supply where customer interruptions are caused due to problems in the bulk electricity supply system (Hydro One).

**Guelph Hydro is committed to the reliability of the distribution system and has set a target index of 1.12 for CAIDI (i.e. SAIDI target of 1.7 and SAIFI target of 1.51) in its 2015 and 2016 in its Asset Management Plan. In order to meet these targets Guelph Hydro will need to continue making capital investments in infrastructure over the next two years at levels which will decrease the number of interruptions and the number of affected customers.

Table 2-82

Momentary Average Interruption Frequency Index

MAIFI is an indication of the quantity of momentary interruptions. It is defined as the average quantity of interruptions in the year, and is expressed as follows:

MAIFI: Momentary Interruptions
Average Customer Quantity

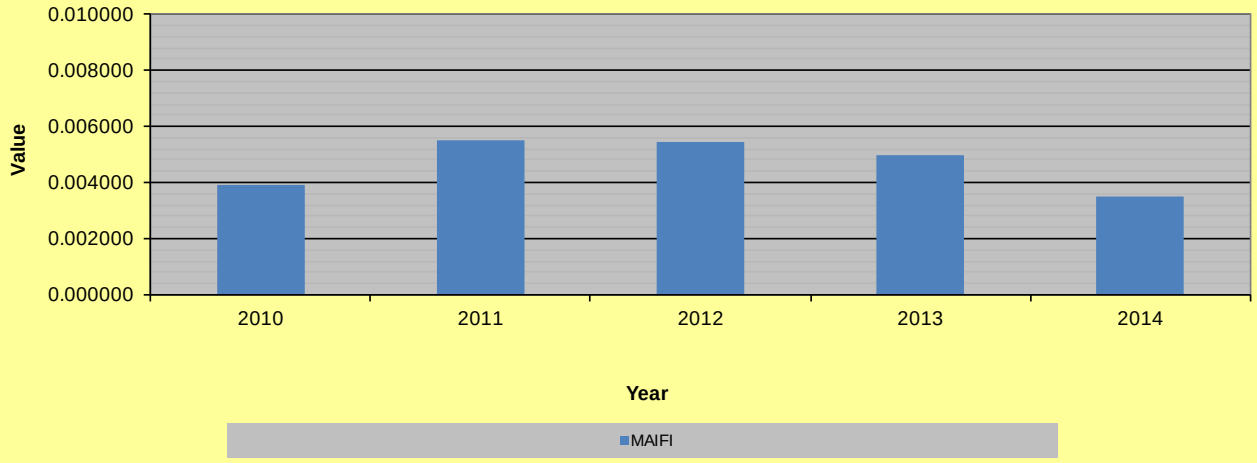


Table 2-83

Appendix 2-G
Service Reliability Indicators
2010 - 2014

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
SAIDI	0.391	2.024	1.409	3.410	0.516	0.334	1.697	0.312	2.210	0.752
SAIFI	1.265	2.452	2.526	4.010	1.045	0.747	1.510	1.491	3.360	1.242

	5 Year Historical Average	
SAIDI	1.550	1.061
SAIFI	2.260	1.670

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2010	2011	2012	2013	2014
Low Voltage Connections	90.0%	99.8%	99.9%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	80.0%	92.9%	80.0%	83.7%	87.7%
Appointments Met	90.0%	98.9%	98.6%	99.0%	97.1%	83.9%
Written Response to Enquires	80.0%	100.0%	94.7%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	89.1%	96.1%	93.5%	89.7%	94.0%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	3.0%	1.9%	2.3%	3.0%	5.8%
Appointment Scheduling	90.0%	98.9%	98.9%	99.0%	97.0%	85.4%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	N/A	100.0%	100.0%	94.1%	100.0%

APPENDIX 2-A: Distribution System Plan

Guelph Hydro Electric Systems Inc.

Distribution System Plan

Historical Period and Bridge Year: 2011-2015

Test Year and Forecast Period: 2016-2020






Guelph Hydro
Electric Systems Inc.

April 24, 2015

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Executive Summary

Guelph Hydro Electric Systems Inc. ("**GHESI**") capital expenditures over the historical period and estimated capital expenditures during the forecasted period are set out in Table 0-1 on the following page. A summary of **GHESI's** expenditures for the proposed capital investments in the test year in each of the investment categories are briefly discussed below:

1. System Access

System Access investments account for the highest portion of the capital expenditures for 2016. The majority of the investments in system access are in response to customer requests for connections. **GHESI** must complete requested connections in order to remain compliant with regulations. The estimated expenditures for this category is based on investment from previous years, taking into consideration forecasted developments in the service area.

2. System Renewal

System renewal projects make up the second largest category of investment for 2016. Projects in this category consist of the replacement of distribution assets. Applying **GHESI's** asset management process, **GHESI** has determined many of these assets are in poor condition and susceptible to failure in the near term if not replaced. System renewal investments also address reliability and localized capacity issues by integrating assets capable of accommodating ongoing system developments.

3. System Service

The system service investment amount consists largely of expenditures on the installation of a current limiting reactor ("**CLR**") as well as **SCADA** related projects. The **CLR** is necessary to maintain fault levels within short-circuit ratings defined in the Transmission System Code in response to an ongoing upstream transmission project. The **SCADA** investments are expected to improve system efficiency and reliability by automating system response with respect to certain power disruption events.

4. General Plant

General plant expenditures account for a small portion of the overall allocation of capital investment. The amount invested in this category in 2016 is largely composed of expenditures on an addition to **GHESI's** administration building in order to accommodate a growing staff and the purchase of an operations line truck as the old one has reached its optimal age of replacement.

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011 (Previous Bridge Year)			2012 (Previous Test Year)			2013			2014			2015 Bridge Year			2016 Test Year	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Budget	Var					
			%			%			%			%			%					
System Access	N/A	6,574,742	-	N/A	5,018,365	-	N/A	4,229,054	-	N/A	4,886,595	-	N/A	5,846,937	-	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	N/A	1,648,262	-	N/A	2,536,522	-	N/A	2,830,493	-	N/A	3,726,430	-	N/A	3,960,130	-	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	N/A	16,898,611	-	N/A	3,139,974	-	N/A	3,185,982	-	N/A	2,250,748	-	N/A	3,842,621	-	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	N/A	1,052,721	-	N/A	984,738	-	N/A	1,220,577	-	N/A	2,359,438	-	N/A	2,212,704	-	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	-	26,174,335	-	-	11,679,598	-	-	11,466,106	-	-	13,223,211	-	-	15,862,392	-	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305
System O&M	-	5,379,426	-	-	5,619,519	-	-	6,425,264	-	-	6,784,094	-	-	7,186,934	-	7,856,913	7,966,910	8,078,446	8,191,545	8,306,226

Table 0-1 Capital Expenditure Plan

5.0 Introduction

GHESI has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB's**") Chapter 5 Consolidated Distribution System Plan Filing Requirements dated March 28, 2013 (the "**Filing Requirements**") as part of its 2016 Cost of Service Application (the "**Application**").

GHESI was established in 1907 and supplies electrical service to customers within the City of Guelph as well as in the Village of Rockwood, which is located in the Township of Guelph-Eramosa (since acquiring this service territory in 2001). **GHESI** had 53,007 customers as of the end of 2014, including over 48,000 residential customers, with a service territory of 93 sq. km. (89 sq. km within the City of Guelph, and 4 sq. km within the Village of Rockwood). In both service territories, the neighbouring utility is Hydro One Networks Inc. ("**Hydro One**"). Figure 5.0-1 and Figure 5.0-2 illustrate **GHESI's** service territory boundaries.

GHESI owns, maintains and operates approximately 431 km of overhead primary distribution feeders and 672 km of underground primary distribution circuits including 57 13.8 kV feeders and six 8.32kV feeders. Bulk power system supply in Guelph is provided by three **Hydro One** owned transformer stations and one **GHESI** owned transformer station. Bulk power system supply in Rockwood is provided by one **Hydro One**-owned Distribution Station and two **GHESI**-owned distribution stations. **GHESI** is a partial distributor in relation to **Hydro One** for Rockwood distribution.

Guelph is one of Ontario's fastest growing communities. With its strategic geographic location, Guelph attracts businesses and new residents at a steady rate outlined in Figure 5.0-3. Developments are underway to further promote local economic development. In order to keep the lights on and accommodate growth in its service territory, **GHESI** has made investment plans, as part of this **DSP,** to maintain and upgrade its distribution system to allow it to continue to provide reliable and quality power supply to existing and future customers.

As indicated in Figure 5.0-3 , the customer base of **GHESI** is mainly comprised of large commercial and industrial customers, although residential customer's account for the majority of the customer counts. As of 2014, approximately 63% of the annual electricity consumption on **GHESI's** distribution system was contributed by commercial customers, while 16% was contributed by large industrial customers. Residential customers represent over 90% of **GHESI's** customer count and account for only 21% of total electricity consumption. It is also evident in Figure 5.0-4 that the annual electricity consumption of **GHESI's** large industrial customers is growing at an accelerated rate, while that of residential customers has remained unchanged in the past five years.

GHESI's vision is "An Energy Company Powering Sustainable Communities". Over the last three years alone, **GHESI** has connected more than 269 customer-owned rooftop and ground-mounted solar facilities that have the potential to feed more than 8,000 kilowatts of electricity into the Ontario grid under the Independent Electricity System Operator's[1] ("**IESO**") Feed-in-Tariff ("**FIT**") and micro**FIT** programs. With an eye on the future, **GHESI** is continuing to invest capital to upgrade the electricity distribution network to accommodate more and different sources of renewable and sustainable energy in the community.

GHESI's vision is reinforced by its success in achieving Conservation and Demand Management ("**CDM**") results. At the time of writing this report, **GHESI's** 2014 Final Verified **CDM** Results were not available. However, by the end of 2013, three years into the 2011-2014 tranche of **CDM** targets, **GHESI** had achieved 127.4% of its 2014 energy savings target of 79.53 GWh, and had achieved 77.6% of its 16.71 MW demand savings target, under reporting Scenario 2, which assumes that demand response resources remain in service until 2014. As noted in **GHESI's** Q4-2013 **CDM** Preliminary Results Status Report, the 2013 achievement ranks **GHESI** as one of the top four Local Distribution Companies ("**LDCs**") in the province. By year-end 2014, **GHESI** is forecasting to have achieved over 135% of its 4-year energy savings target, and close to 100% of its demand target,

This **DSP** was prepared to provide to the **OEB** and all interested stakeholders:

- An overview of **GHESI's** asset planning objectives and goals;
- A review of **GHESI's** asset-related operational performance in the five-year historical period;
- A preview of **GHESI's** planned expenditures for the forecast period that illustrate **GHESI's** plan for further-improving its asset-related performance to achieve the four performance outcomes established by the **OEB**; and
- A detailed justification of **GHESI's** planned capital expenditures in the test year**.**

An integrated approach was taken for investment planning on **GHESI's** distribution system. All investments have been planned and optimized together, including for example:

- System renewal and expansion;
- Renewable generation connections;
- Customer connections and regulatory requirements;

[1] On January 1, 2015, the operations of the IESO and the Ontario Power Authority ("**OPA**") were merged. The amalgamated organization continues to operate as the IESO. Under the amended *Electricity Act, 1998*, any reference to the predecessor IESO or the OPA in any by-law, resolution, agreement or other document, will be read as if it were a reference to the IESO.

- System growth and planning criteria;
- General plant in support of daily operations;
- Smart grid development and implementation; and
- Regionally planned infrastructure.

This allows **GHESI** to develop a **DSP** that allocates its resources in an optimal way to achieve cost-effective planning over the planning horizon of five years starting in the test year, which is 2016 in the case of this filing.

Employing this longer term approach requires **GHESI** to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing **GHESI's** ability to plan ahead and respond to the evolving needs of customers in a timely manner while managing and leveling the impacts of these expenditures on consumer rates.

GHESI is part of the Group 1 Kitchener-Waterloo-Cambridge-Guelph ("**KWCG**") region. The lead transmitter in this region is **Hydro One**. Other **LDC's** in the region include:

- Kitchener-Wilmot Hydro ("**KWH**");
- Waterloo North Hydro ("**WNH**"); and
- Cambridge & North Dumfries Hydro ("**CNDH**").

GHESI has actively participated in both the Integrated Regional Resource Planning Process ("**IRRP**") and Regional Infrastructure Planning Process ("**RIP**") of its region to:

- Assist the **IESO** and **Hydro One** in addressing the near-, mid-, and long-term issues and requirements on the regional level;
- Integrate regional plans into its own distribution system planning process to ensure that any distribution system requirements identified during the Regional Planning Process are included in this **DSP**; and
- Align its own **DSP** planning with planning at the regional level to achieve planning efficiency in the long –term.

More information on **GHESI's** consultation with other stakeholders during the regional planning process will be provided in Section 5.2.2.

On October 18, 2012, the Ontario Energy Board released its Report, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "**RRFE**").

Smart grid development has been made an integral part of **DSP** under the **RRFE**. To **GHESI**, smart grid development has the following meanings:

- Transforming features of its current system to optimize system operational performance;
- Capturing and utilizing real-time data to better understand customer preferences and give more control to customers on their own electricity usage ; and
- Modifying the current system, where necessary, to accommodate and facilitate distributed generation.

Together, these meanings outline **GHESI's** overall strategy for moving towards a smarter grid.

Innovative technologies provide the mechanisms for implementing the desirable functionalities of a smarter grid. **GHESI** is aware of the existence of these technologies and continues to adopt innovative technology where it presents efficiency in the operation and maintenance of the distribution system. An example of this type of innovation is automatic load restoration which automatically reconfigures the distribution system after a fault and quickly restores service to segments of the feeder which are not affected by the fault.

GHESI's investments in smarter grid technologies such as the automatic load restoration system implemented on two of **GHESI's** feeders have greatly reduced outage times for specific sections of overhead lines. Continual investments will be made to progress towards a more resilient, modernized system, and the plans for these investments will be presented in this **DSP**.

Taking a performance-based approach for regulating electricity distributors under the **RRFE**, the **OEB** has established four performance outcomes to be achieved by electricity distributors, including the following:

- **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

This is **GHESI's** first Application under the **RRFE**.

GHESI's service territory consists of the City of Guelph and the Village of Rockwood, a small town approximately 20 minutes east of the City of Guelph. Both are outlined in the following, Figure 5.0-1and Figure 5.0-2.

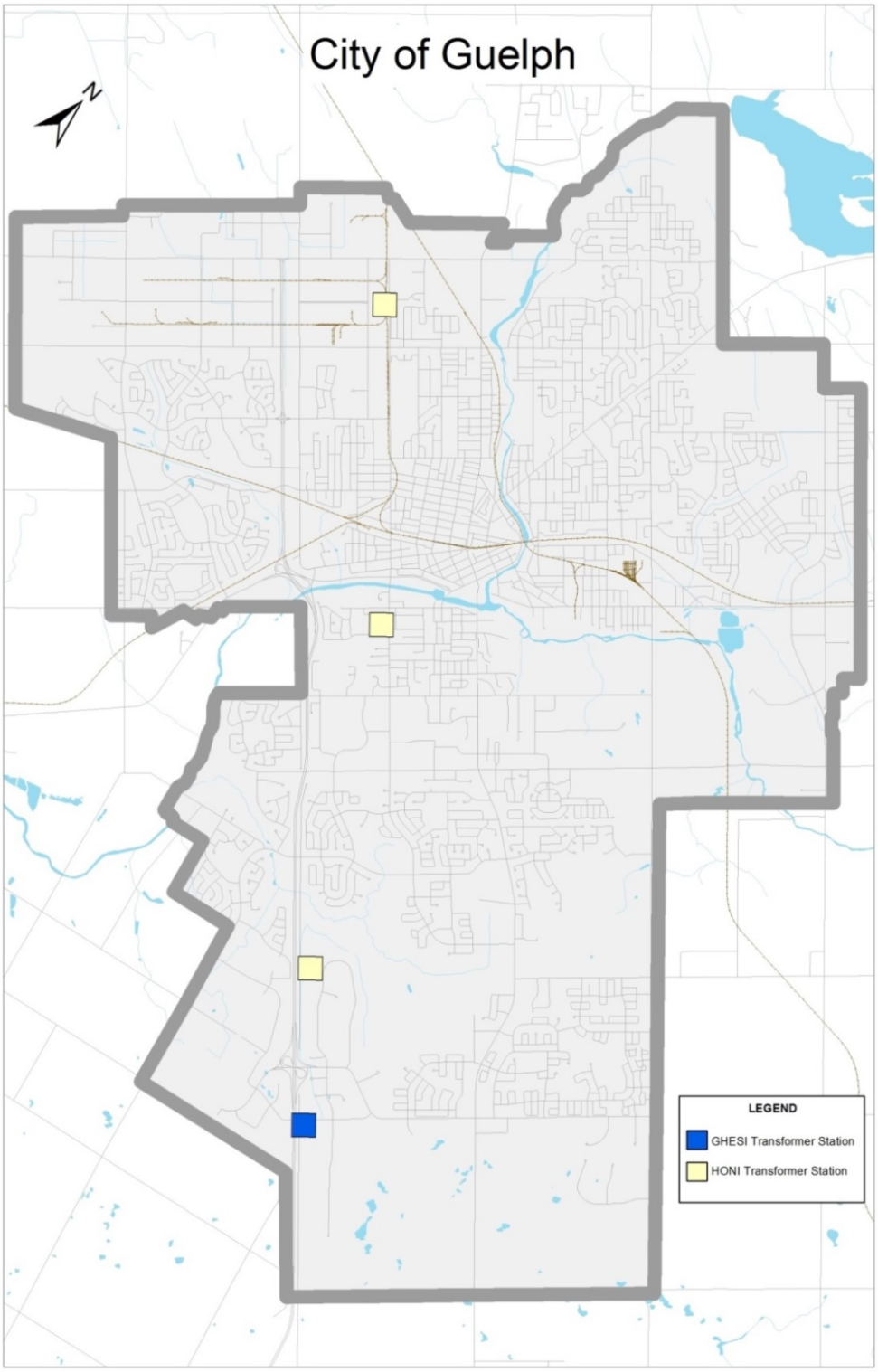


Figure 5.0-1 City of Guelph Service Territory

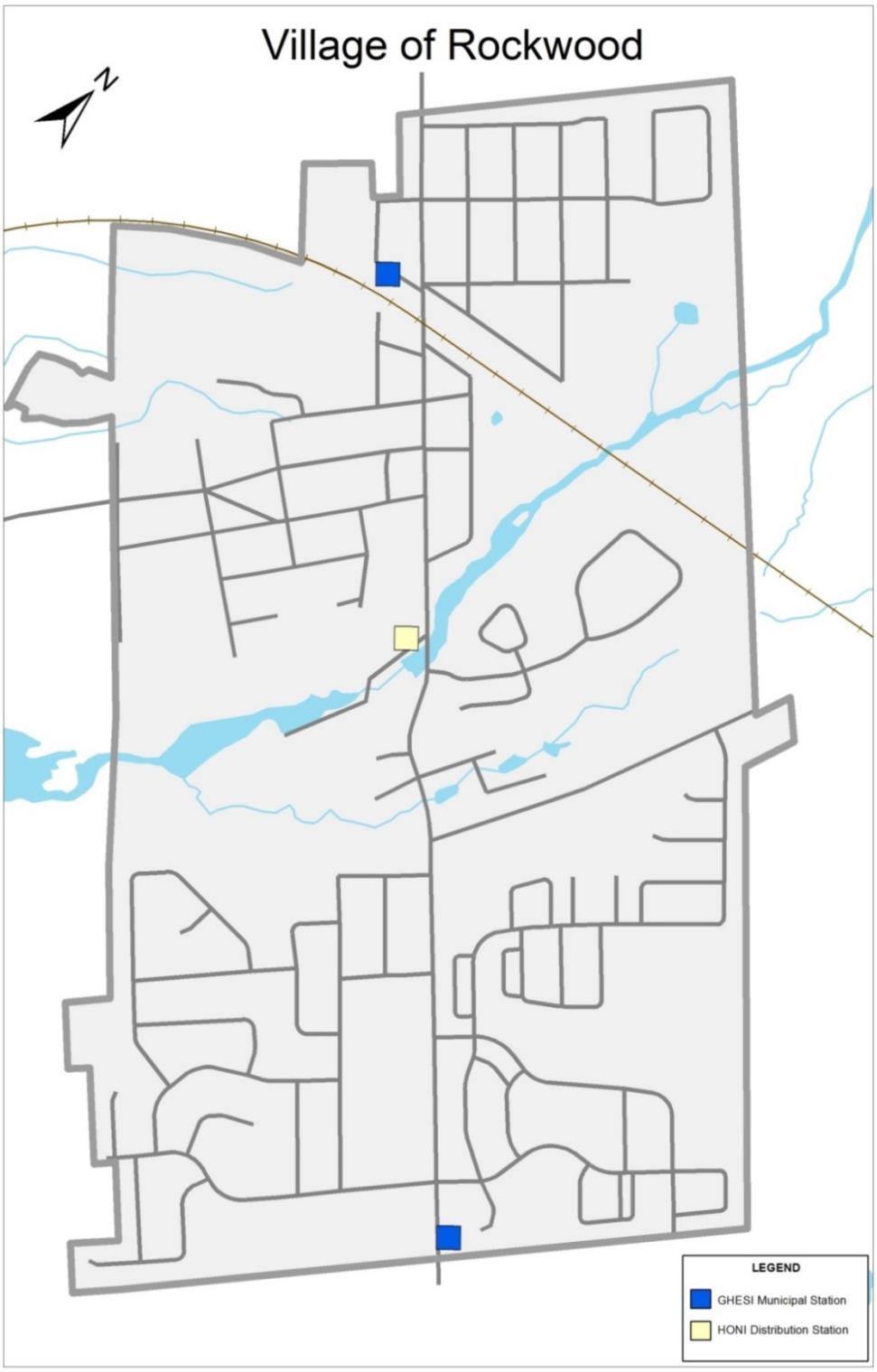


Figure 5.0-2 Village of Rockwood Service Territory

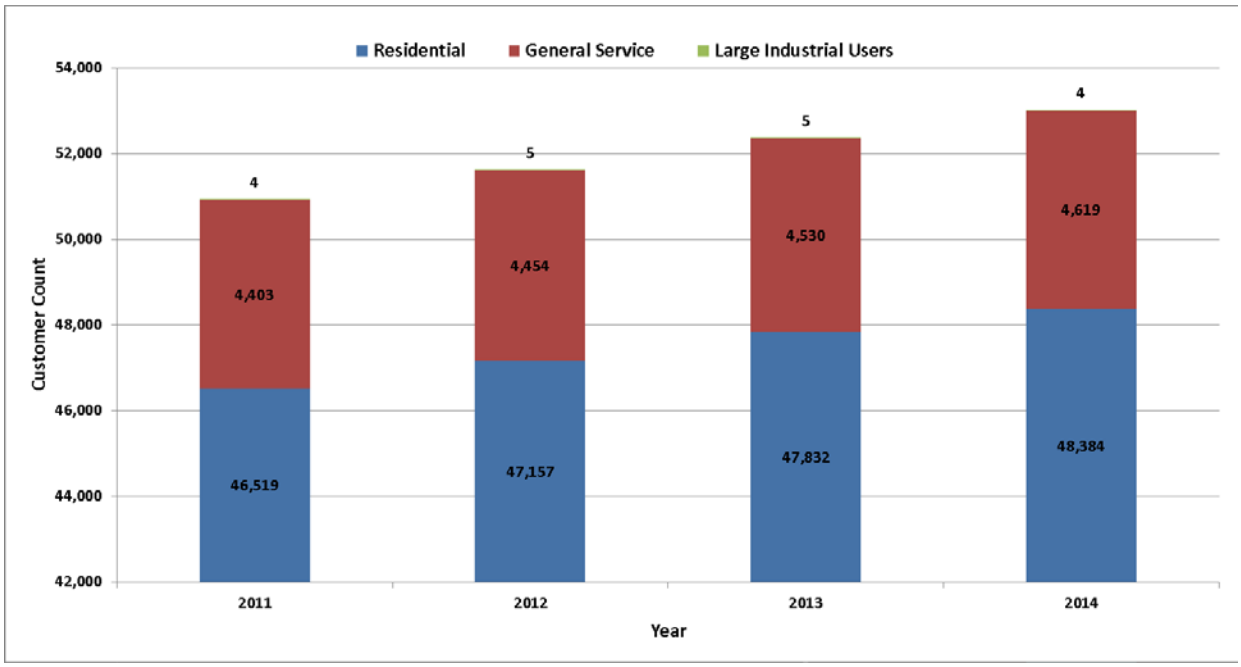


Figure 5.0-3 Customer Counts by Customer Class

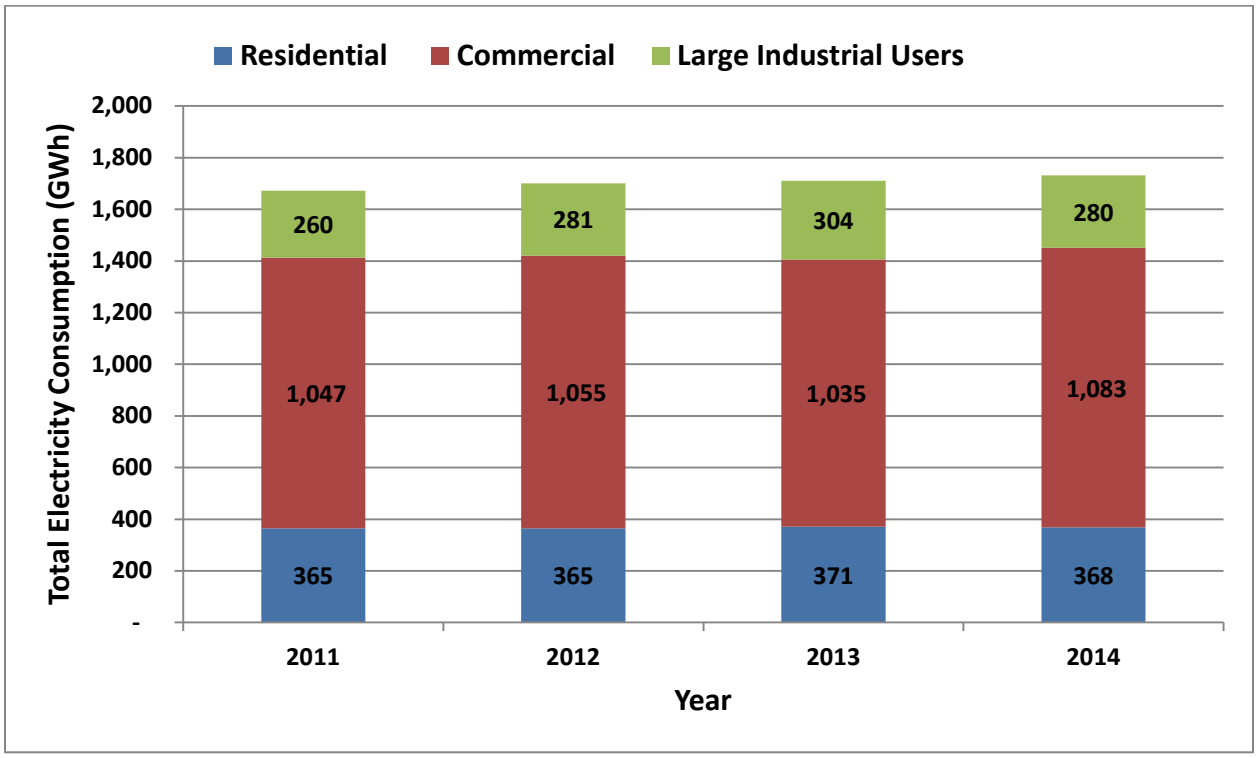


Figure 5.0-4 Total Electricity Consumption by Customer Class

5.1 General and Administrative Matters (OEB Filing Req. 5.1)

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.

GHESI has prepared this **DSP** for the Application. It utilizes the headings in, the terminology of and the formats set out in the Filing Requirements.

5.1.1 Investment Categories (OEB Filing Req. 5.1.1)

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

- ***System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system***
- ***System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.***
- ***System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements***
- ***General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities***

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal

investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

In the **Filing Requirements**, the **OEB** has specified the investment categories to be used by distributors in their filings. **GHESI** has identified for each investment category, the key drivers that are applicable in its case, and listed at a program category level a representative example of the applicable projects/activities presented in this **DSP** based on the 'trigger' driver of the expenditure. The result of this is summarized in Table 5.1-1 below. Each program category has been expanded in greater detail in subsequent sections of the **DSP** that details specific projects within each program category. Each project category has a code in brackets which is used for internal purposes.

	OEB Example Drivers	OEB Example Projects/Activities	GHESI Drivers	GHESI Program Category
System Access	Customer Service Requests	- New customer connections - Modifications to existing customer connections - Expansions for customer connections or property development	Customer Service Requests	- Apartment, Commercial, Industrial Customer Connections (CACI) - Distribution System Modifications / Expansions for Customers (CMOD) - Expansions for New Residential Subdivisions (CRES) - Expansions for New Residential Townhouse Subdivisions (CTH) - New Residential Service Connections (CSER)
	Other 3rd party infrastructure development requirements	- System modifications for property or infrastructure development (e.g. relocating pole lines for road widening)	Other 3rd party infrastructure development requirements	- System Relocations Property Development (CREL)
	Mandated Service Obligations (Distribution System Code, Conditions Of Service.; etc.)	- Metering - Long Term Load Transfer	Mandated Service Obligations	- Metering Installations (CMEG)
System Renewal	Assets/asset systems at end of service life due to: • Failure • Failure risk • Substandard performance • High performance risk • Functional	Programs to refurbish/replace assets or asset systems; e.g. batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type);	Assets/asset systems at end of service life due to: • Failure • Failure risk	- Distribution System Replacement (CREP) - Distribution System Transformer replacement upgrades (CTRU)

	Obsolescence	other equipment (by type)		
System Service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	- Property acquisition - Capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation - Line extensions	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	- Transformer Stations & Distribution Stations (CTS/CDS) - Distribution System Feeder Infrastructure (CFDR)
	System operational objectives: • Safety • Reliability • Power Quality • Other performance/functionality	- Protection & control upgrade; e.g. re-closers; tap changer control/relays; transfer trip - Automation (new/upgrades) by device type/function - SCADA - Distribution loss reduction	System operational objectives: • Safety • Reliability • Power Quality • Other performance/functionality	- SCADA Infrastructure (CSC) - SCADA / Remotely Operated Switches (CSW)
General Plant	System capital investment support System maintenance support Business operations efficiency Non-system physical support	- Land acquisition - Structures & depreciable improvements - Equipment and tools - Supplies - Finance/admin/billing software & systems - Rolling stock - Intangibles (e.g. land rights; capital contributions to other utilities)	System capital investment support System maintenance support Business operations efficiency Non-system physical support	- Building / Fixtures - Office Equipment / Graphics - IT Capital - Fleet / Rolling Stock - Major Tools

Table 5.1-1 Summary of Drivers

5.1.2 **Investments Related to Renewable Energy Generation** (OEB Filing Req. 5.1.2)

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DSP, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

GHESI acknowledges its responsibility to ensure that its distribution system has, and will continue to have, the ability to connect renewable energy generation ("**REG**") facilities. Explanations will be provided in this **DSP**, where system modifications are required to accommodate the system impacts of **REG** investments, on the nature and magnitude of the system impacts of the project, the costs of these system modifications, and the means by which these costs are to be recovered.

5.1.3 **Timing of Filing** (OEB Filing Req. 5.1.3)

All distributors are required to file a DSP as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DSP to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

This **DSP** is filed as part of **GHESI's** Application.

5.1.4 **Planning in Consultation with Third Parties** (OEB Filing Req. 5.1.4)

5.1.4.1 **Regional Planning and Consultations** (OEB Filing Req. 5.1.4.1)

Prior to filing a DSP and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1) ***Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:***
   - ***forecast load at existing (and proposed, if any) points of interconnection;***
   - ***forecast renewable generation connections and any planned network investments to accommodate the connections;***
   - ***investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and***
   - ***the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.***
2) ***Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DSP.***

GHESI has provided various pieces of information such as load forecast, narratives for supporting the load forecast and methodologies, and information pertaining to community self-sufficiency in an effort to assist **Hydro One** and the **IESO** during the Regional Planning Process ("**RPP**"), and has consulted with all other stakeholders in its region in preparing this **DSP**. A description of these consultation processes are provided in Section 5.2.2 and the **IRRP LDC** Gross Forecast Assumptions and Methodologies document can be found at Appendix O. **GHESI**, along with our neighbouring utilities, collaborates and shares information on a regular basis via the **IRRP** meetings established by the **IESO**. While awaiting the **IESO's** draft of the **IRRP**, **GHESI** remains committed to the process and continues to collaborate with neighbouring utilities where possible. **GHESI** will also continue to promote community self-sufficiency, participation with interconnected **LDCs** and will continue to make and attend presentations at the **IESO** municipal engagement events.

5.1.4.2 **Renewable Energy Generation Investments** (OEB Filing Req. 5.1.4.2)

Prior to filing a DSP, 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 DSP 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.***

2) ***The 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 DSP are consistent with any Regional Infrastructure Plan.***

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

It is mandated by the **OEB** that all distributors submit information to the **IESO** in relation to the **REG** investments identified in their **DSP** and request in writing that the **IESO** provide a letter commenting on the **REG** Plan, no less than 30 days in advance of filing the **DSP** where the distributor is not requesting investments related to **REG** projects.

GHESI has followed these instructions from the **OEB** by preparing and submitting to the **IESO** a **REG** Investment Plan identified in Appendix A that details the following:

- Existing Distributed Generation Connections;
- Anticipated Distributed Generation Connections; and
- Investments to facilitate Renewable Energy Generation.

The **IESO** has reviewed the **REG** investment plan and comments are set out in Appendix C of this **DSP**.

5.1.5 **Performance Reporting** (OEB Filing Req. 5.1.5)

A distributor is to provide information on its performance in relation to its DSP as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

To facilitate performance monitoring and utility benchmarking, the **OEB** employs a balanced scorecard approach that translates the four **RRFE** performance outcomes into a set of measures that can be monitored and compared.

GHESI utilizes the performance scorecard metrics shown in Figure 5.2-5 on page 82 established by the **OEB** to continuously monitor its achievement in relation to the four performance outcomes and reports its performance to the **OEB** as required.

5.2 Distribution System Plans (OEB Filing Req. 5.2)

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

The **DSP** was developed in compliance with the **Filing Requirements** to ensure all key elements are included.

Information in this report is organized using the section headings indicated in the **Filing Requirements**. The table below demonstrates the cross-references between headings/subheadings used in this **DSP** and the section headings/subheadings indicated in the **Filing Requirements**.

OEB headings/subheadings		GHESI headings/subheadings	
5.0	**Introduction**	**5.0**	**Introduction**
5.1	**General & Administrative Matters**	**5.1**	**General & Administrative Matters**
5.1.1	Investment Categories	5.1.1	Investment Categories
5.1.2	Investments Related to Renewable Energy Generation	5.1.2	Investments Related to Renewable Energy Generation
5.1.3	Time of Filing	5.1.3	Time of Filing
5.1.4	Planning in Consultation with Third Parties	5.1.4	Planning in Consultation with Third Parties
5.1.4.1	Regional Planning and Consultations	5.1.4.1	Regional Planning and Consultations
5.1.4.2	Renewable Energy Generation Investments	5.1.4.2	Renewable Energy Generation Investments
5.1.5	Performance Reporting	5.1.5	Performance Reporting
5.2	**Distribution System Plans**	**5.2**	**Distribution System Plans**
5.2.1	Distribution System Plan Overview	5.2.1	Distribution System Plan Overview
	a) "Key elements of the **DSP**…"	5.2.1.1	Key Elements of the **DSP**
	b) "the sources of cost savings …"	5.2.1.2	Sources of cost savings expected
	c) "the period covered by …"	5.2.1.3	Period covered by the **DSP**
	d) "an indication of the vintage of …"	5.2.1.4	Vintage of the information on investment 'drivers'
	e) "where applicable, an indication …"	5.2.1.5	Important changes to the **AM** process
	f) "aspects of the **DSP** that relate …"	5.2.1.6	**DSP** aspects contingent upon the outcome of ongoing activities
5.2.2	Coordinated Planning with Third Parties	5.2.2	Coordinated Planning with Third Parties

5.2.3	Performance Measurement for Continuous Improvement	5.2.3	Performance Measurement for Continuous Improvement
	a) "identify and define the methods …"	5.2.3.1	Metrics to Monitor Distribution System Planning Process Performance
	b) "provide a summary of …"	5.2.3.2	Summary of Performance over the Historical Period
	c) "explain how this information …"	5.2.3.3	Effect on the **DSP**
5.3	**Asset Management Process**	**5.3**	**Asset Management Process**
5.3.1	Asset Management Process Overview	5.3.1	Asset Management Process Overview
	a) "a description of the distributor's …"	5.3.1.1	Asset Management Objectives
	b) "information regarding the …"	5.3.1.2	Asset Management Strategy
5.3.2	Overview of assets managed	5.3.2	Overview of Assets Managed
	a) "a description and explanation …"	5.3.2.1	Features of the Distribution Service Area
	b) "a summary description of the …"	5.3.2.2	System Configuration
	c) "information (in tables and/or …"	5.3.2.3	Asset Condition
	d) "an assessment of the degree to …"	5.3.2.4	Asset Utilization
5.3.3	Asset Lifecycle Optimization Policies and Practices	5.3.3	Asset Lifecycle Optimization Policies and Practices
	a) "A description of asset lifecycle …"	5.3.3.1	Asset Lifecycle Optimization Policies and Practices
	b) "A description of asset life cycle risk …"	5.3.3.2	Asset Lifecycle Risk Management Policies and Practices
5.4	**Capital Expenditure Plan**	**5.4**	**Capital Expenditure Plan**
5.4.1	Summary	5.4.1	Summary
	a) "information on the capability …"	5.4.1.1	**GHESI's** Distribution System Capability to Connect New Load or Generation
	b) "total annual capital expenditures …"	5.4.1.2	Summary of Annual Capital Expenditures by Investment Category
	c) "a brief description of how for …"	5.4.1.3	Total Proposed Capital for forecast period Capital Expenditures in Relation to **AM** and Capital Expenditure Planning Process
	d) "a list and brief description …"	5.4.1.4	Material Capital Expenditure Projects
	e) "information related to a Regional …"	5.4.1.5	Material Impact of **IRRP**/**RIP** on the **DSP**
	f) "a brief description of customer …"	5.4.1.6	Customer Preferences
	g) "a brief description of how the …"	5.4.1.7	Expected System Development over

			the Planning Horizon
	h) "a list and brief description …"	5.4.1.8	Planned Projects in Response to Customer Preferences, Technology-based Opportunities, and Innovative Processes, Services, Business Models, or Technologies
5.4.2	Capital Expenditure Planning Process Overview	5.4.2	Capital Expenditure Planning Process Overview
	a) "a description of the distributor's …"	5.4.2.1	Capital Expenditure Planning Objectives
	b) "if not otherwise specified in (a) …"	5.4.2.2	Non-Distribution System Alternatives to Relieve System Capacity
	c) "a description of the process(es) …"	5.4.2.3	Project Prioritization Tools and Methods
	d) "if not otherwise included in c) …"	5.4.2.4	Mechanisms Used to Engage Customers
	e) "if different from that described …"	5.4.2.5	Method and Criteria Used to Prioritise **REG** Investments
5.4.3	System Capability Assessment for Renewable Energy Generation	5.4.3	System Capability Assessment for Renewable Energy Generation
	a) "applications from renewable …"	5.4.3.1	Anticipated **REG** Connections Over the Forecast Period
	b) "the number and the capacity …"		
	c) "the capacity (MW) of the …"	5.4.3.2	System Capacity for **REG** Connections
	d) "constraints related to the …"	5.4.3.3	Existing and Anticipated System Constraints
	e) "constraints for an embedded …"		
5.4.4	Capital Expenditure Summary	5.4.4	Capital Expenditure Summary
5.4.5	Justifying Capital Expenditures	5.4.5	Justifying Capital Expenditures
5.4.5.1	Overall Plan	5.4.5.1	Overall Plan
5.4.5.2	Material Investments	5.4.5.2	Material Investments

Table 5.2-1: Cross-References Between Filing Requirements and DSP

5.2.1 **Distribution System Plan Overview** (OEB Filing Req. 5.2.1)

This section provides the Board and stakeholders with a high level overview of the information filed in the DSP, including but not limited to

a) Key elements of the DSP that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives
b) The sources of cost savings expected to be achieved over the forecast period through good planning and DSP execution
c) the period covered by the DSP (historical and forecast years);
d) An indication of the vintage of the information on investment 'drivers' used to justify

investments identified in the application (i.e. the information should be considered "current" as of what date?);

d) where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DSP filing; and

f) aspects of the DSP that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

5.2.1.1 **Key Elements of the DSP** (OEB Filing Req. 5.2.1a)

Key elements of the DSP that affects its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

GHESI's DSP is a comprehensive collaboration of information with inputs from numerous sources starting from our core business objectives, asset management objectives and performance evaluation, and our consultation with major stakeholders. The drivers are addressed under the headings of System Access, System Renewal, System Services and General Plant. The planning objectives and processes are explored in detail in Section 5.4.2.1, but in summary include:

1. Ensure proper allocation of investments to meet regulatory obligations;
2. Ensure adequate level of investment in the renewal of distribution system assets ;
3. Determine the acceptable level of expenditures required to meet existing and future demand levels;
4. Ensure proper allocation of investments in general plant assets; and
5. Determine impacts to financials, and adjust spending as required.

The output of this process is a sustainable, levelized five-year capital plan for the forecast period. The **DSP** was developed with the objective, to not only address the identified short- and mid-term issues on the distribution system, but also to prepare for foreseeable future changes and requirements on the system to achieve sound and effective financial planning in the long term. A snapshot of the capital expenditure plan for the forecast period is provided in Table 5.2-2 below. Investments are grouped by primary drivers and objectives into four categories including System Access, System Renewal, System Service, and General Plant.

Category	2015 Plan	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2020 Plan
System Access	5,846,937	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	3,960,130	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	3,842,621	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	2,212,704	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
Total Expenditure	15,862,392	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305

Table 5.2-2: Capital Expenditure Plan

Figure 5.2-1 below shows the trend of capital expenditures over historical and forecast years. Overall, **GHESI** is moving from a new growth driven planning mode to an asset renewal mode.

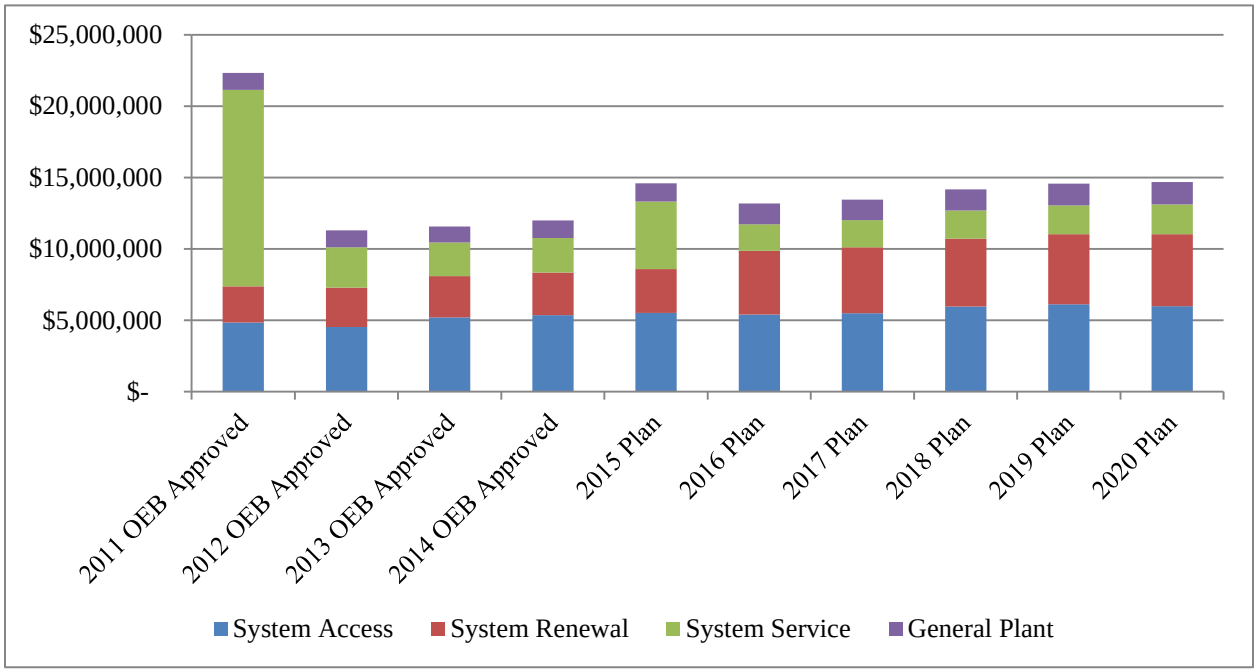


Figure 5.2-1: Trend of Capital Expenditures

System Access

System Access investments are modifications to the existing system that will allow **GHESI** to provide future customers with access to its electricity services. These investments are often trigged by customer requests and are completed to fulfill **GHESI's** service obligations to other third parties. For **GHESI**, System Access investments in historic years typically include:

- Connecting new customers;
- Line relocations; and
- Metering projects.

For this planning cycle, System Access activities are projected to continue as per previous years. Road relocations, metering, new industrial loads and connections make up the bulk of activities in this area.

System Renewal

System Renewal investments involve replacement and refurbishment of system assets to maintain the system's ability to provide reliable electricity services to customers. As assets become aged and reach end of life **EOL**, these investments are necessary to rectify and maintain the overall asset health condition at an acceptable level to prevent decline in system reliability performance and mitigate safety risks to **GHESI** employees and the public.

GHESI engages Kinectrics Inc. ("**Kinectrics**") to perform Asset Condition Assessment ("**ACA**") on its key distribution system assets on an annual basis to identify assets that have reached, or will be reaching, end of life in the near term. The 2014 **ACA** recommended that the following assets be targeted for replacement:

- Pole mounted transformers;
- Pad mounted transformers;
- Wood poles; and
- Manholes and vaults.

GHESI's decisions on asset replacement and refurbishment are based on asset conditions and corresponding probabilities of failure. Therefore, System Renewal investments proposed in this **DSP** include proactive replacements to address targeted assets identified in the **ACA**, and reactive investments allocated for replacements on failure.

Based on outcomes for the **ACA** with respect to our system renewal requirements, it was determined that **GHESI** has previously been under spending. To address this gap, **GHESI** has been prudently ramping up its expenditures on system renewal efforts to ensure long-term system viability.

System Service

System Service investments include upgrades or expansions of the existing system to support demand growth of existing customers or create flexibility to improve operation efficiency.

The Campbell Transformer Station ("**TS**") is now being utilized beyond its planned capacity as a result of continuous load growth. Therefore, as part of this **DSP**, **GHESI**

plans to build feeders around Campbell **TS** to enable load transferring to other transformer stations, thereby optimizing the loading.

Fault current in the south end of Guelph is expected to exceed **OEB** transmission code limits. Upgrades to the transmission system network are planned in the region and have been scheduled for 2016. Line capacity increases in existing neighbourhoods are expected to continue as per previous cycles. Converting and upgrading manual Load Interrupter Switches **("LIS")** to System Control and Data Acquisition ("**SCADA"**) capable devices and general upgrades to **SCADA** infrastructure is also continuing.

General Plant

General Plant investments are made to maintain assets that are not part of the distribution system, but are used to support day to day business and operational activities. This generally includes:

- Land and buildings;
- Tools and equipment;
- Fleet of Vehicles;
- Information Systems Hardware; and
- Information Systems Software.

GHESI will continue to renew the fleet as described in the fleet assessment report in Appendix L. The IBM AS400 system is aging and no longer meets the needs of **GHESI**. As a result and outlined in Appendix M, **GHESI** will be making an investment in 2015 & 2016 to replace the IBM servers.

5.2.1.2 **Sources of Cost Savings Expected** (OEB Filing Req. 5.2.1b)

Sources of cost savings expected to be achieved over the forecast period through good planning and DSP execution

Over the previous cycle, **GHESI** has undertaken many procedural and policy improvements to improve efficiency in the operation of the system that are expected to show positive results with respect to cost savings and efficiencies. **GHESI** has identified the following sources of cost savings and efficiencies expected to be achieved over the forecast period:

- **ACA study** will drive good asset investment planning. Using the **ACA,** results will lead to reduced emergency replacement costs. Unplanned replacement has higher labour costs due to after-hours trouble calls, higher replacement materials costs and higher costs to mitigate impact on reliability.

- **Life Extension Programs** can reduce costs when compared to replacement programs. An example of life-extension programs in GHESI is the wood pole treatment program. In this program, boron is injected into wood poles, extending the life of the asset as compared to untreated poles for less than the replacement costs of the asset.
- **Distribution Automation** has a clear impact on reliability statistics, but is also a labour savings option when applied on switching devices that are remote from the service centre. The Rockwood Municipal Distribution Station ("**MS**") #1 upgrade is an example where labour savings are expected through distribution automation.
- **Standardized Designs** save money both by reducing the engineering costs of the project as well as reducing installation costs and material stock costs. **GHESI** is part of the Utilities Standard Forum ("**USF**") group to standardize installation drawings for use in the projects in this **DSP**.
- **Devices such as portable computing devices** and the use of web-based applications to replace paper-based data collection and processes will improve operational efficiency, reduce the possibility of data translation errors, and provide cost savings at the time of collection, and the time of data entry. Improved data is used to optimize the planning process for future projects and improve **ACA** processes.
- **Distribution System Losses** are being improved through renewal projects. Specifically, increased conductor sizes and better balancing of transformer station loading results in reduced losses. In the area around the Campbell **TS**, **GHESI** is deferring capacity expansion with the execution of some feeder projects. These projects shorten feeder lengths around Campbell **TS** and optimize loading. **GHESI** has an annual program to run simulations on the Distribution System and optimize for losses using our distribution system analysis software "Distribution Engineering System Software ("**DESS**"). Losses are a factor of current-squared, so an improvement in loading has a larger impact on losses which affects all of the energy carried on that line in perpetuity.

5.2.1.3 **Period Covered by the DSP** (OEB Filing Req. 5.2.1c)

The period covered by the DSP (historical and forecast years);

This **DSP** covers the historical period, which starts at 2011 and ends at 2015, (the "**Historical Period**") and the forecast period, which starts at 2016, the test year, and ends at 2020 (the "**Forecast Period**").

5.2.1.4 **Vintage of the Information on Investment 'Drivers'** (OEB Filing Req. 5.2.1d)

An indication of the vintage of the information on investment 'drivers' used to justify investments identified in the application (i.e. the information should be considered "current" as of what date?)

GHESI respects the value of having the most up-to date information in order to make key decisions within the asset management portfolio. Every effort is made to ensure data is current and key input information, such as inspections, are performed on schedule and the information is captured in a way to best be utilized. **GHESI** makes updates to its Asset Management Plan ("**AMP**") on a yearly basis to ensure information is current and new information is considered is the decision making process. Along with annual updates to the **AMP**, **GHESI**'s **ACA** is updated on a yearly basis. These on-going updates help ensure that current information is readily available and utilized in the planning process.

The **GHESI** Asset Management ("**AM**") group sets out the inspection schedule and requirement for various groups to complete and all inspections result in the creation of inspection databases or reports containing the inspection results.

Information contained in this **DSP** is considered current as of the end of 2014. Inspection data utilized in the **ACA** report was cut-off as of August 31, 2014 to allow time to access the information in order for an end of year completion.

5.2.1.5 **Important Changes to the AM Process** (OEB Filing Req. 5.2.1e)

Where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DSP filing

As this is the first **DSP**, **GHESI** has included information related to changes in the asset management process as it relates to the annual **AMP**, outlined in Table 5.2-3 below.

Changes to AM Process		2011 to 2013	2013 to 2014
Change in ACA	Asset Classes	Thirteen asset classes added	One asset class removed
	Granularity	Increased Granularity	No Change
	Data Availability	Improved data availability	Improved data availability
	Data Gap Closure	Increased data gaps due to health index formula revisions	Data gaps closed for two asset classes
Changes to Inspection Programs	Poles Inspection	• Expanded to include concrete poles, composite poles and third party owned poles where **GHESI** has plant installed. • Moved to three year	No Change

		rotation.	
	Underground Structure Inspections	• Targeted suspect units near Campbell TS, Cedar TS, Hanlon TS, and in the downtown core	• Targeted area inspections in 2013 and a random sample across **GHESI's** service area.
	Cable and Termination Infrared Inspections	Infrared inspections carried out in conjunction with structural inspections	No Change
	Kabar Inspections	No Change	• Inspection programs started for Kabar units • Moved to three year rotation
Changes to Asset Health	**ACA** Population Changes	Population increased in 20 asset classes, decreased in one asset class, and remained unchanged for one asset class	Population increased in 9 asset classes, decreased in 10 asset classes, and remained unchanged for 2 asset classes. One asset class was not assessed
	Average Health Comparison	Average health increased in four asset classes and decreased in six asset classes. Changes were unknown for 12 asset classes because they were not previously assessed.	Average health increased in 7 asset classes, decreased in 9 asset classes, and remained unchanged in 5 asset classes. Changes were unknown for 1 asset class as it was not assessed.
	Average Age Comparison	Average age increased in four asset classes, decreased in four asset classes, and remained unchanged in two asset classes. Changes were unknown for 12 asset classes as they were not previously assessed.	Average age increased in 17 asset classes, decreased in 2 asset classes, and remained unchanged in 2 asset classes. Changes were unknown for 1 asset class as it was not previously assessed.

Table 5.2-3: Important Changes to the AM Process Since the Last Annual **AMP**

I. Changes in Asset Condition Assessment

i. Asset Classes

The 2011 revision of the **AMP** included nine asset classes. The 2013 revision greatly expanded the set of assessed assets to 22 types. The changes in assessed asset classes represent the introduction of some new equipment into the distribution system (namely, composite poles and dead front switchgear) and an effort to begin accumulating data for assets which may need to be prioritized for replacement in the next 20 years (such as civil support structures and underground cable).

The 2014 **ACA** reduced the set of assessed assets to 21 types, as the result of a general inspection of multijunctions. This inspection and subsequent report showed that there are very few multijunctions in poor condition and they do not present a significant risk of failure. Therefore they were removed from the analysis. While some asset classes do not have a large breadth of inspection data available currently, their inclusion in the **ACA** allows the gaps in available inspection data to be identified and closed in the future. A summary of the assets included for analysis in the previous and current **ACA**'s is listed in Table 5.2-4 below.

2011 (Nine asset types)	**2013 (22 asset types)**	**2014 (21 asset types)**
• Power Transformers • Pole Top Transformers • Pad Mounted Transformers • Submersible Transformers • Vault Transformers • Overhead Transformers • Overhead Switches • Pad Mounted Switchgear • Wood Poles • Concrete Poles	• Substation Transformers • Circuit Breakers • Pole Mounted Transformers • Pad Mounted Transformers • Submersible Transformers • Vault Transformers • Overhead Load-Interrupting Switches • Overhead **SCADA** Switches • Live Front Pad Mounted Switchgear • Solid Dielectric Pad Mounted Switchgear • Kabar Units • Multijunction Units • Primary Underground Cable • Secondary Underground Cable • Single Phase Overhead Primary Conductor • Three Phase Overhead Primary Conductor • Overhead Secondary Conductor • Wood Poles • Concrete Poles • Composite Poles • Underground Distribution Vaults • Manholes and Cable Chambers	• Substation Transformers • Circuit Breakers • Pole Mounted Transformers • Pad Mounted Transformers • Submersible Transformers • Vault Transformers • Overhead Load-Interrupting Switches • Overhead **SCADA** Switches • Live Front Pad Mounted Switchgear • Solid Dielectric Pad Mounted Switchgear • Kabar Units • Primary Underground Cable • Secondary Underground Cable • Single Phase Overhead Primary Conductor • Three Phase Overhead Primary Conductor • Overhead Secondary Conductor • Wood Poles • Concrete Poles • Composite Poles • Underground Distribution

2011 (Nine asset types)	2013 (22 asset types)	2014 (21 asset types)
		Vaults • Manholes and Cable Chambers

Table 5.2-4: Assets Examined in the **ACA**

ii. Increased Granularity

The changes to asset classes from the previous revision of the **AMP** to the current version represent a positive change for the following classes:

- Overhead Switches (now broken down into Load Interrupter Switches ("**LIS**") and SCADA Switches)
- Pad Mounted Switchgear (now broken down into Live-Front Switchgear and Solid-Dielectric Switchgear)

The changes to the Overhead Switches asset class was made because **SCADA** Switches follow a different maintenance program than manual **LIS**. Both have different life expectancies and significantly different replacement costs.

The changes to the Pad Mounted Switchgear asset class were made because the inspection needs, failure modes, life expectancy and replacement cost are significantly different depending on the insulation type of the switch. Additionally, because switchgear units are a large investment and because many live-front pad switches are showing accelerated aging due to corrosion and tracking (leakage of electrical current), they need to be specifically monitored and prioritized for replacement separate from dead-front switchgear.

The changes to asset classes from the 2013 revision of the **AMP** to the current version do not represent a change in granularity.

iii. Data Availability

The 2011 revision of the **ACA** does not provide explicit statistics regarding the availability of data for each asset; however, it does provide notes regarding data availability. In the 2011 **ACA**, it was concluded by Kinectrics that insufficient data was available to assess vaults, manholes, underground cables and submersible switchgear.

The 2013 **ACA** concludes that data availability is sufficient for all asset categories except concrete poles, composite poles, circuit breakers, kabar units, multijunction units, overhead lines and underground cables.

The changes in data availability can be attributed to the following:

- Circuit Breakers, Kabar Units, Multijunction Units, Overhead Conductor and Underground Cable were not previously part of the **ACA** and specific data collection plans are yet to be formalized for these assets;
- Composite Poles were not previously part of the **ACA** and, although a specific inspection program has been implemented, the full inspection cycle for these assets is three years and two years of inspection have been completed to date (2013 and 2014); and
- Concrete Poles were previously not inspected and only age and street type were provided. A full inspection program for Concrete Poles has been implemented; however, the full inspection cycle takes place over three years and two years of inspection have been completed to date (completed in 2013 and 2014). The data provided for Concrete Poles is, therefore, much more detailed than previously provided but the detailed information is only available for a portion of the poles at this time.

For most asset classes, the scope of the variables assessed in the **ACA** has increased and, accordingly, more data has been collected and provided for most asset classes. However, since the required inspection variables have increased, data availability (the number of units for which each variable is available) has not increased dramatically. It is expected that over the next three years, as new inspection programs are completed, the data availability will increase significantly from what was available during the course of previous **ACA's**. Data availability for the 2013 **ACA** is presented in Table 5.2-5 below:

Asset Category	Average DAI*	Sample Size** (% of Population)
Substation Transformers	92%	100%
Circuit Breakers	8%	100%
Pole Mounted Transformers	22%	100%
Pad Mounted Transformers	54%	100%
Submersible Transformers	19%	100%
Vault Transformers	95%	100%

Overhead Switches	**LIS**	28%	100%
	SCADA	29%	100%
Pad Mounted Switches	Live Front Switchgear	79%	100%
	Solid Dielectric Switchgear	20%	100%
	Kabar	17%	100%
	Multijunction	17%	100%
Cables	Primary	21%	100%
	Secondary	21%	100%
Lines	1 Phase Primary	21%	100%
	3 Phase Primary	21%	100%
	Secondary	21%	98%
Poles	Wood Poles	86%	100%
	Concrete Poles	10%	100%
	Composite Poles	3%	99%
Vault		12%	12%
Manholes		13%	13%

Table 5.2-5: Data Availability Index ("**DAI**") and Sample Size for 2013 **ACA** assets

Definitions:

*DAI – Data availability is a measure of the amount of data that an individual unit has in comparison with the set of complete condition parameter data currently defined in the Health Index formula. For example, a 92% DAI is better than a 13% DAI in that more data is available to assess the health of the asset.
Sample Size – Percentage of total assets quantities evaluated in the **ACA

The current **ACA** was completed on December 11, 2014 and concludes that data availability is sufficient for all asset categories except circuit breakers, overhead lines and underground cables.

The changes in data availability can be attributed to the following:

- Multijunctions were removed from analysis.
- Specific data collection plans are yet to be formalized for Circuit Breakers, Overhead Conductor and Underground Cable.
- Concrete Poles, Composite Poles, Manholes and Vaults were previously part of the **ACA** and, although a specific inspection program has been implemented, the full inspection cycle for these assets is three years and only two years of inspection have been completed to date (2013, 2014). The data provided for these assets is much more detailed than previously provided, however the detailed information is only available for a portion of the population at this time.
- Slight decreases in data availability for some assets are due to increases in the population which have not undergone subsequent inspections at this time.
- Data availability for the 2014 **ACA** is presented below in Table 5.2-6:

Asset Category		Average DAI	Sample Size (% of Population)
Substation Transformers		94%	100%
Circuit Breakers		8%	100%
Pole Mounted Transformers		22%	100%
Pad Mounted Transformers		53%	100%
Submersible Transformers		26%	100%
Vault Transformers		96%	100%
Overhead Switches	**LIS**	20%	100%
	SCADA	25%	100%
Pad Mounted Switches	Live Front Switchgear	62%	100%
	Solid Dielectric Switchgear	59%	100%
	Kabar	60%	100%
Cables	Primary	21%	100%
	Secondary	21%	100%
Lines	1 Phase Primary	21%	100%
	3 Phase Primary	21%	100%
	Secondary	21%	100%
Poles	Wood Poles	78%	95%
	Concrete Poles	84%	100%
	Composite Poles	95%	100%
Vault		22%	22%
Manholes		22%	23%

Table 5.2-6: **DAI** and Sample Size for 2014 **ACA** Assets

iv. Data Gap Closure

Data gaps are variables that are helpful in assessing the health of an asset, but which are missing from current inspection or reporting practices. The following Table 5.2-7 presents the data gaps closed for each asset type for the 2011, 2013, and 2014 **ACAs**.

Asset	Data Gaps Identified (priority indicated by asterisks)			
	2011 ACA	2013 ACA		2014 ACA
Substation Transformers	Grounding*	Insulation*** Cooling***	Sealing & Connection*	No Change to Data Gaps
Circuit Breakers	Not Assessed	Mechanical Linkage*** Lubrication*** Control Cabinet	Arcing Contact Wear** SF6 Gas Reading**	No Change to Data Gaps

Asset	Data Gaps Identified (priority indicated by asterisks)			
	2011 ACA	2013 ACA		2014 ACA
		Visual* Close Time* Trip Time*	Vacuum CB Status** Insulation Dielectric Test**	
Pole Mounted Transformers	Corrosion** Oil Leak**	Corrosion** Oil Leak*** Connections**	Tank Grounding Condition* Cracked/Dirty Bushing** General Service Record*	No Change to Data Gaps
Pad Mounted Transformers	Grounding* IR Thermography***	None		No Change to Data Gaps
Submersible Transformers	Corrosion**	Corrosion** Oil Leak***	General Service Record*	No Change to Data Gaps
Vault Transformers	Grounding* IR Thermography***	None		No Change to Data Gaps
Load Interruptor Switches	Motor/Manual Operation*** Switch Mounting* Arc Horn/Interrupter** Switch Blade Condition** Insulator**	Mechanical Linkage*** Switch Mounting* Arc Horn Surface Condition*	Arc Snuffer Condition** Insulator* Switch Blade Condition***	No Change to Data Gaps
SCADA Switches	Motor/Manual Operation*** Switch Mounting* Arc Horn/Interrupter** Switch Blade Condition** Insulator**	Mechanical Linkage*** Switch Mounting* Arc Horn Surface Condition*	Arc Snuffer Condition** Insulator* Switch Blade Condition***	No Change to Data Gaps
Live Front Switchgear	Base** Access* Switch/Fuse Condition*** Arc Chute** Grounding* Insulators**	Switch Condition** Arc Extinguisher Condition**	Fuse Condition** Connection Condition**	No Change to Data Gaps
Solid Dielectric Switchgear	Not Assessed	Enclosure Corrosion** Case Condition* Foundation*	Connection and Termination** Overall General Condition***	Data Gaps Closed
Kabar	Not Assessed	Enclosure Corrosion** Case Condition* Foundation*	Connection and Termination** Overall General Condition***	Data Gaps Closed
Multijunction	Not Assessed	Connections**	Overall General Condition***	
Underground Primary	Not Assessed	Cable Splice	Maintenance on	No Change

Asset	Data Gaps Identified (priority indicated by asterisks)			
	2011 ACA	2013 ACA		2014 ACA
Cable		Condition** Termination Condition**	Segment** Segment Loading History***	to Data Gaps
Underground Secondary Cable	Not Assessed	Cable Splice Condition** Termination Condition**	Maintenance on Segment** Segment Loading History***	No Change to Data Gaps
Overhead 1 Phase Primary Conductor	Not Assessed	Splice or Repair Condition**	Line Section Maintenance**	No Change to Data Gaps
Overhead 3 Phase Primary Conductor	Not Assessed	Splice or Repair Condition**	Line Section Maintenance**	No Change to Data Gaps
Overhead Secondary Conductor	Not Assessed	Splice or Repair Condition**	Line Section Maintenance**	No Change to Data Gaps
Wood Poles	None	None		No Change to Data Gaps
Concrete Poles	None	None		No Change to Data Gaps
Composite Poles	Not Assessed	None		No Change to Data Gaps
Vault	Not Assessed	None		No Change to Data Gaps
Manholes	Not Assessed	None		No Change to Data Gaps

Table 5.2-7: **ACA** Data Gap Comparison

"*" represents the priority of the data gap with
1-* representing a low priority data gap
2-** representing a medium level gap
3-*** representing a high priority data gap

Although many of the assets had a higher number of data gaps in 2013 than in the 2011 **ACA**, the formulas used to derive asset health indices were revised and included more variables in 2013, hence the additional categories.

The following data gaps were targeted and addressed as indicated in Table 5.2-8 below for the 2014 edition of the **ACA**:

Asset	Data Gap to Close	Result
Submersible Transformers	Service Record	Three of four sub-condition parameters were addressed. Overall service record data still required.
Live Front Switchgear	Switch Condition Fuse Condition	Adjustments to inspection forms still required.

	Arc Extinguisher Condition Connection Condition	
Solid Dielectric Switchgear	Enclosure Corrosion Case Condition Foundation Connection & Termination Overall Condition	Completed.
Kabar	Enclosure Corrosion Case Condition Foundation Connection & Termination Overall Condition	Completed.

Table 5.2-8: Targeted 2014 **ACA** Data Gaps

II. Changes to Inspection Programs

Some inspection programs have been revised since the previous revision of the **AMP**. The following sections detail the changes that have been made.

i. Poles Inspection

A pole inspection specification and new inspection forms were created in 2012/2013 to rectify data inconsistency issues in previous inspection years and to include the inspection of concrete poles, composite poles and third party owned poles where **GHESI** has plant installed.

The inspection forms were made digital, limiting the entry possibilities in an effort to reduce clerical errors. After one year of use, the new forms appear to be working well, and very few errors have been found in the data that was returned.

Photographs of what constitutes various types of damage were also requested and received helping to gauge comparison of future inspections to normalize the data and remove subjectivity.

Pole inspections have been moved to a three year rotation, with Rockwood being incorporated into area 3. Inspection areas are represented in Figure 5.2-2: **GHESI** Inspection Areas on page 59 at the end this section. The three year cycle makes the pole inspection program compliant with Distribution System Code ("**DSC**") Appendix C requirements. To date one year of inspection data has been collected for concrete and composite poles. The inspection area completed in 2013 was Area 2, while Areas 3 and Rockwood are planned for 2014 inspections.

ii. Underground Structure Inspections

In 2013, Kinectrics performed an underground structure assessment which resulted in the inspection of 99 **UD's**, **UDV's** and Manholes. The inspection targeted suspect installations in critical areas such as near Campbell **TS**, Cedar **TS** and Hanlon **TS**, and in the downtown core. The inspection program identified some Vaults and Manholes in need of short term restoration or replacement work and was deemed a success, providing valuable health information on the assets and photos from within each asset. The images captured will make future work in the area of the assessed structures more efficient and has been utilized on some large capital projects in 2013 with good results.

In order to extrapolate the data reliably across the **GHESI** distribution system, further inspections must be carried out on a random sample.

iii. Cable and Termination Infrared Inspection

In addition to the underground inspection, in 2013 Kinectrics performed an infrared inspection of cables, splices and elbows within vaults and manholes in conjunction as part of the structural inspection they were carrying out.

The inspection, which covered a subset of underground infrastructure assets located in Guelph, confirmed the overall health of splices, elbows and multijunction units in the inspected area. Only two locations showed fair condition, while all others were in good or very good condition.

Changes made in the current revision of the **AMP** include:

i. Kabar Inspections

An inspection program has been put together and started for Kabar units. The inspection data combines the methodology used for pad mounted transformers and includes the collection of sub-condition parameters identified in the 2013 **AMP**. The inspection of Kabar units also includes the implementation of new unit numbering (units were previously not uniquely identified). Numbers are being applied to each unit during their first inspection. Kabar inspections have been moved to a three year rotation, with Rockwood service territory being incorporated into Area 3. The three year cycle makes the Kabar inspection program compliant with **DSC** Appendix C requirements. To date one year of inspection data has been collected.

ii. Underground Structure Inspections

In 2013 and 2014, Kinectrics performed an underground structure assessment which resulted in the inspection of 241 **UD's**, Underground Distribution Vault's ("**UDV's**") and

Manholes. The inspection targeted suspect installations in critical areas such as near Campbell, Cedar and Hanlon Transformer Stations, and in the downtown core, as well as a random sample across **GHESI**'s service area. The inspection program identified some Vaults and Manholes in need of short term restoration or replacement work and was deemed a success, providing valuable health information on the assets, as well as photos from within each asset. The images captured will make future work in the area of the assessed structures more efficient and has been utilized on some large capital projects in 2013 and 2014 with good results, as well as in the planning of future projects in 2015-2020.

In order to extrapolate the data reliably across **GHESI**, further inspections must be carried out on a random sample.

III. Changes to Asset Health

ACA's provide valuable insight into the overall health of **GHESI**'s system and doing yearly assessments also provides the ability to gauge how the health of the system is responding to maintenance and reconstruction efforts driven by the **AMP**. Three metrics are of consideration when comparing system health across multiple years, namely, changes in the population of each asset class, changes in the average age of the asset classes and changes in the average health index rating of the asset classes. A comparison between the findings in the previous revision of the **AMP** and the current version are detailed in sections below.

ACA Population Changes

Table 5.2-9 below details the population of the various asset classes in the 2011, 2013, and 2014 **ACA's** and notes the changes. The populations presented differ from actual populations in **GHESI** since the populations presented in the **ACA** report are based on data made available.

Asset	Population Assessed in the Asset Condition Assessment				
	2011 ACA	2013 ACA	Change	2014 ACA	Change
Substation Transformers	2	4	+2	4	0
Circuit Breakers	Not Assessed	20	+20	18	-2
Pole Mounted Transformers	1799	1791	-8	1821	+30
Pad Mounted Transformers	3623	3722	+99	3825	+103
Submersible Transformers	41	42	+1	42	0
Vault Transformers	82	82	0	81	-1

LIS	237	372	+135	361	-11
SCADA Switches		85		94	+9
Live Front Switchgear	62	89	+27	88	-1
Solid Dielectric Switchgear	Not Assessed	6	+6	11	+5
Kabar	Not Assessed	60	+60	77	+17
Multijunction	Not Assessed	34	+34	Not Assessed	N/A
Underground Primary Cable	Not Assessed	663	+663	679	+16
Underground Secondary Cable	Not Assessed	1074	+1074	1123	+49
Overhead 1 Phase Primary Conductor	Not Assessed	101	+101	99	-2
Overhead 3 Phase Primary Conductor	Not Assessed	326	+326	329	+3
Overhead Secondary Conductor	Not Assessed	471	+471	459	-12
Wood Poles	7888	10426	+2538	10105	-321
Concrete Poles	676	897	+221	881	-16
Composite Poles	Not Assessed	191	+191	180	-11
Vault	Not Assessed	560	+560	469	-91
Manholes	Not Assessed	247	+247	275	+28

Table 5.2-9: Asset Population Assessed in **ACA**

Average Health Comparison

The following Table 5.2-10 details the change in the average health of the assets assessed in the 2011, 2013 and 2014 **ACAs**. An increase in average health indicates that older assets are being retired and/or newer assets are being installed. This information, in conjunction with the average age of the assets, is an indicator of the trends in overall system health and the effectiveness of current replacement investments.

Asset	Average Health				
	2011 ACA	2013 ACA	Change	2014 ACA	Change
Substation Transformers	85%	94%	+9%	93%	-1%
Circuit Breakers	Not Assessed	100%	NA	100%	0%
Pole Mounted Transformers	90%	81%	-9%	78%	-3%
Pad Mounted Transformers	95%	88%	-7%	88%	0%
Submersible Transformers	90%	88%	-2%	86%	-2%
Vault Transformers	92%	90%	-2%	91%	+1%
LIS	92%	86%	-6%/-24%	97%	+11%
SCADA Switches		78%		84%	+6%
Live Front Switchgear	83%	90%	+7%	87%	-3%
Solid Dielectric Switchgear	Not Assessed	100%	NA	99%	-1%
Kabar	Not Assessed	93%	NA	91%	-2%
Multijunction	Not Assessed	86%	NA	N/A	N/A
Underground Primary Cable	Not Assessed	96%	NA	95%	-1%
Underground Secondary Cable	Not Assessed	97%	NA	97%	0%
Overhead 1 Phase Primary Conductor	Not Assessed	99%	NA	99%	0%
Overhead 3 Phase Primary Conductor	Not Assessed	100%	NA	100%	0%
Overhead Secondary Conductor	Not Assessed	97%	NA	98%	+1%
Wood Poles	72%	80%	+8%	86%	+6%
Concrete Poles	74%	96%	+22%	83%	-13%
Composite Poles	Not Assessed	99%	NA	88%	-11%
Vault	Not Assessed	58%	NA	89%	+31%
Manholes	Not Assessed	51%	NA	87%	+36%

Table 5.2-10: Asset Average Health Comparison

In several categories, overall asset health shows a decrease from 2011 to 2013. However, many changes to health index formulation were made and significantly more asset data was made available for 2013. Because of this combination of factors, a conclusive trend cannot be drawn. More years of asset assessment, using the current health formulation, will be required to determine a definitive trend for the health of **GHESI**'s system. However, given known events, some conclusions can be drawn which explain the differences observed in the **ACA**:

- Substation transformer data was updated to consider the rebuild date for Rockwood **MS**#1 transformer, significantly improving its health rating;
- New power transformers have been added at Arlen **MTS**, significantly reducing the average age and increasing the average health of the Substation Transformer category;
- Only 38 pole mount transformers were installed in 2012 and the entire population of 1995 installed pole mount transformers were excluded from the results due to an obvious data error found in the Geographic Information Systems ("**GIS"**) records. This resulted in overall age being skewed towards earlier installations;
- A de-rating factor has been applied to pad mounted transformers that are live-front type, lowering previous health ratings for these units;
- Number of operations was factored into the health of overhead switches. Introducing this factor had a profound impact on the calculated average health;
- Some older pad mounted switchgear units are starting to fail and are being replaced with solid dielectric units. This has had a slight impact on overall health;
- The de-rating factor on Douglas Fir poles was changed from setting the pole health to 30% to a de-rating factor applied to the health as determined from actual inspection data. While some Douglas Fir poles were showing accelerated decay, this has not been the case across the board and the previous calculation methods were applying too harsh a penalty to some poles; and
- A greater amount of data is available for concrete poles, reducing the emphasis on age and location and increasing the emphasis on visual identification of damage to the pole. This has resulted in an increase in overall health as the first inspection area for concrete poles did not include many of the suspected oldest or worst shape poles in the system.

A decrease in the overall asset health from 2013 to 2014 was observed for several asset categories. However, some of the decreases can be attributed to more detailed data being collected from multiple inspection cycles (in the case of Kabar units, pad mounted switchgear, concrete poles and composite poles). This behaviour is expected as data availability increases since problem units will begin to be identified and health indexing becomes based on more than age alone. More years of asset assessment, using the current health formulation, will be required to determine a definitive trend for

the health of the **GHESI** system. However, given known events, some conclusions can be drawn which explain the differences observed in the **ACA**:

- Some older pad mounted switchgear units are starting to fail and are being replaced with solid dielectric units. This has had a slight impact on overall health;
- A greater amount of data is available for concrete and composite poles, reducing the emphasis on age and location and increasing the emphasis on visual identification of damage to the pole. This has resulted in an increase in overall health as the first inspection area for concrete poles did not include many of the suspected oldest or worst shape poles in the system and subsequent decrease in health index as the older poles were inspected in the second cycle;
- A greater amount of data is available for Kabar units, reducing the emphasis on age and l increasing the emphasis on visual identification of damage to the unit. This has resulted in a decrease in overall health; and
- The vault and manhole inspection program has been expanded to include random sampling. In 2012, only vaults and manholes suspected to be in poor condition were inspected and therefore the sample was not representative. The use of a representative sample in 2014 presents a more realistic picture of asset health.

Average Age Comparison

The following Table 5.2-11 details the change in the average age of the assets assessed in the 2011 and 2013 **ACA's**. A decrease in average age indicates that older assets are being retired and/or newer assets are being installed. This information in conjunction with the average health of the assets is an indicator of the trends in the overall system health and the effectiveness of current replacement investments.

Asset	Average Age					Current IFRS* Useful Life (Typical)	Proposed IFRS** Useful Life (Typical)
	2011 ACA	2013 ACA	Change	2014 ACA	Change		
Substation Transformers	10	7	-3	9	+2	45	45
Circuit Breakers	Not Assessed	3	NA	3	0	40	40
Pole Mounted Transformers	19	20	+1	21	+1	40	40
Pad Mounted Transformers	17	14	-3	16	+2	40	40
Submersible Transformers	14	14	0	16	+2	35	35
Vault Transformers	24	23	-1	26	+3	35	35
LIS	12	13	+1/-5	15	+2	50	50
SCADA Switches		8		9	+1	45	45
Live Front Switchgear	11	12	+1	14	+2	25	25
Solid Dielectric Switchgear	Not Assessed	1	NA	2	+1	30	30
Kabar	Not Assessed	14	NA	15	+1	30	30
Multijunction	Not Assessed	23	NA	N/A	N/A	30	N/A
Underground Primary Cable	Not Assessed	16	NA	17	+1	40	40
Underground Secondary Cable	Not Assessed	17	NA	18	+1	40	40
Overhead 1 Phase Primary Conductor	Not Assessed	27	NA	29	+2	60	50
Overhead 3 Phase Primary Conductor	Not Assessed	18	NA	20	+2	60	50
Overhead Secondary Conductor	Not Assessed	27	NA	29	+2	60	50
Wood Poles	28	34	+6	27	-7	45	50
Concrete Poles	16	16	0	18	+2	60	40
Composite Poles	Not Assessed	4	NA	2	-2	70	70
Vault	Not Assessed	23	NA	26	+3	60	60
Manholes	Not Assessed	18	NA	18	0	60	60

Table 5.2-11: Average Age of Assets Assessed in **ACA**

*Current International Financial Reporting Standards ("**IFRS")** Useful Life Typical represents useful life values currently in use.
Proposed **IFRS Useful Life (Typical) values represent a new useful life study conducted by Kinectrics in 2014 in Appendix K.

Most asset categories show very little change in average age between the two **ACAs**. This indicates that new installations and replacement assets were roughly equal to retired assets and caused little change in the overall age of the system.

Changes in average age of wood poles may be due to the use of better inspection data for deriving the installation year of poles across the board, where in the past inspection data and Geographic Information System ("**GIS")** data differed.

Change in Asset Health Conclusion

The following conclusions have been drawn from the data presented in the 2011 and 2013 **ACAs** as it relates to change in the asset health conditions in order to unitize the results in future planning cycles:

- Assessment criteria has changed from 2011 to 2013 both in the formulas for determining health indices and the assets and variables monitored;
- Additional assessments, without varying health formulas, will be needed to accurately trend the health of the distribution system;
- Overall asset age has not changed dramatically over the past two years but populations have generally increased, indicating that replacements are not keeping pace with the age of the installed assets (since new installations would lower the overall age of each asset if replacements were equal to the oldest installations in a given year);
- Whether the current replacement frequency is adequate given actual asset health is inconclusive due to the changes in health formulation between the two **ACA** reports that have been completed to date;
- Increased data availability and asset consideration has improved awareness of the current health of important assets in the distribution system; and

The following conclusions have been drawn from the data presented in the 2013 and 2014 **ACAs** as it relates to change in the asset health conditions in order to unitize the results in future planning cycles:

- Assessment criteria has changed from 2013 to 2014 both in terms of the assets and variables monitored;
- Continual additional assessments without varying health formulas will be needed to accurately trend the health of the distribution system;
- Overall asset age has not changed dramatically over the past year but populations have both increased and decreased for the various classes, indicating that replacements are not keeping pace with the age of the installed assets in some cases (since new installations would lower the overall age of

each asset if replacements were equal to the oldest installations in a given year). This is true particularly for pole and pad mounted transformers and underground cable;

- Increased data availability and asset consideration has improved awareness of the current health of important assets in the distribution system; and

The following Figure 5.2-2 outlines **GHESI's** breakdown of inspection areas with the City of Guelph and the Village of Rockwood for the purpose of distribution system inspections which follow a three year cycle compliant with **DSC** Appendix C requirements as described above in the pole inspection description.

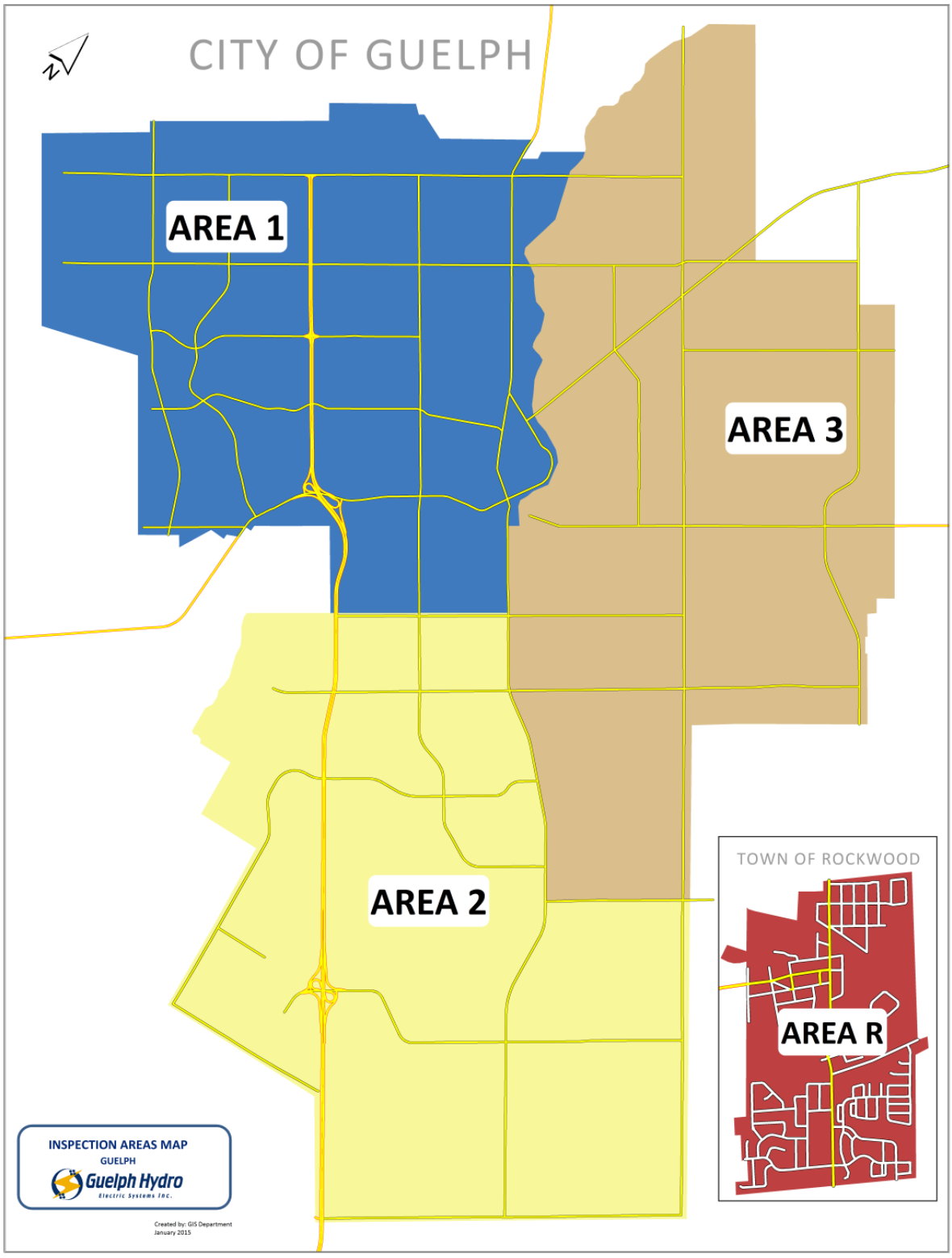


Figure 5.2-2: **GHESI** Inspection Areas

5.2.1.6 **Aspects contingent upon the outcome of ongoing activities** (**OEB** Filing Req. 5.2.1f)

Aspects of the DSP that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known

While the overall **DSP** spending program itself is contingent upon the **OEB** approval of the rates as applied for, a select few investments described in the **DSP** are contingent upon the outcome of ongoing activities or future events. Specifically, the level of actual investments within the System Access category may be altered slightly year-to-year from the proposed investment levels, depending upon the number of customer requests for new services connections and line relocation requests by municipal and provincial land owners. These capital expenditures are highly dependent on external drivers and the level may deviate significantly during the next five years. However, best efforts are made to understand the level of investment needed by meeting with planning agencies within the municipality and utilizing historic trends.

One aspect of the plan that is an indirect result of the **RPP,** is the need for a solution at **GHESI** Arlen **MTS** in order to mitigate high levels of short circuit due to the **Hydro One** Guelph Area Transmission Refurbishment ("**GATR**") project which itself came out of the **RPP** process. Following the completion of the Hydro One Customer Impact Assessment ("**CIA**") for the **GATR** project outlined in Appendix H, **GHESI** conducted its own internal investigation study to determine the impacts of the transmission system upgrades on **GHESI's** distribution system. The result of the study indicated a significant increase to the available short circuit levels at Arlen **MTS**. The increase in short circuit levels will be effective when the **GATR** project becomes in-service in Q2 2016 thus a solution is required prior to remain compliant with transmission system code ("**TSC**") requirements. This project is described in detail in the 2016 Material Capital Project Summary Appendix N**.**

5.2.2 Coordinated Planning with Third Parties (OEB Filing Req. 5.2.2)

To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, 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 DSP as filed and if so, a brief explanation as to how.***
- ***b) where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:***
  - ***the role of the distributor in the consultation;***
  - ***the status of the consultation process; and***
  - ***Where applicable the expected date(s) on which final deliverables are expected to be issued.***
- ***c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DSP (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.***

To meet the **OEB's** expectations with respect to coordinated planning with third parties, **GHESI** has initiated or participated in the following consultation processes with major stakeholders:

- Customer stakeholder engagement;
- Consultation with regional and municipal governments;
- Integrated Regional Resource Planning with the **IESO**, Hydro One, and other **LDCs**;

- Renewable energy generation planning with the **IESO; and**
- Consultation with Conservation and Demand Management ("**CDM**") program partners – **IESO.**

For each of these consultation processes, descriptions are provided in sections below:

- Purpose of the consultation;
- Role of **GHESI** in the consultation;
- Participants in the process;
- Nature and timing of the final deliverables; and
- Impact of the consultation process on this **DSP**.

5.2.2.1 **Customer Stakeholder Engagement**

A. Large Customer Information Session

On March 19th, 2014, **GHESI** hosted a Large Customer Information Session inviting key commercial and industrial customers to attend in order to gather customer input and feedback that can be incorporated into this DSP planning process to help **GHESI** deliver better service to customers. The **GHESI CDM** group used normal **CDM** planning practices utilizing past event experience to create the invitation list. A total of 156 invitations to the event were issued, resulting in twenty representatives from fourteen organizations accepting. On the day of the event ten representatives from eight organizations representing a cross section of business sectors in Guelph attended the session which featured presentations on the following topics:

- Overview of **GHESI**
- Rate Application Process
- Distribution Plan
- Energy Efficiency Programs
- Reliability and Power Quality
- Know Your Bill

The organizations represented at the event were:

- ABS Friction Inc.
- Gay Lea Foods
- Hammond Manufacturing Inc.
- Homewood Health Centre
- Owens Corning
- Sleeman Breweries

- Stone Road Mall
- Wellington Catholic District School Board

Of the ten people in attendance at the event, seven submitted feedback forms for a response rate of 70 percent. Feedbacks received were surrounding quality of the presentation, large customers' preferences on the frequency and form of communication, and topics suggested for future information sessions.

Energy conservation and incentive programs and billing appeared to be the most valued and informative presentations at the session, with energy conservation and incentive programs receiving ten mentions in anecdotal feedback and billing receiving eight mentions in anecdotal feedback. This feedback supports the conservation first approach to **DSP** planning undertaken by **GHESI** in this **DSP**.

Discussions were facilitated among participants around the following topics:

- Impact of power interruptions to the operation of these businesses
- Customer "Wish List"

Valuable insights were gained through this meeting regarding the expectations of these large customers on the service they receive from **GHESI**.

To improve the quality of service delivered to these large customers, **GHESI** has planned for capital investments to reduce the frequency of power outages on its distribution system. In particular, System Renewal projects to maintain asset health and System Service projects, such as new feeders and extensions, are targeted to reduce frequency of outages.

Key elements of the customer "wish list" included the provision of communication based functions such as:

- 24/7 service in the control room
- Proactive notifications of outages

Feedback received by **GHESI** indicated that the customers were generally supportive of higher electricity rates in return for extended hours of operation of the control room. Moving forward, as more real-time system information becomes available through continued automation and monitoring, this customer expectation will increase and become the norm and **GHESI** will continue to explore ways to deliver this information to the customer.

Capital expenditures that these methods of customer engagement have informed include, *inter alia*: outage management, implementation of a 24/7 service controller and the website outage system.

B. Customer Engagement Survey

GHESI is committed to sound financial planning and budgeting that balances quality electricity distribution services with affordability for ratepayers while fostering innovation and making investments in energy infrastructure that will benefit the community in the long term.

In 2014, GHESI launched its Customer Engagement Survey. Residential and commercial customers were invited to participate through Twitter, a bill insert, ads in local newspapers and the Guelph Chamber of Commerce. Participation was incented with the chance to win one of five Apple iPads. The survey period ran from December 1, 2014 to January 30, 2015. This survey is attached as Appendix P.

The 2014 Customer Engagement Survey was designed to gain customer feedback in the following key areas:

- Customer Service
- Online Customer Service
- Social Media
- Your Hydro Bill
- Energy Conservation
- Renewable Energy/New Technologies
- Reliability/Power Outages/Safety
- Providing Value to Customers
- Future Investments

Overall, customer satisfaction with **GHESI** was high, with 91% of respondents rating **GHESI's** performance as good or excellent. Respondents were also generally satisfied with reliability of the system, with 91% rating the overall reliability of their electrical services as good or excellent. An investment to reduce the number and duration of power outages was the category to receive the most responses of very or somewhat important with respect to future investments.

GHESI plans to use the feedback received on reducing power interruptions to help design its capital investment and business plans by implementing projects to specifically address reliability issues in the future. Projects currently being evaluated include single phase re-closures that will assist in sectionalizing faulted areas of the overhead distribution system to allow the main 3-phase feeder to remain in-service and improve

reliability. This approach puts stakeholders at the heart of **GHESI's** decision-making processes, and ensures that investment decisions are made to directly support their needs.

5.2.2.2 **Consultation with Regional and Municipal Governments**

The City of Guelph prepares and issues an annual Development Priorities Plan ("**DPP**") to the Planning & Building, Engineering and Environment Committee. The **DPP** is intended to manage the rate and timing of development in the city. It provides a multi-year forecast of development activity as measured by the anticipated registration of draft plans of subdivision and the monitoring of infill development. The goal of the **DPP** is to manage growth in a balanced and sustainable manner in keeping with the City's Strategic Plan. **GHESI** uses the **DPP** to help estimate potential load growth in its service territory from the City's land zoning and development plans presented in the **DPP**. This ensures enough capacity is planned for in the **DSP** for meeting growing demand.

Consultations with regional governments have not occurred, however, informal discussions with regional departments such as the Ministry of Transportation ("**MTO**") and Ministry of the Environment ("**MOE**") have occurred on an as needed basis to address specific project related topics such as permitting requirement and specific details regarding certain projects. These specific project discussions are generally initiated by the project owner and participants in the discussion typically include the MTO, MOE, City of Guelph, **GHESI** and other third party utilities such as communications and the gas company. The outcome of such specific project discussions include, for example, plans and direction for the project currently being constructed or a request for a concept design and estimate to relocate assets related to an upcoming project. Other examples of discussions include a request by **GHESI** to obtain permits for an upcoming project. **GHESI** would initiate and take the lead on such correspondence and the outcome would be obtaining the necessary approvals, documents and permits to proceed with the project. **GHESI** will continue to follow a similar path in the future by including such agencies in project discussions.

Generally, the informal discussions apply to distribution system planning on a case by case basis. However, **GHESI** has used its knowledge and relationships with governments to inform the **DSP** as applicable. Knowledge of how **GHESI's** relationships with the Ministries have developed thus far allows it to understand expectations for directions in the future and plan accordingly.

5.2.2.3 **Integrated Regional Resource Planning ("IRRP") with the IESO**

As mentioned above in the introduction at Section 5.1, **GHESI** is a participant in the regional planning process of the **KWCG** region, of which it is part of. This region

includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and the townships of Wellesley, Woolwich, Wilmot and North Dumfries. The **IRRP** process in this region has been initiated and led by the **IESO** to assess the reliability needs within this region to develop an integrated plan for the appropriate mix of investments to address electricity needs.

Other participants in this process include:

- Cambridge and North Dumfries Hydro Inc.;
- Kitchener-Wilmot Hydro Inc.;
- Waterloo North Hydro Inc.; and
- Hydro One Distribution Networks Inc.

GHESI has participated in monthly meetings with the other three local **LDC's** as well as **Hydro One** distribution, whose distribution system territory surrounds the **GHESI's** service territory.

This region currently has an **IRRP** document under development. Two projects have been identified by the **KCWG** Working Group to address the near- and medium term needs in this region:

- The Guelph Area Transmission Reinforcement (**GATR**) project; and
- The second Preston auto-transformer project.

On May 29, 2013, the **IESO** issued a letter to hand off the lead responsibility to **Hydro One** and requested **Hydro One** to initiate the planning and implementation of the transmission components of this **IRRP**. This letter is included in Appendix I.

The final output of this process is an **IRRP** that is expected to be completed by the **IESO** in 2015.

GHESI is a participant in the **RIP** Process for the **KWCG** region. This process is initiated and led by **Hydro One**, the lead transmitter in the region. Other participants in this process include:

- Cambridge and North Dumfries Hydro Inc.;
- Kitchener-Wilmot Hydro Inc.;
- Waterloo North Hydro Inc.; and
- Hydro One distribution.

The purpose of the **RIP** process is to develop and implement wires solutions for the two projects that were identified during the **IRRP** process. These are:

- The **GATR** Project; and
- The second Preston auto-transformer project.

The final deliverable of this process, a **RIP** is not available at this time and no indication as to the final timing of the deliverable has been given from **Hydro One**. **GHESI** has submitted an inquiry to **Hydro One** regarding the status of the **RIP**. A planning status letter was received from **Hydro One** on December 2, 2014 indicating that planning activity for the first project is currently underway while the second project is being further reviewed. The letter also explained that the **GATR** project will affect **GHESI's** system in the following ways:

- The **GATR** project will involve extension of the 230kV supply to Cedar **TS** and installation of 2-230/115kV autotransformers at the station. The 115kV circuits B5G/B6G and F11C/F12C will be networked at Cedar TS thus eliminating the radial nature of supply to the stations supplying **GHESI** customers, and improving supply reliability for these customers.
- The **GATR** project will also involve the installation of two **LIS's** on the 230kV circuits D6V/D7V at Guelph North Junction. The switches will minimize the impact of interruptions to **GHESI** customers in the event of the loss of both transmission circuits D6V and D7V.

Investments associated with the **GATR** project are proposed as a network pool cost. Therefore, GHESI understands it has no cost implication for **GHESI** over this **DSP** planning period.

This Planning Status Letter sent to **Hydro One** by **GHESI** and the responses from **Hydro One** are both provided in Appendix E and F respectively.

5.2.2.4 **Renewable Energy Generation Planning with the IESO**

GHESI has consulted with the **IESO** on numerous occasions in an effort to keep both groups up to date on the **REG** developments as well as to review the available thermal and short circuit current limitations for several of the transformer stations in the Guelph service area. **GHESI** prepared and submitted a **REG** investment plan to the **IESO** on November 28, 2014 and received a comment letter on the subject referenced in Appendix B**.**

The **REG** investment plan along with the **IESO** comment letter are referenced in Appendix A and C respectively.

5.2.2.5 **Consultation with CDM Program Partners – IESO**

GHESI has delivered **CDM** programs to its customers since 2004, and has regularly consulted with the **IESO** since its introduction as the provincial authority with electricity conservation responsibilities. This includes the **IESO** "Every Kilowatt Counts" 2007-2010 **CDM** tranche followed by the 2011-2014 **IESO** "saveONenergy" **CDM** tranche. Through these **CDM** frameworks **GHESI** participated in **IESO** program design and change management, utilized **CDM** delivery funding received from the **IESO**, and completed a variety of regular monthly and annual reporting requirements under the Master Agreement with the **IESO**.

Currently, **GHESI** is preparing for **CDM** program design and delivery for the 2015-2020 Conservation First Framework (CFF) **CDM** tranche. Through 2014, **GHESI** was involved the Conservation Framework First ("**CFF")** design and development, along with the **IESO** and a variety of other stakeholders and interest groups. With the **OPA** merger with the **IESO**, **GHESI** will continue to work collaboratively with the **IESO** under the 2015-2020 Energy Conservation Agreement for program delivery, funding, and results reporting against GHESI's six (6) year 99.04 GWh electricity savings target.

5.2.3 **Performance Measurement for Continuous Improvement** (**OEB** Filing Req. 5.2.3)

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

5.2.3.1 **Metrics to Monitor DSP Process Performance** (**OEB** filing Req. 5.2.3a)

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

- ***customer oriented performance (e.g. consumer bill impacts; reliability; power quality);***
- ***cost efficiency and effectiveness with respect to planning quality and DSP implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and***
- ***Asset and/or system operations performance.***

GHESI uses a set of performance measures to continuously monitor and evaluate its achievement with respect to the four performance outcomes established by the **OEB** particularly in respect of the Electricity Distributers Scorecard (**Scorecard**). Most of these measurements are required by the **OEB** for the DSP filing, while some are not. Regardless of requirement, these measurements are recorded as they are considered meaningful in the case of **GHESI**. There are also a few additional metrics contemplated in the **Filing Requirements.** In aggregate, these measures not only allow **GHESI** to capture deviations in its own performance from year to year, but also provide a means for **GHESI** to compare its performance with other **LDC's** in Ontario.

Five of the performance measures reported in the **Scorecard**, were added by the **OEB** in May 2014 to capture performance in value to customers, effective planning, and asset management. **GHESI** does not keep historical records for theses performance measures as they were not tracked prior to 2014. The newly added measures are:

- First Contact Resolution
- Billing Accuracy
- Customer Satisfaction Survey Results
- Public Safety
- Distribution System Plan Implementation Progress

These measures have not been historically tracked by **GHESI** and, therefore, it is not possible to report on this metric at this time. The baseline data and the actuals will be included in future fillings.

A summary of these performance measures detailed in the **Scorecard** are outlined in Table 5.2-12 below.

Performance Outcomes	Performance Categories	Measures
Customer Focus	Service Quality	New Residential/Small Business Connected On Time
		Scheduled Appointments Met On Time
		Telephone Calls Answered On Time
	Customer Satisfaction	First Contact Resolution †
		Billing Accuracy †
		Customer Satisfaction Survey Results
	Customer Bill Impacts*	Percentage Average Total Bill Impact
		Average Dollar Impact
	Power Quality*	Power Quality and Electrical Disturbances

Performance Outcomes	Performance Categories	Measures
Operational Effectiveness	Safety	Public Safety †
		Electrical Safety Authority (**ESA**) Audits
		Injury Rates
	System Reliability	SAIDI (Including and Excluding LoS)
		Normalized SAIDI (Including and Excluding LoS)
		SAIFI (Including and Excluding LoS)
		CAIDI (Including and Excluding LoS)
		MAIFI (Including and Excluding LoS)
	Asset Management	Distribution System Plan Implementation Progress †
		Data Availability Index (**DAI**)*
	Cost Control	Total Cost per Customer
		Total Cost per Km of Line
		Total Cost per MWh of Electricity Consumed
Public Policy Responsiveness	CDM	Net Annual Peak Demand Savings
		Net Cumulative Energy Savings
Financial Performance	Financial Ratios	Liquidity: Current Ratio
		Leverage: Total Debt to Equity Ratio
		Profitability: Achieved Regulated Return on Equity

† New Metrics in 2014 **Scorecard**
***** Additional metrics outside of **Scorecard** process

Table 5.2-12: Performance Measures and Metrics

I. Definition of Customer Focus Metrics

Service Quality

New Residential/Small Business Connected On Time

The utility must connect new service for the customer within five business days 90% of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.) **GHESI's** target is >=90%.

Scheduled Appointments Met On Time

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long and must arrive within that window 90% of the time. **GHESI's** target is >=90%.

Telephone Calls Answered On Time

During regular call centre hours, the utility's call centre staff must answer phone calls within 30 seconds of receiving the call directly or of having the call transferred to them 65% of the time. **GHESI's** target is >=65%.

Customer Satisfaction

Performance metrics added by the **OEB** in 2014 include First Contact Resolution and Billing Accuracy. **GHESI** has historically not tracked these metrics and will be developing processes to monitor and report in these areas.

The **OEB** also added a requirement to report on Customer Satisfaction Survey Results**. GHESI** participates bi-annually in the Electric Utility Customer Satisfaction Survey, a telephone survey conducted by UtilityPULSE which is attached in Exhibit 1, Appendix 1-B. This survey gauges the satisfaction of customers with the services of and their experiences with their local electric utility. Utilities are graded on the quality of information they provide to customers, the professionalism, attitude and helpfulness of staff, timeliness of response, and accessibility as well as a variety of other factors. **GHESI's** target is to remain a leader among all **LDC's** in Ontario based on equivalent surveys undertaken by **LDC's**.

Customer Bill Impacts

Two measures can be used to quantify the impact of **GHESI's** rate application on customers' electricity bills:

- Percentage Average Total Bill Impact; and
- Average Dollar Impact.

GHESI's historical and future target as it relates to bill impact shown in

Table **5.2-14** of section 5.2.3.2 is to keep the bill impact lower than 10% for all customer classes.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates, monthly service charge, volumetric rates and proposed retail transmission service rates, revised loss factors, proposed **LRAM** rate riders, and regulatory asset recover rate riders to dispose of the

balances in the Deferral and Variance Accounts requested in this Application, are set out below in Figure 5.2-3 and Figure 5.2-4. The Bill Impacts are calculated by comparing the predicted 2016 Test Year bills at the proposed rates with the actual 2015 bill at the existing rates.

2016 Total Bill Impact Summary

Residential	kWh	100	250	500	800	1,000	1,500	2,000
	Bill Impact $	$2.07	$2.20	$2.42	$2.68	$2.85	$3.28	$3.71
	Bill Impact %	6.64%	4.14%	2.69%	2.00%	1.75%	1.38%	1.20%
Loss Factor	1.0260							

General Service Less than 50 kW	kWh	1,000	2,000	5,000	10,000	15,000
	Bill Impact $	$0.90	$0.76	$0.33	($0.40)	($1.11)
	Bill Impact %	0.58%	0.26%	0.05%	-0.03%	-0.05%
Loss Factor	1.0260					

General Service 50 to 999 kW	kWh	22,776	37,960	189,800	379,600	
	kW	60	100	500	1,000	
	Bill Impact $	($76.16)	($127.79)	($646.31)	($1,293.90)	
	Bill Impact %	-2.05%	-2.10%	-2.22%	-2.23%	
Loss Factor	1.0260	Load Factor 52%				

General Service 1000 to 4999 kW	kWh	48,910	244,550	489,100	
	kW	100	500	1,000	
	Bill Impact $	$222.84	$221.64	$220.15	
	Bill Impact %	2.81%	0.60%	0.30%	
Loss Factor	1.0260	Load Factor 67%			

Large Use	kWh	3,035,340	4,215,750	5,621,000	8,431,500
	kW	5,400	7,500	10,000	15,000
	Bill Impact $	$298.62	$354.45	$420.93	$553.87
	Bill Impact %	0.07%	0.06%	0.05%	0.05%
Loss Factor	1.0036	Load Factor 77%			

Unmetered Scattered Load	kWh	325
	Bill Impact $	($4.37)
	Bill Impact %	-6.72%
Loss Factor	1.0260	

Sentinel Lighting	kWh	365
	kW	1
	Bill Impact $	($0.74)
	Bill Impact %	-1.06%
Loss Factor	1.0260	Load Factor 50%

Street Lighting	kWh	946,080	63
	kW	2,400	0.16
	Bill Impact $	$3,015.62	$0.12
	Bill Impact %	1.89%	1.07%
Loss Factor	1.0260	Load Factor 54%	

Figure 5.2-3 2016 Total Bill Impact summary

		Selected Delivery Charge and Bill Impacts								
		Subtotal A - Monthly Delivery Charge					Total Bill			
		Current	Proposed	Change			Current	Proposed	Change	
				$	%				$	%
Residential	800 kWh/month	$ 29.51	$ 33.56	$ 4.05	13.74%		$ 133.91	$ 136.59	$ 2.68	2.00%
GS < 50 kW	2000 kWh/month	$ 42.35	$ 45.84	$ 3.49	8.25%		$ 296.55	$ 297.32	$ 0.76	0.26%

Figure 5.2-4 Residential and General Service Less Than 50kW Bill Impacts

Power Quality

In response to a customer power quality concern, where the utilization of electricity adversely affects the performance of electrical equipment, **GHESI** will perform an investigative analysis to attempt to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data and/or use of power and power quality measurement tools. Connection of power measurement tools will be at the demarcation point or nearest safely accessible point of connection. Upon determination by **GHESI** that the power quality concern is deemed to be a system delivery issue where industry standards are not being met, **GHESI** will recommend and/or take appropriate mitigation measures. **GHESI** will use appropriate industry standards (such as International Electrotechnical Commission ("**IEC**"), Institute of Electrical and Electronics Engineers ("**IEEE**"), or CSA Group ("**CSA**") standards) and good utility practice as a guideline. If the problem lies on the customer side of the system and, provided that the problem does not impact other customers connected to the system, **GHESI** will indicate as such to the customer, but take no further action.

Customers' electrical equipment can produce undesirable system disturbances that have an adverse impact on the distribution system. Customers are required to consult with **GHESI** when planning to install equipment that may cause disturbances. **GHESI's** limits on voltage distortion are 3% for individual voltage harmonic distortion and 5% for total harmonic distortion.

Given the nature of the concern, all power quality requests are investigated immediately and efforts to ameliorate concerns, if any are needed, are taken care of right away. As these issues are resolved on a case-by-case as needed basis, **GHESI** relies only on a record of occurrences. This record is kept by way of work order form. While this is not a formal tracked metric in the same manner of other metrics considered and discussed in this **DSP**, **GHESI** does keep record of any raised Power Quality occurrences.

As power quality issues are difficult to track and quantify, specifically as the inputs come from customer feedback in many cases, a target for Power Quality issues is equally

difficult to set. Generally, **GHESI** has attempted to reduce power quality issues on a year to year basis through its asset management and capital planning. **GHESI** will continue to maintain this 'target' in a general sense.

II. Definition of Operational Effectiveness Metrics

Safety

Public Safety

According to the *Report of the Board on Performance Measurement for Electricity Distributors* (EB-2010-0379), a measure for public safety has not been determined. Under directive of the **OEB**, the Electrical Safety Authority **("ESA")** convened and met with an **LDC** Public Electrical Safety Measure Working Group in October and November 2014 to establish a public electrical safety measure for the **LDCs'** annual **OEB Scorecard**. As a member of the Working Group, **GHESI** has attended three working group sessions since October 2014 with twelve other **LDC's** in Ontario and members of **ESA's** Consumer Advisory Council ("**CAC**"). The following three options were identified during these working sessions:

- Public Safety Awareness (as discussed and modified in the working session);
- Number of serious electrical safety incidents as defined by Ontario Regulation 22/04 – *Electrical Distribution Safety*. ("**Reg. 22/04**") involving the public as defined by **Reg. 22/04**; and
- A combination of public safety awareness & number of serious electrical safety incidents as defined by **Reg. 22/04** involving the public (as defined by **Reg. 22/04**).

ESA has just launched a public consultation that runs from January 26, 2015 to March 4, 2015. Submission of the finalized measures to the **ESA** board of directors and the **OEB** is anticipated in March, 2015.

ESA Audits

ESA audits of **GHESI** are conducted on an annual basis under Ontario **O. Reg. 22/04**. The audits are completed by the Quality Systems Assessment Registrar ("**QUASAR**"). QUASAR is qualified by the ESA to conduct audits under **O. Reg. 22/04**.

The purpose of the audit is to assess the extent of compliance of the distributor to **O. Reg. 22/04**, to measure whether the distributor has met the electrical requirements established for the design, construction, and maintenance of electrical distribution systems in **O. Reg. 22/04**.

GHESI targets to achieve full compliance of **O. Reg. 22/04**, meaning zero "Non-compliance" and "Needs improvement" in future **ESA** audits.

Injury Rate

Incidents rates are used as a means of recording frequency and severity of recordable workplace injuries. These are injuries that result in time off from work after the day of the incident. It is calculated as follows:

Injury Rate = Total number of injuries and illness*200,000 / Number of Hours Worked by All Employees.

Where 200,000 represent the approximate number of hours worked for 100 employees working 40 hours per week, 50 weeks per year. This provides the standard base for calculating incident rates.

GHESI treats safety of its employees, contractors, and the general public as number one priority and strives to maintain zero injury rates at all times.

System Reliability

SAIDI

The system average interruption duration index ("**SAIDI**") is an indicator of system reliability that expresses the average length of outage customers experience in the year. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served and is expressed as:

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

GHESI's target range for **SAIDI** is 0.21-1.70 under normal operating conditions.

Normalized **SAIDI**

The **IEEE** Working Group on System Design presented a statistics based methodology at **IEEE** Transactions on Power Delivery in 2013. This method, called the beta method ("**Beta Method**"), provides a means for calculating reliability indices on a normalized basis.

In this method, a major event day is defined as a day in which daily **SAIDI** exceeds a threshold value T_{MED} determined at the end of the previous reporting period. The threshold value, T_{MED}, is calculated by the following procedure:

- Collect values of **SAIDI** for a number of sequential yeas, ending on the last day of the last complete reporting period
- Replace any day in the data set that has a value of zero for **SAIDI** with the lowest non-zero **SAIDI** value in the data set
- Take the natural logarithm (ln) of each daily SAIDI value in the data set
- Calculate the average of the logarithms, α
- Calculate the standard deviation of the logarithms, β
- Calculate the T_{MED} threshold value using equation $T_{MED} = e^{(\alpha+2.5\beta)}$

Any day with a daily **SAIDI** exceeding this threshold value during the subsequent reporting period is designated a major event day and neglected when calculating the normalized **SAIDI**.

The purpose of employing this method is to allow a utility to separately assess its performance during normal operation and major event days.

SAIFI

The system average interruption frequency index ("**SAIFI**") is an indicator of the average numbers of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the number of interruptions normalized per customer served and is expressed as:

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

GHESI's target range for **SAIFI** is 0.50-1.51 under normal operating conditions.

CAIDI

The customer average interruption duration index ("**CAIDI**") is an indication of the speed at which power is restored after an interruption. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the average duration of interruptions in the year and is expressed as follows:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customer Interruptions}}$$

GHESI's target value for **CAIDI** is 0.85.

MAIFI

The momentary average interruption frequency index ("**MAIFI**") is an indicator of the average numbers of momentary interruptions each customer experiences. All planned and unplanned interruptions of less than one minute are used to calculate this index. It is defined as the average number of momentary interruptions in the year and is expressed as follows:

$$\text{MAIFI} = \frac{\text{Total Number of Momentary Interruptions for all Customers}}{\text{Total Number of Customers Served}}$$

GHESI's target value for **MAIFI** is 9.04.

Asset Management

Performance metrics added by the **OEB** in 2014 include monitoring the cost efficiency and effectiveness with respect to planning quality and **DSP** implementation. **GHESI** has historically not tracked these metrics and will be developing processes to monitor and report in these areas. Metrics will include:

- Physical project progress vs plan;
- Financial project progress vs. plan; and
- Actual vs. planned cost of work completed.

Data Availability Index (**DAI**)

DAI is the measure that **GHESI** considers to be an important indicator of the validity of the Asset Health Index results and is a measure of the data available for each individual asset in the database in comparison with the complete set of data fields as defined in the health index formula for that asset group. The target **DAI** varies by asset category and is specified in Table 5.2-5. The **DAI** is not a metric that is based on the **OEB** scorecard, however it helps **GHESI** track the progress of asset assessment and shows continuous improvement in the availability of data. For example, **GHESI** will look at the **DAI** to determine whether more data is required for a specific asset investigation. The more data available, the higher level accuracy that can be applied to health index of specific **GHESI** asset assessments.

Cost Control

Total Cost per Customer

Total cost as the sum of a distributor's Capital Costs and Operation, Maintenance and Administration ("**OM&A**") costs, including certain adjustments to make the costs more comparable between distributors per reporting period. This amount is then divided by

the total number of customers that the distributor serves. **GHESI** does not have a target value for this measure. Performance is evaluated through benchmarking, using information from the **OEB** scorecard that is published annually for all **LDCs**. **GHESI's** target is to achieve and maintain high standards and high **OEB** scorecard ranking as compared to its peers for lowest total cost per customer.

Total Cost per km of Line

The total cost per customer is calculated as the sum of a distributor's capital costs and **OM&A** costs, including certain adjustments to make the costs more comparable between distributors per reporting period. This amount is then divided by the total number of kilometers of line that the distributor operates to serve its customers. **GHESI** does not have a target value for this measure. Performance is evaluated through benchmarking, using information from the **OEB** scorecard that is published annually for all **LDCs**. **GHESI's** target is to achieve and maintain high standards and high **OEB** scorecard ranking as compared to its peers for lowest total cost per km of line operated.

Total Cost per MWh of Electricity Consumed

Total cost is calculated as the sum of a distributor's capital costs and **OM&A** costs, including certain adjustments to make the costs more comparable between distributors per reporting period. This amount is then divided by the total MWh consumption of all customers. GHESI does not have a target value for this measure. Performance is evaluated through benchmarking, using information from the **OEB** scorecard that is published annually for all **LDCs**. **GHESI**'s target is to achieve and maintain high standards and high **OEB** scorecard ranking as compared to among its peers for lowest total cost per MWh of electricity consumed.

III. Definition of Public Policy Responsiveness Metrics

Conservation and Demand Management

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998*, directed the **OEB** to establish **CDM** targets to be met by electricity distributors. Accordingly, on November 12, 2010, the **OEB** amended the distribution licence of **GHESI** to require **GHESI**, as a condition of its license, to achieve 79.53 GWh of net persistent cumulative energy savings and 16.71 MW of net persistent summer peak demand savings, over the period of January 1, 2011 through to December 21, 2014.On March 31, 2014, the **OPA** received direction from the Minister of Energy to develop a new Conservation First Framework (**CFF**) with the goal of achieving 7 TWh of province-wide electricity conservation between 2015 and 2020. The 7 TWh energy only targets would be

allocated to Ontario **LDCs**, with 99.04 GWh of net incremental persistent electricity savings allocated to **GHESI** as its share of the provincial target. On December 18, 2014, **GHESI's** electricity distribution license was amended to include a requirement to make **CDM** programs available to its customers in an effort to achieve reductions in electricity consumption. A specific electricity savings target was not included in the distribution license amendment. **GHESI** monitors its performance against comparable **LDCs** and strives to remain a leader in the implementation of **CDM** initiatives. Effective January 1, 2015, the **OPA** merged with the **IESO**, with the **IESO** taking on oversight responsibility and support of **LDC** Conservation First Framework **CDM** delivery.

Peak Demand Savings

Peak demand savings are reductions in overall demand during summer peak periods as defined by the **IESO** for the 2011-2014 timeframe. **GHESI's** target for peak demand savings is 16.71MW by December 21, 2014. Although peak demand savings are no longer a target under the Conservation First Framework, **GHESI** intends to continue to track and record demand savings achieved through **CFF CDM** activities against the energy only savings target.

This metric remains of use to **GHESI** due to the nature of its distribution system planning. Capital system planning is typically done based on a peak demand, thus having **CDM** information available on the energy side at a peak is important in system planning and, accordingly, in capital planning. Energy targets are converted by an industry standard formula to be applied to a peak which is used to assist in capacity planning, specifically as it relates to forecasting.

Net Energy Savings

Net energy savings (kWh) are reductions in total energy consumption. **GHESI's** target for net cumulative energy savings for the 2011-2014 timeframe was 79.53GWh by December 21, 2014. Under **CFF**, **GHESI's** net energy savings target is no longer cumulative, but rather net incremental savings, with a six year target of 99.04 GWh.

IV. Definition of Financial Performance Metrics

Financial Ratios

Liquidity: Current Ratio

The current ratio is a financial ratio that measures whether or not the **LDC** has enough resources to pay its debts over the next 12 months. It is calculated as: Liquidity = Current Assets / Current Liabilities.

Leverage: Total Debt to Equity Ratio

Leverage ratios show the degree to which the **LDC** is leveraging itself through its use of borrowed money. It is calculated as:

Leverage Ratio = Total Debt (including short-term and long-term debt) / Total Equity.

Profitability: Achieved Regulated Return on Equity

This is the distributor's achieved Regulated Return on Equity earned in the preceding fiscal year. The reported return is calculated on the same basis as was used in establishing the distributor's base rates. This measures the use of assets and control of expenses to generate a rate of return.

Profitability is the board-approved Return on Equity that is embedded in the distributor's base rates.

All of the above financial ratios are set out in the **OEB** scorecard and applied by **GHESI** for its performance evaluations.

5.2.3.2 **Summary of Performance over the Historical Period** (**OEB** Filing Req. 5.2.3b)

b) Provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DSP), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

As is introduced in Section 5.2.3.1, among the set of performance measures **GHESI** uses to continuously monitor and evaluate its achievement are the four performance outcomes established by the **OEB,** collectively known as (**Scorecard**). Most of these measurements are required by the **OEB** for the **DSP** filing, but some are not. These measures provide a means for **GHESI** to compare its performance with other **LDC's** in Ontario. Five of the performance measures reported in this scorecard, including First Contact Resolution, Billing Accuracy, Customer Satisfaction Survey Results, Public

Safety, and **DSP** Implementation Progress, were added by the **OEB** in May 2014 to capture performance in value to customers, effective planning, and asset management. **GHESI** does not keep historical records for these performance measures as they were not tracked prior to 2014.

In addition to the **OEB** scorecard, the **Filing Requirements** require metrics on:

Customer Focus:

Customer Bill Impacts;

- Percentage Average Total Bill Impact,
- Average Dollar Impact

Power Quality;

- Power Quality and Electrical Disturbances

As illustrated in the **OEB** scorecard**,** two areas of potential concern are highlighted. "System Reliability" fell outside target values in 2013. This is analysed in detail in Section 5.2.3.2 II.ii, showing that in 2013 **GHESI's** distribution system experienced an unusual number of high impact major event days as defined in **IEEE** 1366-2003, "**IEEE** Guide for Electric Power Distribution Reliability Indices". A second area of concern is the decreasing trend in "Telephone Calls Answered On Time", which is described in Section 5.2.3.2.I.i and has already been addressed with the implementation of a new voice recognition system.

The 2013 **OEB** scorecard, provided in Figure 5.2-5 below, summarizes **GHESI's** historical performance from 2009 to 2013. **GHESI** notes that 2014 OEB scorecard data is not yet available for all metrics.

Performance Outcomes	Performance Categories	Measures	2009	2010	2011	2012	2013	Trend	Target	
									Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	99.80%	99.90%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time	96.50%	98.90%	98.60%	99.00%	97.10%		90.00%	
		Telephone Calls Answered On Time	70.60%	80.00%	92.90%	80.00%	83.70%		65.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy								
		Customer Satisfaction Survey Results					96%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]								
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	0.21	0.33	1.70	0.31	2.21			at least within 0.21 - 1.70
		Average Number of Times that Power to a Customer is Interrupted	0.50	0.75	1.51	1.49	3.36			at least within 0.50 - 1.51
	Asset Management	Distribution System Plan Implementation Progress								
	Cost Control	Efficiency Assessment				3	3			
		Total Cost per Customer [See Note below]	$633	$663	$696	$587	$608			
		Total Cost per Km of Line [See Note below]	$29,341	$31,284	$32,650	$27,427	$28,952			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved)			20.00%	30.00%	36.50%			16.71MW
		Net Cumulative Energy Savings (Percent of target achieved)			72.00%	107.00%	127.40%			79.53GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			83.33%	80.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.97	3.00	1.97	1.64	1.33			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.95	1.38	1.10	1.13	1.04			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)			8.57%	9.42%	9.42%			
		Profitability: Regulatory Return on Equity — Achieved			8.41%	7.50%	7.29%			

Figure 5.2-5: **OEB** Scorecard 2013

I. Summary of Customer Focus Metrics

Service Quality

Metric	OEB Approved Standard	2009	2010	2011	2012	2013	2014
Scheduled appointments met on time	>=90%	96.5 %	98.9 %	98.6 %	99%	97.1 %	83.9 %
Telephone calls answered on time	>=65%	70.6 %	80.0 %	92.9 %	80.0 %	83.7 %	87.7 %
New residential/small business services connected on time	>=90%	100 %	99.8 %	99.9 %	100 %	100 %	100 %

Table 5.2-13: Customer Service Quality Performance in Historical Period

GHESI's customer service quality in the historical period has been consistently beyond the industry target as identified above in Figure 5.2-5. Although **GHESI's** 2012 telephone accessibility results of 80% are well above the industry target of 65%, **GHESI** acknowledged a 2012 reduction in performance when compared to previous years. This issue was addressed with the implementation of an **IVR** system (corporate voice system). In 2014, **GHESI** experienced a lower than expected result in scheduled appointments met on time as it related to underground locates due to the larger than normal volume of locate requests that were received in April to May of 2014. **GHESI** experienced an increase of over 30% of locates requests within the month of May 2014, which proposed a challenge to the **GHESI** contractors completing the scheduled locates within the five (5) day allowance. Along with the increase in locate requests, **GHESI** was also transitioning to a new locate contractor beginning in the month of April which further added to the challenges and lower than average response time. Issues with this metric were promptly resolved by GHESI's efforts and transition to the new locate contractor. Specifically, **GHESI** met on a regular basis with our locate contractor to work through any issues and continuously monitored performance. **GHESI** will continue to monitor the metric and consider the need to act accordingly to meet the requirements of the **OEB**.

Customer Satisfaction

Performance metrics were added by the **OEB** in 2014 to monitor First Contact Resolution, and Billing Accuracy. **GHESI** has historically not tracked these metrics and will be developing processes to monitor and report in these areas.

The 2013 Customer Satisfaction Survey was based on telephone interviews of 400 respondents who pay or look after the electricity bills from **GHESI**. Customers surveyed were based on a random sample approach, with 1025 households and small businesses being contacted, and 400 completed interviews. Of the customers that were

surveyed, 85% were residential customers and 15% were commercial customers. **GHESI** ranked number one in Customer Satisfaction among the 14 Ontario electric utilities that took part in this survey and scored substantially higher than the national and provincial customer satisfaction averages. The results of this survey can be found in Exhibit 1, Tab 4, Schedule 3- Appendix 1B

Historical data with respect to customer satisfaction is not available for every metric for every year in the historical period as some of data is not collected on an annual basis. For example the UtilityPULSE Customer Satisfaction Survey was only conducted in 2013. The historical data available with respect to the various customer satisfaction metrics can be found in section 5.4.1.6.

Customer Bill Impacts

As part of the Application process, Guelph Hydro undertakes an analysis of bill impacts for all customer classes at the distribution, delivery and total bill impact level. Total bill impact consideration, including the percentage increase and the absolute dollar impact in comparison to an average bill, informs part of the decision making process. **GHESI's** historical and future target as it relates to bill impact shown in

Table **5.2-14** is to keep the bill impact lower than 10% for all customer classes. If the bill impact is forecast to be above 10%, with a customer focus and satisfaction in mind, **GHESI** will propose a mitigation plan as, for example, improving and lowering the loss factor, proposing a longer period of disposition for deferral and variance account balances disposition, working towards cost savings as reflected in Exhibit 1, Tab 3, Schedule 3, Filing Requirements 2.3.3 – Sub-section Efficiencies and Cost Improvements.

Historical Distribution Rates Increase		Historical Bill Impact			
		Residential [800 kWh per month]		GS< 50 kW [2000 kWh per month]	
Year	Increase	$	%	$	%
2010	0.18%	-$1.00	-1%	-$232.00	-0.90%
2011	0.18%	$1.04	0.90%	$1.59	0.60%
2012	7.86%	-$2.09	-1.85%	-$2.79	-1.10%
2013	1.08%	$0.26	0.23%	$3.37	1.30%
2014	1.40%	$3.47	2.94%	-$2.33	-87.00%
2015	1.30%	$3.84	2.72%	$6.77	2.38%
2016	13.74%	$2.68	2.00%	$0.76	0.26%

Table 5.2-14 Historical Bill Impact

Power Quality

As referenced in section 5.2.3.1, **GHESI's** limits on voltage distortion are 3% for individual voltage harmonic distortion and 5% for total harmonic distortion. For any reported situation where a system delivery issue is deemed to be the cause, **GHESI** acts to mitigate the issue.

Further, and as discussed above, due to immediate resolution of power quality concerns, historical data has not typically been kept outside of a list of occurrences. **GHESI** maintains a record of all work order forms for reported power quality issues. In the future, **GHESI's** intends to aggregate the number of power quality issues experienced per year and include this as a metric.

II. Summary of Operational Effectiveness Metrics

Safety

In Section 13 of **O. Reg. 22/04**, **ESA** mandates all distributors to engage an auditor to audit on an annual basis the distributor's compliance with Sections 4, 5, 6, 7 and 8 of the regulation and prepare an audit report for **ESA's** review. **ESA** audits of **GHESI** from 2011 to 2014 were conducted by qualified auditors from **QUASAR**, results of which are provided in Table 5.2-15 below. **GHESI** received a total of three non-conformances ("**NC**") and one needs-improvement ("**NI**") designation in these audits, for the following reasons:

- One **NC** in 2011: "[r]ecords of inspection or no undue hazards are not being signed off and/or recorded for all types of maintenance work (like for like) as outlined in **GHESI's** Construction Verification Program ("**CVP**"). Work performed under a trouble report or a pole replacement have the required sign offs."
- One **NI** in 2012: "[c]ertificates for the Royal Bank project were not available at the time of the audit. With the project files being viewed by all parties in rotation, all drawings and certificates should be available at any time. This is especially important when new equipment is being used on a project to ensure approvals are in place before energizing the system."
- One **NC** in 2013: "[r]ecords of inspection were not completed for all types of maintenance performed on the distribution system. Some maintenance was performed under a yearly maintenance work order with a certificate signed at the year end. The **CVP** states that Records of Inspection should also be completed. Maintenance is also performed with verbal instructions and no paper work is

recorded as with the replacement of **SCADA** equipment, only equipment requisition was recorded."

- One **NC** in 2014: "[r]ecords of Inspection were not always completed for all types of maintenance performed on the distribution system. Records of inspection were missing for regular maintenance, infrared report repairs and trouble calls."

Year	Safety Standards				Electrical Equipment				Plans, drawings and specifications for installation of work				Inspection and Approval of Construction			
	C	NI	NC	N/A	C	NI	NC	N/A	C	NI	NC	N/A	C	NI	NC	N/A
2011	4	0	0	0	2	0	0	1	6	0	0	2	5	0	1	4
2012	4	0	0	0	2	0	0	1	6	0	0	2	5	1	0	4
2013	4	0	0	0	2	0	0	1	6	0	0	2	5	0	1	4
2014	4	0	0	0	2	0	0	1	6	0	0	2	4	0	1	5
Evaluation Code: C – Complies; NI – Needs Improvement; NC – Non-conformance; N/A – Not Applicable																

Table 5.2-15: 2011-2014 **ESA** Audit Results

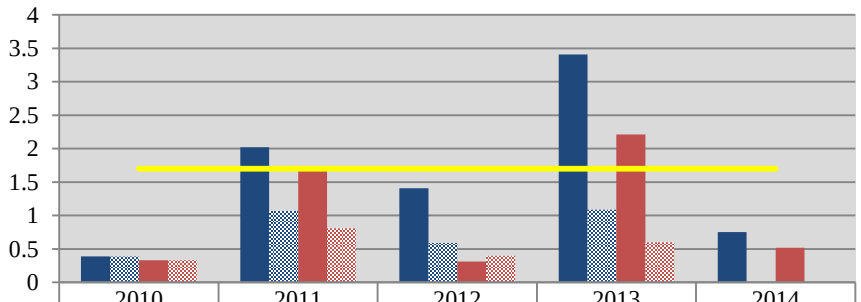
An important indicator of workplace safety is the injury rate, which takes into account both the frequency and the severity of recordable workplace injuries. **GHESI** has not experienced any employee injuries or illness based on data current to August 30, 2014. By calculation, using the formula provided in Section 5.2.3.1, the injury rate for 2011-2014 is zero, meeting **GHESI's** target value.

System Reliability

Figure 5.2-6 through Figure 5.2-9 summarizes **GHESI's** reliability performance in the historical period, measured by **SAIDI**, **SAIFI**, **CAIDI**, **MAIFI** including and excluding loss of supply. Figure 5.2-6, Figure 5.2-7 and Figure 5.2-8also present normalized **SAIDI, SAIFI and CAIDI** performance respectively that was calculated utilizing the Beta Method developed by the **IEEE** Working Group on System Design. This method removes the effect of major events to obtain **SAIDI** and **SAIFI** values that better represent the reliability performance of the system under normal operating conditions. The cumulative alpha and beta functions and the corresponding major event day thresholds for each of the historical years were determined using historical outage data. Events above the threshold were flagged and excluded from analysis and performance index calculations where it was considered prudent. The decision to include or exclude an event was largely based on whether the root cause event had a direct impact on **GHESI's** system or was through bulk supply issues in adjacent areas, and whether it was due to faults caused by extenuating circumstances or by equipment breakdown or animal/tree contact issues occurring on typical days.

For SAIDI and SAIFI, the motivation behind collecting normalization data has been to explain the unusual or particular impacts of the ice storm in 2013 in order to provide a clear comparator to previous metrics. As such, GHESI notes that Figure 5.2-7 below is missing historical normalized SAIFI data for outside of 2013. This limit on historical data carries forward the normalized CAIDI in Figure 5.2-8 based on the calculation of CAIDI.

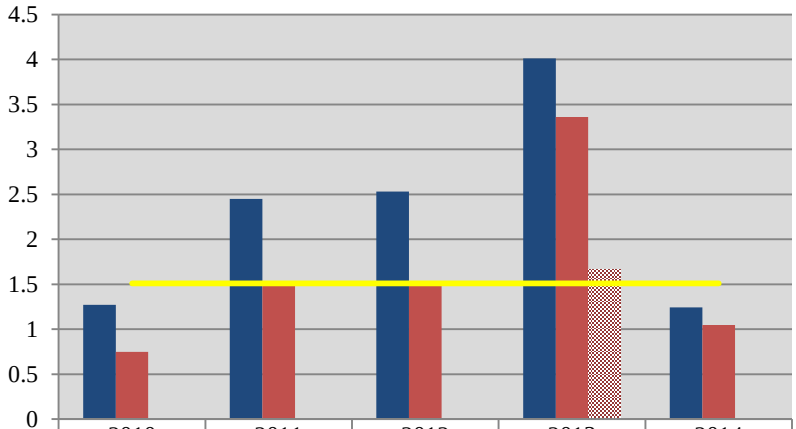
Reliability Performance - SAIDI (Unadjusted and Normalized)



	2010	2011	2012	2013	2014
SAIDI (Including LoS)	0.39	2.02	1.41	3.41	0.752
Normalized SAIDI (Including LoS)	0.39	1.07	0.59	1.09	
SAIDI (Excluding LoS)	0.33	1.7	0.31	2.21	0.516
Normalized SAIDI (Excluding LoS)	0.33	0.81	0.4	0.6	
SAIDI Target	1.7	1.7	1.7	1.7	1.7

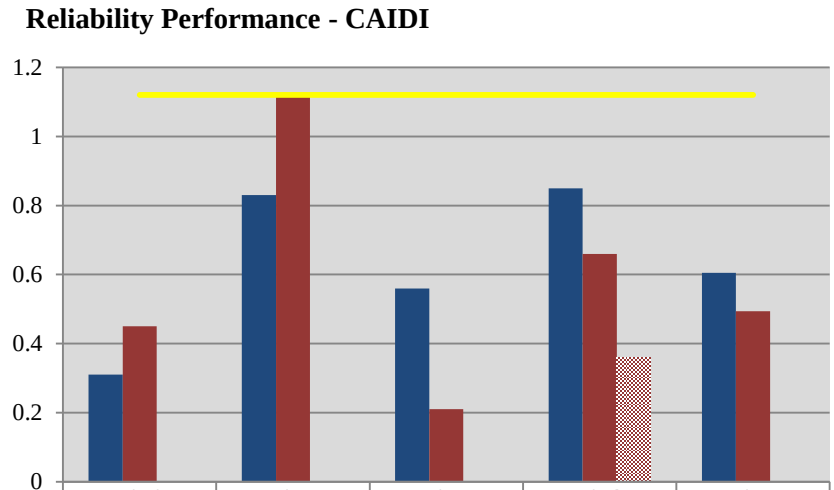
Figure 5.2-6: Historical SAIDI Performance

Historical Performance - SAIFI (Unadjusted and Normalized)



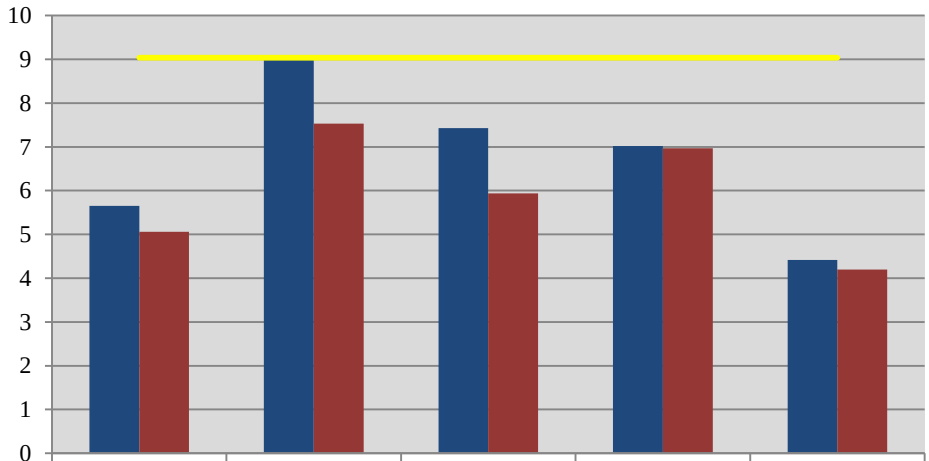
	2010	2011	2012	2013	2014
SAIFI (Including LoS)	1.27	2.45	2.53	4.01	1.242
SAIFI (Excluding LoS)	0.75	1.51	1.49	3.36	1.046
Normalized SAIFI (Excluding LoS)				1.66	
Target Value	1.51	1.51	1.51	1.51	1.51

Figure 5.2-7: Historical SAIFI Performance



	2010	2011	2012	2013	2014
CAIDI (Including LoS)	0.31	0.83	0.56	0.85	0.605
CAIDI (Excluding LoS)	0.45	1.12	0.21	0.66	0.494
Normalized CAIDI (Excluding LoS)				0.36	
CAIDI Target	1.12	1.12	1.12	1.12	1.12

Figure 5.2-8: Historical CAIDI Performance



	2010	2011	2012	2013	2014
MAIFI (Including LoS)	5.65	9.04	7.43	7.02	4.42
MAIFI (Excluding LoS)	5.06	7.53	5.94	6.97	4.2
Target	9.04	9.04	9.04	9.04	9.04

Figure 5.2-9: Historical MAIFI Performance

In 2013, **GHESI's** system reliability statistics for both **SAIDI** and **SAIFI** fell outside our distributor target of 0.21-1.70 and 0.50-1.51 respectively. **GHESI** has reviewed the interruption data for 2013 along with previous years going back to 2009 in order to

determine the root causes for the outages. Based on the data it was evident that deviations in 2013 had resulted from a higher number of significant events compared to previous years, except for 2011.

Analysis of the interruption data indicated that in 2013 **GHESI's** distribution system experienced five major event days removing loss of supply. The major event day calculation was done using the **IEEE** 1366-2003, "IEEE Guide for Electric Power Distribution Reliability Indices". Comparison with previous years is provided in Figure 5.2-10.

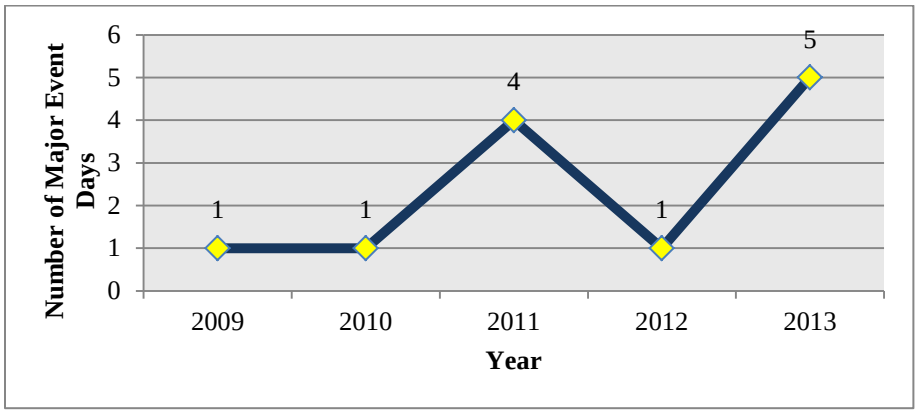


Figure 5.2-10: Number of Major Events Days in Historical Years

When comparing the events of 2011 and 2013 shown in Table 5.2-16, it is evident that, while a similar number of major events took place, the impact in 2013 was much more widely felt. The table below illustrates the **SAIDI** and **SAIFI** impacts of just those major events.

Year	2011	2013
SAIDI of Major Events	0.89	1.61
SAIFI of Major Events	0.26	1.7

Table 5.2-16: SAIDI and SAIFI of Major Events in 2011 and 2013

Of the five major event days in 2013, four can be directly related to storms which are outside the control of **GHESI**. By removing the effects of the four storms from the reliability calculation the normalized **SAIDI** and **SAIFI** statistics are 0.60 and 1.66 respectively, consistent with other years.

In addition to employing key reliability indicators to monitor its overall system reliability level, **GHESI** also tracks outage statistics including root causes on a regular basis. This data is collected through trouble reports and can be mapped to the **GHESI GIS** to help identify areas of concern within the service territory. Together with key reliability indicators, these statistics provide valuable insight to the root causes for system outages and enable **GHESI** to target specific areas in an effort to lower outage frequency and reduce lengths of outages.

A summary of the causes of outages within **GHESI's** system is presented in Figure 5.2-11 through Figure 5.2-15 along with the percentage of overall outage incidents attributable to each cause type. These Figures provide as follows:

- Figure 5.2-11: Percentage of Total Outages (including both momentary and sustained) that were recorded from 2010 to 2014, sorted by cause of the outage.
- Figure 5.2-12: Percentage of Momentary Outages (< 1 minute) recorded from 2010 to 2014, sorted by cause of the outage.
- Figure 5.2-13: Number of Incidents of Momentary Outages recorded from 2010 to 2014, sorted by cause of the outage.
- Figure 5.2-14: Percentage of Sustained Outages (>= 1 minute) recorded from 2010 to 2014, sorted by cause of the outage.
- Figure 5.2-15: Number of Incidents of Sustained Outages recorded from 2010 to 2014, sorted by cause of the outage.

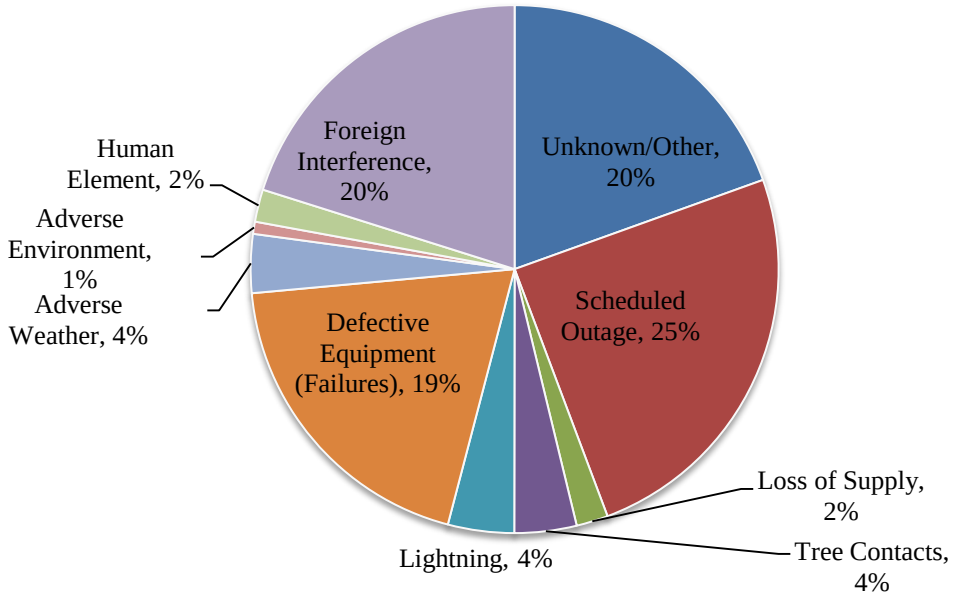


Figure 5.2-11: Cause of all Outages

Defective equipment, foreign interference, scheduled outage, and unknown/other causes have been identified to be the four most common causes for outages on **GHESI's** distribution system in the last few years. Together, these causes contributed to

84% of the total number of outages from 2010 to 2014, including momentary and sustained outages.

Scheduled outages are customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance. Outages caused by defective equipment are customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance. Foreign Interference includes factors beyond the control of **GHESI** such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects. Customer interruptions with no apparent cause that contributed to the outage are recorded as outages of unknown/other causes.

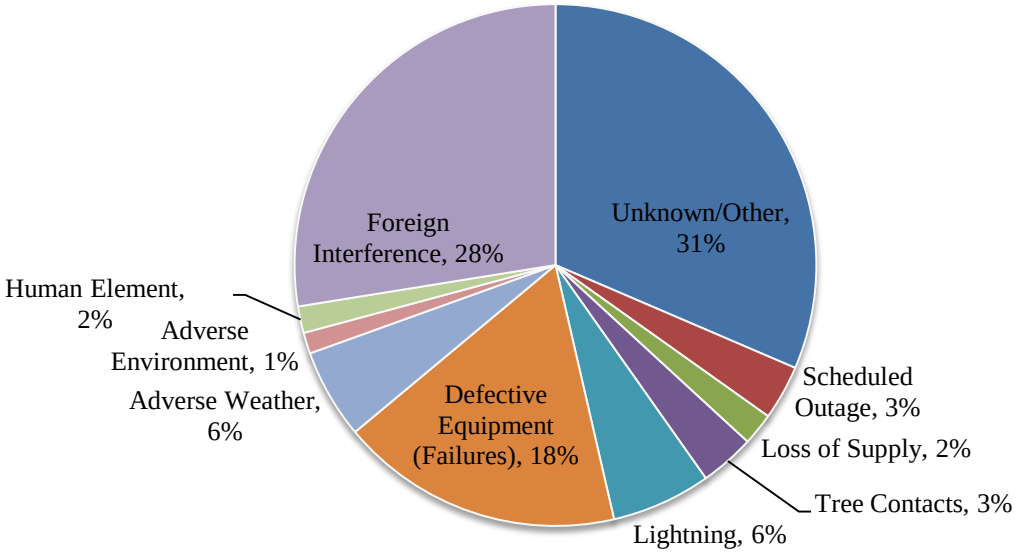
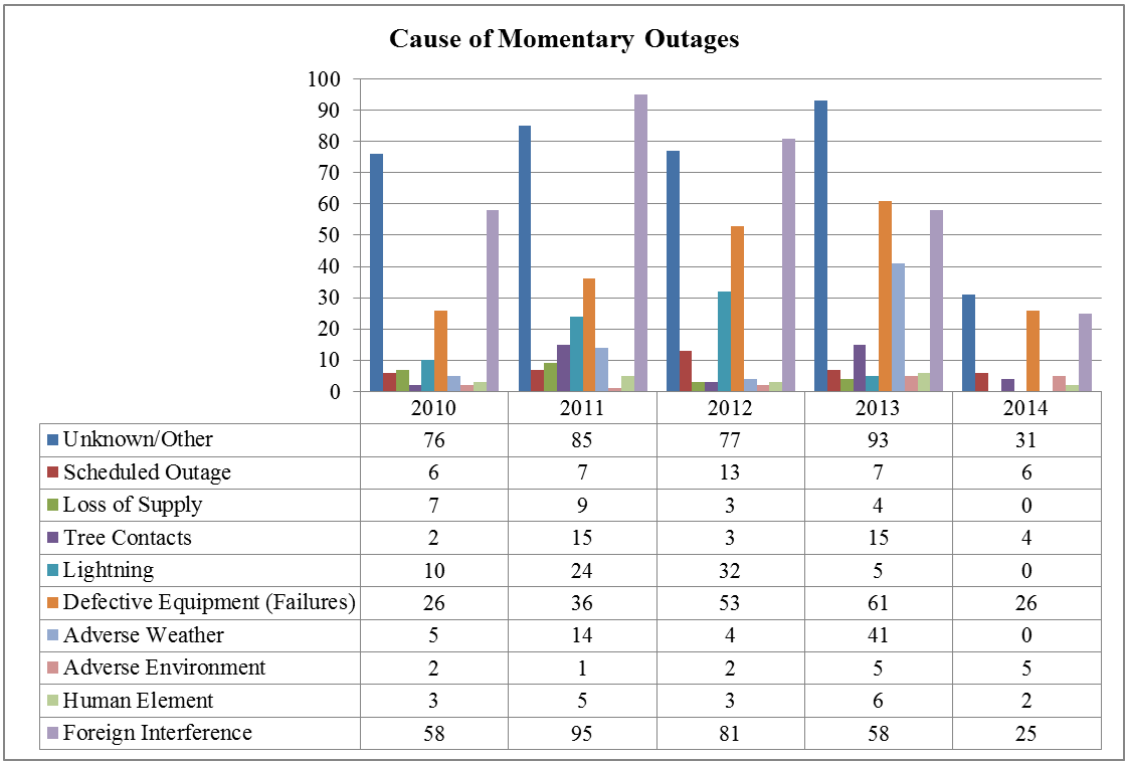


Figure 5.2-12: Causes of Momentary Outages



	2010	2011	2012	2013	2014
Unknown/Other	76	85	77	93	31
Scheduled Outage	6	7	13	7	6
Loss of Supply	7	9	3	4	0
Tree Contacts	2	15	3	15	4
Lightning	10	24	32	5	0
Defective Equipment (Failures)	26	36	53	61	26
Adverse Weather	5	14	4	41	0
Adverse Environment	2	1	2	5	5
Human Element	3	5	3	6	2
Foreign Interference	58	95	81	58	25

Figure 5.2-13: Historical Incidents of Momentary Outages

Momentary outages have a direct impact on **MAIFI**, which is an important measure to **GHESI** because industrial customers are sensitive to momentary outages. Top causes identified for momentary outages include Foreign Interference, Defective Equipment, and Unknown/Other Causes.

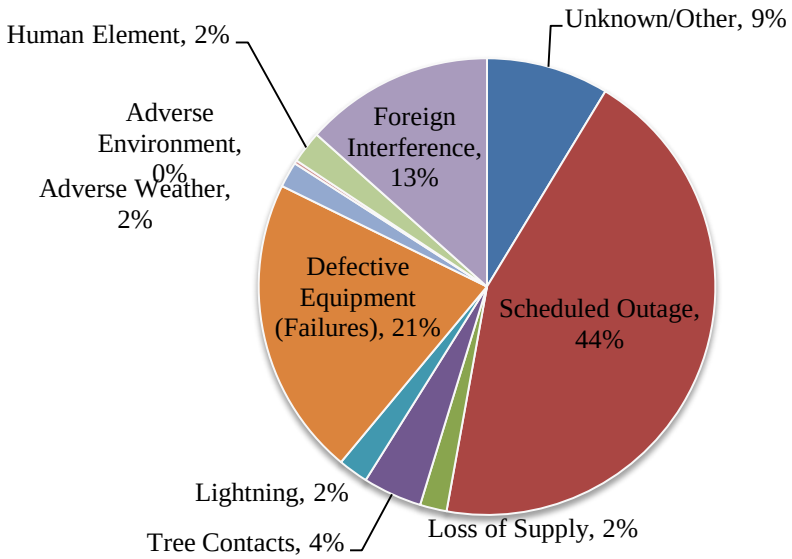
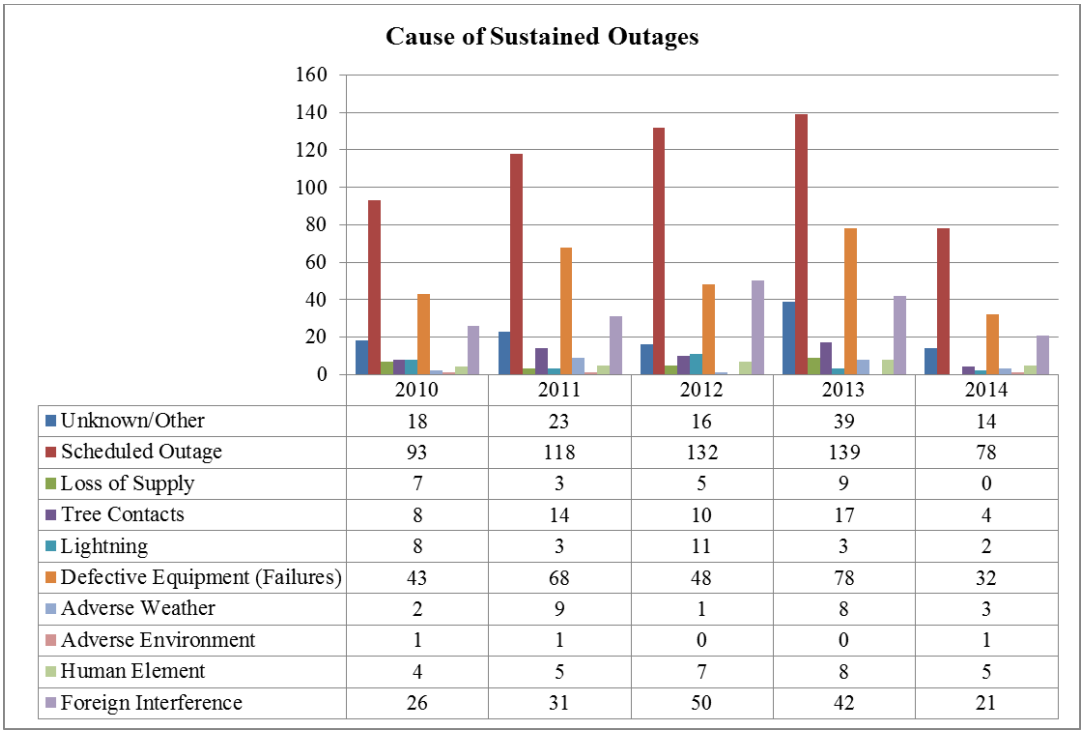


Figure 5.2-14: Causes of Sustained Outages



	2010	2011	2012	2013	2014
Unknown/Other	18	23	16	39	14
Scheduled Outage	93	118	132	139	78
Loss of Supply	7	3	5	9	0
Tree Contacts	8	14	10	17	4
Lightning	8	3	11	3	2
Defective Equipment (Failures)	43	68	48	78	32
Adverse Weather	2	9	1	8	3
Adverse Environment	1	1	0	0	1
Human Element	4	5	7	8	5
Foreign Interference	26	31	50	42	21

Figure 5.2-15: Historical Incidents of Sustained Outages

Common causes of sustained outages include Defective Equipment, Foreign Interference, and Scheduled Outages.

Asset Management

Performance metrics added by the **OEB** in 2014 include monitoring the cost efficiency and effectiveness with respect to planning quality and **DSP** implementation. **GHESI** has not historically tracked these metrics and will be developing processes to monitor and report in these areas going forward.

The following Table 5.2-17: Target **DAI** outlines the amount of data utilized to determine the health index of a specific asset (Average **DAI**) (calculated in 2014), sample size of the data and the targeted **DAI** to achieve in future iterations of the **ACA**.

Asset Category	2013 Average DAI*	2014 Average DAI*	Sample Size** (% of Population)	Target DAI***
Substation Transformers	92%	94%	100%	100%
Circuit Breakers	8%	8%	100%	18%
Pole Mounted Transformers	22%	22%	100%	32%
Pad Mounted Transformers	54%	53%	100%	63%

Submersible Transformers		19%	26%	100%	36%
Vault Transformers		95%	96%	100%	100%
Overhead Switches	**LIS**	28%	20%	100%	30%
	SCADA	29%	25%	100%	35%
Pad Mounted Switches	Live Front Switchgear	62%	62%	100%	72%
	Solid Dielectric Switchgear	20%	59%	100%	69%
	Switching Cubicles	N/A	60%	100%	70%
Cables	Primary	21%	21%	100%	31%
	Secondary	21%	21%	100%	31%
Lines	1 Phase Primary	21%	21%	100%	31%
	3 Phase Primary	21%	21%	100%	31%
	Secondary	21%	21%	100%	31%
Poles	Wood Poles	86%	78%	95%	31%
	Concrete Poles	10%	84%	100%	94%
	Composite Poles	3%	95%	100%	100%
Vault		12%	22%	22%	32%
Manholes		13%	22%	23%	32%

Table 5.2-17: Target **DAI**

Definitions:
* Average **DAI** – Average amount of data available for determining the health index of assets in a specific asset class compared to the maximum amount of data available.
** Sample Size (% of Population) – Percentage of total assets quantities evaluated in the **ACA.**
*** Target **DAI** -Data availability that is expected to be achieved after closing the gaps.
Note [1] – For some assets the DAI has decreased due to an increase in the granularity of the data being assessed.

Cost Control

Total Cost per Customer

Figure 5.2-16 summarizes **GHESI's** historical performance measured by the total cost per customer while Figure 5.2-17 displays a comparison of the total cost per customer amongst Ontario utilities.

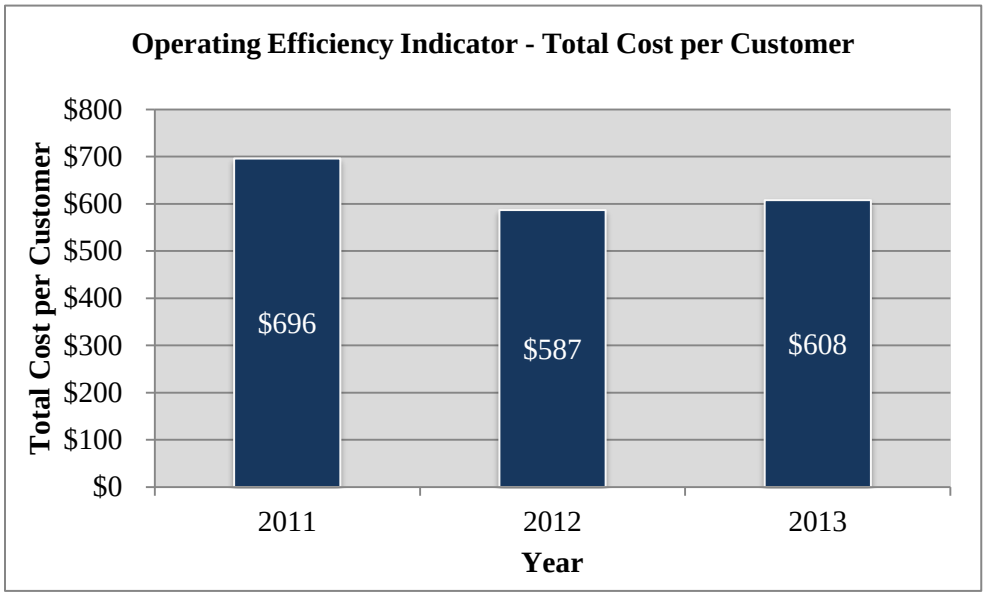


Figure 5.2-16: Historical Performance – Total Cost per Customer

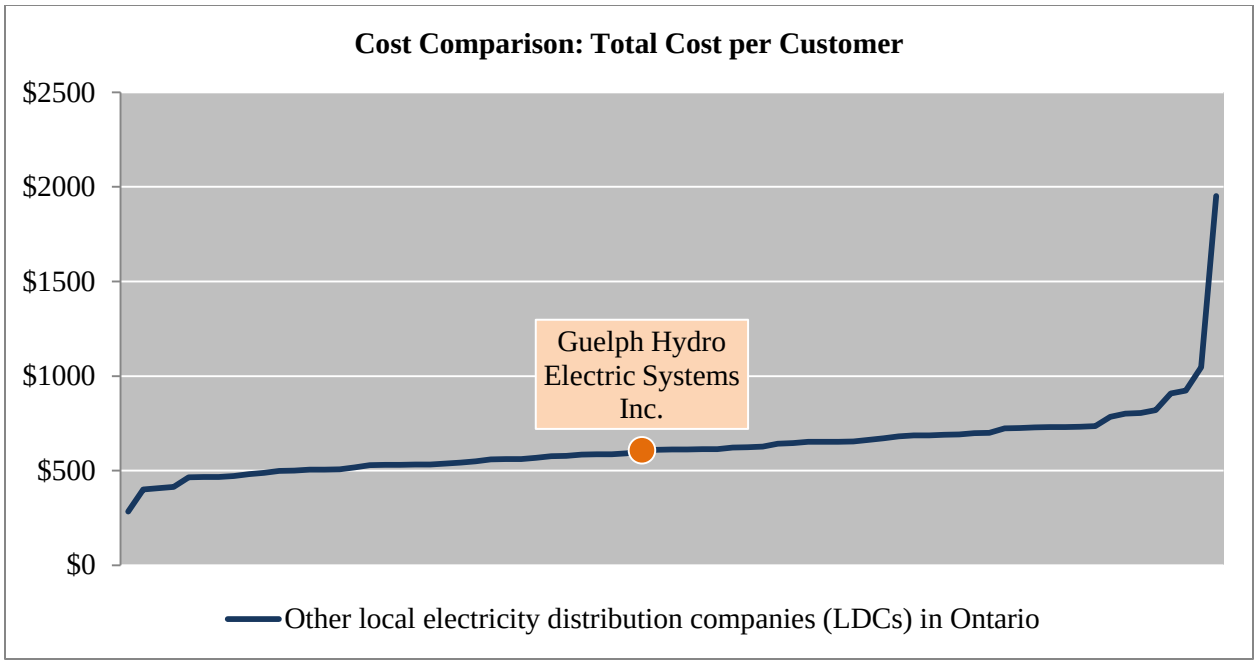


Figure 5.2-17: Comparison among Ontario utilities – Total Cost per Customer[2]

Total Cost per Km of Line

Figure 5.2-18 and Figure 5.2-19 summarize **GHESI's** historical performance and comparison against Ontario Utilities with respect to total cost per km of line.

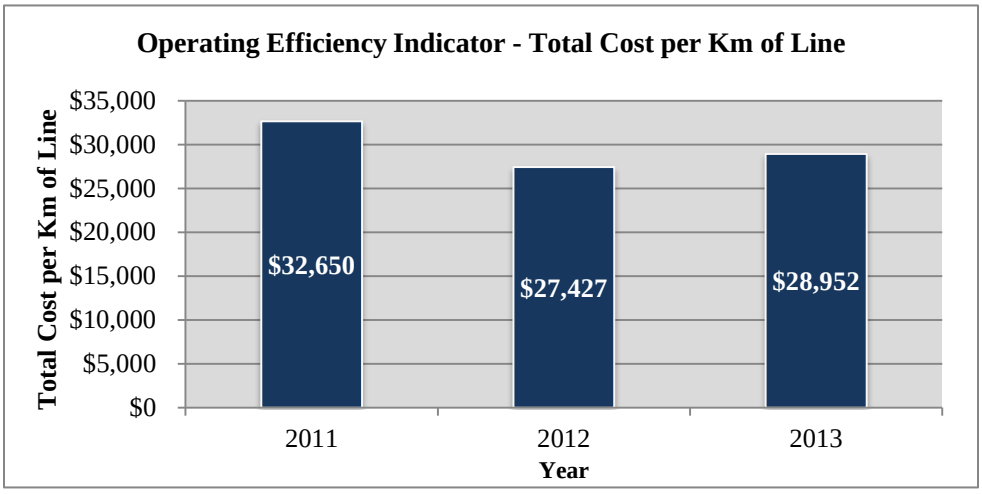


Figure 5.2-18: Historical Performance – Total Cost per km of Line

[2] Source: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

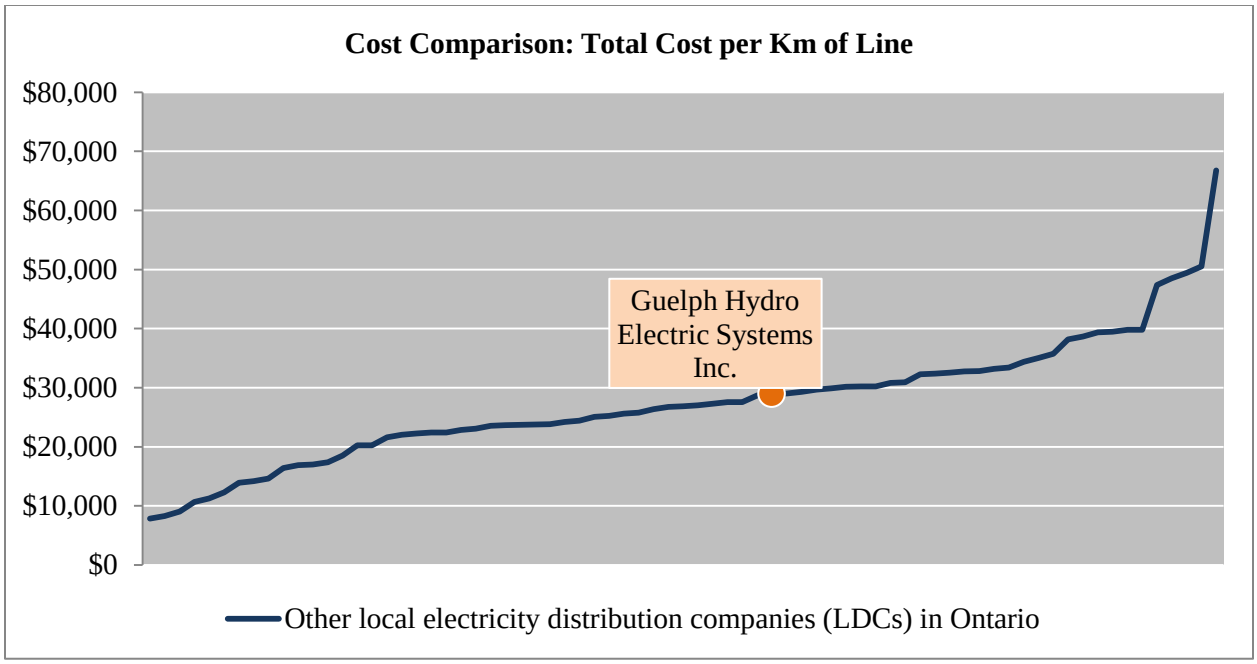


Figure 5.2-19: Comparison of Ontario LDCs – Total Cost per km of Line (s)[3]

Total Cost per MWh of Electricity Consumed

When compared to Total Cost per Customer, the total cost per MWh of electricity consumed provides a different perspective of the **LDC's** operational productivity or effectiveness, as not all "users" of electricity are counted as "customers". According to 2013 **OEB** yearbook statistics, **GHESI** ranks as one of the top **LDC's** with the highest MWh consumption per customer, as illustrated in Figure 5.2-20. Over 70 percent of the electricity consumption (MWh) in **GHESI's** service territory is contributed by large commercial and industrial customers, each counted as one customer **GHESI** will have a higher cost per customer when compared with another **LDC** of similar size that serves mainly residential customers. Therefore, looking at the total cost per customer measure alone can result in a biased view on **GHESI's** operational effectiveness.

[3] Source: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

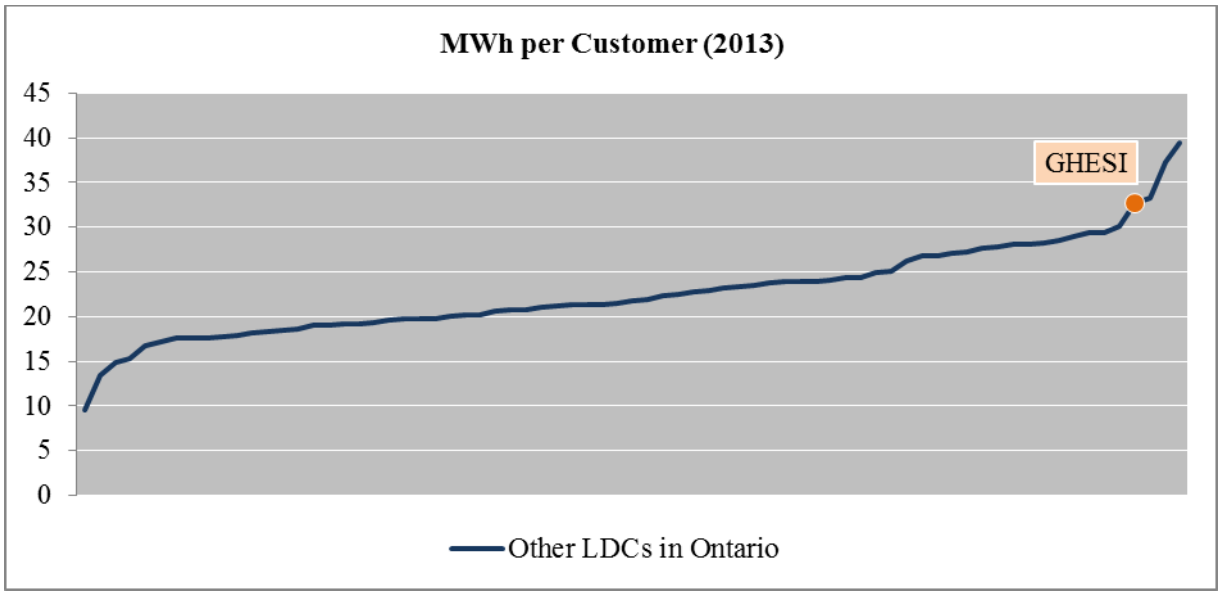


Figure 5.2-20: Comparison of Ontario LDCs – Electricity Consumption per Customer (MWh)[4]

Measuring the cost per megawatt-hour of electricity consumed in a utility's service territory serves as an alternative measure to assist in understanding the nuances of the LDC distribution system, service territory and customer profile, and eliminates inconsistencies to provide a fairer and more transparent picture of operational efficiency. Viewed in this fashion, it can be seen that **GHESI** operates one of the most efficient electric utilities in the province, as shown in Figure 5.2-21

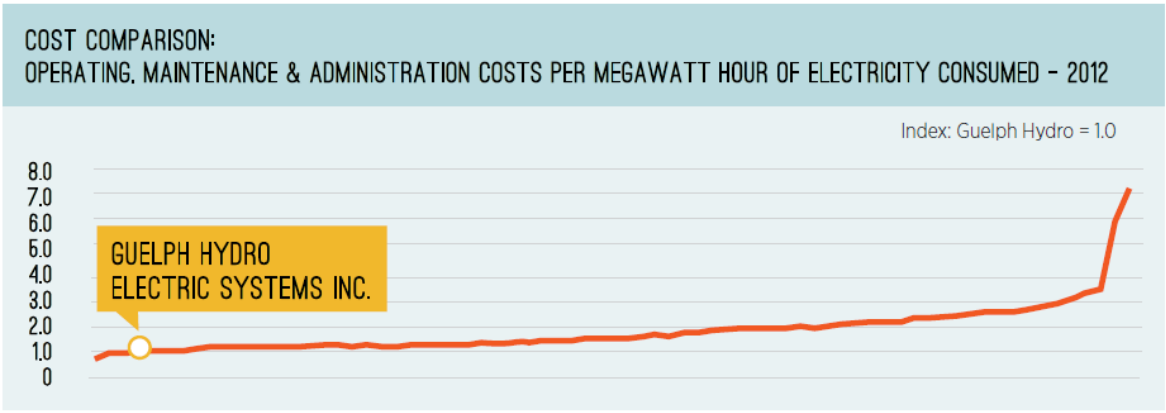


Figure 5.2-21: Comparison among Ontario utilities – Total Cost per MWh Electricity Distributed[5]

[4] Source: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

[5] Source: http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Electricity+Distributor+Scorecards

III. Summary of Public Policy Responsiveness Metrics

Conservation and Demand Management

Figure 5.2-22 summarizes **GHESI's CDM** achievements from 2011 to 2013. Percentages presented in this table are percentages of the 2011-2014 cumulative **CDM** energy targets that had been achieved by each year. At the time of writing this report, **GHESI's** 2014 Final Verified **CDM** Results were not available. However, by the end of 2013, three years into the 2011-2014 tranche of **CDM** targets, **GHESI** had achieved 127.4% of its 2014 energy savings target of 79.53 GWh, and had achieved 77.6% of its 16.71 MW demand savings target, under reporting Scenario 2, which assumes that demand response resources remain in service until 2014. As noted in **GHESI's** Q4-2013 **CDM** Preliminary Results Status Report, the 2013 achievement ranks **GHESI** as one of the top four **LDCs** in the province.

By December 31, 2013, **GHESI** has achieved 77.6 percent of its target for peak demand savings, and 127.4 percent of its target for cumulative energy savings which is evident in Figure 5.2-22. This target was cumulative with an end date of 2014. Therefore, by year-end 2013, GHESI had achieved a greater than 25% increase in CDM achievement over 2012. The result for 2014 are currently not finalized, however, by year-end 2014, **GHESI** had forecasted to have achieved over 135% of its 4-year energy savings target, and close to 100% of its demand target.

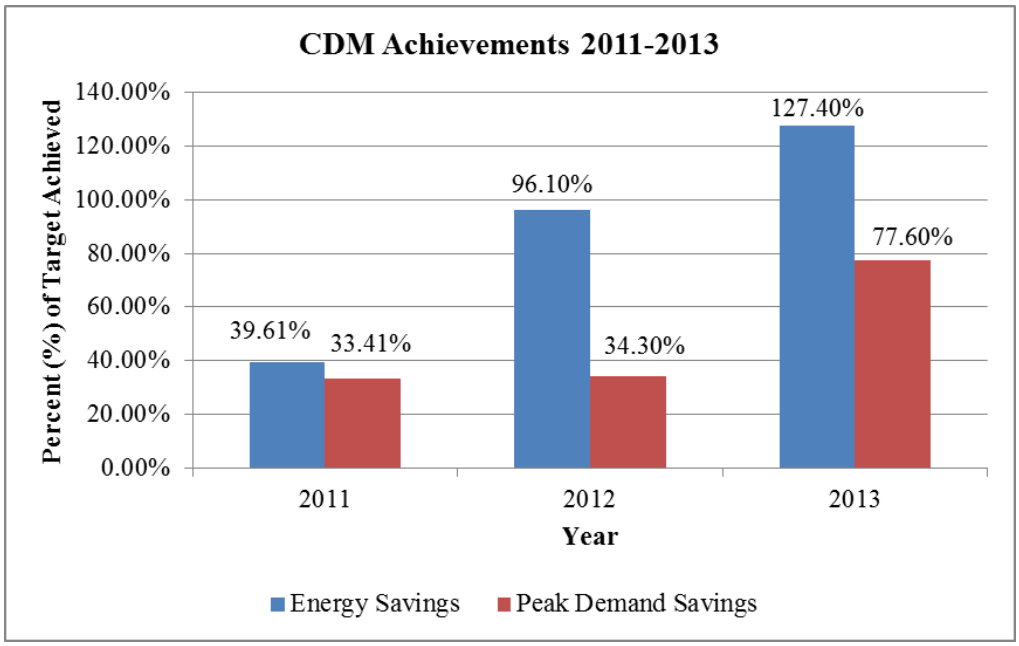


Figure 5.2-22: Historical Performance – CDM Achievements

IV. Financial Performance

Financial Ratios

GHESI's financial performance in historical period, including the Current Ratio, Total Debt to Equity Ratio and Achieved Regulated Return on Equity is provided in Figure 5.2-5.

5.2.3.3 **Effect on the DSP (OEB Filing Req. 5.2.3c)**

c) Explain how this information has affected the DSP (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

Customer Focus Improvement Projects

Service Quality

GHESI addressed the reduction in performance of the 2012 telephone accessibility results with the implementation of an IVR system (corporate voice system in 2014) which will be monitored to ensure that the performance of "Telephone Calls Answered on Time" reverses its negative trend. As is evidenced in the Scorecard results in Figure 5.2-5 other customer focus metrics are meeting or exceeding target, and are not driving capital expenditure in this planning cycle. **GHESI's** new target is to meet or exceed the **OEB's** target and to show improvement over 2012. (Nominal Target 85% and rising).

Customer Satisfaction

New Metrics introduced in 2014 for "First Contact Resolution" and "Billing Accuracy" will be developed and tracked over this planning cycle. In the future, **GHESI** plans to use this information in developing its **DSP** in order to identify cost effective investments in customer service focused projects and products. **GHESI**'s target is to achieve and maintain high ranking among its peers for Customer Satisfaction.

Customer Bill Impacts

The bill impacts metric, as discussed above in section 5.2.3.1, impact the distribution system planning process in a general sense. **GHESI** has developed its capital budget and informed its inputs from the **ACA** process below. The information ultimately finds its way into the customer bill. The iterative process here is to generally evaluate how customers perceive their rates as they are provided and use that information to balance future spending. This information is not a stand-alone metric however. While customer bill impacts are important, customer feedback into other metrics and needs are also critical.

The nature of customer input is there is some reluctance in accepting certain increases to bills in order to successfully see their energy needs met. Customers have also historically been interested in a well-functioning **LDC** providing their energy and this is taken into account when considering bill impacts. As much as **GHESI** would like to provide the lowest rates to its customers it also needs to provide and continue to provide top level service and power quality.

In the future, **GHESI** will continue to pursue various avenues to incorporate customer bill impacts into its distribution system planning process.

Power Quality

GHESI will continue to monitor complaints from customers for Power Quality issues and act to ensure the customer's needs are addressed wherever possible. **GHESI's** limits on voltage distortion are 3% for individual voltage harmonic distortion and 5% for total harmonic distortion. **GHESI** targets zero on-going power quality issues.

Operational Effectiveness Improvement Projects

Safety

A minor non-conformance under **O. Reg. 22/04** was rectified by improvement in the maintenance records processes. As is evidenced in the Scorecard results in Figure 5.2-5 other safety metrics are meeting or exceeding target and are not driving capital expenditures in this planning cycle. Where other works are underway, safety improvements are included in the projects. **GHESI** targets to achieve full compliance of **O. Reg. 22/04**, meaning zero "Non-compliance" and "Needs improvement" in future **ESA** audits.

System Reliability

Historically, storm events have been the main reason for system reliability performance outside of the target range. To reduce the impact of these severe weather events, **GHESI** is installing additional and upgrading existing **SCADA** switches and making improvements to construction standards in an effort to strengthen the system against significant weather events. This will shorten the time required to restore services to customers during outages, thereby improving system **SAIDI** and **CAIDI**.

Underground cables reaching **EOL** are causing a significant number of outages and will become a cause of long outage events. Having recognized this, **GHESI** has included plans in this **DSP** to proactively replace underground cables to minimize outages related to cable failures.

Normalized **SAIDI** and **SAIFI** are within target values. Therefore reliability is not a major

driver in this planning cycle. **GHESI**'s target is to achieve and maintain high ranking among its peers for "Major Event Inclusive" **SAIDI** and **CAIDI**.

Asset Management

In 2014, new requirements for reporting were introduced in the area of monitoring cost efficiency and effectiveness with respect to planning quality and DSP implementation. **GHESI**'s target is to achieve and maintain high ranking among its peers in this reporting area. New metrics will include:

- Physical project progress vs plan;
- Financial project progress vs. plan; and
- Actual vs. planned cost of work completed.

Asset management metrics are evolving and still in development. In the meantime, **GHESI** is continuing to maintain asset health through renewal programs and maintenance. There are no high profile changes to the **AM** process. Improvements in data collection and asset condition data management continue to close gaps. In particular, the **DAI** continues to inform the reliability of the health index of **GHESI's** assets, which intern helps **GHESI** to plan what assets will require expenditures on maintenance or renewal in the coming years. Accordingly, tracking and improving the **DAI** is important in ensuring **GHESI** has an accurate picture of the condition of assets when making capital expenditure decisions.

The following Table 5.2-18 identifies data gaps that are planned to be closed during the forecast period.

Asset	Data Gap to Close	Target Year for Closure
Circuit Breakers	Mechanical Linkage Lubrication Control Cabinet Visual Close Time Trip Time Arcing Contact Wear SF6 Gas Reading Vacuum CB Status Insulation Dielectric Test	2015
Pole Mounted Transformers	Corrosion Oil Leak Connections Tank Grounding Bushing Condition Service Record	2015
Submersible Transformers	Service Record	2015
LIS	Mechanical Linkage Switch Mounting Arc Horn Surface Condition Arc Snuffer Condition Insulator	2015

Asset	Data Gap to Close	Target Year for Closure
	Switch Blade Condition	
SCADA Switches	Mechanical Linkage Switch Mounting Arc Horn Surface Condition Arc Snuffer Condition Insulator Switch Blade Condition	2015
RTU's	(To Be Identified)	2016
Capacitor Banks	(To Be Identified)	2016
Live Front Switchgear	Switch Condition Fuse Condition Arc Extinguisher Condition Connection Condition	2015
Cables and Conductors	Loading History	2016/2017

Table 5.2-18: Planned Data Gap Closure

Cost Control

GHESI has been working diligently to improve its performances, to reduce the costs, and to be more efficient. For this planning cycle **GHESI** expects to further improve its operational efficiencies by implementation of the following:

- Control Room 24/7 Operation and Shared Services Project

  In an effort to respond to customers' needs and upcoming regulatory requirements, Guelph Hydro is endeavouring to expand its operational services to 24/7 coverage. Helping accelerate this process, Guelph Hydro has entered into an agreement with another **LDC** to provide shared operational services. The rationale, further details, and agreement are provided in appendix 1-J of Exhibit 1. Revenue from the shared service arrangement will help offset the additional cost associated with expanded hours of coverage.

- Implementation of operations technology / **SCADA**

GHESI's investments into implementing operations technology in the historical period have contributed to improved operational efficiency by providing better, more refined and timely distribution system field device operational information. For example, certain technologies (such as remote switches and FCIs) have been installed in several of the years in the historical period based on implantation that would best assist field operatives. For this planning period **GHESI** is proposing expenditures to continue investments into operations technology such as further employment of remote operated switches, FCIs and other technologically efficient technologies

Public Policy Responsiveness

Conservation and Demand Management

Feedback from the customer engagement processes described in section 5.2.2.1 does not directly drive operational metrics, but does illustrate that the customer base supports the conservation first approach to **DSP** planning undertaken by **GHESI** in this **DSP. GHESI** will continue to support conservation programs such as “saveONenergy” and other initiatives aimed at reducing consumption.

It is **GHESI’s** intent to further improve **GHESI’s** distribution system to accommodate anticipated future **CDM** projects and **DG** projects. **GHESI** is planning to implement additional distribution system projects to better manage fault current, to permit transfer trip, and to improve digital communications in support of the anticipated **CDM** and **DG** projects.

With the intention of the making the **GHESI** distribution system accommodating for **CDM** projects and **DG** projects, **GHESI** is implementing projects to manage fault current, to permit transfer trip, and to improve communications. **GHESI** target is to be seen as a leader in the industry in enabling **CDM** and **DG** projects.

Financial Performance

Financial Ratios

As noted in Exhibit 5/Tab 1/Schedule1, in response to performance metrics on Financial ratios, **GHESI** intends to issue new long-term debt as soon as practical to remedy its under-leveraged balance sheet. The company expects its current ratio, along with other key financial metrics, to improve following this debt issue.

5.3 Asset Management Process (OEB Filing Req. 5.3)

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset Management Process Overview (OEB Filing Req. 5.3.1)

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

The asset management process is used to analyze the assets in **GHESI's** distribution system and general plant in order to determine the optimal maintenance and capital work required to meet **GHESI's** asset management objectives (described in detail in Section 5.3.1.1). The optimized expenditures identified through the **AM** process inform the preparation of **GHESI's** capital expenditure plan, including the budget allocations for various investment categories and material projects.

Asset investments resulting from the **AM** Process may be divided into two general categories:

- **Annual Programs.** These include annual capital and operation and maintenance investments and the challenge is to decide on the most appropriate investment level for each program. The required investment level is derived from the levelized replacement schedule and available work force.
- **Discrete Projects.** These include discrete capital projects that are incorporated into an Annual Program and the challenge is to prioritize them within the overall capital plan.

Wherever possible, **GHESI** seeks to integrate or optimize work under Annual Programs and Discrete Projects to reduce the overall investment required. Examples of such integration could include:

- Replacement of some of the assets in poor condition, e.g. pole or pole top transformers, could be deferred if the whole feeder is expected to be rebuilt to accommodate municipal road widening;
- Whenever possible combining discrete program inspections at the same location; and
- When a targeted replacement program is implemented to address a known problem, such as flawed design or proximity to major roads that causes premature asset aging, the corresponding future estimated corrective maintenance costs should be reduced.

All asset investment Annual Programs and Discrete Projects follow the same process regardless of size, department and category. The process allows the **AMP** to be completed annually while considering a five-year planning window. Detailed plans are developed annually, with forecasted outlooks for the following four years.

The asset management process is an ongoing task and the process is cyclical, consisting of five stages which encompass **GHESI's** asset management strategy and investment planning process: Evaluate, Develop, Prioritize, Approve, and Manage. The following diagram in Figure 5.3-1 illustrates the ongoing process.



Figure 5.3-1: Asset Management Process

I. Evaluate

The first stage is designed to evaluate performance of past investments as they relate to the **AM** Objectives (defined below) and the defined Annual Programs. During this stage, data is gathered to analyze the current state of assets and to compare the results year over year to ensure that the program objectives are being met. This data includes recent asset condition assessments and inspections, changes in design standards, and the number of assets affected. This also includes data related to future requirements for

the assets, load forecasts, planned development in the City of Guelph and planned new or upgraded connections.

This stage also re-assesses the parameters of past asset management cycles. If past strategies are not accomplishing the required program goals, changes are required to the program. In the case of asset replacement, this may include modifying the refurbishment or replacement method, re-assessing the replacement asset or increasing the rate of replacement or expenditure. In the case of asset utilization, this may include accelerating upgrade work or planning new reconfigurations of the assets.

The evaluation of the annual asset programs to determine progress in the program and determine whether the program is still relevant or needs adjustment in scope or pacing is also required. Additionally, new programs may be identified and added to the **AM** process as needed.

II. Develop

In this stage, the completed evaluation conclusions are analyzed and changes are made to Annual Programs as required. The asset management process considers all of the criteria of evaluation and determines the appropriate strategies for asset investment. The developed plans include:

- Evaluation of recommended actions;
- Consideration of all available options;
- Forecasted program requirements;
- Development of program goals; and
- Costs for one year and a forecast for subsequent years.

III. Prioritize

Each developed asset program is evaluated using a risk based methodology. Projects are selected and prioritized based on the consideration of their descending level of risk and the cost effectiveness of the risk abated by the planned work. The criticality score of each project takes the factors that define programs into consideration. For all projects that are selected, information such as the primary, and in some cases secondary and tertiary driver, and the Annual Program they are attributed to is recorded so that the investment in the various programs can be monitored and evaluated for efficacy. A detailed analysis of this selection and prioritization methodology is outlined in section 5.4.2.3.

IV. Approve

At the approval stage, programs are weighed according to priority, budget, alternatives, synergy and available workforce. Complete or partial approvals may be granted to proposed programs, while others may be waitlisted for future completion. Projects are optimized according to the levelized replacement quantities outlined in the **ACA**, as well as budget envelopes and available resources, prior to approval by senior management.

V. Manage

Within the manage stage, approved programs are included in maintenance and replacement plans, or integrated into capital construction and development investments. Any work required for the execution of programs, such as the procurement of stock, modification of standard drawings and practices, training, and completion of construction drawings is determined and arranged. Workforce arrangement and task scheduling is completed in order to meet approved program requirements. Progress is constantly monitored to ensure program goals, such as timelines and project budgets are met. Deviations from approved program requirements and results are identified on a regular basis for evaluation.

5.3.1.1 Asset Management Objectives (OEB Filing Req. 5.3.1a)

a) A description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments

GHESI's asset management goal is to identify and implement the optimal timing and methodology of asset maintenance and replacement, in such a way as to minimize risks to **GHESI's** Vision, Mission and Core Values, while maximizing long term investment benefits. This goal is achieved by adhering to the following asset management objectives:

- **Public Safety** – Minimize impacts to public safety through the consideration of the physical and geographical aspects of the project area and the assets involved.
- **Employee Safety** – Minimize impacts to employee safety through the consideration of geographical congestion, the proximity to energized equipment, the safety levels of equipment design and the complexity of the physical arrangement of assets in the project.
- **Environmental** – Minimize impacts to sensitive environmental features through the consideration of the equipment types in the project area, potential contaminants

released during asset failure, and proximity to sensitive environmental areas and waterways.

- **Reliability and Power Quality** – Minimize impacts to reliability and power quality through the analysis of the number, duration and cause of events responsible for power interruptions and maximize opportunities to reduce or eliminate future issues through design and construction practices.
- **Operational Efficiency** – Minimize factors that negatively affect operational efficiency through the consideration of equipment types and the analysis of increased operational effort in the project area due to system constraints.
- **Value for Ratepayers** – Optimize asset lifecycle costs and replacement decisions to minimize the overall cost to ratepayers while maximizing benefits. Designs should consider future upgrade or technology requirements and be constructed in a way that minimizes the future costs associated with changes in the project area. Value for Ratepayers is considered during the selection process, rather than the prioritization process and all designs are formulated with Value for Ratepayers in mind. For discretionary projects, only those projects which present good value for the ratepayers will be selected.

Each of the asset management objectives described above – except for "Value for Ratepayers", which is a function of project design and ultimate project selection – (collectively the "**AM Objectives**") are weighted and utilized for project selection and prioritization as shown in Table 5.3-1 (detailed scoring methods for determining the amount to which a project satisfies the above objectives is found in Section 5.4.3.2.ii) and they also relate to **GHESI's** broader corporate core values as seen below (the "**Core Values**") as well as **GHESI's** strategic imperatives (the "**Strategic Imperatives**") which are outlined in Exhibit 1 Table 1-54 and also referred to as corporate goals which are discussed below.

AM Objectives	Corporate Core Value	Weighting
Public Safety	Safety, Relationships	5 (26.3%)
Employee Safety	Safety, Caring, Relationships	5 (26.3%)
Environmental	Environmental Stewardship	4 (21.1%)
Reliability and Power	Reliability, Relationships	3 (15.8%)

Quality		
Operational Efficiency	Efficiency, Innovation and Leadership	2 (10.5%)

Table 5.3-1: AM Objectives Weighting

Core Values:

GHESI's Core Values are the set of characteristics the company seeks to maximize in its day-to-day actions. These Core Values define the degree to which the actions of the company adhere to the strategy laid out in the corporate Mission Statement and are also indirectly used as a gauge of the degree to which certain projects adhere to the guiding principles of the company through the use of the asset management objectives described above.

I. Safety

GHESI aims to provide the highest level of safety for the public and our employees. **GHESI** has attained the Sustainability Level, or Platinum, within the Infrastructure Health & Safety Association's ("**IHSA**") ZeroQuest system ("**ZeroQuest**"). Zeroquest is a safety management system, and the rank of Platinum is the highest level achievable within the program. **GHESI** is also working towards achieving the Certificate of Recognition from **IHSA** in 2015 which demonstrates that a health and safety management system has been developed, implemented, and annually evaluated by both internal and external audits.

I. Reliability

GHESI maintains a very high level of distribution system reliability, as demonstrated in section 5.2.3.2 and is committed to its reliability statistics. We are working hard with our transmitter in order to achieve a higher level of reliability on the bulk supply side while continuing to maintain our distribution reliability levels as better than target, as identified in section 5.2.3.2 . The **AMP** is an important component of **GHESI's** work to achieve its reliability goals.

II. Efficiency

GHESI is dedicated to working efficiently and effectively at all times, to ensure that time and resources are used prudently. This commitment includes fostering an environment

in which the recommendation and implementation of efficiency enhancements is openly encouraged. By embracing advances in efficiency, **GHESI** can keep capital expenditures and operations and maintenance costs down to minimize undue bill impacts. This Core Value is also strongly linked to the **AMP**, which seeks to prioritize and ensure the prudence of resource allocations.

III. Caring

GHESI is committed and cares about our employees and the contribution they provide. **GHESI** works hard to provide a welcoming work environment and monitors this value very closely through employee surveys. **GHESI** seeks out employee feedback during the project selection and design processes to ensure that lessons-learned are incorporated and to ensure that important considerations are integrated up-front to reduce costs related to changes and re-work, as well as to ensure the highest level of safety is attained.

IV. Relationships

GHESI takes great pride in the relationships we have with our employees, customers, local utilities and the municipality and township. These strong relationships put **GHESI** in a great position to follow through with our Vision and Mission. **GHESI** meets regularly with local utilities as well as the **IESO** and **Hydro One** to discuss regional planning and to share current best practices in engineering and operations. Regional planning with the municipality, the township, other utilities and government agencies is an important part of the distribution system planning process. Known developments, constraints and requirements are factored into project selection and design to ensure that GHESI selects the projects which provide the greatest benefit to the ratepayer and makes provisions for future development in a prudent manner. **GHESI**'s relationships and the mutual planning it engages in ensure that it can provide a safe and reliable distribution system.

V. Innovations and Leadership

GHESI is one of the first electrical utilities in Ontario to internally develop an integrated enterprise **GIS** application, which has revolutionized our entire operation and inspired other electrical utilities to follow in our footsteps. **GHESI** first began implementing its **GIS** system and technology in 2003 to convert paper and Computer Aided Design ("**CAD**") maps into **GIS**. Since then our vision and use of **GIS** has increased dramatically, impacting many areas of the organization. **GHESI** also strives to be a leader in the implementation of **SCADA** and automation technologies in Ontario and has a large number of remote operated switches and telemetry devices installed throughout the system.

VI. Environmental Stewardship

GHESI has displayed Environmental Stewardship through the building of a Leadership in Energy Environmental Design (LEED) certified administration building, installing geo-thermal heating and cooling at our facility and being Polychlorinated Biphenyls (PCB) free since 2005, as per Ministry of Environment and Climate Change ("**MOECC**") provincial regulations. Along with our internal environmental responsibilities, **GHESI** is committed to, and plays an active role in, the City of Guelph's Community Energy Initiative, the vision of which is to *"create a healthy, reliable and sustainable energy future by continually increasing the effectiveness of how we use and manage our energy and water resource.*

Strategic Imperatives:

1. Deliver balanced financial and social returns by investing in quality distribution infrastructure
2. Be a leader in the provision and implementation of an energy conservation and sustainable energy culture to our customers and employees that is consistent with the energy initiatives of our shareholder and Province
3. Be a leader in efficient, safe, reliable, and economic distribution of energy
4. Be a great place to work and communicate it to attract and retain employees
5. Ensure that we enhance our position as an asset to our shareholder and the communities by engaging all stakeholders in our key initiatives and objectives

Vision and Mission Statements:

GHESI's Core Values direct the day-to-day business decisions that support the corporate Mission Statement, described below. The Mission Statement is the strategic path to achieving the Corporate Vision described below. By applying the weighting system above to prioritize and select projects, **GHESI** minimizes the risk to both the Vision and Mission and ensures that all projects selected provide positive benefit to the overall corporate goals.

I. Vision Statement

An energy company powering sustainable communities.

II. Mission Statement

Provide superior customer service while investing in energy-related initiatives that benefit the communities in which we operate and align with the energy-related

objectives of the Province of Ontario, the City of Guelph and our shareholder, Guelph Municipal Holdings Inc.; thus enabling the Guelph Hydro group of companies to grow and enhance our position as an industry leader.

Weighting of Projects Based on Asset Management Objectives and Core Values

5.3.1.2 As described in section 5.3.1.2, GHESI has broken the distribution system down into project areas. These project areas are analyzed to determine a criticality score based on the asset management objectives and their weighting.. The weighting of each objective and its corresponding core value demonstrates how the core values are compared against each other when assessing and designing projects. For example, the Environmental objective relates to the Environmental Stewardship core value. This objective has a higher weighting than Operational Efficiency, which corresponds to the core values of Efficiency and Innovation and Leadership. Based on this ranking, a project that has a poor condition oil containing asset that is located in an environmentally critical area (adjacent to a wetland, for example) would have priority over the need to update a manual load-break switch to a SCADA-controlled switch in order to improve operational efficiency. The weighting system allows all of the core values to be respected and allows all of the asset management objectives to be considered simultaneously. These values are also considered on a qualitative basis when evaluating discrete projects that do not fall within the scope of the project area assessments. Asset Management Strategy (OEB Filing Req. 5.3.1b)

5.3.1.2 **Asset Management Strategy (OEB Filing Req. 5.3.1b)**

b) Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- ***asset register***
- ***asset condition assessment***
- ***asset capacity utilization/constraint assessment***
- ***historical period data on customer interruptions caused by equipment failure***
- ***reliability-based 'worst performing feeder' information and analysis***
- ***Reliability risk/consequence of failure analyses.***

Use of a flowchart illustration accompanied by explanatory text is recommended.

I. Key Considerations

i. Asset Considerations

For distribution assets, considerations are primarily driven by the completion of **ACAs**. While the asset's age alone may not necessarily correlate to its condition, the collection and analysis of various asset data can be used for long-term planning estimates. Areas of specific concern, such as termite concentrations for wood poles, design standard changes and obsolescence must also be considered in short and long-term planning.

ii. System considerations

System considerations for asset replacement include reliability, efficiency, and customer and public safety. Asset upgrades may also be driven by future load growth. Future expansion and connections due to increasing load, expanding territory and distributed generation can drive asset upgrades, capital construction and new asset integration.

iii. Personnel Considerations

The safety of personnel working on or around energized and non-energized assets must be considered during investment planning. Furthermore, human resource constraints may impact the ability to manage and complete programs.

iv. Budgetary Considerations

A comparison of the value of an asset and anticipated maintenance costs can determine the optimal replacement time for an asset. Generally, as the asset ages, maintenance and risk costs increase while the asset capital cost per year decreases. Adding the two curves yields the total annual asset cost. The optimal replacement point for an asset occurs approximately as annual asset cost reaches its minimum.

While the above concept identifies the optimal point from an economics perspective, budgetary constraints and logistics may limit the ability to complete asset replacement on an optimal basis. Maintenance costs and cost of replacement must be weighed according to the available budget and potential risks.

The **AM** strategy utilized by **GHESI** is described in the flowchart in Figure 5.3-2 (the "**Asset Management Strategy**"). The flowchart depicts the processes utilized in **GHESI's** Asset Management Strategy, the inputs to each process and the output documents and databases generated by the processes. Arrows show the flow of the process and the interconnections between the various processes, inputs and outputs. The process begins with the collection of asset data, followed by the asset assessment processes, which are, in turn, followed by the selection and prioritization processes,

culminating in the asset management plan, capital plan and asset database updates. Sub-sections II and III provide detail on the data sets and processes in the Asset Management Strategy.

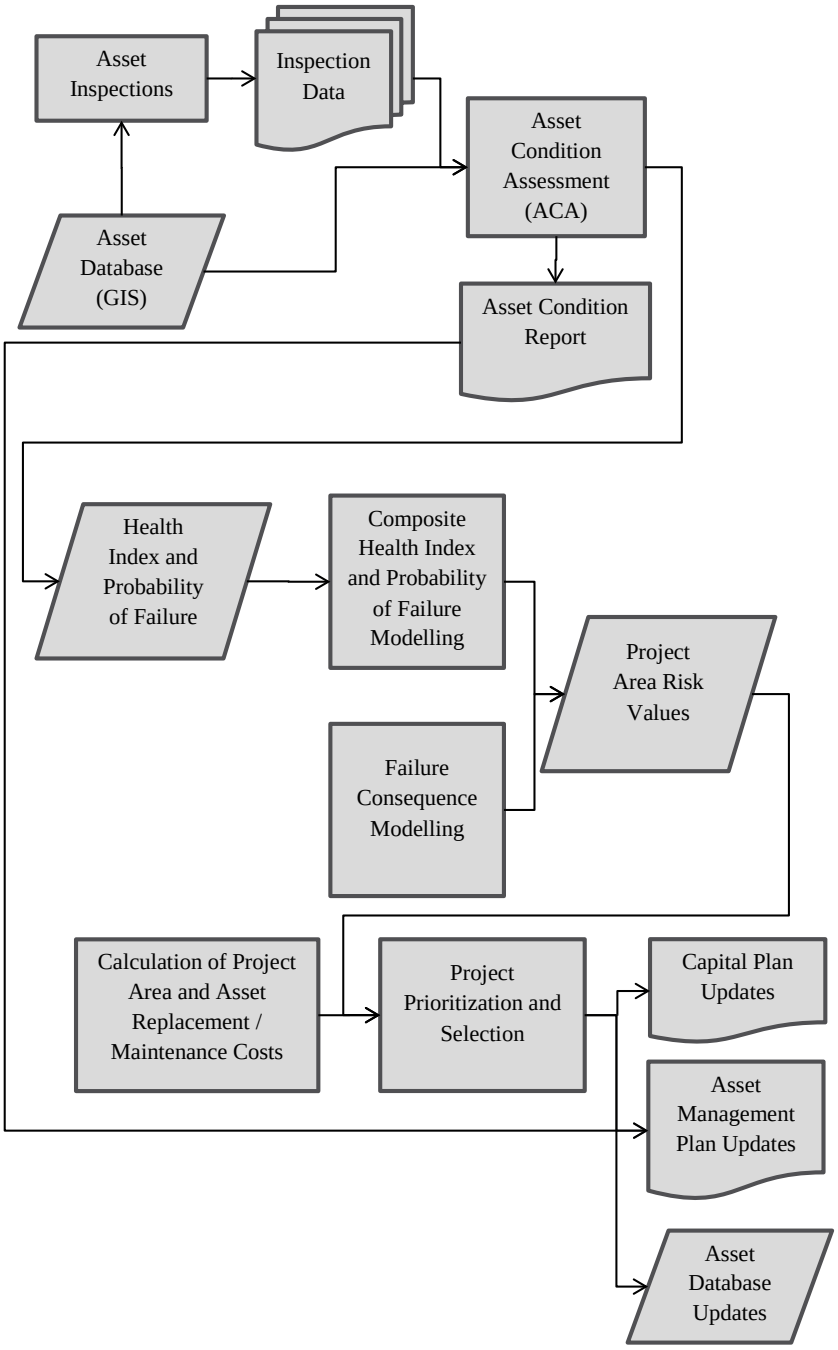


Figure 5.3-2: Asset Management Strategy Flowchart

II. Data Sets

i. Asset Database

Data regarding assets is stored in tables within **GHESI's GIS** database according to their type (i.e. overhead primary conductor, transformers, etc.) (the "**Asset Database**"). The tables contain relevant information that allows each asset to be uniquely identified, such as unique location numbers, addresses, physical location, and local (serial) numbers. The tables also contain descriptive information of the asset, such as capacity, age, type, manufacturer and configuration. For assets that are inspected and included in the asset condition assessment process, inspection data is also connected to the assets in the database. The Asset Database is updated as assets are removed, installed and refurbished and to include updated information from other processes described herein.

ii. Meter Data and Transformer Loading Database

Metered customer consumption data is stored in **GHESI's** Customer Information System ("**CIS**") and Operational Data Store ("**ODS**") for smart metered customer accounts. This data is analysed on a daily basis and is used to determine loading levels on distribution transformers. The transformer to customer meter connectivity model is maintained in a transformer loading application using the **GIS** as the primary display tool for Engineering and Operations Departments, This system has been in use for over thirty years, and is routinely used to identify potentially overloaded transformers for remediation before an overload event occurs. It is also used both on an adhoc basis as part of any new or upgraded service connection requests, as well as on an annual basis to identify transformers with potential loading issues due to incremental customer load increases. The system was enhanced with the introduction of smart meter interval data in 2011. The enhanced system replaced a single bi-monthly meter read and calculated electricity consumption for residential customers with much more refined and reliable hourly consumption information, eliminating the need to estimate load diversity.

iii. Inspection Data

GHESI performs annual inspections on the major components of its distribution system assets. These inspections can be performed in house or by a third party contractor and are unique to the type of asset being inspected. For example, poles inspection consists of a visual inspection, non-destructive fibre stress test and pole sounding, while overhead equipment inspection consists of visual inspection and infrared thermography. Some inspection programs are completed on a three-year rotating basis (inspecting roughly one-third of a particular asset class per year) in order to comply with **OEB DSC** requirements, while other inspections are performed system-wide on an annual basis.

Inspection data is returned, by asset category, in either spreadsheet or database form and used to inform replacement and maintenance decisions.

iv. Asset Condition Report

Independent third-party **ACAs** has been prepared by Kinectrics to assess the current health of **GHESI's** distribution system assets. The assessment results in an Asset Condition Report which describes the methodology of analysis, the results (by major asset category) and identifies data gaps for inspections, where they exist. The Asset Condition Report provides information related to the performance of **GHESI's AM** efforts and assists in identifying opportunities for continual improvement. The report also provides levelized 20-year replacement schedules for assets which are used in optimizing the rehabilitation portion of the capital plan.

v. Health Index and Probability of Failure Database

The **ACA** deliverables include data tables containing health index and probability of failure data for the assets in **GHESI's** system which are used by the AM process to identify and prioritize system rehabilitation investments. The data sets are organized by asset category and the health indices and probabilities of failure are the results of calculations based on the various condition criteria outlined in the Asset Condition Report as well as information returned from asset inspections. The Health Index and Probability of Failure Database contain the aforementioned data, as well as calculated composite health indices and probabilities of failure by project area. This data is used in the project prioritization process when calculating the overall risk score for each project area and for separating project areas requiring complete reconstruction from areas that can benefit from targeted minor work.

vi. Failure Consequence Database

GHESI's service territory is subdivided into project areas (based on operationally significant areas, geographically significant boundaries and density of equipment value and general system topology). These project areas are assessed to determine the consequence of a component failure, and the subsequent repair efforts, in terms of impacts to safety (both public and worker), reliability, environmental damage and operational efficiency. The resulting Failure Consequence Database is used in the project prioritization process when calculating the overall risk score for each project area.

vii. Project Area Risk Value Database

Composite probability of failure values and composite consequence of failure values are multiplied together to determine an overall risk value for each project area. These values are stored in the Project Area Risk Value Database and are used in the project prioritization process.

III. Processes

i. Asset Inspections

Inputs:

- **Asset Database** – provides listing of assets requiring inspection and graphical maps of asset locations to aid inspection crews.
- **Inspection Forms** – inspection forms are by paper for third party inspections and by electronic forms linked to the **GIS** system for internal inspections.

Process Description:

The following inspections and method of inspection shown in Table 5.3-2 are performed on an annual or monthly basis and are based on the **OEB's** minimum inspection requirements outlined in Appendix C of the **DSC** which are further discussed in section 5.3.2.3 of the **DSP**.

Asset	Frequency / Inspection Cycle	Method	Performing Party
Substation Transformers	Monthly	Visual (monthly) & DGA (as needed)	**GHESI**
Pole Mounted Transformers	Annual	Infrared	Third Party Contractor
Pad Mounted Transformers	Annual (1/3 of System per year)	Visual Inspection	**GHESI**
Submersible Transformers	Annual (1/3 of System per year)	Visual Inspection	**GHESI**
Vault Transformers	Annual	Visual Inspection	**GHESI**
LIS Switches	Annual	Infrared and Targeted Maintenance*	**GHESI**
SCADA Switches	Annual	Infrared and Targeted Maintenance	**GHESI**
Live Front Switchgear	Annual (1/3 of	Visual	**GHESI**

Asset	Frequency / Inspection Cycle	Method	Performing Party
	System per year)	Inspection	
Solid Dielectric Switchgear	Annual (1/3 of System per year)	Visual Inspection	**GHESI**
Kabar	Annual (1/3 of System per year)	Visual Inspection	**GHESI**
Overhead 1 Phase Primary Conductor	Annual	Infrared	Third Party Contractor
Overhead 3 Phase Primary Conductor	Annual	Infrared	Third Party Contractor
Overhead Secondary Conductor	Annual	Infrared	Third Party Contractor
Wood Poles	Annual (1/3 of System per year)	Visual & Non-Destructive Testing**	Third Party Contractor
Concrete Poles	Annual (1/3 of System per year)	Visual Inspection	Third Party Contractor
Composite Poles	Annual (1/3 of System per year)	Visual Inspection	Third Party Contractor
Vault	Annual (Sample Population)	Visual	Third Party Contractor
Manholes	Annual (Sample Population)	Visual	Third Party Contractor

Table 5.3-2: List of Asset Inspections

* Targeted Maintenance: Based on an annual list of switches with a certain number of operations
**Non-Destructive Testing: Testing performed on the wood pole without altering its end-use capabilities

The term “Sample Population” as used in the above table indicates that a representative sample of the overall asset population has been used to assess and extrapolate health information across the system.

Inspections are started in the summer for each year and conclude by the end of that year. Each inspection method is unique, however, most inspections are completed using inspection forms that are specific to the asset type being inspected, and all inspections result in the creation of inspection databases or reports containing the inspection results. These databases are collected at the start of the year following the inspection cycle and validated for any data inconsistencies. The finalized data is then connected to the Asset Database for ease of access on a per asset basis and also sent to a third party to be used as a basis for the **ACA**. During the inspection cycle, any major defects or safety concerns found are immediately reported for corrective action. An example would be a transformer being shifted off its foundation base which poses a safety hazard. Defects, such as this, are corrected immediately.

Outputs:

- **Inspection Data** – data is returned from most asset inspections in the forms of electronic spreadsheets and databases which tabulate the information recorded on inspection forms. Infrared thermography inspection data for overhead assets is also returned in report form.

ii. Meter Data and Transformer Loading Database

Inputs:

- CIS Database – provides listing of electricity meters connected to service address locations, as well as consumption data for non-smart metered customers
- ODS Database - provides smart meter hourly interval data for customers with smart meters
- GIS System – is used to create and maintain the meter to transformer connectivity model

Process Description:

The **GIS** is updated on a daily basis to maintain a distribution transformer to customer meter connectivity model. Metered **CIS** and **ODS** customer consumption data is acquired daily and used to calculate a % loading value for all distribution transformers. This calculation is based on either demand meter readings, or metered customer consumption data.

This system is used daily on an adhoc basis to respond to any new or upgraded service connection requests. During the process, any significant immediate concerns are immediately reported for corrective action.

On an annual basis a system wide report is run to identify transformers with potential loading issues due to incremental customer load increases. The information from the annual reporting is analyzed and used to inform the following year's capital and maintenance programs.

Outputs:

- Transformer Loading Application Results / Report - provides assessment of potential transformer loading issues.

- **GIS** System – is used as a daily operational interface tool for Engineering and Operations staff to identify potential transformer loading issues when responding to potential new service connections or service upgrade requests.

iii. Asset Condition Assessment

Inputs:

- **Inspection Forms** – provides results for the various condition criteria assessed in the **ACA**
- **Asset Database** – provides asset characteristics for the various condition criteria assessed in the **ACA**

Process Description:

The **ACA** is the process of determining the condition of assets in **GHESI's** distribution system, based on known characteristics of the assets and condition data collected during asset inspections. The methodology used to perform **GHESI's ACA** is the formulation of health indexes for each asset and correlation of each health index to a probability of failure for the asset. Failure curves are based on typical failure rates for each asset type and the health index is driven by a weighted average of various condition criteria scores. The condition criteria are unique to each asset type and are based on expert knowledge of failure modes and typical indications of overall health. The results obtained in the **ACA** are extrapolated using the sample population where needed and formulated into histograms depicting the health of the population of each asset type across the distribution system. The **ACA** also includes a review of existing inspection methods and data availability and provides an analysis of data gaps for future consideration. Finally, the results of the **ACA** are presented in a formal report as well as data tables containing the health index and probability of failure data for each asset assessed. **ACAs** have been performed in 2011, 2013 and 2014. The 2012 **ACA** was not performed as a result of **GHESI** requiring time to address asset related health gaps in an effort to improve future revisions to the **ACA**.

Outputs:

- **Asset Condition Report** – the report includes the expected asset replacement frequency, levelized replacement schedules, histograms of asset condition by category and identifies data gaps to aid the continual improvement of the **AM** process.
- **Health Index and Probability of Failure Database** – data is returned from the **ACA** in the form of spreadsheets (by asset category). The spreadsheets contain the asset condition criteria data provided by the inspection forms and asset

database, as well as the resulting scores, health index and probability of failure on an individual asset basis

iv. Reliability Risk/Consequence of Failure Analyses

Inputs:

- **GIS** System – the **GIS** system is used to subdivide **GHESI's** service territory into project areas for assessment. The **GIS** system also provides information on physical locations surrounding assets, which aids in the analysis of potential safety and environmental concerns. The **GIS** system allows reliability data and historical outage events to be tied to project areas and the upstream/downstream connections to be analyzed to determine potential reliability consequences of failure.
- **Health Index and Probability of Failure Database** – Per asset health index and probability of failure information are used to determine composite indices and assess overall project risk.

Process Description:

The Reliability Risk and Consequence of Failure Analyses are the processes of determining a risk value for various project areas in **GHESI's** service territory. **GHESI** divides its service territory into defined project areas based on geographically significant features, significant electrical features (i.e. by major switching zones), system topology (i.e. overhead sections, underground feeders, etc.) and other special considerations. These project areas are assessed for risk to reliability and consequence of failure. The risk to reliability is determined by a weighted assessment of the criticality of various components in the system and their ability to affect different types of reliability impacts on failure. A composite health index for each project area is determined based on individual asset health indices and their criticality. Additionally, the probability of failure for each project area is calculated based on series and parallel probability systems methods and the calculated probability of failure of each individual asset in the project area. Additionally, each project area is assessed using **GHESI's GIS** to score its criticality based on metrics such as impacts to public or worker safety, potential reliability impacts of an outage in the area, potential environmental concerns due to an asset failure and potential impacts to operational effectiveness (either negative impacts caused by failure or benefits realized by updating particular assets). Finally, each project area is assigned a risk score based on the composite probability of failure values and the consequence score for each area. The modelling is performed and stored in the Project Area Risk Value Database.

Outputs:

- **Project Area Risk Value Database** – risk values are determined on a per project area basis from consequence and probability of failure data. The risk values are tabulated in a database which is used to prioritize projects.

v. Calculation of Project Area and Asset Replacement/Maintenance Costs

Inputs:

- **Asset Database** – the number and type of assets contained in a project area are used to determine potential replacement costs.
- **Historic Costs** – Approximately 2-4 years of historical actual costs may be used where needed to assist in the prediction replacement and maintenance costs for specific assets or project areas.
- **Enterprise Resource Planning Software** – estimates for the replacement of generic assets are generated using the available estimating programs in **GHESI's** ERP software. These estimates serve as a per unit basis for estimating the replacement and maintenance costs for each project area.

Process Description:

Each defined project area is assessed for the cost of total replacement of the assets it contains. The estimation of replacement costs is based on known counts and types of assets contained in each project area combined with generic estimates to replace each asset type. The estimates for the replacement of each asset type are updated on an annual basis to capture the change in costs related to year-over-year inflation, material changes, operational practice changes and other considerations. Additionally, historical costing is utilized for overly complex projects where a generic order of magnitude costing would not be sufficient. Finally, the project areas are assessed for the level of work required based on the comparison of composite and individual asset probabilities of failure, and the combination of composite and individual asset health indices. This process allows the scope of work to be refined to the optimal investment in either replacement or maintenance and for cost estimates to be revised as needed where scope has decreased. The estimated replacement and maintenance costs for each project area are stored in the Project Area Reconstruction Costs Database (defined below).

Outputs:

- **Project Area Reconstruction Costs Database** – costs to reconstruct each project area are saved in a database to be used in assessing and prioritizing potential projects and for optimizing the capital expenditure plan.

vi. Project Prioritization and Selection

Inputs:

- **Project Area Reconstruction Costs Database** – The Project Area Reconstruction Costs Database contains the estimated costs for work required in each project area. This is used to aid in project selection by developing cost per risk point data and overall costs for selected work.
- **Project Area Risk Value Database** – The Project Area Risk Value Database contains the risk scores determined for each project area. This database is used as a factor in project prioritization.
- **GIS System** – The **GIS** system is used for project prioritization by analyzing possible efficiencies gained by grouping project areas together and for assessing the ability to handle disparate projects simultaneously based on system constraints.
- **ACA** – the levelized 20-year replacement schedule is used to optimize project selection so that assets replaced per year meet the levelized targets identified in the **ACA**.
- **System Capacity Constraints** – System Capacity Constraints in the forms of load forecasts, switching schedules, load levels and **GHESI's** System Controlling Authority or System Control Operators ("**SCO**") expert opinion is used to determine the feasibility of performing various projects simultaneously, as well as to identify limiting conditions that would prevent projects from being possible. Additionally, the system capacity constraints identify areas where upgrading of assets is required to alleviate current and predicted supply risks.

Process Description:

Projects are prioritized based on a number of criteria such as overall risk values, cost per risk point alleviated, health index versus risk (to identify overall good health areas with high risk points indicating an opportunity to reduce scope and realize risk abatement benefits at lower cost), fulfilment of existing **AM** programs and potential investment efficiency opportunities (i.e. work required in areas that also require capacity upgrading, grouping of adjacent projects to minimize mobilization costs, etc.). The projects are ranked in several lists based on the factors mentioned above (i.e. descending value of risk score, ascending value of construction dollars per risk point, ascending value of composite health index, etc.). Projects are selected from these lists and the selection is optimized based on the levelized replacement schedule requirements determined in the **ACA** and available resource timing. Resources such as available line crews, switching and supply capacity on feeders, contractor availability and materials availability can impact the final selection and scheduling of projects. This

optimization process ensures that the optimal numbers of each asset class are replaced to maintain the system health (as described in the **ACA**) and that system reliability and construction costs are not affected by the use and timing of resources by concurrent projects. The final project selection provides input for capital replacement budgeting and updates to the capital plan, asset management database and asset management plan.

Outputs:

- **Capital Plan Updates** – The capital expenditure plan is updated to include the selected and forecasted projects and estimated costs.
- **Asset Database Updates** – The Asset Database is updated to reflect the planned reconstruction year and to track any replaced or maintained assets.
- **AMP Updates** – The **AMP** is updated to include changes to **AM** Programs and lessons learned through the completion of each **AM** cycle. The **AMP** includes the processes and programs that make up **GHESI**'s asset management functions. The updates to this document will inform the next cycle of project selection and investment so that lessons learned and continual improvement can be integrated into **GHESI'**s future projects

vii. Asset capacity utilization/constraint assessment

GHESI considers asset capacity utilization and constraints in both the failure consequence modelling process described in the previous section and in the design of replacement assets. This includes the consideration of feeder loading levels, area load and supply balance and forecasted loads throughout the service territory. For example, from an electrical perspective, feeder switching restrictions are identified in each project area and the possible corrective options are analyzed as potential benefits during the project prioritization process. From a mechanical perspective, the class of poles and equipment mounted on them are considered when determining the scope of replacement work and are factored into the replacement cost which is used as part of the project selection process.

viii. Historical period data on customer interruptions caused by equipment failure

Historical period data on customer interruptions, including those caused by equipment failure, are considered during the failure consequence modelling process and the project selection and prioritization process. This involves analyzing the number of interruptions, durations and the number of customers affected in each project area. The impacts to reliability indices such as **SAIDI** and **SAIFI** are considered when selecting

and prioritizing projects. These factors are also considered in the design of the planned work, where decisions are made to reduce or eliminate the causes of outages in the area.

ix. Reliability-based 'worst performing feeder' information and analysis

GHESI does not follow a typical 'worst performing feeder' process. Because feeders are dynamic and a section of line can be assigned to one of several feeders at any time due to operational needs, analyzing reliability affecting events from a geographical perspective can offer more useful information. **GHESI** analyzes reliability impacting events from a geographical perspective to identify specific worst performing areas and correct reliability and power quality issues in them, as described in Subsection vii above.

5.3.2 Overview of Assets Managed (OEB Filing Req. 5.3.2)

Appropriate regulatory assessment of DSPs requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

5.3.2.1 Features of the Distribution Service Area (OEB Filing Req. 5.3.2a)

a) A description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DSP;

GHESI serves over 53,000 customers in the City of Guelph and Village of Rockwood. Its service area is entirely urban. For this reason, over 50 percent of its distribution circuits are located underground.

Local climate in this region is typically continental with cold winter, warm and humid summers, and moderately high rainfall and snowfall. Climate change experts predict that severe weather events will become more frequent in years to come. This will bring additional challenges to **GHESI's** distribution system. **GHESI** plans to increase investments into maintaining and upgrading its infrastructure to ensure the resiliency of its system during severe weather events. The most common extreme weather events that affect **GHESI** are freezing rain, ice storms, severe thunderstorms and high wind events. **GHESI** records weather data as part of its reliability incident reporting process.

This data is used to analyze the impact of major event days. The following weather related major events, as calculated using the methodology outlined in section 5.2.3.2 shown in Table 5.3-3, occurring between January 2011 and January 2015, affected **GHESI's** system, causing outages based on the calculated major event day threshold SAIDI value of 3.62, 4.64 and 4.56 in 2011, 2012 and 2013, respectively. The frequency of the extreme weather events below is 1.5 days per year on average.

Event	Date of Major Event
Severe thunderstorm	6/4/2011
Severe thunderstorm	6/7/2011
Freezing rainstorm	2/29/2012
Ice storm	4/12/2013
Ice storm	12/21/2013-12/22/2013

Table 5.3-3: Extreme Weather Events

The local economy in Guelph features a solid, diversified industrial base including advanced manufacturing, life science, **IT**, environmental enterprise, automotive and advanced high-technology industries. The advanced manufacturing industry, in particular, employs approximately 25 percent of the City's labour work force. This strong and diverse economy mix has been a main driver for the steady growth of the local economy in Guelph. For example, the 2015 Regional Economic Outlook for Kitchener-Waterloo-Barrie, presented by the Credit Unions of Ontario, the Ontario Chamber of Commerce and the Guelph Chamber of Commerce, which includes the City of Guelph, indicates significant growth in the automotive manufacturing sector in Guelph, such as Linamar's announcement of a $507-million dollar expansion. The report also sites an estimated additional 30,000 jobs for the combined region over the next two years.

With its strategic location in the heart of Southern Ontario, Guelph continues to attract businesses in various industrial sectors. Regional developments are underway to create environments that will encourage more businesses to settle in Guelph as evident with.

the newly developed Hanlon Creek Business Park, a 675-acre mixed use greenfield site located in the south end of Guelph.

GHESI, as the only electricity distributor in this region, has assessed the potential impact of these developments on demand for electricity in its service area. Investment plans have been made and included as part of this **DSP** for system expansions and upgrades that will accommodate the growing needs of existing and future customers.

5.3.2.2 System Configuration (OEB Filing Req. 5.3.2b)

b) A summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

GHESI owns, maintains and operates approximately 431 km of overhead primary distribution feeders and 672 km of underground primary distribution circuits in the City of Guelph and in the Village of Rockwood. **GHESI** also operates and maintains 474 km of overhead and 1130 km of underground secondary circuits. **GHESI** operates a total of 57-13.8 kV feeders and 6-8.32 kV feeders within its service territory, broken down as follows:

- Campbell TS – 24 Feeders;
- Cedar TS – 22 Feeders;
- Hanlon TS - 8 Feeders;
- Arlen MTS - 3 Feeders;
- Rockwood MS#1 -3 Feeders;
- Rockwood MS#2 - 2 Feeders; and
- Rockwood DS – 1 Feeder.

Wholesale supply in the City of Guelph is provided by three **Hydro One** Transformer Stations (Hanlon **TS**, Cedar **TS**, and Campbell **TS**) and one **GHESI**-owned Transformer Station (Arlen **MTS**). Cedar **TS**, Hanlon **TS** and Arlen **MTS** step-down 115 kV transmission supply to 13.8 kV while Campbell **TS** steps-down 230 kV transmission supply to 13.8 kV for primary distribution feeders. In the Village of Rockwood, supply is provided by two **GHESI**-owned Municipal Substations (Rockwood **MS**1, Rockwood **MS**2) and one Hydro One owned Distribution Station (Rockwood **DS**). All three stations are supplied from 44 kV feeders originating from Fergus **TS** and their primary distribution feeders are operated at 8.32 kV.

Station capacity information as of the end of 2014 is provided below in Table 5.3-4.

Station Name	Campbell TS			Cedar TS			Hanlon **TS**	Arlen MTS #1	Rockwood MS1*	Rockwood MS2	Rockwood DS	Total Guelph	Total Rockwood
Station Owner	**Hydro One**			**Hydro One**			**Hydro One**	**GHESI**	**GHESI**	**GHESI**	**Hydro One**	--	--
Number of Transformers	4			4			2	2	1	1	1	12	3
Transformer	T1-T2		T3-T4	T1-T2		T7-T8	T1-T2	T1-T2	T1	T1	T1	--	--
Bus Pair	B-Y	J-Q	Z-E	B-Y	Z-E	J-Q	B-Y	B-Y	N/A	N/A	N/A	--	--
Transformer Size ONAN (MVA)	45	45	45	45	45	22.5	22.5	30	5	5		--	--
Transformer Size ONAF (MVA)	60/75	60/75	60/75	60/75	60/75	37.5	37.5	40/50	N/A	6.67	N/A	--	--
Winding LTR Summer (MVA)	63.6	51.5	62.5	57.4	57.4	44.3	47.7	52.5	N/A	N/A	N/A	436.9	--
Winding LTR Winter (MVA)	64.2	57.5	64.7	61.4	61.4	50	52.9	52.5	N/A	N/A	N/A	464.6	--
DESN LTR Summer (MVA)	115.1		62.5	114.8		44.3	47.7	52.5	N/A	N/A	N/A	436.9	--
DESN LTR Winter (MVA)	121.7		64.7	122.8		44.3	52.9	52.5	N/A	N/A	N/A	458.9	--
Existing Summer LTR in Forecast (MW @ 0.9 PF)	159.8			103.3		39.5	42.9	56.7	N/A	N/A	N/A	402.3	--
Existing Practical Load Limit (MW)	147.4			96.5		39.5	38.4	52.5	N/A	N/A	N/A	374.3	--
Maximum Number of 13.8 kV Feeders	8	8	8	8	8	8	8	8	3	3	1	64	7
Number of 13.8 kV Feeders Being Utilized	8	8	8	8	6	7	8	3	0*	2	1	56	3
Peak Loading (2010) MW	142,794			110,020			39,447	N/A	N/A			292,261[1]	N/A
Peak Loading (2011) MW	136,993			124,730			33,540	N/A	5.11			295,263[1]	5.11
Peak Loading (2012) MW	148,598			111,187			32,895	18,939	5.03			292,680[1]	5.03
Peak Loading (2013) MW	141,008			123,364			33,990	14,054	4.95			298,362[1]	4.95
Peak Loading (2014) MW	149,020			107,150			26,859	13,794	4.27			283,029[1]	4.27

Table 5.3-4: System Capacity of Transformer and Distribution Stations

*Rockwood MS1 is currently being rebuilt. Data for Rockwood MS1 is based up to the end of August 2014.

Definitions;
MTS – Municipal Transformer Station
Bus Pair – Two medium voltage switchgear lines electrically supplied by the secondary windings of a single transformer
ONAN – Oil circulation by Natural convection, Air circulation by Natural convection
ONAF - Oil circulation by Natural convection, Air circulation by Forced convection
LTR – Limited Time Rating (typically 10-day)
DESN – Dual-Element Spot Network
Practical Load Limit – Station capacity as determined by limiting factors other than the transformer rating
Installed Capacity – The maximum peak demand supplied by a station divided by station capacity

5.3.2.3 **Asset Condition (OEB Filing Req. 5.3.2c)**

c) Information (in tables and/or figures) by asset type (where available) on the quality/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled;

The following table summarizes the approximate number of distribution assets within the **GHESI** service territory. Information contained in Table 5.3-5 is current as of August 31, 2014

Asset Description	Quantity (units)	Quantity (km)
Wood poles	9275	
Composite Poles	169	
Concrete Poles	834	
Insulators	24793	
Fused Cutouts	3611	
Manual Overhead Switches – Solid Blade Disconnects	250	
Manual Overhead Switches – Gang Operated LIS	374	
Remote Automated Switches - RTU	86	
Integral Switch - Scadamate	86	
Overhead Primary Conductor		430
Overhead Secondary Conductor		474
Capacitor Banks	24	
Pole top transformers	1825	
Pole-Trans	79	
Pad mounted transformers	3778	
Submersible transformers	42	
Vault transformers	82	
UG Switchgear – Solid Blade	301	
UG Switchgear – Fused	239	
UG Switchgear – Live Front	90	
UG Switchgear – Dead Front (Kabar)	80	

Asset Description	Quantity (units)	Quantity (km)
UG Switchgear – Solid Dielectric	6	
Underground Primary cable		652
Primary 3 phase feeder egresses		21
Underground Secondary cable		1130
UG Ducts		1857
Cable Chambers - Manholes	363	
Cable Chambers - Vaults	630	
Power Transformers - TS	2	
Power Transformers - MS	2	
Medium Voltage Switchgear – TS Assembly	2	
Medium Voltage Switchgear - Breakers	12	
Medium Voltage Switchgear – MS Assembly	2	
Medium Voltage Switchgear – MS Breakers	8	
Independent Breakers – TS	2	
P&C Devices – TS - Panels	15	
P&C Devices – TS – relays - Digital	28	
P&C Devices – MS – Panels	10	
P&C Devices – MS – Relays - Electromechanical	3	
P&C Devices – MS – Relays - Digital	5	
Station Disconnect Switch - TS	4	
Station Disconnect Switch - MS	2	
DC System - TS	2	
DC System - MS	2	
Station Grounding System	3	
Station Bus Work and Structures	20	
Station Building	1	
Metering	52316	
SCADA	85 Non-switch or FCI RTUs	
Remote FCI’s	30	
Communications	95	

Table 5.3-5: Number of Distribution Assets Managed by **GHESI**

In 2011, 2013 and 2014 **GHESI** selected and engaged Kinectrics to perform an **ACA** on **GHESI’s** key distribution assets. The **ACA** report for 2014 is attached in Appendix D for reference and an overall summary and trend analysis of the health index of each asset between the 2013 and 2014 assessments is provided on page 134 Asset Condition Assessments Trend Analysis with further detail and information on the asset health index Described in section 5.2.1.5.

Table 5.3-5 provides a summary of the collected data for all the asset categories that are evaluated as part of the **ACA** Health indices determined in this study for key assets are summarized in Figure 5.3-3, and the average years in service for these assets are provided in Table 5.3-6 on page 134.

A graphical comparison between the 2012 and 2014 assessments is provided in Figure 5.3-4 on page 136.

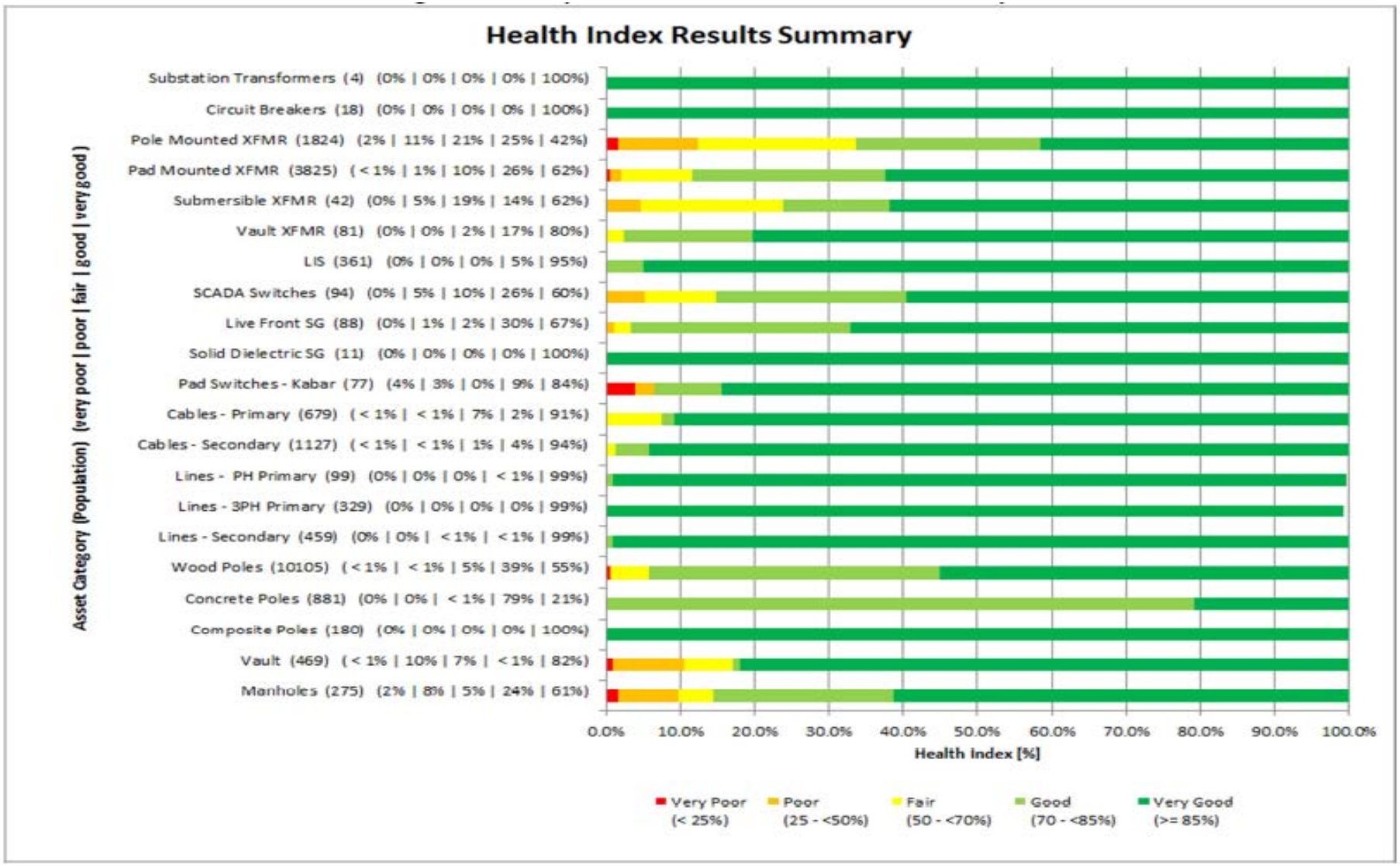


Figure 5.3-3: Health Index Results Summary

Asset Class	Average Years in Service	IFRS Useful Life
Substation Transformers	9	45
Breakers	3	40
Pole Mounted Transformers	21	40
Pad Mounted Transformers	16	40
Submersible Transformers	16	35
Vault Transformers	26	35
LIS	15	50
SCADA Switches	9	45
Live Front Switchgear	14	25
Solid Dielectric Switchgear	2	30
Switching Cubicles	15	30
Primary Cables	17	40
Secondary Cables	18	40
Single Phase Primary Lines	29	50
Three Phase Primary Lines	20	50
Secondary Lines	29	50
Wood Poles	27	50
Concrete Poles	18	40
Composite Poles	2	70
Vaults	26	60
Manholes	18	40

Table 5.3-6: Asset In-Service Life Summary

Asset Condition Assessments Trend Analysis

Asset	Average Health Index Measure		
	2013 ACA	2014 ACA	Change
Substation Transformers	94%	93%	-1%
Circuit Breakers	100%	100%	0%
Pole Mounted Transformers	81%	78%	-3%
Pad Mounted Transformers	88%	88%	0%
Submersible Transformers	88%	86%	-2%
Vault Transformers	90%	91%	+1%
LIS Switches	86%	97%	+11%
SCADA Switches	78%	84%	+6%
Live Front SG	90%	87%	-3%
Solid Dielectric SG	100%	99%	-1%
Kabar	93%	91%	-2%
Multijunction	86%	N/A	N/A
Underground Primary Cable	96%	95%	-1%
Underground Secondary Cable	97%	97%	0%
Overhead 1 Phase Primary	99%	99%	0%

Conductor			
Overhead 3 Phase Primary Conductor	100%	100%	0%
Overhead Secondary Conductor	97%	98%	+1%
Wood Poles	80%	86%	+6%
Concrete Poles	96%	83%	-13%
Composite Poles	99%	88%	-11%
Vault	58%	89%	+31%
Manholes	51%	87%	+36%

Table 5.3-7: Asset Condition Health Index Trend Analysis



Figure 5.3-4: 2012 and 2014 Health Index Results Summary

- In several asset categories, overall asset health shows a decrease from the 2012 **ACA** to the 2014 **ACA**. However, some of the decreases can be attributed to more detailed data being collected from multiple inspection cycles (in the case of Kabar units, pad-mounted switchgear, concrete poles and composite poles). This behaviour is expected as data availability increases since problem units will begin to be identified and health indexing becomes based on more than age alone. More years of asset assessment, using the current health formulation, will be required to determine a definitive trend for the health of **GHESI's** assets. Conclusions summarizing the differences observed in the **ACA's** are explained in detail in Section 5.2.1.5 .

The following information presented in Table 5.3-8 outlines a summary of key information related to each asset within **GHESI's** distribution system. Information in this chart is updated on an annual basis and serves as a tool to assist in the management of the given asset.

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
Wood poles	Yes	Douglas Firs are part of the Douglas Fir Replacement Program	Yes	3 year inspection cycle	Proactive	9275	50	4 Year testing cycle, 3 Year testing cycle being implemented in 2013
Composite Poles	No	No	Yes	3 year inspection cycle	Proactive	169	50	3 Year inspection cycle being implemented in 2013
Concrete Poles	Yes	Concrete poles are being replaced with Composite poles at end-of-life	Yes	3 year inspection cycle	Proactive	834	50	3 Year inspection cycle being implemented in 2013
Insulators	No	No	No	3 year inspection cycle	Reactive	24793	50	Infrared Scan
Fused Cutouts	Yes	Porcelain Cutout Replacement Program	No	3 year inspection cycle	Reactive	3611	50	Infrared Scan
Manual Overhead Switches – Solid Blade Disconnects	Yes	No	No	3 year inspection cycle	Reactive	250	50	Infrared Scan
Manual Overhead Switches – Gang	Yes	Horizontal and	No	3 year inspection	Reactive	374	50	Infrared Scan and most/least operated

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
Operated LIS		Triangular LIS Replacement Program		cycle				yearly maintenance schedule
Remote Automated Switches - RTU	No	No	No	3 year inspection cycle	Reactive	86	15	N/A
Integral Switch - Scadamate	Yes	No	No	3 year inspection cycle	Reactive	86	45	Infrared Scan
Overhead Primary Conductor	Yes	No	No	3 year inspection cycle	Reactive	430 km	60	Infrared Scan
Overhead Secondary Conductor	Yes	No	No	3 year inspection cycle	Reactive	474 km	60	Infrared Scan
Capacitor Banks	No	No	No	3 year inspection cycle	Reactive	24	25	Infrared Scan
Pole top transformers	Yes	3-Phase overhead transformer replacement program	No	3 year inspection cycle	Reactive	1825	40	Infrared Scan
Pole-Trans	No	Pole-Tran Removal Program	Yes	3 year inspection cycle	Proactive	79	30	Phase-out program in place
Pad mounted transformers	Yes	Live Front Equipment Removal	Yes	3 year inspection cycle	Proactive	3778	40	3 Year inspection cycle (Rockwood Incl. in Year 2)

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
		Program						
Submersible transformers	Yes	No	Yes	3 year inspection cycle	Reactive	42	35	3 Year inspection cycle (Rockwood Incl. in Year 2)
Vault transformers	Yes	No	Yes	3 year inspection cycle	Reactive	82	35	Yearly Visual Inspection
UG Switchgear – Solid Blade	No	No	Yes	3 year inspection cycle	Reactive	301	30	Yearly Visual Inspection
UG Switchgear – Fused	No	No	Yes	3 year inspection cycle	Reactive	239	30	Yearly Visual Inspection
UG Switchgear – Live Front	Yes	Live Front Equipment Removal Program	Yes	3 year inspection cycle	Reactive	90	30	Yearly Visual Inspection
UG Switchgear – Dead Front (Kabar)	No	No	No	3 year inspection cycle	Reactive	80	30	Inspection Program currently being developed for a 2014 implementation
UG Switchgear – Solid Dielectric	Yes	No	Yes	3 year inspection cycle	Reactive	6	30	Yearly Visual Inspection
Underground Primary cable	Yes	No	No	3 year inspection cycle of risers and in	Reactive	652 km	40	Not Currently Part of An Inspection Program

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
				equipment				
Primary 3 phase feeder egresses	Included in UG Primary Cable	No	No	3 year inspection cycle of risers and switchgear, cable trays, etc.	Reactive	21 km	40	Not Currently Part of An Inspection Program
Underground Secondary cable	Yes	No	No	3 year inspection cycle in transformers and at risers	Reactive	1130 km	40	Not Currently Part of An Inspection Program
UG Ducts	No	No	No	Not required due to accessibility	Reactive	1857 km	40	Not Currently Part of An Inspection Program
Cable Chambers - Manholes	Yes	No	No	3 year inspection cycle	Proactive	363	60	Sample Inspection performed in 2013
Cable Chambers - Vaults	Yes	No	No	3 year inspection cycle	Proactive	630	50	Sample Inspection performed in 2013
Power Transformers - TS	Yes	No	Yes	1 year inspection cycle	Proactive	2	40	Monthly Visual Inspection, Yearly In-Depth Inspection
Power Transformers - MS	Yes	No	Yes	1 year inspection cycle	Proactive	2	40	Monthly Visual Inspection
Medium Voltage Switchgear – TS	No	No	Yes	1 year inspection	Proactive	2	40	Monthly Visual Inspection, Yearly

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
Assembly				cycle				In-Depth Inspection
Medium Voltage Switchgear - Breakers	Yes	No	Yes	1 year inspection cycle	Proactive	12	40	Monthly Visual Inspection, Yearly In-Depth Inspection
Medium Voltage Switchgear – MS Assembly	No	Yes	Yes	1 year inspection cycle	Proactive	2	40	Monthly Visual Inspection
Medium Voltage Switchgear – MS Breakers	Yes	No	Yes	1 year inspection cycle	Proactive	8	40	Monthly Visual Inspection
Independent Breakers – TS	Yes	No	Yes	1 year inspection cycle	Proactive	2	40	Monthly Visual Inspection, Yearly In-Depth Inspection
P&C Devices – TS - Panels	No	No	No	1 year inspection cycle	Reactive	15	40	Monthly Visual Inspection, Yearly In-Depth Inspection
P&C Devices – TS – relays - Digital	No	No	No	1 year inspection cycle	Reactive	28	15	Monthly Visual Inspection, Yearly In-Depth Inspection
P&C Devices – MS – Panels	No	Yes	No	1 year inspection cycle	Reactive	10	40	Monthly Visual Inspection
P&C Devices – MS – Relays - Electromechanical	No	Yes	No	1 year inspection cycle	Reactive	3	30	Monthly Visual Inspection
P&C Devices – MS – Relays - Digital	No	Yes	No	1 year inspection cycle	Reactive	5	15	Monthly Visual Inspection
Station Disconnect Switch	No	No	Yes	1 year inspection	Proactive	4	40	Monthly Visual Inspection, Yearly

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
- TS				cycle				In-Depth Inspection
Station Disconnect Switch - MS	No	No	Yes	1 year inspection cycle	Proactive	2	40	Monthly Visual Inspection
DC System - TS	No	No	Yes	1 year inspection cycle	Proactive	2	20	Monthly Visual Inspection, Yearly In-Depth Inspection
DC System - MS	No	No	Yes	1 year inspection cycle	Proactive	2	20	Monthly Visual Inspection
Station Grounding System	No	No	Yes	1 year inspection cycle	Proactive	3	40	Monthly Visual Inspection, Yearly In-Depth Inspection
Station Bus Work and Structures	No	No	Yes	1 year inspection cycle	Proactive	20	40	Monthly Visual Inspection, Yearly In-Depth Inspection
Station Building	No	No	Yes	1 year inspection cycle	Reactive	1	50	Monthly Visual Inspection
Metering	No	No	No	3 Year inspection cycle	Reactive	52316	15	Not Currently Part of an Inspection Program
SCADA	No	No	No	3 Year inspection cycle	Reactive	85 Non-switch or FCI RTUs	20	Not Currently Part of an Inspection Program
Remote FCI’s	No	No	No	3 Year inspection cycle	Reactive	30	15	Not Currently Part of an Inspection Program

Asset Class	Evaluated in ACA	Part of a Specific Replacement Program?	Maintenance Inspection form Established?	Minimum Maintenance Inspection Requirement?	Replacement strategy	Quantity	IFRS Life Maximum	Notes Replacement Approach
Communications	No	No	No	3 Year inspection cycle	Reactive	95	15	Not Currently Part of an Inspection Program

Table 5.3-8: Distribution Assets Inspection

5.3.2.4 **Asset Utilization (OEB Filing Req. 5.3.2d)**

d) An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

- ***Where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.***

The capacity of key distribution system assets, namely transformer and distribution stations is one of the first steps in assessing the over capabilities of the distribution system to function properly in order to service load and generation customers and is at the forefront of the planning stage. As outlined in section 5.3.2.2 above and described in detail in Table 5.3-4 , **GHESI** operates the distribution system in the City of Guelph and Rockwood via supply from four transformer stations and three distribution stations. Utilization of each transformer and distribution station is evident in Table 5.3-4 and within acceptable capacity levels. Of note, following the rebuild of Rockwood MS#1 in 2015, the community of Rockwood will be serviced only by the two **GHESI** owned municipal stations. Over the past ten years, **GHESI** has invested in improving the capacity of our system with the following projects:

- 2006 - Cedar TS Additional Station bus to accommodate eight distribution feeders
- 2009 – Hanlon TS – Additional two feeder breakers
- 2009 – New Distribution station in Rockwood, Rockwood MS#2
- 2012 – New transformer station, Arlen MTS
- 2015 – Rebuild and capacity increase to Rockwood MS#1

Based on the above improvements to distribution system capacity over recent years, which will provide enough capacity to serve **GHESI'**s service territory over the planning period, **GHESI** has not identified any capacity constraints requiring an investment in capacity over the horizon period

Utilization of the Campbell **TS** capacity has started to approach planned loading levels and as a result, an expansion of the **TS** or alternative is projected in the next five to ten years depending on growth and other factors such as **CDM** and **DG**. In order to assist in the deferral of this capacity expansion, feeder projects on the distribution are planned which will progressively move load to Arlen **MTS** and balance out capacity utilization between transformer stations.

5.3.3 Asset Lifecycle Optimization Policies and Practices (OEB Filing Req. 5.3.3)

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life extending refurbishment, and should include but need not be limited to:

5.3.3.1 Asset Lifecycle Optimization Policies and Practices (OEB Filing Req. 5.3.3a)

a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

- ***a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;***
- ***a description of maintenance planning criteria and assumptions; and***
- ***a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).***

GHESI optimizes asset lifecycles by performing inspections to monitor the health of distribution system assets, performing preventative and corrective maintenance where necessary and determined to be financially prudent and by proactively replacing critical assets at or near their **EOL**.

GHESI's Operations & Maintenance ("**O&M**") programs are designed to follow the guidelines set out in the **OEB's** Appendix C of the **DSC** for the inspection and maintenance of all key distribution system assets. Our **O&M** programs are reviewed annually in order to best align with our capital programs and to improve the programs based on industry best practices and standards. Inspection of assets is critical for the prioritization of operations and maintenance spending, as well as capital spending. The results of inspections are used to identify and prioritize system rehabilitation projects as discussed in Section 5.3.1.2. The outcome of that process is a replace, repair or do-nothing decision which allows **GHESI** to optimize system renewal investment impact.

Assets for which replacement of the asset or reconstruction of the surrounding system is identified as the most ideal solution will be replaced. For assets where replacement is not deemed to be the ideal approach, **GHESI's O&M** programs include minor repair and

maintenance work that is designed to economically extend asset lives. In both cases, planned replacement projects and planned operations and maintenance activities are selected in order to align with budget envelopes by optimizing the scope and timing of work during project prioritization and selection processes.

Asset Replacement and Refurbishment Policies

GHESI's asset replacement and refurbishment policies are optimized, prioritized and scheduled to align with budget envelopes and reduce **O&M** costs. **GHESI's ACA** determines health index ratings for assets based on inspection and maintenance records. This information is used to determine the predicted rate of failure of assets over a twenty-year window, which is levelized to minimize peaks and valleys in the replacement quantities over the twenty-year timeframe.

The levelized replacement schedule is used in the project prioritization and selection process to identify the optimal assets that should be replaced to satisfy the levelized replacement schedule and remain within budget envelopes (a description of the prioritization process, inputs and outputs can be found in section 5.3.1.2). Additionally, some assets may be replaced as a result of failure or in response to a trouble-call. When assessing a trouble-call, assets that cannot be repaired, or where repairs are not determined to be financially prudent, will be replaced. This decision is made by expert opinion, as well as by comparing the estimated repair costs and the estimated new residual value, based on the change in health index the repair will generate, to the costs associated with a new unit. If the updated residual value based on the effective age, less the repair costs, is less than annualized value of a replacement unit, the asset will be replaced instead of repaired. However, due to practical considerations, many repair decisions must be made by expert opinion due to time constraints in dealing with trouble calls and outages.

The impact of replacement and repair decisions on **O&M** costs is considered during the project selection and prioritization process. **O&M** costs are a factor of the Operational Efficiency Asset Management Objective (as described in section 5.3.1.1). Considerations range from the impact on **O&M** costs by improving asset capacity, asset remote operability, ease of access and ease of work on the asset. Operational Efficiency gains are assigned a score based on the level of efficiency gain, on a project-by-project basis. The same logic applies when assessing impacts on **O&M** costs for asset repairs and discrete replacements. The level to which **O&M** costs are estimated to be impacted weighs on the decision to repair or replace.

Maintenance Planning Criteria and Assumptions

GHESI plans maintenance and inspection activities on an annual basis. Budgets for maintenance activities are informed by historical costs for repairing various asset types, as well as planned inspections costs.

It is assumed that historical repair costs for each asset class will be consistent with future repair costs, proportional to the population of the asset class. These envelopes may be adjusted up and down based on the population of assets in a certain age range and the health index scoring of asset classes in the system. For example, if an asset class has a particularly poor health index rating, additional repair activity is expected for that asset type.

Inspection costs are based on historical per unit inspection costs and for most distribution assets, inspections run on three-year cycles. The cycles are based on known inspection areas, designed to split the service territory into three approximately equal sectors. The annual inspection budgets are based on the known population of assets in each sector, the inspection cycle year and the historical per-unit costs.

A description of the routine and preventative inspection and maintenance programs which flow from these planning criteria and assumptions is described below.

Routine and Preventative Inspection and Maintenance Programs

The following **O&M** programs are conducted annually in order to extend the life of our distribution assets, gauge the condition of our assets to determine end of life and to improve the safety and reliability of our distribution system:

i. Transformer and Substation Inspection and Maintenance

GHESI currently owns and operates one transformer station in the City of Guelph and two municipal substations in the Village of Rockwood. **GHESI** completes monthly inspections of the transformer and station equipment as well as annual testing of specific station equipment. Specific maintenance on transformer and substation equipment takes place if any issues arise during the inspection period. The breakdown of items that are inspected is shown in Table 5.3-9.

Monthly Transformer Equipment Inspection	Monthly Station Equipment Inspection	Yearly Transformer Equipment Testing
OIL TEMP, TX, MAX / PRESENT, (˚C)	PHYSICAL CHECK OF SWITCHGEAR	BATTERY VOLTAGE
OIL TEMP, ULTC, MAX / PRESENT, (˚C)	PHYSICAL CHECK OF BREAKER CELLS	BATTERY CHARGING CURRENT
WINDING TEMP MAX / PRESENT, (˚C)	PHYSICAL CHECK OF FENCING	BATTERY CONDITION
CONSERVATOR OIL LEVEL	PHYSICAL CHECK OF STATION	O.L.T.C. PRESENT COUNT
TRANSFORMER PRESSURE (+)/VAC(-)	INFRARED CHECK OF STATION	O.L.T.C. FUNCTIONAL CHECK

PHYSICAL CHECK OF TRANSFORMER	INDICATOR LAMPS	O.L.T.C. OIL LEVEL
TRANSFORMER OIL LEAKS	RELAY STATUS INDICATION	OIL TEST
GAS RELAY ACCUMULATION		CHECK OF ULTC COMPARTMENT
TRANSFORMER FANS		

Table 5.3-9: Substation Inspection and Maintenance

ii. Padmount Transformer and Switching Cubicle (Kabar) Inspections and Maintenance

GHESI assesses the current condition of padmount transformers and determines an estimated life expectancy through the Asset Condition Assessment process. A visual inspection is completed of the surrounding area to ensure the integrity of the area, as well as both public safety and the safety of **GHESI** employees operating and maintaining these transformer and Kabar units. Also, a visual inspection of all connections and conductors is completed to ensure a safe reliable supply of power. The inspection results are reviewed to determine the nature and scope of maintenance to be completed. For example, low cost maintenance activities that can prolong the life of the transformer or Kabar unit, such as obstruction clearing, rust repair and repair of damaged or loose connections is performed. If the transformer is in sufficiently poor condition or deemed unrepairable, it will be replaced if failure is imminent. Inspections of padmount transformers and Kabar units are performed on a three year rotational basis.

iii. Submersible Transformer Inspections and Maintenance

In our submersible transformer inspections, **GHESI** checks transformer loading to ensure that transformers are operating within their designed capacity limits. **GHESI** also inspects all electrical connections and ground level grates to ensure adequate ventilation and public safety. The enclosing vault is also inspected for structural integrity. Minor maintenance work that can prolong the life of the transformer may be performed as follow-up to the inspection (such as replacing damaged grating, repairing damaged or loose connections, cleaning debris out of vaults and grating or pumping out excess water from the vault). Submersible transformers are also fitted with stainless steel bottoms to avoid corrosion issues that are common in continually damp environments. If the transformer is in sufficiently poor condition or deemed unrepairable, it will be replaced if failure is imminent. Inspections are performed on a three year rotation.

iv. Vault Transformer Inspections and Maintenance

GHESI's vault transformers are located on private property in electrical rooms that have been designed for this purpose. **GHESI** will inspect items related to public safety and accessibility to ensure only qualified personnel have access to the electrical room and

equipment i.e. vents, doors and locks. Fire alarms are checked yearly in conjunction with the property owner. Sump pumps and room lighting are inspected along with a visual inspection of the transformer, switchgear, connections and conductor. A review of the inspection results will guide the nature and scope of maintenance to be completed. Minor repairs and maintenance will be performed as a result of deficiencies identified in inspections (for example, room cleaning, and tightening or replacing connections). Because vault transformers are in an environmentally controlled room and typically do not see additional customers attached to them above their original design over the course of their life, they typically require little maintenance. However, due to the cost and complexity of removing and replacing these assets, measures are taken to upgrade supporting equipment to prolong their life, such as the replacement of air insulated live front switchgear with solid dielectric insulated dead front equipment and the replacement of dead-break elbow bushings with load break elbow bushings.

v. Infrared Thermography Inspection – Overhead

Infrared inspection is contracted out and completed on an annual basis. The inspection captures all of our distribution lines and overhead equipment. This inspection has proven itself to be valuable in the past years showing a steady decline in “hot spots” which can lead to equipment failure and service outages in our system. Hot spots identified by this program have been inspected and in some cases have led to changes in installation practices and materials in order to prevent issues in future construction.

vi. Pole Tran Inspection and Maintenance

Pole Transformers (“**Pole Tran**”) inspections are completed on an annual basis. The inspection checks for leaks, deterioration of connections and tracking. All of our Pole Tran switchgear is dry iced to help prevent and slow down the development of corona and tracking, providing a safer work environment for our employees and improving the reliability of the equipment. Due to their high failure rates and safety concerns inherent to their design, **Pole Tran’s** transformers are being replaced with pad mounted transformers and they are expected to be removed completely from **GHESI’s** system by 2016. In order to optimize the lifecycle of **Pole Trans** remaining in the system until the removals are completed, spare parts are salvaged from the units taken out of service that can be used to make minor repairs to the remaining in-service units.

vii. Padmount Switchgear Inspection and Maintenance

Padmount switchgear inspections are completed on a three year rotation. The inspection consists of a visual inspection of the inside and outside of the cabinet, condition of the cabinet locking mechanism, inspection of the control cabinet (if present), verifying the appearance of each unit and ensuring that nomenclature is correct and

legible. Inside the unit, **GHESI** employees inspect all of the moving parts, insulators, arc stranglers, connections, fusing and termination points. In heavy condensation areas the units have been replaced with a modified unit that houses a ventilation system to help improve the life of the unit and reduce outages. **GHESI** identifies live front padmount switchgear with a high risk of flash over and tracking and has them dry iced to mitigate the development of faults and damage from partial discharge and tracking. Air insulated padmount switchgear has become obsolete for these reasons and new installations are solid-dielectric insulated which provides a higher degree of safety and reliability. Solid dielectric units are inspected in the same way. In both cases repairs will be made based on inspection results where units have not reached their end of life. Examples of repair work include the replacement of broken or loose connections, painting and repairing damaged cabinets, repairing damaged barriers, repair to damaged locking systems and rectifying marking issues. Because of the high cost and lead-time of the units and the reliability impacts of a unit failure, padmount switchgear is maintained to extend service life and replaced proactively, where possible, to avoid collateral damage and reliability impacts.

viii. Tree Trimming

GHESI performs tree trimming in the City of Guelph service area on a three year rotation. **GHESI** contracts this maintenance project to a qualified arborist. The contractor and **GHESI** work in co-operation with the City of Guelph and the homeowners when contentious trees are determined to be a threat to **GHESI** overhead lines. Engaging in regular tree trimming has shown to improve system integrity during major storm events.

ix. Porcelain/Polymer Insulator Replacement

GHESI replaces suspect OHIO Brass porcelain insulators and all single skirt polymer insulators when identified in the field. This maintenance program has helped lower outages and increase safety for employees and the general public.

x. Distribution Pole Inspection and Testing

Pole testing has been contracted out on a three year basis, corresponding with the three inspection areas. All poles, including wood, concrete, composite and third-party owned poles are visually inspected, while poles that are older than fifteen years undergo full testing including non-destructive testing of remaining fibre stress and shell depth. The contractor supplies us with a report that identifies and prioritizes poles that need replacement. The report includes other useful information for proactive planned replacement of cross arms, attachments, nomenclature, etc. Poles that are identified as rejects, or unfit for climbing, are replaced and other poles are prioritized based on health

index and probability of failure data derived from the inspection data. Preventative maintenance is also carried out on poles where decay, termites or carpenter ant infestation has been identified. Maintenance activities include treatment of poles with boron rods or below grade boron wraps and the removal of external decay. Composite poles with exterior damage are also reported so that any damage to UV-resistant outer coatings can be repaired to optimize the life of these poles.

xi. LIS Inspection and Maintenance

LIS maintenance is performed throughout the year on switches installed in the field. Lists of the top fifty and bottom fifty most operated switches are produced, as well as lists of switches that have had operating issues or sustained lightning damage. These switches are targeted for maintenance activities which may include the alignment of control rods and switch blades, tests of switch action, continuity tests on snuffer switches, capping of snuffer exhaust chutes, and the replacement of any worn parts. **SCADA** switches are also maintained but not all operations are performed in the field. Examples of work on **SCADA** switches include the replacement of current and potential instrument transformers, failed batteries, Remote Terminal Units ("**RTU's**") or antenna assemblies. Switch configurations that have historically caused a high number of reliability impacts are replaced with a different style of unit instead of being repaired. Examples include triangular and horizontal configurations of **LIS** which are more susceptible to seizing and animal contact.

xii. Vault and Manhole Inspection and Maintenance

The inspection of distribution vaults and manholes are completed by a third party contractor, working in conjunction with **GHESI** employees. Inspection of these units is visual and is completed by an articulated high-definition camera which is used to take photos of the entire interior of the unit. The photos are analyzed by industry experts who determine the condition of the concrete structure. Additionally, any issues with connections and cables that are identified are noted by **GHESI** employees. Minor repair work is conducted on site to prolong the life of units, such as replacement or repair to access grates and pumping excess water out of the chambers. More advanced maintenance or replacement work for vaults and manholes are determined on a case-by-case basis depending on the extent of damage and the efficacy of various repair methods (i.e. parging, concrete injection, and replacement of roof structure for vaults, repair to access collar for cable chambers or complete replacement).

Reactive Maintenance

Reactive maintenance includes responses to trouble calls which fall outside the specifications for regular maintenance described in section 5.3.1.1. These events can

include responses to equipment breakdown that has resulted in an outage and trouble call, or responses to unexpected deficiencies. Work completed as part of reactive maintenance varies due to the wide-range of possible events that can occur. This work may occur during normal working hours and be completed by an underground or overhead line crew, or may be completed in response to an after-hours call, and be completed by an on-call line crew.

An example of reactive maintenance is the replacement of an insulator in a live-front pad mounted switchgear unit that has unexpectedly tracked and caused a fault. If the rest of the unit is in good condition, as indicated by the **ACA** results, a line crew will respond to the unit location, isolate the unit, replace the faulty insulator and return the unit to service. This example of reactive maintenance occurred at a pad mounted switchgear unit at Allen's Bridge in Guelph, in 2014.

Depending on the severity of the health of the unit being repaired or maintained, the unit may then be placed on an accelerated schedule for planned replacement at a later date. This schedule is determined by the updated health index value and corresponding probability of failure, in concert with existing planned projects and available resources.

5.3.3.2 Asset Life Cycle Risk Management Policies and Practices (OEB Filing Req. 5.3.3 b)

b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

For discretionary projects, **GHESI** participates in asset life cycle risk management by assessing the existing levels of risk on an asset by asset and a project area basis, and determining the appropriate action to either minimize or remove risk where necessary.

The assessment of risk begins with the inspection of assets. Assets are inspected and inspection data is returned which can be used to derive a health index for each asset. The health index that is derived during the **ACA** process is tied to a probability of failure for the asset by relating the health of the asset to an effective age and corresponding known failure curve. The probability of failure data is multiplied by the consequences of failure for each project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts to worker and public safety, the environment, reliability and power quality and

operational effectiveness that could arise if a failure event occurs. Once the risk of each project area has been established it is placed into a prioritization and selection process that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Projects with very high risk scores are monitored closely and plans are designed to either modify, maintain or replace the assets in these areas to reduce the risk to an acceptable level (some assets carry an inherently higher risk than others, for example, power transformers have a higher nominal risk level associated with them than pole mount transformers). Projects which have high risk values but correspondingly low health indices indicate that the risk is a function of the asset health rather than natural risk associated with the assets in the project area and these projects are prioritized, generally for replacement. Additionally, projects which do not necessarily have the highest risk values, but where the cost to lower the risk to an appropriate level is very low (in terms of dollars invested per risk point mitigated) will be analyzed as they provide an opportunity to greatly improve the overall system risk in a very cost effective way. Finally, those projects that carry very high risk but also a corresponding high overall health index are analyzed to determine which asset in the project area is responsible for the elevated risk and plan either maintenance or spot replacement work to bring the project area to a low risk, high health status at minimal cost. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work. Finally projects are selected and integrated into the capital budget based on their effectiveness at minimizing risk and to ensure that projects that are relatively discretionary are selected based on the effectiveness of the investment. Projects having the highest risk and low health index ratings are given higher priority than low cost per risk point projects because they typically cannot be deferred (due to very high probability of failure values and high impact of failure values), however the probability of failure of the project area provides guidance on which projects can be deferred in order to make room for the more cost-effective risk reducing projects.

Because the inspection and **ACA** processes provide valuable information on asset health, effective age and probabilities of failure, risk management can be continually undertaken for assets which do not fall in the top priority projects identified in the above method. The inspection and **ACA** processes result in identifying and implementing regular maintenance programs as described in section 5.3.3.1 Asset Lifecycle Optimization Policies and Practices (**OEB** Filing Req. 5.3.3a) to optimize asset lifecycles and manage risk over the lifecycle of each asset.

In addition to the discretionary projects, **GHESI** must also undertake mandatory projects. These projects are most often driven by connection requests and relocation requirements due to changes to the right-of-way (i.e. road-widening or realignment projects). **GHESI** seeks to plan these projects as much as possible, however, in the event that an unforeseen mandatory project impacts the ability to perform planned discretionary projects, **GHESI** reviews the discretionary projects to determine the best course of action. Analysis typically includes whether projects can be deferred, approached in a different way, or whether additional resources must be obtained to complete both the discretionary and mandatory projects. The decision to defer a project will be based on the level of risk that will be taken on by doing so and whether that level of risk is deemed acceptable. The prioritization process described above informs which projects should be deferred, should completing all discretionary projects not be possible. Deferrable projects ar deferred in reverse priority order.

5.4 Capital Expenditure Plan (OEB Filing Req. 5.4)

A distributor's DSP details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process. As noted above, a DSP must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary (OEB Filing Req. 5.4.1)

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

A summary of **GHESI's** capital expenditure plan is outlined below demonstrating key information and supporting information to explain in detail the significant aspects of the plan in order to meet **GHESI** strategic corporate objectives. The capital expenditure plan was developed in part by leveraging on key outputs within the asset management process. Projects have been divided into four categories as outlined in the **Filing Requirements**.

5.4.1.1 System Capability to Connect New Load or Generation (OEB Filing Req. 5.4.1a)

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

GHESI assesses system capacity capability through on-going updates to key information such as transformer station loading data along, **CDM** information summarized in Appendix J, and distributed generation ("**DG**") information contained in the REG investment plan in Appendix A**.** This information serves an important role in order to help identify historic and future load growth trends to assist in the decision

making process for system capacity changes. This step of reviewing the capabilities of the capacity at each station is followed by an individual assessment of various areas within each load centre on an as needed basis to determine potential constraints. The basis behind the system capability assessment was the resulting analysis of **GHESI's** load forecasting. This forecasting, tailored for this particular need, showed that the requirement for additional capacity was not needed by future load growth in a general sense. Capacity issues were not identified on a station level.

On a feeder level, a different analysis performed and system reconfigurations are being done and will be required to transition load to where it is needed. This involves redefining boundaries of feeders and small investments below the materiality threshold. **GHESI's** adjustments to its feeder load do not require or involve additional capacity being input to or added to the system as a whole, particularly as the distribution system is able to support the level of customer demand and distributed generation currently imposed and anticipated to be imposed. Therefore, as a result of this process described above and outlined in Table 5.3-4, **GHESI** does not foresee any capacity constraints that would affect the capability to connect new load or generation customers over the planning period.

GHESI's distribution system peak load has seen a gradual increase over the past ten years with an average growth rate of approximately 1.16%. This rate factors in efforts of **CDM** and **DG**. Without the addition of **CDM** and **DG**, **GHESI's** system growth rate was determined to be 2.5%. Evident in section 5.3.2 Campbell **TS** has started to reach acceptable loading levels. As a result, an expansion of the **TS** or alternative is projected within the ten year forecast but outside this planning cycle. In order to defer this capital investment at Campbell **TS** to increase system capacity, distribution system feeder projects are planned which will progressively move load to the Arlen **MTS** and alleviate constraints in the north end of Guelph supplied by Campbell **TS**. Following the implementation of these projects **GHESI's** distribution system is capable of connecting new load customers beyond 2018. **GHESI's** distribution system is well diversified to allow the connection of new generation. As proven in our historical connection of **REG** projects, with minimal changes to the distribution system and as outlined in **GHESI REG** investment plan, future **DG** connections can be accommodated with minimal to no changes to the distribution system.

5.4.1.2 **Summary of Annual Capital Expenditures (OEB Filing Req. 5.4.1b)**

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

The total annual gross capital expenditures over the forecast period by investment category are presented below in Table 5.4-1. The overall spending increases slightly

over the forecast due to inflation however no material changes in investments are planned.

CATEGORY	Forecast Period (planned)				
	2016 Test Year	2017	2018	2019	2020
System Access	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305

Table 5.4-1: Total Annual Forecast Gross Capital Expenditures

5.4.1.3 Asset Management and Capital Expenditure Planning (OEB Filing Req. 5.4.1c)

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

The following information provides a brief outline of the outputs of the asset management and capital expenditure planning process that have affected capital expenditures in each of the four main major categories and overall allocation of the capital budget. The overall allocation of the capital budget amongst major categories for the **Test year** and **Forecast period** can be seen in figures Figure 5.4-1 and Figure 5.4-2 below.

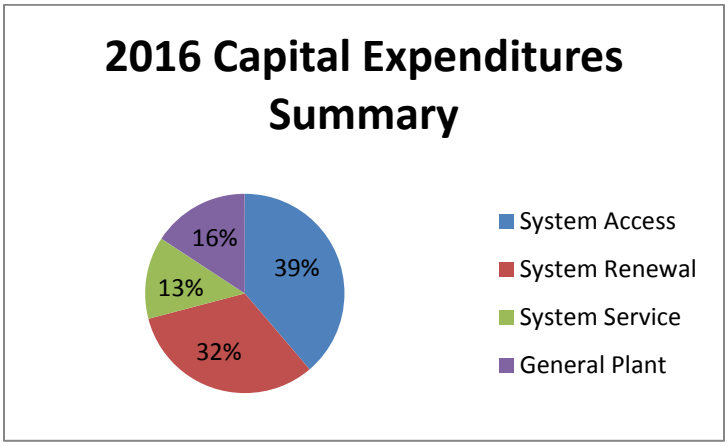


Figure 5.4-1 2016 Capital Expenditures by Category

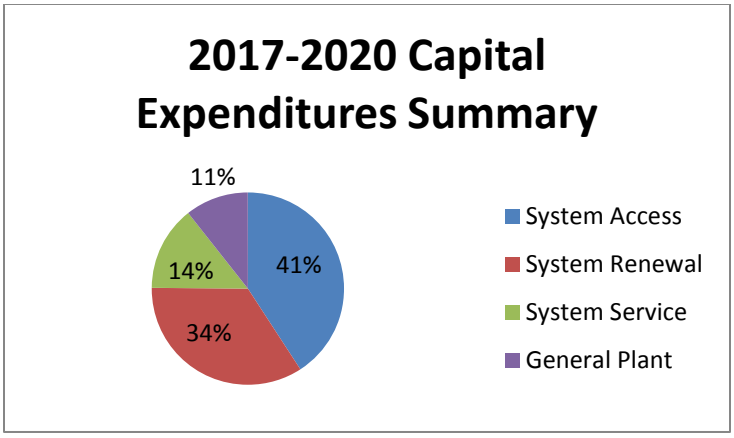


Figure 5.4-2 2017-2020 Capital Expenditures by Category

System Access Investments

System Access investments account for the highest portion of the capital expenditures for the Test Year and Forecast Period averaging 40% of total capital budget. These expenditures are an integral part of the distribution system and the most challenging to plan as they include a number of outside influences that have contributions to the overall investment. A number of outputs resulting from asset management and capital expenditure process contribute to the outcome of the investment in System Access and have affected the overall capital expenditures:

- Consultation with municipal officials to understand future projects requiring relocation of distribution system assets in support of System Access investments. This process assists in shaping the overall allocation of investment required to support relocations resulting from projects on municipal right of ways.
- The outcome of the City of Guelph **DPP** assists in forecasting capital expenditures for residential developments in support of System Access investments.
- Consultation with existing customers, specifically industrial and large use customers, to gain perspective to current and future electrical needs to help plan the system accordingly in support of System Access investments.

System Renewal Investments

System renewal investments contribute the remaining bulk of the overall capital expenditures averaging approximately 33% of the investments for the forecast period. Expenditures within the renewal sector are highly dependent on the condition of distribution system assets and play a crucial role in the overall sustainment of the distribution system. The asset management process on the renewal of assets is managed based on the foundation of the **ACA** on distribution system assets. This information in turn acts as an input into the **GHESI** system renewal project prioritization process described in section 5.4.2.3.

System Service Investments

System Service Investments account for approximately 14% of the overall allocation of the capital budget and consist of expenditures related to the installation of a current limiting reactor ("**CLR**") as well as feeder projects to support the capacity within certain areas of the City of Guelph. System forecasting showed that the requirement for additional capacity was not needed by future load growth however on a feeder level, a different analysis performed and system reconfigurations are being done and will be required to transition load to where it is needed. .

General Plant Investments

General plant expenditures account for a small portion of the overall allocation of capital investment averaging approximately 16% for the test year and approximately 11% for the forecast period. Expenditures in general plant relate to modifications, replacements or additions to assets that are not part of its distribution system, including land and buildings, tools and equipment, fleet and electronic devices, and software used to support day-to-day business and operations activities. A number of key outputs related to the asset management and capital planning process contribute to the capital expenditures for non-distribution system items in general plant. Assessments completed on **IT** infrastructure and the operations fleet of vehicles play a major role in determining the expenditure requirements for these given area.

5.4.1.4 **Material Capital Expenditure Projects (OEB Filing Req. 5.4.1d)**

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

GHESI has prepared a list and brief description including total capital cost of material capital expenditure project/activities sorted by category shown in Table 5.4-2. It is important to note the **GHESI** does not have a complete list of detailed projects contained within a number of the activities for the 2016 test year due to the nature of these programs which consist of a series of numerous individual projects below the materiality threshold.

Projects	2011 (Previous Bridge Year)	2012 (Previous Test Year)	2013	2014	2015 Bridge Year	2016 Test Year	Total by Project
	Actual	Actual	Actual	Actual	Budget	Budget	
Reporting Basis	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	
System Access							
Apartment, Commercial, Industrial Customer Connections (CACI)	600,858	546,155	544,823	1,035,517	628,053	646,894	4,002,301
Meter Installations (CMEG)	162,476	121,866	-30,003	-19,038	485,000	415,000	1,135,302
- Meters & Metering	224,735	237,712	381,702	302,009			1,146,158
- Smart Metering	897,505	176,751	7,918				1,082,174
- Spec S/C burden - WMP's at TS's	58,230	30,819	63,283	106,927			259,259
- SSN AMI Hardware Upgrades					525,000		525,000
Distribution System Modifications / Expansions for Customers (CMOD)	181,659	68,172	75,760	-10,230	761,407	784,249	1,861,016
- MacLennan Street @ Wheeler Court				173,036			173,036
- Customer, 75 Southgate Dr	1,966,781	7,576					1,974,357
- Customer - 63 Independence Place				800,104			800,104
System Relocations Property Development (CREL)	63,951	4,747	109,517	-18,795	1,262,023	1,299,884	2,721,328
- Carden St, Wyndham to MacDonell	203,008	703					203,711
- Hanlon Parkway at Laird Road Intersection	56,698	1,199,729	60,094				1,316,521
- Laird Road and Southgate Drive Intersection			180,697				180,697
- Norfolk St, Woolwich Intersection	265,969	32,664					298,633
- Speedvale Ave E, Stevenson Rd N to Sherwood		40,687	369,640				410,327
- Victoria Road South - Arkell Rd to MacAlister Blvd		329,165	36,740				365,905
- Wellington St W - Gordon St UG				269,437			269,437
- Wellington St W - Wellington to Gordon UG				925,914			925,914
- Wyndham St S, Farquhar to Wellington	56,639	120,347	3,776				180,762
Expansions for New Residential Subdivions (CRES)	485,186	566,058	521,164	135,031	1,401,224	1,443,261	4,551,924
- Arkell Meadows Subdivision			35	192,395			192,431
- Chillico Glen, Phase 2 Subdivision	243,563	2,650					246,213
- Chillico Run Subdivision				189,741			189,741
- Cityview Heights, Ph 2, Cityview & Oakes		103,413	110,233				213,646
- Grangehill, Phase 7A		27,207	356,092	-74,688			308,611
- Kortright East, Phase 3 A Subdivision				378,588			378,588
- Morningcrest, Ph 2C, Couling Cr		193,183	50,112				243,295
- Noble Ridge Estates, Phase 1 - Rockwood		158,831	465,671				624,502
- Northern Heights, Phase 5		325	139,219	40,735			180,279
- Watson Creek, Phase 3	67,663	358,266	162				426,091
New Residential Service Connections (CSER)	410,079	311,801	348,477	216,128	231,994	238,954	1,757,433
Expansions for New Residential Townhouse Subdivions (CTH)	513,372	373,985	111,539	190,009	552,236	568,803	2,309,944
- Lakeview Place Townhomes, 15 Carere Cres	116,367	5,553	30,424	40,804			193,148
- Westminister Woods East, Phase 5			291,981	12,971			304,952
Sub-Total	**6,574,742**	**5,018,365**	**4,229,054**	**4,886,595**	**5,846,937**	**5,397,045**	**31,952,738**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total System Access	**6,574,742**	**5,018,365**	**4,229,054**	**4,886,595**	**5,846,937**	**5,397,045**	**31,952,738**

Projects	2011 (Previous Bridge Year)	2012 (Previous Test Year)	2013	2014	2015 Bridge Year	2016 Test Year	Total by Project
	Actual	Actual	Actual	Actual	Budget	Budget	
Reporting Basis	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	
System Renewal							
Distribution System Replacment (CREP)	569,065	527,883	950,686	1,443,423	168,117	770,741	4,429,915
- 21 Woodlawn Rd E Reconstruction			171,694	121,583			293,278
- 295 Water Street Single Phase Ug W/ Secondary Ug Cable						448,000	448,000
- Acorn Pl and Chestnut Pl Rehabilitation			178,115				178,115
- Alice St, Arthur S to Stevenson S	246,589	209,017	3,174				458,780
- Alma St N / Plymouth Crt						218,000	218,000
- Alma St N/Julia Dr/Drew St						216,000	216,000
- Arrow Rd						432,000	432,000
- Campbell TS Easement, Dawson Rd to Edinburgh Rd	226,030						226,030
- Damaged or Deteriorated Poles	292,502	303,400	90,218	237,767			923,887
- Dawson Rd – U/G					369,000		369,000
- Deerfield Pl Pole Trans					174,000		174,000
- Edinburgh Rd N - Speedvale to Woodlawn Rd W	169,642	122,580	69,881				362,103
- Fife (Wellington To Gateway)						173,000	173,000
- Hands Dr, Latenda Pl, Dimson Ave Rehab			125,114	479,310			604,425
- Imperial Rd N North Of Paisley					351,000		351,000
- Imperial Rd S / Samantha Crt						247,000	247,000
- Lewis Road Reconstruction		2,670	315,868	240,172			558,710
- Macdonell St Carden To Woolwich					300,000		300,000
- Nicklin Road Reconstruction		195,481					195,481
- Paisley St West Of Norfolk					261,000		261,000
- Parkwood Gardens, Phase 3 Rehab		1,084,440	-2,386				1,082,054
- Elmira Rd South						388,000	388,000
- Sherwood Dr Rehabilitation			567,424				567,424
- Speedvale Ave W - At Kathleen					245,000		245,000
- Victoria Road North - Islington Ave to Speed River				579,897			579,897
- Western Ave Reconstruction			209,181				209,181
- Westgate Dr/Lonsdale Dr/ Edinburgh Rd N [Oh]						285,000	285,000
- Willow Rd At Applewood					278,000		278,000
-8 &16 Wilsonview Ave Vault Replacement				301,969			301,969
- Rickson Ave UG Rehab					1,508,000		1,508,000
- Keats UG Rehab						986,000	986,000
Distribution System Transformer replacement upgrades (CTRU)	144,433	91,051	151,523	322,307	306,013	315,193	1,330,521
Sub-Total	**1,648,262**	**2,536,522**	**2,830,493**	**3,726,430**	**3,960,130**	**4,478,934**	**19,180,770**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total System Renewal	**1,648,262**	**2,536,522**	**2,830,493**	**3,726,430**	**3,960,130**	**4,478,934**	**19,180,770**

Projects	2011 (Previous Bridge Year)	2012 (Previous Test Year)	2013	2014	2015 Bridge Year	2016 Test Year	Total by Project
	Actual	Actual	Actual	Actual	Budget	Budget	
Reporting Basis	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	
System Service							
Distribution System Feeder Infrastrucutre (CFDR)	270,231	115,835	42,765	348,005	1,527	94,833	873,196
- Campbell TS, Campbell Rd, Massey Rd, Elmira Rd N			1,881,150	237,224			2,118,374
- Clair Road - Crawley to Southgate - Composite Pole Line	200,916	31,096	-5,582				226,430
- Crawley Road, South of Clair Rd at MTS#1	197,659						197,659
- Edinburgh Rd N (Bristol To Foster)					400,000		400,000
- Edinburgh Rd N / Sultan St						176,000	176,000
- Edinburgh Road South - From Cedar to Bristol Street				1,146,385			1,146,385
- External Ground Grid, Hanlon Rd - Kortright to Maltby	164,989						164,989
- Feeder to Clairfields					300,000		300,000
- Hanlon Creek Business Park, Phase 1B, Part 1	267,848	8,947					276,795
- Hanlon Creek Business Park, Phase 1B, Part 2	9,680	181,547					191,227
- Hanlon Creek Business Park, Phase 2	386	639,614	42,024				682,024
- Poppy Drive, Phase 1B		203,347	4,309				207,656
- Rockwood - Harris St		15,245	268,354				283,599
- Waterloo Ave					442,000		442,000
- New 5M53 - Cedar St (Edinburgh To Maple)						500,000	500,000
- Edinburgh Rd S (Municipal To Bristol - West Side)						407,000	407,000
- Customer, 75 Southgate Dr	530,780	16,779					547,559
SCADA Infrastructure (CSC)	86,503	124,910	69,317	-14,053	218,360	224,911	709,948
SCADA Master - Web Console/HW Upgrades	147,716	98,614	98,213				344,543
SCADA Master		24,478		188,343			212,821
SCADA / Remotely Operated Switches (CSW)	119,131	78,394	241,920	289,419	248,784	256,248	1,233,896
Transformer Stations & Distribution Stations (CTS/CDS)	26,723	5,140	207,720	55,426	181,950	49,408	526,368
- ARLEN MTS	14,876,047	1,596,028	335,790				16,807,865
- Rockwood MS#1 Reconstruction					1,250,000		1,250,000
- Arlen MTS - Series Reactor					800,000	150,000	950,000
Sub-Total	**16,898,611**	**3,139,974**	**3,185,982**	**2,250,748**	**3,842,621**	**1,858,400**	**31,176,335**
Miscellaneous Projects (under Materiality threshold)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total System Service	**16,898,611**	**3,139,974**	**3,185,982**	**2,250,748**	**3,842,621**	**1,858,400**	**31,176,335**

Projects	2011 (Previous Bridge Year)	2012 (Previous Test Year)	2013	2014	2015 Bridge Year	2016 Test Year	Total by Project
	Actual	Actual	Actual	Actual	Budget	Budget	
Reporting Basis	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	
General Plant							
Building / Fixtures	32,636	0	97,634	483,568	254,500	154,135	1,022,474
Building Addition					500,000	650,000	1,150,000
Office Equipment / Graphics	25,249	43,060	50,495	104,225	58,350	163,100	444,478
Fleet / Rolling Stock	402,093	218,798	461,583	318,503	200	886	1,402,063
2012 Terex C-5052		250,158					250,158
Replace Double Bucket (T8)					350,000		350,000
New Single Bucket (42')					206,000		206,000
Replace Single Bucket (T9)						300,000	300,000
LineChamp Material Handler				302,328			302,328
Replace Crew HD Pickup (T18)						90,000	90,000
Replace Pickup (T19)						35,000	35,000
Replace Pickup (T35)						37,000	37,000
Replace Forklift						110,000	110,000
IT Capital	284,128	155,368	331,387	660,217	460,000	148,931	2,040,031
Corporate Voice System			200,000				200,000
D & R Electronics	240,878						240,878
Comp Software		240,878					240,878
Servers					100,000	100,000	200,000
3-IBM I series Servers					220,000	20,000	240,000
Lansa Software				404,843			404,843
ERP Enhancement						61,800	61,800
HRMS Program						60,000	60,000
Network Switches						35,269	35,269
Printers						35,000	35,000
PC's, Laptops, Monitors						40,000	40,000
DR Site infrastructure						25,000	25,000
HDD SAN Storage						34,000	34,000
Firewall security systems						30,000	30,000
Major Tools	67,738	76,475	79,477	85,754	63,654	65,564	438,663
Sub-Total	1,052,721	984,738	1,220,577	2,359,438	2,212,704	2,195,685	10,025,862
Miscellaneous Projects (under Materiality threshold)	0	0	0	0	0	0	0
Total General Plant	1,052,721	984,738	1,220,577	2,359,438	2,212,704	2,195,685	10,025,862
Total all Categories	26,174,335	11,679,598	11,466,106	13,223,211	15,862,392	13,930,063	92,335,705
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*	0	0	0	0	0	0	0
Total	26,174,335	11,679,598	11,466,106	13,223,211	15,862,392	13,930,063	92,335,705

Table 5.4-2: 2011-2016 Capital Projects Exceeding Materiality Threshold

5.4.1.5 **Material Impact of IRRP/RIP on the DSP (OEB Filing Req. 5.4.1e)**

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

As a result of the regional planning process within the **KWCG** area, the **Hydro One GATR** project was put forward and approved by the **OEB** in 2013 as a solution to areas constraints. The **GATR** project is currently being constructed by **Hydro One** and planned to be in-service in Q2 of 2016. Outlined in Appendix H, **Hydro One** determined the impact to customers and stations connected to transmission system facilities due to the **GATR** project. As a result of the future state of the transmission system due to the **GATR** project within the region of Guelph, **GHESI** undertook a study determine the impact of the **GATR** project on Arlen **MTS**. As identified in Table 9 on page 8 of the Arlen MTS fault reduction feasibility study attached in Appendix G**,** acceptable short circuit ratings will be exceeded when the **GATR** project becomes in service and a need for a solution to reduce fault levels in order to maintain short circuits values within acceptable levels as per the **OEB** Transmission System Code ("**TSC**") is required. Details of the project proposed titled as "Arlen MTS **Reactor** Project" as a solution to the high levels of fault current is outlined in the capital project summaries in Appendix N .

5.4.1.6 **Customer Preferences (OEB Filing Req. 5.4.1f)**

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

In order to obtain information about customer needs and preferences for use in developing the 2016 Distribution System Plan and Cost of Service application, **GHESI** conducted the following activities:

i. Researched industry trends, Exhibit 1, Tab 4, Schedule 4, page 3

ii. Analyzed quantitative and qualitative data such as

- Results of bi-annual **UtilityPULSE Customer Satisfaction Survey** conducted by telephone in the spring of 2013, evident in Exhibit 1, Tab 4, Schedule 3 - Appendix 1B
- Results of a residential and commercial **Online Customer Survey** conducted in the winter of 2014, evident in Appendix 1-D of Exhibit 1.
- Summary of Call Centre tracking of inbound call statistics, customer inquiries (topics), complaints and feedback (Section?)
- Website analytics

- Feedback from customers obtained through outreach activities
- Anecdotal feedback from employees handling **GHESI**'s Twitter account

iii. Held information sessions and workshops with commercial and industrial customers shown in Exhibit 1, Tab 4, Schedule 4, page 30

iv. Met with commercial and industrial customers on a one-on-one basis – Engineering, Metering and **CDM** employees

GHESI uses these activities to:

- inform its customers on the proposals being considered for inclusion in this Application and the value of those proposals to customers i.e. costs, benefits and the impact on rates, and
- Incorporate feedback obtained from customers into planning, prioritizing, and justifying proposed capital expenditures in this Application.

Topics of material interest to customers with regard to the distribution system that were identified through these activities include:

- Reliability
- Outage response
- Cost containment
- Future technologies

Reliability

Feedback from customers indicates that **GHESI** customers continue to be very satisfied with the reliability of the system and the service that **GHESI** provides. This is clearly evidenced by the fact that **GHESI** achieved a score of 96 per cent in Customer Satisfaction and was ranked number one in customer satisfaction among 14 Ontario **LDC's** that took part in the Annual Electric Utility Customer Satisfaction Survey conducted in 2013 by UtilityPULSE, a division of Simul Corporation.

With regard to Service Quality, **GHESI** scored higher than the Ontario averages on all important attributes that shape perceptions about service quality as shown in Figure 5.4-3.

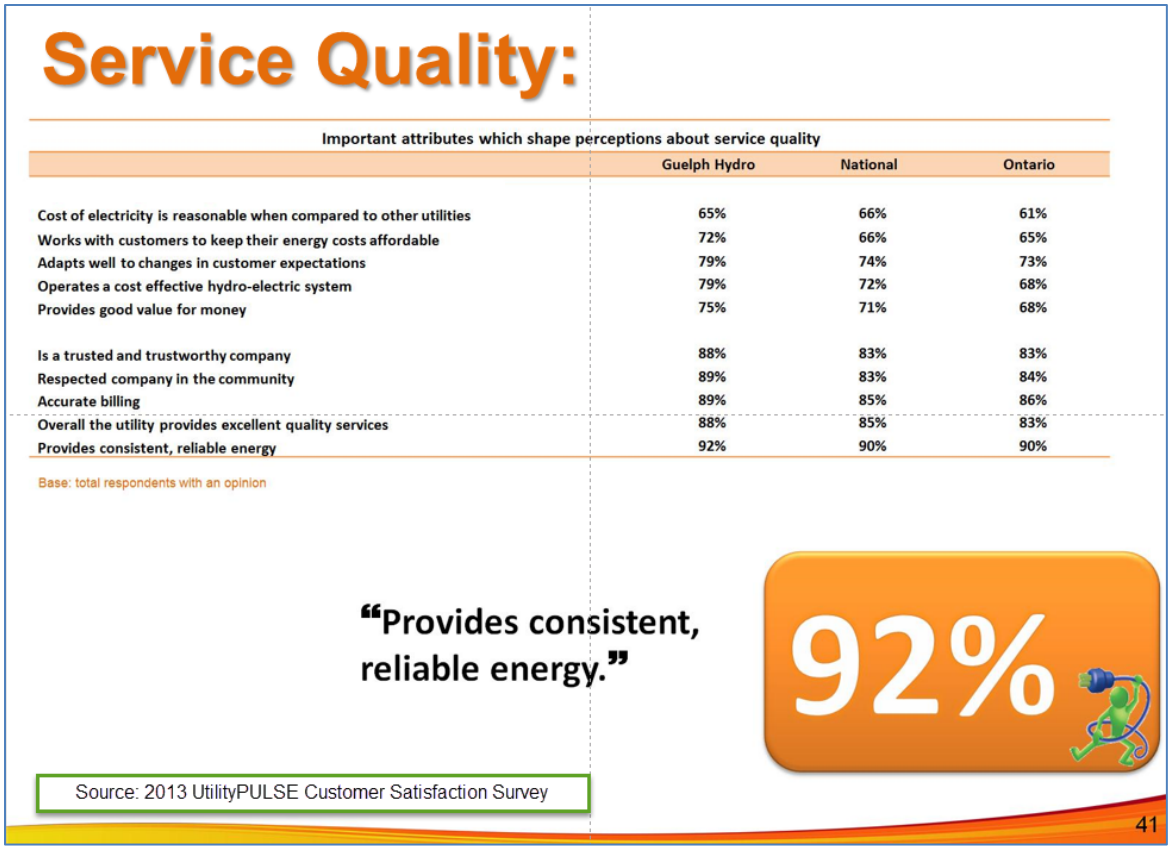


Figure 5.4-3 Survey Results on Service Quality

Of particular note is the fact that **GHESI** achieved a score of 92 per cent for "providing consistent, reliable energy." This exceptionally high rating is reflected in the A+ rating on Power Quality and Reliability on **GHESI**'s UtilityPULSE Report Card as indicated in Figure 5.4-4. Furthermore, 91 per cent of the Residential customers who participated in the Online Customer Survey in late 2014 rated **GHESI**'s overall reliability as good to excellent, an indicator that GHESI's high reliability has continued through 2014. Together, these high scores have been taken as an indication that **GHESI's** current approach to distribution system planning is meeting the needs of customers for a reliable supply of electricity. Maintaining Reliability through prudent System Renewal investment is a primary focus if this Plan.

Guelph Hydro's UtilityPULSE Report Card®				
Performance				
	CATEGORY	Guelph Hydro	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

Figure 5.4-4 GHESI UtilityPULSE Report Card

Outage Response

The UtilityPULSE Customer Satisfaction Survey as shown in Figure 5.4-5 indicates that 29 per cent of customers who responded to the survey reported having an outage problem in the last 12 months; a score that is six per cent lower than the Ontario average. It is important to note that this time period encompassed the severe ice storm experienced in December 2013.

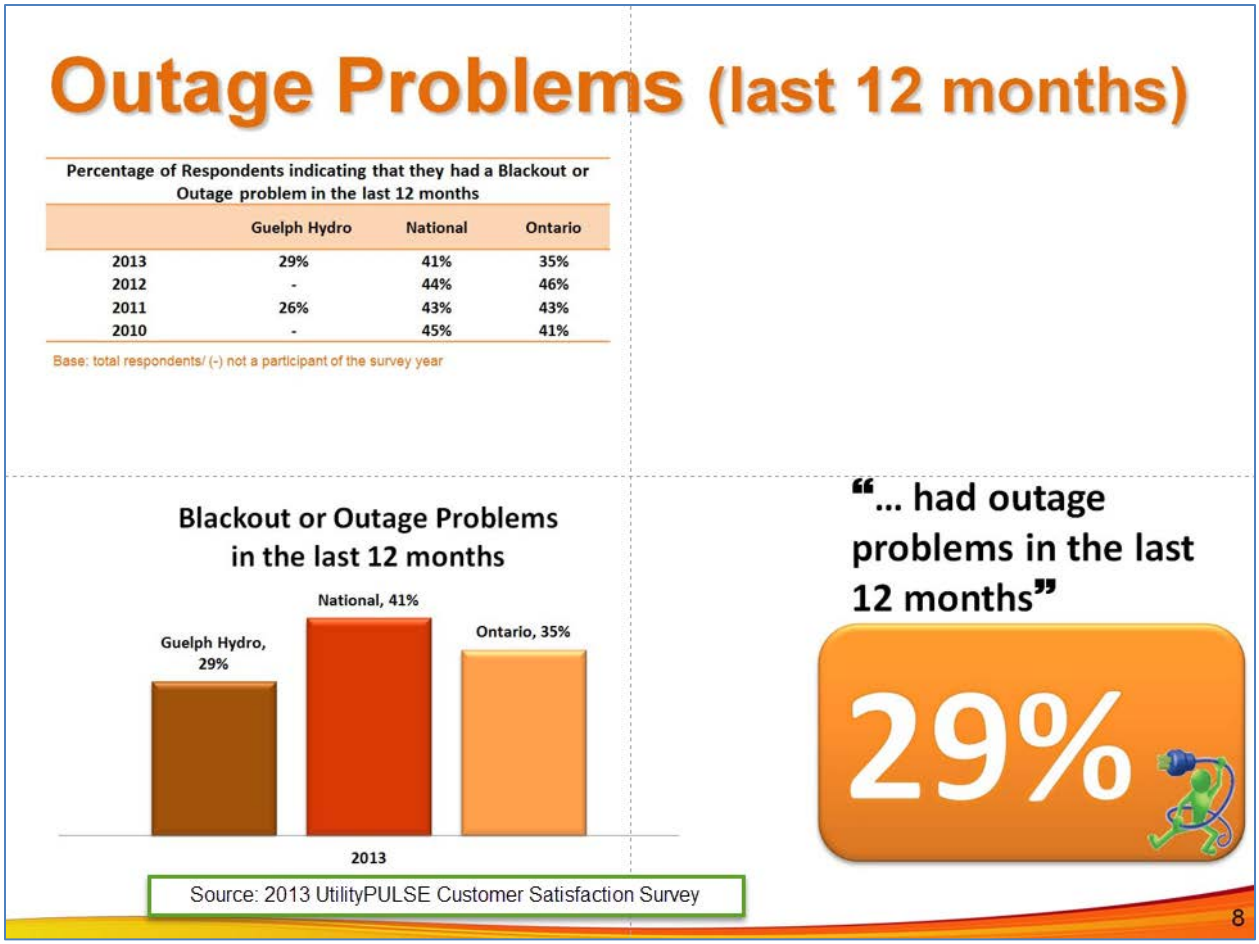


Figure 5.4-5 UtilityPULSE Customer Satisfaction Survey - Outage Problems

When asked specifically about power outages, 68 per cent of customers who responded to the Online Customer Survey conducted in late 2014 recognized that "weather" is the cause of the majority of outages. When asked if any power outages they experienced were for an unreasonable amount of time, 94 per cent responded "no." Survey respondents then rated **GHESI**'s outage performance as follows, a further indication of customer satisfaction with overall system reliability which is supported by the very positive tweets received regularly about the company's outage response during and after power interruptions as shown in Appendix 1-F Exhibit 1.

Online Customer Survey – Fall/Winter 2014/2015					
Guelph Hydro's Performance	Excellent	Good	Fair	Poor	Don't Know
Minimizing the number of power	37%	46%	6%	1%	10%

outages					
Time required to restore power when a power outage occurs	30%	52%	7%	1%	10%
Communicating the cause and estimated restoration time	11%	25%	15%	5%	44%

Table 5.4-3 Online Customer Survey Results

Considering the above and the fact that only 18 per cent of Online Customer Survey respondents indicated that it is very important for the company to invest in ways to reduce the number and duration of power outages, **GHESI** has taken a measured approach to distribution investments and will continue its vegetation and wildlife management programs intended to improve reliability.

Website analytics and tweets regarding **GHESI** during an outage highlight the fact that customers like being able to access detailed information about outages online or via social media. Building on this success and considering comments from customers who call the Call Centre, tweets received and the fact that 15 per cent of respondents to the Online Customer Survey as reported above would like better information about the cause of and estimated restoration times for outages, **GHESI** has plans to explore how best to enhance the company's outage reporting. The project to upgrade the Web Portal will support this effort to the degree that technology and data availability with will allow in the short term and expand over time as new applications are developed.

Cost Containment

As is the case with customers across Ontario, Price and Value received a lower rating of B+ on the UtilityPULSE Report Card which indicates that affordability is an ongoing concern of customers. This was corroborated by comments from customers captured in the Online Customer Survey. For this reason, **GHESI's** annual planning of capital projects is based on affordability and focuses on maximizing resources, improving efficiency and reducing costs.

Future Technologies

Customers responding to the UtilityPULSE Customer Satisfaction Survey were asked their opinion on whether **GHESI** should be involved in a variety of forward-looking projects/services. Responses to these questions can be seen in Figure 5.4-6 below. These results, coupled with the fact that 76 per cent of respondents to the Online Customer Survey indicated a preference for **GHESI** to be investing in research into

future technologies (ex. smart grids, electric vehicles or electricity storage), provide evidence that **GHESI** has the social licence to invest in new technologies and explore new service offerings.

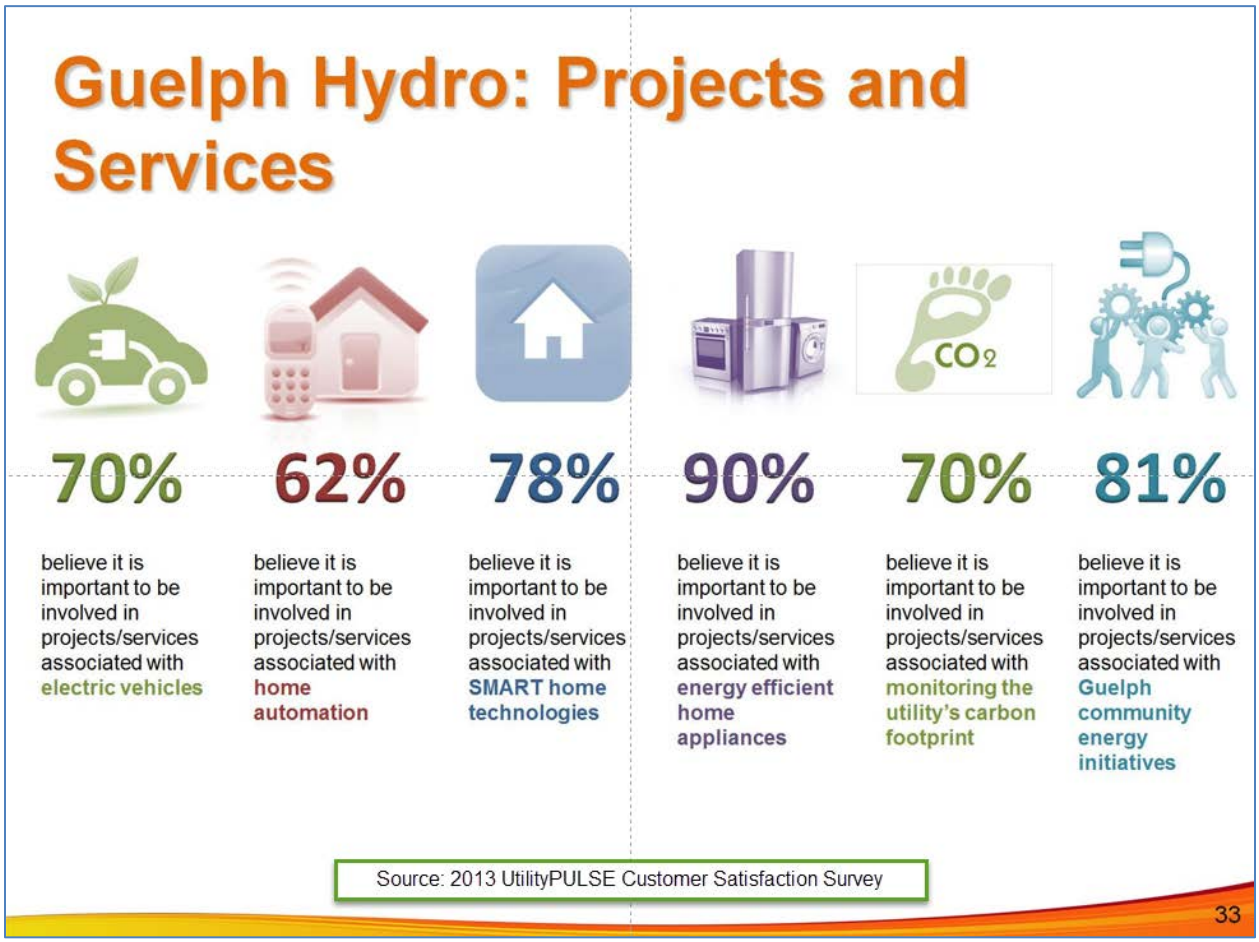


Figure 5.4-6 GHESI Projects and Services

5.4.1.7 Expected System Development over the Planning Horizon (OEB Filing Req. 5.4.1g)

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

GHESI expects the distribution system within its service territory to follow a rather normal trend based on historic activities from the last five years. Load and customer growth rates are expected, on average, to be in the range of 1.5% and 1.3%

respectively. **GHESI** does not have any plan for increases to transformer or distribution station capacity within the **Forecast period** to accommodate additions to load or customer growth, however, **GHESI** has outlined in the **DSP** a number of initiatives that will shape the development of the distribution system over the planning horizon which include:

- A shift in capital expenditures from growth to renewal.
- Additional distribution feeders in the south end of Guelph from Arlen **MTS** to supply new developments and add flexibility to the system between Hanlon **TS** and Arlen **MTS**. **GHESI** expects to expand the number of feeders from Arlen **MTS** from its current three to eight over the next five years.
- Additional feeder capacity to the North West area of the City of Guelph to accommodate additional existing customer growth.

In relation to Smart Grid development, **GHESI** expects minimal investment in this area over the forecast period aside from its continued investment into existing **SCADA** technology as it relates to its **SCADA** master system, communication infrastructure and line sensor technology which is contained in the system service portion of investments. **GHESI** continues to employ smart remotely operable switches in order to improve system reliability, system switching for planned and unplanned events and to assist in the real time monitoring of load levels within the system.

As evident in our **REG** investment plan in Appendix A, **GHESI** has sufficient capacity to connect renewable energy projects and, therefore, will be able to accommodate the majority of generation requests easily and with very little capital investment into the distribution system.

5.4.1.8 Projects relative to customer preferences, technology and innovation (OEB Filing Req. 5.4.1h)

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- ***in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);***
- ***to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and***
- ***to study or demonstrate innovative processes, services, business models, or technologies.***

GHESI has prepared the following **Table 5.4-4** to summarize planned 2016 projects in relation to Customer Preferences (1), to take advantage of Technology based opportunities (2) and to demonstrate innovative processes (3).

Projects	(1) Customer Preference (2) Technology Based (3) Innovative Process	2016 Test Year
		Budget
Reporting Basis		IFRS
System Access		
Apartment, Commercial, Industrial Customer Connections (CACI)	1	646,894
Metering Installations (CMEG)	1, 2	415,000
Distribution System Modifications / Expansions for Customers (CMOD)	1	784,249
System Relocations Property Development (CREL)		1,299,884
Expansions for New Residential Subdivisions (CRES)	1	1,443,261
Expansions for New Residential Townhouse Subdivisions (CTH)	1	238,954
New Residential Service Connections (CSER)	1	568,803
Sub-Total		**5,397,045**
Miscellaneous Projects (under Materiality threshold)		**0**
Total System Access		**5,397,045**
System Renewal		
Distribution System Replacement (CREP)	1	770,741
- Imperial Rd S / Samantha Crt	1	247,000
- Elmira Rd S	1	388,000
- Alma St N / Plymouth Crt	1	218,000
- Alma St N/Julia Dr/Drew St	1	216,000
- Westgate Dr/Lonsdale Dr/ Edinburgh Rd N [Oh]	1	285,000
- Arrow Rd	1	432,000
- Fife (Wellington to Gateway)	1	173,000
- Keats - Ph2 17 Pole Trans	1	986,000
- 295 Water Street Single Phase Ug W/ Secondary Ug Cable	1	448,000
Distribution System Transformer replacement upgrades (CTRU)		315,193
Sub-Total		4,478,934
Miscellaneous Projects (under Materiality threshold)		**0**
Total System Renewal		**4,478,934**
System Service		
Transformer Stations & Distribution Stations (CTS/CDS)	1	49,408
- Arlen MTS - Series Reactor	1	150,000
Distribution System Feeder Infrastrucutre (CFDR)	2	94,833
- Edinburgh Rd N / Sultan St	2	176,000
- New 5M53 - Cedar St (Edinburgh To Maple), Maple St, Water St	2	500,000
- Edinburgh Rd S (Municipal To Bristol - West Side)	2	407,000
SCADA Infrastructure (CSC)	2	224,911
SCADA / Remotely Operated Switches (CSW)	2	256,248
Sub-Total		1,858,400
Miscellaneous Projects (under Materiality threshold)		**0**
Total System Service		**1,858,400**
General Plant		
Building / Fixtures		154,135
- Building Addition		650,000
Office Equipment / Graphics	1	163,100
IT Capital	1, 2	590,000
Fleet / Rolling Stock		272,886
- Replace Single Bucket (T9)		300,000
Major Tools		65,564
Sub-Total		2,195,685
Miscellaneous Projects (under Materiality threshold)		**0**
Total General Plant		**2,195,685**
Total all Categories		**13,930,063**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets		
Total		**13,930,063**

Table 5.4-4: Planned Projects - Response to Customer Preferences, Technology and Innovation

Projects/Activities in Response to Customer Preferences

Reliability, outage response, cost containment, and future technologies were identified as topics of the top interest to customers during **GHESI's** customer engagement process. The following projects/activities provide illustrative examples projects proposed in this **DSP** that demonstrate how **GHESI's** capital expenditure plan fulfills customers' needs and preferences related to these topics.

- Arlen MTS – Series Reactor

As an example of a project in response to customer preference, the Arlen MTS Series Reactor project is a response to changing Hydro One system conditions resulting in increased fault levels at the Station bus. Alternatives investigated include the least expensive option to do nothing except to open the bus tie, resulting in reliability decreases, or various options to install reactors in the station. Balancing the customer preference for reliability, outage management and cost containment, the preferred solution is the installation of series reactors at the tie switch.

- Control Room Shared Services

GHESI currently operates its control room with a schedule that includes five days per week of staffed daytime coverage, and after hours coverage that is provided via on-call SCOs and telephone answering service. Results from the most recent customer meeting – 2014 Large Customer Breakfast – clearly indicated the customer expectation of **GHESI** running a 24/7 operation. To respond to this **GHESI** has entered into an agreement with another **LDC** to provide shared operational services. This expansion of service will be completed in two stages, with the end result being 24 hour per day x 7 day per week x 365 day per year staffed coverage.

With this initiative **GHESI** will go beyond just meeting the expectation of customers, by also realizing other cost savings and efficiencies, thereby minimizing customer bill impact. Provision of 24/7 control room service is also expected to improve system reliability, by reducing switching and restoration response time of outages that occur during hours which are currently outside of staffed control room hours. This aligns with customers' expectation on **GHESI** to further improve its system reliability.

- Distribution System Replacement

GHESI is ramping up its spending into distribution system replacement to keep pace with recommendations in the **ACA**. By maintaining and improving the overall health condition of distribution system assets, this program directly contributes to more reliable performance of **GHESI**'s electricity distribution network.

Projects/Activities to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads

- **SCADA** Infrastructure

Guelph Hydro, like many **LDCs**, have for many years implemented "Operations Technology" to provide better, more refined and timely distribution system field device operational information. This greater visibility into distribution system operation has helped drive improved customer service and operational effectiveness through cost containment, better and more timely decision making, as well as reduced restoration times. To support this initiative **GHESI** will continue to invest in **SCADA** infrastructure and services.

- **SCADA** Switches

The use of **SCADA** switches is a fundamental change in the technological options available to the Utility Industry. **SCADA** switches can automate certain functions and dramatically reduce outage times. Funds have been allocated for this planning cycle to install/upgrade remote operated switches and manual load interrupter switchers within **GHESI's** distribution system, where not part of other feeder work.

- **IT** Upgrades

Ongoing technological enhancements in the handling of data and communications systems are constantly changing the opportunities for enhancing customer experience of **GHESI** services via Internet and Mobile access. In 2016, **GEHSI** is undertaking an **IT** initiative to upgrade the Web Portal to provide the latest options to **GHESI** customers on demand.

Projects/Activities to study or demonstrate innovative processes, services, business models, or technologies

- Control Room Shared Services

GHESI has entered into an agreement with another **LDC** to provide shared operational services. This expansion of service will be completed in two stages, with the end result being 24 hour per day x 7 day per week x 365 day per year staffed coverage. Revenue from this innovative service arrangement will help offset the additional cost associated with expanded hours of coverage.

5.4.2 Capital Expenditure Planning Process Overview (OEB Filing Req. 5.4.2)

The information a distributor should provide includes, but need not be restricted to:

5.4.2.1 Capital Expenditure Planning Objectives (OEB Filing Req. 5.4.2a)

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

The following information provides an overview of **GHESI's** capital expenditure planning process which includes details on planning objectives, planning criteria and assumptions used in the development of the capital expenditure plan. The asset management process is the foundation to the **DSP** and the capital expenditure plan which helps align each to overall corporate objectives. By following a strategic approach to the capital expenditure planning process **GHESI** achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers and providing the highest level of shareholder and customer value.

In the development of the capital expenditure plan, a number of objectives and planning processes are observed and adhered to in order to align the plan with the goals and overall strategic direction of the company. **GHESI's** planning objectives that have informed the distribution system plan and capital expenditure plan include as follows:

1. Ensure proper allocation of investments to meet regulatory obligations of the system access such as metering, system relocations for municipal road work, and future system requirements for residential, commercial and industrial customers;
2. Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system as determined through the continued **ACA's**;
3. Determine the acceptable level of expenditures required to maintain sufficient system capacity to meet existing and future capacity demand levels;
4. Ensure proper allocation of investments in general plant assets to support investment initiatives; and
5. Review overall expenditures and determine impacts to financials, and adjust spending as required.

GHESI has determined that there are a number of important inputs required in order to support and ensure capital expenditure objectives and the level of investment is appropriate and is targeted to the correct area. As such, key planning criteria inputs are utilized to support investments in the four main categories as follows:

- Consultation with municipal officials to understand future projects requiring relocation of distribution system assets in support of System Access investments;
- Incorporating elements of the City of Guelph **DPP**[6] to assist in forecasting capital expenditures for residential developments in support of System Access investments;
- Consultation with existing customers, specifically industrial and large use customers, to gain perspective to current and future electrical needs to help plan the system accordingly in support of System Access investments;
- **ACAs** to support expenditures related to asset renewal to maintain the system as designed in support of System Renewal investments. This is further aided by **GHESI's** prioritization methodology that helps plan the implementation of projects based on a key set of criteria as outlined in section 5.4.2.3;
- System capacity assessments including load forecast models based on information related to **CDM**, **DG** and service territory development at each level of the distribution system including station, area and feeder to maintain adequate capacity margins to supply system security and to improve operational efficiency in support of System Service investments; and
- Individual assessments on key areas in general plant such as building, **IT** and Fleet required to support expenditures.

As part of the capital expenditure planning process, **GHESI** has determined a number of assumptions are also made in order to support in the development of a capital expenditure plan, these key assumptions include:

- The use of historical trends in categories related to system access to forecast capital expenditures
- The validity of information from stakeholders including developers and customers with respect to future requirements of the distribution system to service new projects.
- The use of historical growth, **CDM** and **DG** rates to assist in the forecasting future contributions to the demand of the distribution system

GHESI's asset management goal is to identify and implement the optimal timing and methodology of asset replacement and maintenance, in such a way as to minimize risks to **GHESI's** Vision, Mission and Core Values, while maximizing long term investment benefits. Each of the asset management objectives described in Section 5.3.1.1 are considered by utilizing them in the weighting of objectives to assist in the selection and prioritization of projects in the capital expenditure planning process.

[6] http://guelph.ca/plans-and-strategies/development-priorities-plan-dpp/

GHESI believes that the same objectives and criteria are required to connect and accommodate the connection of renewable generation facilities and has not outlined any specific objectives for this area. **GHESI's** distribution system has the capabilities as outlined in the **REG** plan (in Section 5.4.3 below and Appendix A) to accommodate future renewable generation facilities and has demonstrated the commitment in the connection of over 300 **REG** projects with an installed capacity of over 8MW along with the connection of 5 other non-renewable distributed generation projects.

5.4.2.2 Non-Distribution System Alternatives to Relieve System Capacity (OEB Filing Req. 5.4.2b)

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

GHESI utilizes its capacity load forecast as a key tool in planning and forecasting of the distribution system in order to assess the ability of our current and future system to meet the demands of our service territory and understands that non-distribution alternatives play a key role in the assistance of meeting these objectives. Factored into our capacity load forecast are our **CDM** targets and **DG** forecast. Efforts have also been made to understand the role each has contributed in the historical demand of the system as this serves to assist in the forecast. **CDM** has, and will, continue to play an important part in meeting the requirements of capacity demand. **DG** which consists of both renewable and non-renewable generation also has its part in contributions to alleviate demands on distribution system capacity. **DG** has accounted for approximately 2.6% of our system peak to date and is expected to increase to between 4-5% by 2030. Using the same analysis, **CDM** has accounted for approximately 6% of **GHESI's** system peak to date with an expected increase based on future targets to be in the range of 8-10%. **GHESI** is very aware that, although **CDM** and **DG** have an effect on system demands, it is important to note that actual program figures need to be adjusted in order to align to the peak system demand to understand the true direct impact and effect it has on the overall system capacity. Distribution systems are designed in order to meet the ultimate peak demand of the system for those short periods of time in the year and the reality is that **CDM** and **DG** contributions may or not be available at the specific time thus the balance between both distribution system and non-distribution alternatives of meeting the system demand is critical.

The **RPP** in **GHESI's** region which consists of Kitchener, Waterloo, Cambridge, Guelph and **Hydro One,** meet on a regular basis with the **IESO** to discuss (among other things) the role of each utility as it is related to community self-sufficiency and the impact non-distribution system type projects have on the ability for each utility to meet the capacity requirements within their respective service territory. These meetings serve as a forum to discuss best practices among the group of utilities in the region and allow the utilities to share and foster new ideas amongst each other and the **IESO**. Although there is no formal policy or procedure in place at the moment, **GHESI** by way of including the effects non-distribution activities have on system demand, considers these alternatives as a first path in forecasting system demand and implementing new distribution type projects.

5.4.2.3 **Project Prioritization Tools and Methods (OEB Filing Req. 5.4.2c)**

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

The following methods are used to identify, select, prioritise and pace projects for each investment category:

System Access

System access projects are non-discretionary in nature. Projects are identified through contact with customers wishing to connect new services or requests from municipal land owners to relocate assets to accommodate road construction. Prioritization of projects is based on the expected date when all service requirements will be fulfilled by the customer, as identified through regular contact between both parties. Projects are paced to ensure that low voltage connections are completed within five days of the fulfillment of all service conditions and high voltage services are connected within ten days of the fulfillment of all service conditions. In order to budget for System Access investments, **GHESI** regularly contacts large customers to discuss future electricity needs, plant expansion and proposed projects that impact the distribution system. Additionally, **GHESI** attends monthly Public-Utility Coordination Committee ("**PUCC"**) meetings which discuss upcoming development projects, as well as road and public-utility projects, in the City of Guelph. Discussions include scope and timing of large projects, which informs **GHESI's** budgeting process. Additionally, **GHESI** looks to the City of Guelph **DPP** and zoning maps which highlights planned developments in the City and allows insight into potential developments sites which have not yet been planned. **GHESI** regularly follows up on these potential developments with business owners, developers and the City of Guelph staff to ensure that adequate budgeting and planning is in place to accommodate System Access projects.

GHESI also regularly monitors customer bill impact information for residential customers. This informs system access projects as necessary in a general sense. In addition, **GHESI** considers capital contributions collected as in its evaluation of customer bill impacts. These capital contributions collected by **GHESI** are done so in accordance with the **DSC** and the provisions of its Conditions of Service and carry potential to alleviate impact on its ratepayers and **GHESI** takes this under serious consideration in its asset and capital expenditure planning. **GHESI** uses the economic evaluation methodology

from the **DSC** to determine the level of capital contribution for each project and those levels are factored into the annual capital budget.

System Renewal

GHESI identifies asset replacement requirements through its **ACA**. The **ACA** analyzes the assets across the distribution system and the **AM** process determines the optimal and levelized replacement frequency required to minimize unplanned asset end-of-life failures and maintain the reliability and condition of the system.

Projects are identified, selected, prioritized and paced through the following process and the steps are utilized in the calculation and prioritization:

Step 1 – Calculation of Health Index and Probability of Failure
Step 1a – Calculate Composite HI
Step 1b – Calculate Composite POF
Step 2 – Calculation of Project Area Consequence of Failure
Step 2a – Calculate Category Scores
Step 2b – Calculate Consequence
Step 3 – Calculate Risk
Step 4 – Project Categorization
Step 5 – Project Prioritization

1) Health index and probability of failure data is converted to composite health index and probability of failure values for each project area within the service territory. Asset health indexes ("**HI**") are converted using a weighted average approach with the following weighting applied to per-asset health indices shown in Table 5.4-5:

Asset	Weighting	Electrical Result of Failure*	Mechanical Result of Failure**	Difficulty of Replacement After Failure
Manhole	0.8	1	1	0
Power Transformer	0.7	0	4	0
Substation Breaker	0.7	0	2	1
Pad-mounted Switchgear	0.5	2	2	2
Distribution Vault	0.4	3	2	2
Switching Cubicle (Kabar)	0.3	3	2	3
Switch	0.2	1	4	4

Pole	0.2	3	3	4
Distribution Transformer	0.1	4	3	4

Note: Scores 0-4 where 0 is worse, 4 is better. Weighting is 1-(average of scores/4)
* - Electrical Result of Failure is the potential system electrical reliability impact
** - Mechanical Result of Failure is the damage to equipment and danger to public, where public danger is weighted higher than mechanical damage

Table 5.4-5: Asset Weightings

$$Step\ 1a -\ Composite\ HI = \frac{\sum(HI * Criticality)}{\sum(100\% * Criticality)}$$

The composite HI calculated by the formula above is an index that indicates the overall health of the project area. This index is used along with other indices, such as the composite probability of failure, to provide insight into each prospective project. Criticality, as used in the above equation is defined as consequence of failure of a given asset. The higher the criticality value assigned to a unit, the higher it's consequence of failure. The combination of criticality and probability of failure determines risk and flagged for action priority for that unit.

Probabilities of Failure ("**POF**") values are converted to composite failure rates using a series reliability system approach.

$$Step\ 1b -\ Composite\ POF = 1 - \prod(1 - POF)$$

This calculation above is the probability that at least one asset in the project area will fail within the year. The series reliability approach is used because any of the major asset types listed above will (except in rare cases) result in an interruption of power which will affect system reliability performance.

2) Consequence of failure values are produced for each project area based on the following criteria shown in Table 5.4-6 through Table 5.4-10, which are based on **GHESI's** asset management objectives, and ultimately tie to the corporate core values, as described in section 5.3.1.1 (note: portions of tables in grey and identified as "N/A" indicate no further items in each particular sub-category, not all sub-categories carry the same number of variables):

Public Safety (Category Weight = 5)

Type of Area (Sub-weight = 1)	Score	Distribution Topology (Sub-Weight = 1)	Score
Industrial	1	Underground	0*
Commercial	2	Overhead	1
Residential	3	N/A	N/A

Table 5.4-6: Public Safety Criteria for Consequence of Failure Analysis

* In this scoring matrix, overhead has a higher safety risk than underground by measureable amount. **GHESI** has given these two categories a binary score and, as such, **GHESI** has scored these two items as either a 0 or a 1. A zero is not meant to indicate there are no safety issues, rather it is indicative of a better score relative to overhead.

Worker Safety (Category Weight = 5)					
Number of Primary Circuits (Sub-weight = 3)	Score	Equipment Type (Sub-weight = 4)	Score	Road Type (Sub-Weight = 2)	Score
0	0	None of the below	0	Collector	0
1	0	Live-Front*	4	Arterial	4
2	2	Transite	4	N/A	N/A
≥3	4	Pole Trans	4	N/A	N/A
N/A	N/A	Combination of Above	4	N/A	N/A

Table 5.4-7: Worker Safety Criteria for Consequence of Failure Analysis

*Live-front equipment refers to equipment where, when opened, live components are exposed to the environment and may be more susceptible to faults as well as posing a higher worker safety concern.

Environmental Impact (Category Weight = 4)	
Oil-filled equipment present? (Sub-weight = 1)	Score
No	0
Yes	4

Table 5.4-8: Environmental Impact Criteria for Consequence of Failure Analysis

Reliability and Power Quality Impacts (Category Weight = 3)					
Number of Outage Events Since Reconstruction (Sub-weight = 1)*	Score	Customer Outage Minutes Since Reconstruction (Sub-weight = 1)*	Score	Number of Circuits (Outage Severity) (Sub-weight =4)	Score
0	0	<2703	0	0	0
1	2	≥2703	4	1	0
2	3	N/A	N/A	2	2
3	3	N/A	N/A	≥3	4
4	3	N/A	N/A	N/A	N/A
≥5	4	N/A	N/A	N/A	N/A
* Threshold for score of 4 is based on 80th percentile of outage events and cumulative duration per project area.					

Table 5.4-9: Reliability and Power Quality Impacts Criteria for Consequence of Failure Analysis

Operational Efficiency Improvement Potential (Category Weight = 2)			
Live-Front equipment* present? (Sub-Weight = 1)	Score	Load Transfer Constraints (Sub-weight = 1)	Score
No	0	NA/R (No Requirements or SCADAMate Installed)	0

Yes	4	LN (Manual Switch, No Constraints)	2
N/A	N/A	LH (Partially Constrained Switching)	3
N/A	N/A	OL (Switching Constrained)	4

Table 5.4-10: Operational Efficiency Improvement Potential for Consequence of Failure Analysis

*Live-front equipment refers to equipment where, when opened, live components are exposed to the environment and may be more susceptible to faults as well as posing a higher worker safety concern.

Consequence of failure is calculated using the following formula:

$$Step\ 2a -\ Category\ Score = \frac{\sum \frac{(Score * Sub - Weight)}{4}}{\sum Subweights}$$

$$Step\ 2b -\ Consequence = \frac{\sum(Category\ Score * Category\ Weight)}{\sum Category\ Weights}$$

Each project area is assessed and variables are identified in all of the sub-categories above. Each variable has a corresponding score. Each Sub-Category score is multiplied by the sub-weight and divided by four. The resulting sub-category scores are summed by category, resulting in Category Scores. Each Category Score is then multiplied by the corresponding Category Weight and summed together. This value is divided by the sum of all of the category weights to arrive at the consequence value. The consequence value is therefore a weighted average of categories, which are in turn weighted averages of sub-categories. The weighting of these parameters links back to the Asset Management Objectives, which are derived from the Corporate Core Values as described in section 5.3.1.1.

3) Risk values for each project area are calculated by multiplying composite probability of failure values by consequence values. Costs for the scope of work in each project area are identified at a high-level through historic costs of per-unit asset replacements and the known scope of assets to be replaced in the project area.

4) Projects are sorted based on the risk scores arrived at in the previous processes, into the following categories for further selection and prioritization:

- **High Risk Projects**
    - Projects in this category have overall high risk values and are closely monitored as they tend to be very impactful to cost and either long in

duration or very complex. They are prioritized on a per-project basis through further analysis to determine optimal timing for them. These projects share highest priority with High Risk Projects with Low **HI**.

- **High Risk Projects with Low HI**
    - Projects in this category have highest priority. These projects carry high consequence with failure and a high probability of a failure occurring and are the most important projects to target to ensure system reliability and safety is maintained. These projects share highest priority with High Risk Projects.
- **Projects with Low Cost per Risk Point Abated**
    - These projects may be large or small and represent projects having the best balance of economic and reliability impacts. Projects in this category have the second highest priority. These projects are selected and prioritized based on the timing of the High Risk category projects. For example, a high risk project that can be deferred will be replaced with a Low Cost per Risk Point Abated project that has a more critical timeline for completion. This provides the best economic benefit without increasing the overall risk of the project portfolio above acceptable levels.
- **Projects with Nearly High HI and High POF**
    - This category represents project areas with one or few assets driving up the probability of failure in an otherwise healthy part of the system. These projects undergo further revision of scope and cost to target the problematic assets only. Due to the low cost of these projects they have third priority and are used to help meet levelized replacement frequency requirements and smooth peaks and valleys in the capital schedule.
- **Projects falling into Specific Programs**

    - Special attention is given to projects that fall within specific asset replacement programs identified in the **AMP**. These programs are designed to systematically correct asset or construction types that have been found to be problematic in terms of safety, reliability or operations. Specific targets have been put in place to remove some asset types (for example, Pole Trans) and projects are paced to meet these targets. The specific asset replacement programs are listed below and detailed descriptions are found in the **AMP**:
    - Concrete Distribution Poles
    - Pole-Trans Rehabilitation
    - Douglas Fir Distribution Poles
    - Live Front Equipment Replacement
    - Limited Access Areas

- Direct Buried Cable
- Poor Reliability Areas (Worst Performing Feeders)
- OH Pole Line Rebuilds
- Pad-Mounted Switchgear
- UG Cable Replacement - Unjacketed Cable
- Town House Rehabilitation - Live Front Equipment and Direct Buried Cable
- Rotten Pole Replacement Program
- UG Structures - Degrading Transformer Rooms and Manholes
- Overhead 3-Phase Transformers
- Overhead Double Cluster Switches
- Protective Device Replacement
- Transformer Upgrades

5) Projects from the above sorting process are selected by priority, respecting the degree to which they can or cannot be deferred, available resources and the need to fulfill levelized replacement quantities. This selection process is described in detailed in section 5.3.1.2. The selected projects are paced by year based on risk and probability of failure. Selected projects for each year are then initially paced based on the type of work predominantly involved (overhead or underground) and the estimated resource requirements. Considering these factors allows a crew to be assigned to the work and an annual capital schedule to be determined for all projects and all crews (where projects with higher priority are completed first), and also allows work to be planned around the constraints of system peak seasons and seasons affecting construction costs, such as during frost conditions in the winter. Adjustments are made to the pacing to fill in minor work where possible and to defer projects by priority when system access projects reduce the resources that are available for system renewal projects. When system access projects are competing with system renewal projects, system renewal projects will be deferred where possible (through analysis of the impact of delayed timing on the probability of failure and risk level of the project), or alternatively, other options will be sought out to increase resources and complete both projects, should the project in question be non-deferrable. Projects will be deferred in reverse order of priority, to ensure that highest priority projects are still completed in the face of competing system access projects.

A detailed description and flowchart of the system renewal project identification, selection and prioritization process, including inputs and outputs and the connection to the capital plan can be found in section 5.3.1.2.

System Service

System Service projects follow a three-step process: Identification, Selection and Prioritization.

System Service projects are identified through a variety of methods. These methods include, load monitoring through the **SCADA** system, line switching assessments, voltage modelling and load forecasting are used to predict high-level future capacity constraints. These constraints may be at an area-wide or feeder level. Service and transformer level constraints are identified through smart meter and **SCADA** based load monitoring.

The selection process for System Service projects involves identifying various alternative solutions to solve constraint issues. This process is done to determine projects with the highest economic benefit, as well as to minimize the unnecessary replacement of assets, or optimizing which assets are replaced or upgraded. The identification of alternative solutions does not follow a regimented process, but is instead the result of an investigative effort to determine the root cause of the constraint. Once the root cause is determined, and depending on the scope of the root cause, Engineering and System Operators discuss a range of alternatives to solve the problem. Examples of this process include analyzing the line switching assessment to determine if permanently moving a line segment to a different feeder will solve the problem, determining whether installing remote operated switches will alleviate the issue (if the problem is transitory in nature, or only occurs under certain conditions), determining whether asset capacities need to be increased (such as in the case of an overloaded transformer), among many other possible solutions. Solutions will be selected based on their feasibility, given time, cost and resource constraints, and the degree to which they can be integrated into other efforts such as system access or system renewal projects, to maximize the benefit of the investment while minimizing the cost.

Identified and selected projects are prioritized based upon urgency and the anticipated time to complete the project. Constraints that already exist have highest priority, followed by near future constraints. System Service projects are then paced to ensure that the predicted constraints are relieved before they impact the distribution system. Pacing may also be accelerated where a solution has synergy with a related system access or system renewal project and the related project is already scheduled in advance of the system service project.

General Plant

General Plant projects are identified and assessed using a combination of inspections, policies and expert knowledge. Projects included in this category include investments related to **GHESI's** vehicle fleet, the purchase of major tools, investments related to the Administration Building and Service Centre as well as investment in computer equipment and software.

Fleet

GHESI manages a fleet of 57 vehicles that are essential to the efficient and effective day-to-day operation of the utility. This fleet includes large bucket trucks, radial boom derricks ("**RBDs**"), underground step vans, various trailers, small pickup trucks, small vans, and pool vehicles. It is crucial that all fleet vehicles are maintained properly and replaced in a timely manner - keeping overall costs in mind. This requires balancing new vehicle purchase costs against excessive repair bills and operational downtime that occurs when vehicles are kept for too long.

GHESI's fleet vehicle replacement determination considers the following factors:

a) Age of the vehicle;
b) Odometer reading;
c) Engine/power take-off (**PTO**) hours;
d) Maintenance costs;
e) Annual vehicle test results, including stress/electrical testing;
f) Practicality of existing vehicle including new technology available;
g) Changing emissions, weight, and road safety regulations obsoleting some existing units; and
h) Crew/other department needs.

When the age of the vehicle approaches its end of life, a case by case evaluation is done to determine whether or not replacement is an option ahead of or later than the vehicles normal life expectancy - with factors noted above as additional considerations. Normal life expectancy for small vehicles is 6 to 10 years and 10 to 12 years is the expected life for large trucks. The life expectancy for vehicles is based on long-term experience with residual values at time of sale and are driven by odometer readings, engine hours, maintenance records and depreciation policy.

Odometer readings and engine hours are also factors considered when contemplating vehicle replacement. Generally, when a vehicle reaches 100,000 km, a vehicle's residual value drops significantly and maintenance costs will begin to increase.

Major Tools

This category is used for the purchase of tools and equipment where the cost generally exceeds $1,000. **GHESI** continually looks at upgrading outdated tools and equipment and looks for newer more effective technology that will result in more efficient work practices, combined with the most ergonomic way of accomplishing a task. Decisions requiring the selection and prioritization of these investments are made using expert knowledge and observing changes to industry best practices, as well as balancing the costs of the purchases with the anticipated reduction in work effort.

Building / Fixtures

Investments in this category are identified through inspections carried out on the building assets, expert opinion and through observing, noting and repairing issues throughout the building. Investment levels for maintenance items are based on typical and historical expenditures and include items such as interior and exterior lighting, asphalt, doors and fixtures, HVAC maintenance, yard maintenance, parking lot repair, security system maintenance and building mechanical systems. Investments are also planned based on utilization of the existing building and fixtures. For example, expansion of the building may be required if personnel and equipment needs are forecasted to increase beyond what can be reasonably accommodated by the existing assets. **GHESI** completed a building inspection in 2014 which, in-part, informed the planned expenditures over the planning horizon.

IT Capital

Projects are grouped into Hardware and Software. Projects are selected and prioritized in order to maintain effective and efficient business processes, ensure support for disaster and pandemic business continuity and to maintain integrated and reliable enterprise solutions. Planning of **IT** capital expenditures is based on established life cycle of both hardware and software. Annual IT capital projects leverage replacement and new technology requirements Selection of projects is based on identified need in the organization, best practices in network and security systems and expert knowledge. Because individual business units in the organization are often in the best position to identify their **IT** related needs as they relate to their specific business objectives, need-based projects are determined through coordination between the **IT** department and business unit leaders, such as department directors, and through the feedback received from all employees regarding the performance of their implemented hardware and software solutions

5.4.2.4 Mechanisms Used to engage Customers (OEB Filing Req. 5.4.2d)

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs,

priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DSP that have been particularly affected by consideration of this information; and

GHESI employs a multi-faceted communications platform to communicate and engage with all classes of customers. A summary of the mechanisms used to engage customers in order to identify needs, priorities and preferences for use in developing the Distribution System Plan are detailed below in Table 5.4-11:

Engagement Mechanisms	Customer Class	Stages Process	Aspects of DSP Affected
Telephone calls and emails to Call Centre – inquiries, complaints, topics of interest	All	Planning Phase	Reliability Project Identification Outage management Cost Control Vegetation management Development of Customer Preferences Justification of capital expenditures Ranking and prioritization of projects
Telephone calls to Engineering Department	All	Planning Phase	Plant Relocations requirements Development of Customer Preferences Power Quality Projects Identification New construction? Justification of capital expenditures Ranking and prioritization of projects Capacity planning
Website / Mobile site analytics – Outage map activity	Residential Small Commercial	Planning Phase	Outage management Development of Customer

(Appendix 11)			Preferences Processing of new service requests)
Social Media - Twitter	Residential Small Commercial	Planning Phase	Outage management Development of Customer Preferences
Surveys - Bi-Annual UtilityPULSE Customer Satisfaction Telephone Survey - 2013 - Online Customer Survey - 2014	Residential Commercial	Planning Phase	Reliability Project Identification Cost Control Development of Customer Preferences Outage management
Face-to-Face Discussions - With Engineering, Metering, Operations and CDM staff	Commercial Industrial	Planning Phase	Justification of capital expenditures Ranking and prioritization of projects Plant Relocations Reliability Projects Identification Power Quality Projects Identification Capacity planning System access
Information Sessions	Large Customers	Planning Phase	Power quality Reliability Projects Identification System access Capacity planning System services
Meetings and Information Sessions	Municipality	Planning Phase	Capital planning for growth Power quality Reliability Projects Identification Ranking and prioritization of projects
Community Outreach Activities	Residential	Planning Phase	Outage management Safety

			Cost Control
Focus Groups	Residential Small Commercial	Review of DSP	Justification of capital expenditures Power quality Reliability Projects Identification Ranking and prioritization of projects
Telephone Survey	Residential Small Commercial	Review of DSP	Cost Control Development of Customer Preferences Outage management Reliability Projects Identification
Advertising - Bill messages and inserts - Media releases - Conservation	All	Planning Phase	Capacity planning Development of Customer Preferences Safety
CDM Activities - Commercial and Industrial visits - Outreach activities and events - eMerge home visits - advertising	All	Planning Phase	Capacity planning System access

Table 5.4-11 Customer Engagement Mechanism Summary

5.4.2.5 Method and Criteria Used to Prioritise REG Investments (OEB Filing Req. 5.4.2e)

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

GHESI does not utilize a different method or criteria in the prioritization of **REG** investments. Outlined in our **REG** investment plan below and in Appendix A, **GHESI** does not expect any distribution system investments over the five year horizon related

to **REG** projects. A more detailed analysis of our **REG** plan can be found in Section 5.4.3 and in Appendix A**.**

5.4.3 System Capability Assessment for Renewable Energy Generation (OEB Filing Req. 5.4.3)

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;
b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);
c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;
d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and
e) Constraints for an embedded distributor that may result from the connections.

5.4.3.1 Anticipated REG Connections over the Forecast Period (OEB Filing Req. 5.4.3a & 5.4.3b)

At this time, **GHESI** has received 171 applications for pre-FIT assessments related to renewable generators over 10kW for connection to its distribution system. Of these 171 applications, 32 projects have been completed and connected to the distribution system and 4 projects are in the process of being connected. The status of the remaining projects are unknown at this time with no further information provided to **GHESI** from the generator proponent.

Table 5.4-12 and Table 5.4-13 outline **GHESI's** forecast **REG** connections and corresponding capacity. These forecasts have been developed based on GHESI's experience with REG connections as set out in Appendix A.

Based on information current to the end of November 2014, Table 5.4-12 and Table 5.4-13 have been developed to summarize the anticipated renewable distributed generation connections and corresponding capacity. **GHESI's REG** plan outlined in Appendix A also details non-renewable generation projects that are in the process of connecting, as well as projects that are in the preliminary stage of preparation and submission of documents for **IESO** approval. **IESO's** plan to procure 150MW and 50MW of renewable generation capacity under **FIT** and **micro-FIT** program per year, for the period of 2014-2018 was also considered. **GHESI** has also noted an increasing interest in net metering and **CHP** projects. In the following tables, for **micro-FIT** projects, an average generator size of 8kW is assumed based on existing connections. For **FIT** projects, the capacity requests from Pre-FIT assessments have been included. For other **DG** project connections, ten net metering projects are estimated per year, as there are a significant number of consultations for capacity requests being received. **GHESI** is aware that plans are in place for at least ten homes to be built in 2015 as a pilot project for net metering. In addition, we are also aware of two **CHP** projects that have **IESO** approval with combined generation capacity of 11MW. Preliminary work is being done for three **CHP** projects to be submitted for **IESO** approval, with a combined generation capacity of 13MW. **GHESI** currently has capacity to accommodate future connection to all of the above projects listed in the Table 5.4-12 and Table 5.4-13.

Number of Renewables by Year	2015	2016	2017	2018	2019	2020	Total
Micro Generation (<= 10 kW)	60	60	60	60	60	60	**360**
Small Generation (>10 KW and <= 250 kW)	6	3	5	5	5	5	**29**
Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	0	0	**0**
Mid-Size Generation (> 500 kW)	0	0	0	0	0	0	**0**
Total (Number of Connections)	**66**	**63**	**65**	**65**	**65**	**65**	**389**

Table 5.4-12: Number of Anticipated **REG** Connections

Number of Renewables by Year	2015	2016	2017	2018	2019	2020	Total
Micro Generation (<= 10 kW)	0.48	0.48	0.48	0.48	0.48	0.48	2.88
Small Generation (>10 KW and <= 250 kW)	0.875	0.4	0.89	1.25	0.94	0.765	5.12

Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	0	0	0
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	0	0	0	0
Total (MW)	1.355	0.88	1.37	1.73	1.42	1.245	8.00

Table 5.4-13: Capacity (in MW) of Anticipated **REG** Connections

5.4.3.2 **System Capacity for REG Connections (OEB Filing Req. 5.4.3c)**

The following Table 5.4-14 shows the transformer station and substation generation connection limitations and includes both existing and in-progress generator connections.

This table demonstrates the capacity available in terms of distributed generation, thermal and short circuit capacity transformer station capacities. The conclusion to be drawn from the table below is that sufficient capacity is available based on GHESI's forecast methodology.

Station	Bus	Existing FIT Connections (MW)	Existing micro-FIT Connections (MW)	Existing other Distributed Generation Connections (MW)	Distributed Generation Connections – In Progress (MW)	Thermal Limit (MW)	Short Circuit Limit (MVA)	Remaining Thermal Limit (MW)	Remaining Short Circuit Capacity (MVA)
Hydro One Owned Campbell TS	*BY*	*2.484*	*0.2284*	*0.003*	*8.0*	*13.4**	*59.5**	*2.69*	*2.98*
	JQ	*1.994*	*0.2805*	-	-	*15.3**	*59.5**	*13.03*	*56.09*
	ZE	*1.246*	*0.2077*	*2.8*	-	*15.0**	*30.8**	*10.75*	*14.62*
	Total	**5.724**	**0.7166**	**2.803**	**8.0**	**43.7**	**149.8***	**26.46**	**73.69**
Hydro One Owned Cedar TS	*BY*	-	*0.4501*	*0.002*	-	*17.3**	*112.5**	*16.86*	*111.84*
	ZE	-	*0.4942*	-	-	*6.4**	*137.8**	*5.91*	*137.06*
	JQ	-	*0.2506*	*1.4*	-	*35.3**	*152.4**	*33.65*	*145.15*
	Total	**0**	**1.1949**	**1.402**	**0**	**59.0***	**402.7***	**56.42**	**394.05**
Hydro One Owned Hanlon TS	**BY**	**0.45**	**0.166**	**0**	**0**	**29.6***	**132***	**28.98**	**131.08**
Guelph Hydro Owned Arlen MTS	**BY**	**0**	**0.010**	**0**	**10.2[1]**	**33.0**	26.1	**33.0**	**26.1[1]**
Hydro One Owned Rockwood DS	**Station**	**0**	**0.00**	**0**	**0**	**3.8***	-	**3.8**	-
Guelph Hydro Owned Rockwood MS1	**Station**	**0**	**0.032**	**0**	**0**	**2.5**	-	**2.468**	-
Guelph Hydro Owned Rockwood MS2	**Station**	**0**	**0.00**	**0**	**0**	**2.5**	-	**2.5**	-
Total		**6.174**	**2.119**	**4.205**	**18.2**	**174.1**	**710.6**	-	

*Information obtained from Hydro One website.
1) If the Hanlon Creek, 10.2MW CHP project were to go ahead, then all of Arlen MTS SCC capacity would be taken, otherwise, there is still 26.1 MVA of short circuit capacity.

Table 5.4-14: Transformer Generation Connections and Limitations

5.4.3.3 **Existing and Anticipated System Constraints (OEB Filing Req. 5.4.3d and 5.4.3e)**

Distributions systems were not intended to facilitate the connections and management of a large number of distributed generators. In general the amount of generation capacity that can be connected to a distribution system is constrained by a variety of engineering factors, including but not limited to the following:

- Supply feeder ampacity;
- Power quality;
- Equipment ratings;
- Limits on reserve power flow; and
- Short circuit capacity at the transformer stations and substations.

Existing and Anticipated Constraints on GHESI Distribution System

Overall, **GHESI's** distribution system is well designed, built and maintained to accept an influx of renewable generation. There are no existing constraints on **GHESI's** distribution system.

Existing and Anticipated Constraints on Upstream System (Hydro One Transmission)

Capacity at the **Hydro One**-owned Campbell **TS** station is constrained due to insufficient short circuit capacity. There is currently an 8MW combined heat and power ("**CHP"**) project in the process of connecting to a feeder from Campbell **TS** BY Bus, which will result in reaching the short circuit capacity threshold for that DESN (Dual Element Spot Network). In addition, there is a growing interest among large industrial customers to install CHP equipment in Guelph, which, as a result of the City of Guelph's Community Energy Initiative, aims to have 100MW of co-generation capacity installed in the city by 2031. **GHESI** is also aware that additional industrial customers are interested in installing non-renewable **CHP** plants and are in the process of obtaining **IESO** approvals, which will consume the balance of the remaining Campbell **TS** JQ and ZE Bus generation connection capacity, if these projects were to proceed.

The **IESO** has approved a non-renewable **CHP** project in the south end of Guelph for Hanlon Creek Business Park with an expected nameplate capacity of 10.2MW, which will require dedicated feeders from Arlen **MTS**. If this project were to proceed, then all of Arlen **MTS** short circuit capacity would be consumed. Otherwise, there is still 26.1 MVA of short circuit capacity at this station.

As a result of the above non-renewable generation projects, station upgrades may be required at Campbell **TS** and Arlen **MTS** in order to accommodate additional future generation projects of both the non-renewable and renewable variety.

On Embedded Distribution System

GHESI does not have any embedded distributors.

5.4.4 Capital Expenditure Summary (OEB Filing Req. 5.4.4)

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor's actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that 'Plan' expenditures over the historical period refer to a distributor's previous plan for capital expenditures after adjustments (if any) occasioned by the Board's decision on the relevant prior application.

5.4.4.1 Capital Expenditure Summary

A snapshot of **GHESI's** capital expenditures over the ten year period including the historical period (2011-2014) and forecast period (2015-2020) are divided into the 4 categories shown below in Table 5.4-15. **GHESI** does not have a previously filed or

approved **DSP** and as a result variance explanations of actual capital expenditures compared to planned expenditures are not detailed.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011 (Previous Bridge Year)			2012 (Previous Test Year)			2013			2014			2015 Bridge Year			2016 Test Year	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Budget	Var					
			%			%			%			%			%					
System Access	N/A	6,574,742	-	N/A	5,018,365	-	N/A	4,229,054	-	N/A	4,886,595	-	N/A	5,846,937	-	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	N/A	1,648,262	-	N/A	2,536,522	-	N/A	2,830,493	-	N/A	3,726,430	-	N/A	3,960,130	-	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	N/A	16,898,611	-	N/A	3,139,974	-	N/A	3,185,982	-	N/A	2,250,748	-	N/A	3,842,621	-	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	N/A	1,052,721	-	N/A	984,738	-	N/A	1,220,577	-	N/A	2,359,438	-	N/A	2,212,704	-	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	-	26,174,335	-	-	11,679,598	-	-	11,466,106	-	-	13,223,211	-	-	15,862,392	-	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305
System O&M	-	5,379,426	-	-	5,619,519	-	-	6,425,264	-	-	6,784,094	-	-	7,186,934	-	7,856,913	7,966,910	8,078,446	8,191,545	8,306,226

Table 5.4-15 Appendix 2-AB

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a 'one-off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period

While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where

- ***for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or***
- ***A trend for variances in a given investment category is markedly positive or negative over the historical period.***

5.4.4.2 2011 Actual Vs 2012 Actual Capital Expenditure Variances

Category	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
System Access	6,574,742	5,018,365	-1,556,377
System Renewal	1,648,262	2,536,522	888,260
System Service	16,898,611	3,139,974	-13,758,637
General Plant	1,052,721	984,738	-67,984
Total Expenditure	**26,174,335**	**11,679,598**	**-14,494,737**

Table 5.4-16 Capital Expenditure Variances 2011 Actual Vs 2012 Actual

System Access

The major factors behind the variance within the System Access category can be represented by a significant decrease in projects from 2011 to 2012 related to distribution system expansions for new customers of $2,072,692. Another main driver behind the variance fell within the metering program and was a result of 2011 smart metering capital expenditures that resulted in a decrease in spending on meter installation of $721,200 between 2011 and 2012. Distribution system relocations due to municipal and provincial land owners represented a significant variance with an increase of projects totaling $1,082,000. The total capital expenditure for the expansions and servicing of new residential developments decreased for 2011 to 2012 due to a slight drop in residential development activity and accounts for a variance of ($265,000). The majority of capital expenditures contained with the system access category, with the exception of metering, are recovered through capital contributions.

Projects	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	600,858	546,155	-54,703
Meter Installations (CMEG)	1,342,946	567,148	-775,798
Distribution System Modifications / Expansions for Customers (CMOD)	2,148,440	75,748	-2,072,692
System Relocations Property Development (CREL)	646,265	1,728,042	1,081,777
Expansions for New Residential Subdivisions (CRES)	796,412	1,409,933	613,521
New Residential Service Connections (CSER)	410,079	311,801	-98,278
Expansions for New Residential Subdivisions (CTH)	629,739	379,538	-250,201
Total Expenditure	**6,574,742**	**5,018,365**	**-1,556,377**

Table 5.4-17 System Access Capital Expenditure Variances 2011 Actual Vs 2012 Actual

System Renewal

This variance is primarily due to an underground rehabilitation project in the Parkwood Gardens subdivision in 2012 by which obsolete pole transformers in poor condition were removed from the system and replaced with new pad mounted transformers and new underground distribution and service cable.

Projects	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
Distribution System Replacement (CREP)	1,503,828	2,445,471	941,643
Distribution System Transformer replacement upgrades (CTRU)	144,433	91,051	-53,382
Total Expenditure	**1,648,262**	**2,536,522**	**888,260**

Table 5.4-18 System Renewal Capital Expenditure Variances 2011 Actual Vs 2012 Actual

System Service

The most significant driver behind the variance within the system service category is due to the capital expenditure related to the Arlen **MTS** project in 2011. The project was started in 2009 with an in-service date of early 2012. A significant amount of costs were contained within the 2011 fiscal year and final project closing expenditures carried over to the 2012 fiscal year. A variance in overall system service spending was also due to a decrease in distribution system feeder infrastructure as a result of the construction of Arlen **MTS**.

Projects	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
Distribution System Feeder Infrastructure (CFDR)	1,642,489	1,212,410	-430,079
SCADA Infrastructure (CSC)	234,219	248,002	13,783

SCADA / Remotely Operated Switches (CSW)	119,131	78,394	-40,737
Transformer Stations & Distribution Stations (CTS/CDS)	14,902,770	1,601,168	-13,301,602
Total Expenditure	**16,898,611**	**3,139,974**	**-13,758,637**

Table 5.4-19 System Service Capital Expenditure Variances 2011 Actual Vs 2012 Actual

General Plant

The variance is below the materiality threshold; however Table 5.4-20 provides additional information on each of the specific projects/activities for the benefit of the Board.

Projects	2011	2012	Variance from 2011 Actual
	Actual	Actual	Variance
Building / Fixtures	32,636	0	-32,636
Office Equipment / Graphics	25,249	43,060	17,812
Fleet / Rolling Stock	402,093	468,956	66,863
IT Capital	525,006	396,246	-128,760
Major Tools	67,738	76,475	8,737
Total Expenditure	**1,052,721**	**984,738**	**-67,984**

Table 5.4-20 General Plant Capital Expenditure Variances 2011 Actual Vs 2012 Actual

5.4.4.3 2012 Actual Vs 2013 Actual Capital Expenditure Variances

Category	2012	2013	Variance from 2012 Actual
	Actual	Actual	Variance
System Access	5,018,365	4,229,054	-789,311
System Renewal	2,536,522	2,830,493	293,971
System Service	3,139,974	3,185,982	46,008
General Plant	984,738	1,220,577	235,840
Total Expenditure	11,679,598	11,466,106	-213,493

Table 5.4-21 Capital Expenditure Variances 2012 Actual Vs 2013 Actual

System Access

The main driver behind the variances within the System Access category are due to the a decrease in projects related to distribution system relocations to accommodate work due to municipal and provincial land owners infrastructure projects accounting for a variance of ($967,578) and an increase in projects for the expansions and servicing of new residential developments amounting to a variance of $ $323,837. The majority of

capital expenditures contained with the system access category with the exception of metering are capital costs recovered through capital contributions.

Projects	2012	2013	Variance from 2012 Actual
	Actual	Actual	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	546,155	544,823	-1,332
Meter Installations (CMEG)	567,148	422,899	-144,249
Distribution System Modifications / Expansions for Customers (CMOD)	75,748	75,760	12
System Relocations Property Development (CREL)	1,728,042	760,464	-967,578
Expansions for New Residential Subdivisions (CRES)	1,409,933	1,642,688	232,755
New Residential Service Connections (CSER)	311,801	348,477	36,676
Expansions for New Residential Subdivisions (CTH)	379,538	433,944	54,406
Total Expenditure	**5,018,365**	**4,229,054**	**-789,311**

Table 5.4-22 System Access Capital Expenditure Variances 2012 Actual Vs 2013 Actual

System Renewal

The variance within the System Renewal category is a result of a slight increase in capital expenditures related to the removal of pole-transformers from the distribution system as compared to spending the previous year on the same type of program.

Projects	2012	2013	Variance from 2012 Actual
	Actual	Actual	Variance
Distribution System Replacement (CREP)	2,445,471	2,678,970	233,499
Distribution System Transformer replacement upgrades (CTRU)	91,051	151,523	60,472
Total Expenditure	**2,536,522**	**2,830,493**	**293,971**

Table 5.4-23 System Renewal Capital Expenditure Variances 2012 Actual Vs 2013 Actual

System Service

The overall variance within the system service category of $46,008 is below the materiality threshold, however, specific variances within the category of $1,020,611 and ($1,057,658) for distribution system feeder infrastructure and transformer and distribution stations respectively. The significant portion of the variance within the distribution system feeder infrastructure program is a result of the Campbell Road underground feeder project which was implemented in 2013 in order to provide additional capacity to the North West region of Guelph. The variance within the Transformer and Distribution station program was a result of the Arlen MTS which went into service in 2012.

Projects	2012	2013	Variance from

			2012 Actual
	Actual	Actual	Variance
Distribution System Feeder Infrastructure (CFDR)	1,212,410	2,233,021	1,020,611
SCADA Infrastructure (CSC)	248,002	167,530	-80,472
SCADA / Remotely Operated Switches (CSW)	78,394	241,920	163,526
Transformer Stations & Distribution Stations (CTS/CDS)	1,601,168	543,510	-1,057,658
Total Expenditure	**3,139,974**	**3,185,982**	**46,008**

Table 5.4-24 System Service Capital Expenditure Variances 2012 Actual Vs 2013 Actual

General Plant

Overall capital expenditures are consistent in the general plant category for the 2012 and 2013 year with the primary variance contained in **IT** capital as a result of the purchase of a corporate voice system ($200,000).

Projects	2012	2013	Variance from 2012 Actual
	Actual	Actual	Variance
Building / Fixtures	0	97,634	97,634
Office Equipment / Graphics	43,060	50,495	7,434
Fleet / Rolling Stock	468,956	461,583	-7,372
IT Capital	396,246	531,387	135,141
Major Tools	76,475	79,477	3,002
Total Expenditure	**984,738**	**1,220,577**	**235,840**

Table 5.4-25 General Plant Capital Expenditure Variances 2012 Actual Vs 2013 Actual

5.4.4.4 2013 Actual Vs 2014 Actual Capital Expenditure Variances

Category	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
System Access	4,229,054	4,886,595	657,542
System Renewal	2,830,493	3,726,430	895,937
System Service	3,185,982	2,250,748	-935,233
General Plant	1,220,577	2,359,438	1,138,861
Total Expenditure	**11,466,106**	**13,223,211**	**1,757,105**

Table 5.4-26 Capital Expenditure Variances 2013 Actual Vs 2014 Actual

System Access

The variance in the 2013 and 2014 system access work is associated with the following:

- Apartment, Commercial and Industrial Customer Connections increase by $490,694 due to the increase in customer related servicing projects;
- System Modifications to accommodate customers increased by $887,150 due specifically to a single project for a large industrial customer; and
- Asset relocations due to City of Guelph projects increased by $416,093 due to the City of Guelph's road reconstruction work on Wellington and Gordon Streets.

The overall spending in the residential development servicing sector decreased by $1,103,395 as result of a decrease in the number of projects in 2014. Work in this area was very slow in the beginning of the year due to the late winter in 2013 which caused projects to be delayed.

Projects	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	544,823	1,035,517	490,694
Meter Installations (CMEG)	422,899	389,899	-33,000
Distribution System Modifications / Expansions for Customers (CMOD)	75,760	962,910	887,150
System Relocations Property Development (CREL)	760,464	1,176,556	416,093
Expansions for New Residential Subdivisions (CRES)	1,642,688	861,802	-780,885
New Residential Service Connections (CSER)	348,477	216,128	-132,349
Expansions for New Residential Subdivisions (CTH)	433,944	243,783	-190,161
Total Expenditure	**4,229,054**	**4,886,595**	**657,542**

Table 5.4-27 System Access Capital Expenditure Variances 2013 Actual Vs 2014 Actual

System Renewal

The main contributors to the variance in capital expenditures for system renewal projects between 2013 and 2014 can be linked to differences in spending on the major sustainment programs as a result of outcomes form the **ACA**. A comparison on specific programs with respect to asset replacements concluded the following spending amounts variances:

- Concrete Distribution Poles – Additional $213,399 spent on this activity in 2014
- OH Pole Line Rebuilds - Additional $546,638 spent on this activity in 2014
- Pole-Trans Rehabilitation - A decrease of $(421,977) spent on this activity in 2014
- Replacement of Damaged Equipment - An increase of $157,513 was spent on this activity in 2014
- UG Structures - An increase of $277,736 spent on this activity in 2014

- Distribution Transformer Replacement - Additional $181,990 spent on this activity in 2014

Projects	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
Distribution System Replacement (CREP)	2,678,970	3,404,122	725,152
Distribution System Transformer replacement upgrades (CTRU)	151,523	322,307	170,784
Total Expenditure	**2,830,493**	**3,726,430**	**895,937**

Table 5.4-28 System Renewal Capital Expenditure Variances 2013 Actual Vs 2014 Actual

System Service

The contributing factor to the variance in spending on distribution system feeder infrastructure was due to the types of projects implemented between the years. 2013 saw capital expenditures in the distribution feeder's area spent on the addition of an underground feeder system to accommodate additional load growth in the North West portion of the City of Guelph. In 2014 the major feeder project was the reconstruction of an overhead pole line to increase capacity as part of the 2013 project. Within the Stations program a variance of ($488,085) was a result of the finalization of projects related to the construction of Arlen **MTS** in 2013.

Projects	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
Distribution System Feeder Infrastructure (CFDR)	2,233,021	1,731,614	-501,406
SCADA Infrastructure (CSC)	167,530	174,290	6,759
SCADA / Remotely Operated Switches (CSW)	241,920	289,419	47,498
Transformer Stations & Distribution Stations (CTS/CDS)	543,510	55,426	-488,085
Total Expenditure	**3,185,982**	**2,250,748**	**-935,233**

Table 5.4-29 System Service Capital Expenditure Variances 2013 Actual Vs 2014 Actual

General Plant

Major variances in spending within the General Plant sector between 2013 and 2014 can be accounted for based on the following factors:

- Replacement of the administration building roof due to age and condition in 2014of $473,479
- Purchase of Lansa IT software in 2014 of $404,843

Projects	2013	2014	Variance from 2013 Actual
	Actual	Actual	Variance
Building / Fixtures	97,634	483,568	385,934
Office Equipment / Graphics	50,495	104,225	53,730
Fleet / Rolling Stock	461,583	620,831	159,248
IT Capital	531,387	1,065,060	533,673
Major Tools	79,477	85,754	6,277
Total Expenditure	**1,220,577**	**2,359,438**	**1,138,861**

Table 5.4-30 General Plant Capital Expenditure Variances 2013 Actual Vs 2014 Actual

5.4.4.5 **2014 Actual Vs 2015 Forecast Capital Expenditure Variances**

Category	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
System Access	4,886,595	5,846,937	960,341
System Renewal	3,726,430	3,960,130	233,700
System Service	2,250,748	3,842,621	1,591,873
General Plant	2,359,438	2,212,704	-146,734
Total Expenditure	**13,223,211**	**15,862,392**	**2,639,180**

Table 5.4-31 Capital Expenditure Variances 2014 Actual Vs 2015 Budget

System Access

The variance in the 2014 actuals to the 2015 budget for system access work is associated with the following:

- Apartment, Commercial and Industrial Customer Connections is scheduled to decrease by $407,464 due an expected decrease in the number of projects related to customer servicing. 2014 capital expenditures in this area were considered to be anomaly based on the historic spending range of $546,155 in 2012 and $600,858 in 2011.
- System modifications to accommodate customers is planned to decrease slightly in comparison to 2014 due to a forecasted decline in projects.
- Combined capital expenditures in the residential development servicing sector is slated to increase as a result of projects whose starts were delayed in 2014 and that spilled over into 2015.
- Metering includes a significant increase related to a major Smart Metering Advanced Metering Infrastructure (AMI) back-office system hardware upgrade budgeted at $525,000 in 2015. The existing hardware has reached its service life, and its replacement will be sized to accommodate anticipated future growth over the next five years.

Projects	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	1,035,517	628,053	-407,464
Meter Installations (CMEG)	389,899	1,010,000	620,101
Distribution System Modifications / Expansions for Customers (CMOD)	962,910	761,407	-201,503
System Relocations Property Development (CREL)	1,176,556	1,262,023	85,467
Expansions for New Residential Subdivisions (CRES)	861,802	1,401,224	539,422
New Residential Service Connections (CSER)	216,128	231,994	15,866
Expansions for New Residential Subdivisions (CTH)	243,783	552,236	308,452
Total Expenditure	**4,886,595**	**5,846,937**	**960,341**

Table 5.4-32 System Access Capital Expenditure Variances 2014 Actual Vs 2015 Budget

System Renewal

Minor variations in the types of projects within the renewal of assets category are the contributing factor for the difference in capital expenditures between 2014 and 2015. Planned expenditures for 2015 are consistent with 2014 capital replacement projects.

Projects	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
Distribution System Replacement (CREP)	3,404,122	3,654,117	249,995
Distribution System Transformer replacement upgrades (CTRU)	322,307	306,013	-16,294
Total Expenditure	**3,726,430**	**3,960,130**	**233,700**

Table 5.4-33 System Renewal Capital Expenditure Variances 2014 Actual Vs 2015 Budget

System Service

The variance within the system service category can be attributed to a decrease in capital expenditures related to distribution system feeder infrastructure of ($588,087) and an increase in spending to projects related to transformer and distribution stations. The large variance in feeder infrastructure was a result of a single project in 2014 related to the rebuilding and capacity increase to a multi circuit pole line on Edinburgh Road South from Cedar **TS** to Bristol Street. The variances within the stations category are a result of the rebuild of Rockwood MS#1 coming into service in 2015 and the addition of a series reactor at Arlen **MTS** to mitigate high fault levels which will start in 2015 and come into service in 2016.

Projects	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
Distribution System Feeder Infrastructure (CFDR)	1,731,614	1,143,527	-588,087

SCADA Infrastructure (CSC)	174,290	218,360	44,070
SCADA / Remotely Operated Switches (CSW)	289,419	248,784	-40,635
Transformer Stations & Distribution Stations (CTS/CDS)	55,426	2,231,950	2,176,524
Total Expenditure	**2,250,748**	**3,842,621**	**1,591,873**

Table 5.4-34 System Service Capital Expenditure Variances 2014 Actual Vs 2015 Budget

General Plant

The variance in costs between 2014 and 2015 within the General Plant category can be attributed to the following:

- Building roof ($473,289)
- Administration Building addition ($500,000)

The addition to **GHESI's** administration building project involves a building addition leading to increased office, control room, and meeting room space. The existing **GHESI** building has been designed to readily accommodate a second floor addition only requiring one new outside wall, minor existing HVAC modifications, and a new roof in addition to normal internal facility construction. The variances in expenditures for the IT capital are a result of the 2014 Lansa IT software purchase. Capital expenditures in all remaining programs in the general plant are uniform with previous years and fall below the material threshold.

Projects	2014	2015	Variance from 2014 Actual
	Actual	Budget	Variance
Building / Fixtures	483,568	754,500	270,932
Office Equipment / Graphics	104,225	58,350	-45,875
Fleet / Rolling Stock	620,831	556,200	-64,631
IT Capital	1,065,060	780,000	-285,060
Major Tools	85,754	63,654	-22,100
Total Expenditure	**2,359,438**	**2,212,704**	**-146,734**

Table 5.4-35 General Plant Capital Expenditure Variances 2014 Actual Vs 2015 Budget

5.4.4.6 **2015 Forecast Vs 2016 Forecast Capital Expenditure Variances**

Category	2015	2016	Variance from 2015
	Budget	Budget	Variance
System Access	5,846,937	5,397,045	-449,892
System Renewal	3,960,130	4,478,934	518,804
System Service	3,842,621	1,858,400	-1,984,221
General Plant	2,212,704	2,195,685	-17,019

Total Expenditure	**15,862,392**	**13,930,063**	**-1,932,328**

Table 5.4-36 Capital Expenditure Variances 2015 Budget Vs 2016 Budget

System Access

The primary variance within this category is a result of a decrease in capital expenditures in the metering program due to a $525,000 upgrade project completed in 2015 on the Smart Meter back-office hardware.

Projects	2015	2016	Variance from 2015
	Budget	Budget	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	628,053	646,894	18,842
Meter Installations (CMEG)	1,010,000	415,000	-595,000
Distribution System Modifications / Expansions for Customers (CMOD)	761,407	784,249	22,842
System Relocations Property Development (CREL)	1,262,023	1,299,884	37,861
Expansions for New Residential Subdivisions (CRES)	1,401,224	1,443,261	42,037
New Residential Service Connections (CSER)	231,994	238,954	6,960
Expansions for New Residential Subdivisions (CTH)	552,236	568,803	16,567
Total Expenditure	**5,846,937**	**5,397,045**	**-449,892**

Table 5.4-37 System Access Capital Expenditure Variances 2015 Budget Vs 2016 Budget

System Renewal

The variance in spending can be attributed to an increase in capital expenditures in order to address the need to increase the replacement of asset targets related to the replacement of overhead infrastructure as a result of the conclusions set out in the 2014 **ACA**. A complete justification for 2016 system renewal spending is provided later in this DSP.

Projects	2015	2016	Variance from 2015
	Budget	Budget	Variance
Distribution System Replacement (CREP)	3,654,117	4,163,741	509,624
Distribution System Transformer replacement upgrades (CTRU)	306,013	315,193	9,180
Total Expenditure	**3,960,130**	**4,478,934**	**518,804**

Table 5.4-38 System Renewal Capital Expenditure Variances 2015 Budget Vs 2016 Budget

System Service

The primary variance is a result of a the capital expenditures related to the construction and rebuilding of Rockwood MS#1 in 2015 which accounts for $1,250,000 as well as the

Arlen MTS reactor project scheduled to be in service in 2016 which resulted in a variance of $650,000.

Projects	2015	2016	Variance from 2015
	Budget	Budget	Variance
Distribution System Feeder Infrastructure (CFDR)	1,143,527	1,177,833	34,306
SCADA Infrastructure (CSC)	218,360	224,911	6,551
SCADA / Remotely Operated Switches (CSW)	248,784	256,248	7,464
Transformer Stations & Distribution Stations (CTS/CDS)	2,231,950	199,409	-2,032,542
Total Expenditure	**3,842,621**	**1,858,400**	**-1,984,221**

Table 5.4-39 System Service Capital Expenditure Variances 2015 Budget Vs 2016 Budget

General Plant

Planned expenditures for 2015 and 2016 are very consistent and the overall General Plant variance falls below the material threshold. However, Table 5-4-40 is provided for additional information.

Projects	2015	2016	Variance from 2015
	Budget	Budget	Variance
Building / Fixtures	754,500	804,135	49,635
Office Equipment / Graphics	58,350	163,100	104,750
Fleet / Rolling Stock	556,200	572,886	16,686
IT Capital	780,000	590,000	-190,000
Major Tools	63,654	65,564	1,910
Total Expenditure	**2,212,704**	**2,195,685**	**-17,019**

Table 5.4-40 General Plant Capital Expenditure Variances 2015 Budget Vs 2016 Budget

5.4.4.7 2016 Forecast Vs 2017 Forecast Capital Expenditure Variances

Category	2016	2017	Variance from 2016
	Budget	Budget	Variance
System Access	5,397,045	5,496,506	99,461
System Renewal	4,478,934	4,613,302	134,368
System Service	1,858,400	1,914,152	55,752
General Plant	2,195,685	1,431,505	-764,179
Total Expenditure	**13,930,063**	**13,455,465**	**-474,598**

Table 5.4-41 Capital Expenditure Variances 2016 Budget Vs 2017 Plan

System Access

Planned expenditures for 2016 and 2017 are very consistent and the variance falls below the material threshold. However, Table 5-4-40 is provided for additional information.

Projects	2016	2017	Variance from 2016 Budget
	Budget	Plan	Variance
Apartment, Commercial, Industrial Customer Connections (CACI)	646,894	666,301	19,407
Meter Installations (CMEG)	415,000	365,000	-50,000
Distribution System Modifications / Expansions for Customers (CMOD)	784,249	807,777	23,527
System Relocations Property Development (CREL)	1,299,884	1,338,881	38,997
Expansions for New Residential Subdivisions (CRES)	1,443,261	1,486,559	43,298
New Residential Service Connections (CSER)	238,954	246,123	7,169
Expansions for New Residential Subdivisions (CTH)	568,803	585,867	17,064
Total Expenditure	**5,397,045**	**5,496,506**	**99,461**

Table 5.4-42 System Access Capital Expenditure Variances 2016 Budget Vs 2017 Plan

System Renewal

Planned expenditures for 2016 and 2017 are very consistent and the variance falls below the material threshold. However, Table 5-4-40 is provided for additional information.

Projects	2016	2017	Variance from 2016 Budget
	Budget	Plan	Variance
Distribution System Replacement (CREP)	4,163,741	4,288,653	124,912
Distribution System Transformer replacement upgrades (CTRU)	315,193	324,649	9,456
Total Expenditure	**4,478,934**	**4,613,302**	**134,368**

Table 5.4-43 System Renewal Capital Expenditure Variances 2016 Budget Vs 2017 Plan

System Service

Planned expenditures for 2016 and 2017 are very consistent and the variance falls below the material threshold. However, Table 5-4-40 is provided for additional information.

Projects	2016	2017	Variance from 2016 Budget
	Budget	Plan	Variance
Distribution System Feeder Infrastructure (CFDR)	1,177,833	1,213,168	35,335
SCADA Infrastructure (CSC)	224,911	231,658	6,747

SCADA / Remotely Operated Switches (CSW)	256,248	263,935	7,687
Transformer Stations & Distribution Stations (CTS/CDS)	199,409	205,391	5,982
Total Expenditure	**1,858,400**	**1,914,152**	**55,752**

Table 5.4-44 System Service Capital Expenditure Variances 2016 Budget Vs 2017 Plan

General Plant

The overall spending variance of ($764,179) within the General Plant category is mainly attributed to the decrease in capital expenditures related to the project for the addition to the administration building. This project is planned to be completed in 2016 and, as a result, **GHESI** does not expect any further expenditures related to this project beyond 2016.

Projects	2016	2017	Variance from 2016 Budget
	Budget	Plan	Variance
Building / Fixtures	804,135	163,909	-640,226
Office Equipment / Graphics	163,100	64,993	-98,107
Fleet / Rolling Stock	572,886	590,073	17,187
IT Capital	590,000	545,000	-45,000
Major Tools	65,564	67,531	1,967
Total Expenditure	**2,195,685**	**1,431,505**	**-764,179**

Table 5.4-45 General Plant Capital Expenditure Variances 2016 Budget Vs 2017 Plan

5.4.4.8 2017-2020 Forecast Capital Expenditure Variances trending analysis

Overall trending from 2017 – 2020 between categories is very consistent with an average increase rate to account for minor year to year increase planned for inflation of approximately 2.3%.

Category	2017	2018	2019	2020
	Plan	Plan	Plan	Plan
System Access	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	4,613,302	4,751,701	4,894,252	5,041,080
System Service	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	1,431,505	1,474,450	1,518,684	1,564,244
Total Expenditure	**13,455,465**	**13,868,179**	**14,272,674**	**14,679,305**

Table 5.4-46 Capital Expenditure Variances 2017-2020 Plan Trending Analysis

System Access

Year over year average variance and trending for 2017-2020 is very consistent with an average increase of approximately 2.2%. The effect is an increase of $125,000 and is below the materiality threshold.

Projects	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Apartment, Commercial, Industrial Customer Connections (CACI)	666,301	686,290	706,879	728,085
Meter Installations (CMEG)	365,000	385,000	385,000	375,000
Distribution System Modifications / Expansions for Customers (CMOD)	807,777	832,010	856,970	882,679
System Relocations Property Development (CREL)	1,338,881	1,379,047	1,420,418	1,463,031
Expansions for New Residential Subdivisions (CRES)	1,486,559	1,531,156	1,577,090	1,624,403
New Residential Service Connections (CSER)	246,123	253,506	261,112	268,945
Expansions for New Residential Subdivisions (CTH)	585,867	603,443	621,546	640,192
Total Expenditure	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**

Table 5.4-47 System Access Capital Expenditure Variances 2017-2020 Plan Trending Analysis

System Renewal

Year over year average variance and trending for 2017-2020 is very consistent with a slight increase of approximately 2.32%. The effect is an increase of $107,000 and is below the materiality threshold.

Projects	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Distribution System Replacement (CREP)	4,288,653	4,417,312	4,549,832	4,686,327
Distribution System Transformer replacement upgrades (CTRU)	324,649	334,389	344,420	354,753
Total Expenditure	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**

Table 5.4-48 System Renewal Capital Expenditure Variances 2017-2020 Plan Trending Analysis

System Service

Year over year average variance and trending for 2017-2020 is very consistent with a slight increase of approximately 2.32%. The effect is an increase of $44,300 and is below the materiality threshold.

Projects	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Distribution System Feeder Infrastructure (CFDR)	1,213,168	1,249,563	1,287,050	1,325,661
SCADA Infrastructure (CSC)	231,658	238,608	245,766	253,139
SCADA / Remotely Operated Switches (CSW)	263,935	271,853	280,009	288,409

Transformer Stations & Distribution Stations (CTS/CDS)	205,391	211,552	217,899	224,436
Total Expenditure	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**

Table 5.4-49 System Service Capital Expenditure Variances 2017-2020 Plan Trending Analysis

General Plant

Year over year average variance and trending for 2017-2020 is very consistent with a slight increase of approximately 1.52%. The effect is an increase of $21,750 and is below the material threshold.

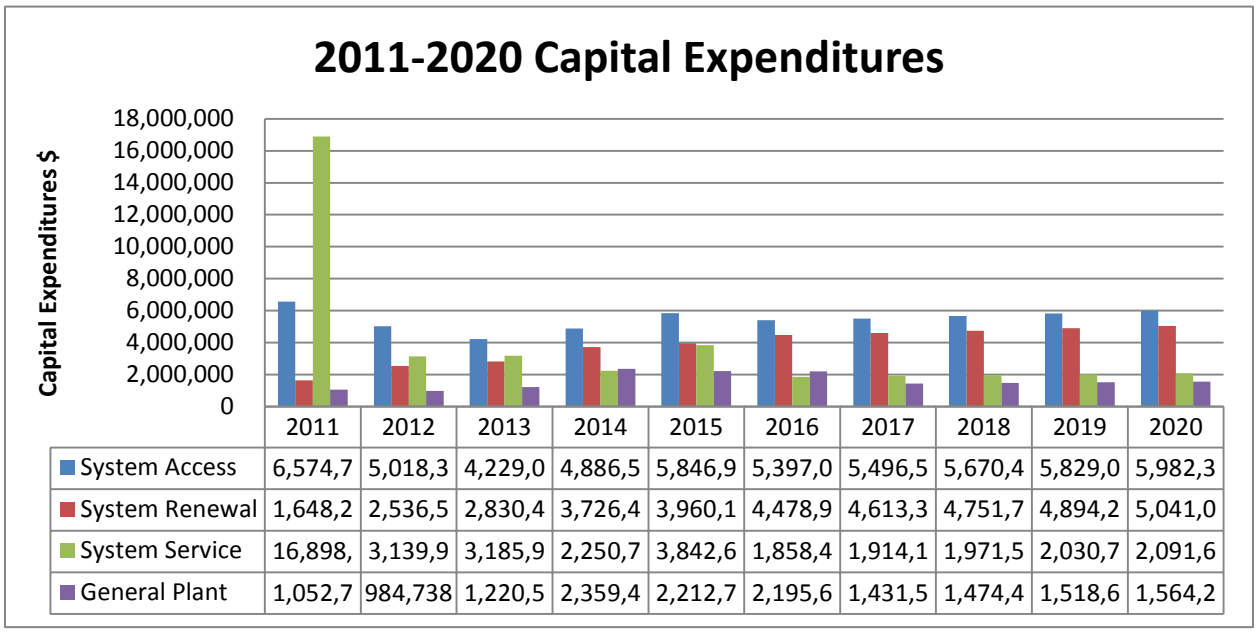
Projects	2017	2018	2019	2020
	Plan	Plan	Plan	Plan
Building / Fixtures	163,909	168,826	173,891	179,108
Office Equipment / Graphics	64,993	66,943	68,951	71,020
Fleet / Rolling Stock	590,073	607,775	626,008	644,788
IT Capital	545,000	561,350	578,191	595,536
Major Tools	67,531	69,556	71,643	73,792
Total Expenditure	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**

Table 5.4-50 General Plant Capital Expenditure Variances 2017-2020 Plan Trending Analysis

5.4.4.9 Summary of Variations in the Total Investment - Forecast Period to Historical Period

An overview of the variations in the total investment within each category for the historical and forecast period is shown below in Figure 5.4-7 with specific focus on any trend for variances in a given investment category that is marked positive or negative over the historical period. Variations in spending between categories for historical vs forecast can be explained based on the following reasons:

- 2011 increase in System Access spending due to the smart metering program;
- 2011 increase in System Service expenditures due to the construction of Arlen **MTS**;
- An increase in 2015 System Service expenditures as a result of the rebuilding and capacity increase at Rockwood MS#1;
- Overall increase in System Renewal since 2011 when the first **ACA** was conducted. A levelized approach to the replacement of assets was taken and is evident through gradual increases over the study period (2011-2020);
- Decrease in 2013 spending within System Access due, in part, to projects related to relocation of distribution system assets for road construction; and
- Decrease in System Service capital expenditures for the forecast period as a result of no planned station projects which were completed in the 2011-2015 timeframe.



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
System Access	6,574,7	5,018,3	4,229,0	4,886,5	5,846,9	5,397,0	5,496,5	5,670,4	5,829,0	5,982,3
System Renewal	1,648,2	2,536,5	2,830,4	3,726,4	3,960,1	4,478,9	4,613,3	4,751,7	4,894,2	5,041,0
System Service	16,898,	3,139,9	3,185,9	2,250,7	3,842,6	1,858,4	1,914,1	1,971,5	2,030,7	2,091,6
General Plant	1,052,7	984,738	1,220,5	2,359,4	2,212,7	2,195,6	1,431,5	1,474,4	1,518,6	1,564,2

Figure 5.4-7: Share of Total Investment by each Investment Category

5.4.5 Justifying Capital Expenditures (OEB Filing Req. 5.4.5)

5.4.5.1 Overall Plan (OEB Filing Req. 5.4.5.1)

The Board's assessment of DSPs includes the costs of material projects/activities included in the DSP, as well as the costs represented by the respective shares of the overall DSP budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DSP by category, a distributor should include information on:

The make-up of **GHESI's** overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures based on the **AM** process. The following information addresses the allocation of funds in order to ensure overall objectives are met.

Comparative Expenditures by Category Over the Historical Period

Comparative expenditures by category over the historical period;

Comparative expenditures over the **Historical Period** are presented below in Table 5.4-51. For comparative purposes, capital expenditures for the **Forecast Period** are also shown in Table 5.4-52. Analysis of the variances of historic expenditures is summarized in section 5.4.4.

CATEGORY	Historical Period					
	2011	2012	2013	2014	2015 Bridge Year	Total
	Actual	Actual	Actual	Actual	Budget	
System Access	6,574,742	5,018,365	4,229,054	4,886,595	5,846,937	26,555,693
System Renewal	1,648,262	2,536,522	2,830,493	3,726,430	3,960,130	14,701,836
System Service	16,898,611	3,139,974	3,185,982	2,250,748	3,842,621	29,317,935
General Plant	1,052,721	984,738	1,220,577	2,359,438	2,212,704	7,830,177
TOTAL EXPENDITURE	26,174,335	11,679,598	11,466,106	13,223,211	15,862,392	78,405,642

Table 5.4-51: Comparative Expenditures by Category over the Historical Period

CATEGORY	Forecast Period					
	2016 Test Year	2017	2018	2019	2020	Total
	Plan	Plan	Plan	Plan	Plan	
System Access	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336	28,375,354
System Renewal	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080	23,779,268
System Service	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645	9,866,496
General Plant	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244	8,184,568
TOTAL EXPENDITURE	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305	70,205,687

Table 5.4-52: Comparative Expenditures by Category over the Forecast Period

Forecast Impact of System Investment on System O&M Costs

The forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts

While it is difficult to quantify specific system investments that directly impact system **O&M** costs, in general there are a number of activities within the capital program that tend to have a positive influence on the reduction of future system **O&M** related expenditures. In particular, **GHESI** is addressing several underground projects such as pole-transformer removal and the replacement of direct buried underground conductors which have reduced system **O&M** costs arising due to cable and transformer failures. Renewal of these underground assets is anticipated to further reduce future **O&M** costs related to these assets although not in a readily quantifiable way.

A list of examples is provided below to help demonstrate commitment and consideration taken on the reduction of **O&M** related costs during the asset management and capital expenditure planning process.

- Installation of remote operated switches ("**SCADAmates**") to help reduce operational costs for switching during planned and unplanned events;
- Installation of Faulted Circuit Indicators ("**FCI**") to reduce time for trouble shooting system faults on the overhead distribution system;
- Software and **GIS** based asset analytics to improve inspection and maintenance records and assist field operations. The tools employed will reduce the time at each inspection location, assist in meeting regulations for **O. Reg. 22/04** compliance as well as simplify the overall analysis of the data;
- Change in standards and use of new technology for the installation of solid di-electric switchgear that will assist and potentially eliminate the

need for costs related to dry-icing typical air insulated pad mounted switchgear;

- Installation of composite poles which carry a lower overall life cycle cost and will reduce inspection costs; and
- Replacement of obsolete equipment, such as pole transformers, which in the past contributed to significant **O&M** costs related to maintaining the equipment and replacing in service equipment with spare parts taken from units replaced.
- Installation of animal guards on overhead pole lines in order to help reduce the frequency of animal contacts thus reducing the costs associated with the replacement of protective devices.

Drivers of Investments

the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);

As overviewed in Section 5.1.1 and Table 5.1-1 Summary of Drivers the following information provides a summary of the ten key drivers **GHESI** has established for all capital expenditures within the four major categories. Outlined in Table 5.4-53 is information that categorizes the capital expenditures for the forecast period in relation to each driver. Projects with multiple drivers are categorized by the primary driver.

		2011 (Previous Bridge Year)	2012 (Previous Test Year)	2013	2014	2015 Bridge Year	2016 Test Year	2017	2018	2019	2020
System Access											
Driver	**Program/Activity**										
Customer Service Requests	**Apartment, Commercial, Industrial Customer Connections (CACI)** **Distribution System Modifications / Expansions for Customers (CMOD)** **Expansions for New Residential Subdivions (CRES)** **New Residential Service Connections (CSER)** **Expansions for New Residential Subdivions (CTH)**	4,585,530	2,723,175	3,045,691	3,320,140	3,574,914	3,682,161	3,792,626	3,906,405	4,023,597	4,144,305
System Relocations Property Development	**System Relocations Property Development (CREL)**	646,265	1,728,042	760,464	1,176,556	1,262,023	1,299,884	1,338,881	1,379,047	1,420,418	1,463,031
Mandated Service	**Meter Installations (CMEG)**	1,342,946	567,148	422,899	389,899	1,010,000	415,000	365,000	385,000	385,000	375,000
Sub-Total		**6,574,742**	**5,018,365**	**4,229,054**	**4,886,595**	**5,846,937**	**5,397,045**	**5,496,506**	**5,670,452**	**5,829,015**	**5,982,336**
System Renewal											
End of Life service Assets	**Distribution System Replacment (CREP)** **Distribution System Transformer replacement upgrades (CTRU)**	1,648,262	2,536,522	2,830,493	3,726,430	3,960,130	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
Sub-Total		**1,648,262**	**2,536,522**	**2,830,493**	**3,726,430**	**3,960,130**	**4,478,934**	**4,613,302**	**4,751,701**	**4,894,252**	**5,041,080**
System Service											
Capacity Upgrade	**Distribution System Feeder Infrastrucutre (CFDR)** **Transformer Stations & Distribution Stations (CTS/CDS)**	16,545,260	2,813,578	2,776,531	1,787,040	3,375,477	1,377,241	1,418,559	1,461,115	1,504,949	1,550,097
SCADAand Automation	**SCADA Infrastructure (CSC)** **SCADA / Remotely Operated Switches (CSW)**	353,351	326,396	409,450	463,708	467,144	481,158	495,593	510,461	525,775	541,548
Sub-Total		**16,898,611**	**3,139,974**	**3,185,982**	**2,250,748**	**3,842,621**	**1,858,400**	**1,914,152**	**1,971,576**	**2,030,724**	**2,091,645**
General Plant											
Building / Fixtures	**Building / Fixtures**	32,636	0	97,634	483,568	754,500	804,135	163,909	168,826	173,891	179,108
Equipment and Tools	**Office Equipment / Graphics** **Major Tools**	92,987	119,536	129,972	189,979	122,004	228,664	132,524	136,499	140,594	144,812
Fleet / Rolling Stock	**Fleet / Rolling Stock**	402,093	468,956	461,583	620,831	556,200	572,886	590,073	607,775	626,008	644,788
IT Capital	**IT Capital**	525,006	396,246	531,387	1,065,060	780,000	590,000	545,000	561,350	578,191	595,536
Sub-Total		**1,052,721**	**984,738**	**1,220,577**	**2,359,438**	**2,212,704**	**2,195,685**	**1,431,505**	**1,474,450**	**1,518,684**	**1,564,244**
Total all Categories		**26,174,335**	**11,679,598**	**11,466,106**	**13,223,211**	**15,862,392**	**13,930,063**	**13,455,465**	**13,868,179**	**14,272,674**	**14,679,305**

Table 5.4-53 Planned Capital Investments in Relation to Project Drivers

System Access

Customer Service Requests

Capital expenditures for projects related to customer service request are summarized as follows:

1. **Apartment, Commercial, Industrial Customer Connections –** These are projects that are essential in order to meet the demand of new and existing customers connected or requesting connection to **GHESI's** distribution system. Supply is at a primary voltage level, or through a utility transformer providing secondary voltage to a single building or group of buildings. The distribution system to individual customers within the building(s) is not part of utility's assets. Projects also include any upgrades to existing customer services. A portion of this cost is recovered through capital contributions.
2. **Distribution System Modification and Customer Expansion –** These projects relate to additions or modifications to the distribution system to accommodate new commercial and industrial development. A portion of this cost is recovered through capital contributions. Capital expenditures within this sector vary year to year and are solely based on customer driven initiatives.
3. **New Residential Subdivision Expansion (Including Townhousing)** – These projects are related to expansion for new residential developments based on the projections by the City of Guelph's **DPP**. Work within this section covers the installation of new underground distribution system facilities to accommodate new residential developments. A large portion of the cost is recoverable through capital contributions by the developer based on an economic evaluation model.
4. **New Residential Service Connection** - Funds in this category are allocated in order to provide electrical service installations to residential subdivisions as well as in-fill and small commercial properties. **GHESI** bases its budgeted service installations on information from the City of Guelph's **DPP** and past history. Similar to residential development expansions, a significant portion of this cost is recovered through capital contributions based on an economic evaluation model.

System Relocations Property Development

Line relocation projects are required in order to accommodate projects related to road work by the City of Guelph, the Township of Guelph-Eramosa, and projects associated with the **MTO**. Projects in this category are driven by other authorities and are difficult to predict. Monthly utility meetings are held with the City of Guelph in order to plan for future work being carried out by the City to help plan **GHESI's** projects and align work efficiencies between both groups. A portion of the capital costs are recovered through

capital contributions based on a cost sharing agreement, when available, between the parties involved.

Mandated Service Related to Metering

GHESI is required to maintain its retail meter inventory to ensure compliance with Measurement Canada and other applicable regulatory requirements. The maintenance of all conventional general service metering for customers who require demand meters may include the upgrade of existing meters due to:

- Customer electrical service upgrades;
- The need to replace obsolete or damaged meters; and
- Conversion from 2.5 element metering to 3 element metering.

System Renewal

End of life service assets

Furthermore, depending on the asset category and impact of **EOL** failure, some assets, such as power transformers, are replaced proactively before they fail, while some assets, such as pole top transformers, are replaced reactively and are run to failure. In some cases, assets that are normally run to failure are replaced proactively if a known condition exists, e.g. proximity to major roads or continuous high loading level, which causes premature ageing.

GHESI maintains a number of capital rehabilitation and sustainment programs. The sustainment programs that are currently operated by **GHESI** are referenced in section 5.4.2.3 page 191.

System Renewal projects are required in order to maintain a safe and reliable distribution system by replacing end of life facilities so that the system can operate as designed. The purpose of maintaining the long-term and short-term functionality of assets is to ensure **AM** Objectives such as public and employee safety are met to comply with regulatory requirements and to provide a high level of reliability to our customers that falls in line with **GHESI's** objectives and policies.

Electrical distribution assets are subject to deterioration that will eventually impede their ability to function as originally designed. Asset deterioration depends on factors such as age, environment, utilization, weather and maintenance practices. As assets start to deteriorate, performance and reliability begin to fade, resulting in an increase to risk of failure that could lead to potential safety hazards to the public and to our employees.

The identification and prioritization of projects is driven based on the collection of data from the **ACA** as outlined in **Appendix D**. Along with the **ACA**, there are other factors that drive distribution system rehabilitation projects including: historical performance, design and functional obsolescence, regulatory requirements, new standards, flawed design or substandard manufacturing.

System Service

Capacity Upgrade

Capital expenditures for projects related to capacity constraints are summarized as follows:

1. Distribution System Feeder Infrastructure
2. Transformer Stations and Distribution Stations

1. **Distribution System Feeder Infrastructure** – These projects are required to provide system capacity for new residential, commercial and industrial developments. Projects within this category include new pole line builds and feeders for station egress. Utilizing outputs from the overall system capacity study, an individual assessment of various areas within each load centre is conducted based on operational and customer specific requirements in order to operate the distribution system.
2. **Transformer and Distribution Stations** - Capital expenditures related to this category are driven by specific requirements for additional capacity based on outputs that form the system capacity assessment.

SCADA and Automation

Capital expenditures for projects related to **SCADA** and Automation are summarized as follows

1. **SCADA - GHESI's SCADA** system is comprised of hardware, software and supporting communications infrastructure which provide the tools for **GHESI's** System Control Operators ("**SCO**") to efficiently and effectively monitor and operate the electric distribution systems servicing the City of Guelph and Rockwood service areas. The **SCADA** system provides real time operating information to **SCOs**, who use the information to optimize distribution system performance. Improved customer service is achieved through better distribution system reliability, and reduced response times in the event of distribution system disturbances. **GHESI's SCADA** system also manages the operation of over 200 field devices, including over 100 remotely operable distribution switches. Through the operation of these remote

switches, an **SCO** can reduce outage times experienced by customers. **SCADA** capital investments include minor upgrades to traditional **SCADA** hardware and software, expansion of the Control Room electronic wall display, and the implementation of a new hardware and software solution to better manage an increasing number of field network communication devices Projects that will enhance customer service by supporting improved customer restoration response include:

- Continued integration of Advanced Metering Infrastructure ("**AMI**") and **SCADA** communications;
- Implementation of GridScape solution for communication network visibility and operational support;
- Installation of wireless line sensors to expand our distribution system monitoring capabilities; and
- Smart Meter **AMI** power outage information to provide better near-real time distribution system status information.

2. **SCADA** / Remote Operated Switches - Projects in this category are allocated funds to install or upgrade remote operated switches and manual **LIS** within our distribution system, which are not part of other feeder work. This work will improve distribution system load handling capability, operational flexibility and system reliability.

General Plant

Building / Fixtures

Investments in this category are identified and driven by inspections and monitoring of building asset condition through expert opinion and observing and noting repair issues throughout the administration building. Building assets are grouped into the following classifications based on a complete inventory assessment completed in 2014.

- Building Structure;
- Building Interior;
- Building Envelope;
- Fire Protection;
- Mechanical/Electrical; and
- Site Works.

Overall historic and forecast spending on building assets is very consistent with one exception noted in 2015 and 2016 for the replacement of part of the administration building roof. This project involves a building addition leading to increased office, control room, and meeting room space. The existing **GHESI** building has been designed to readily accommodate a second floor addition only requiring one new

outside wall, minor existing **HVAC** modifications, and a new roof in addition to normal internal facility construction.

Equipment and Tools

Capital expenditures for projects related to equipment and tools are summarized as follows:

1. **Office Equipment / Graphics** - capital expenditures related to office equipment and graphics are driven based on specific requirements to perform day to day functions within the office environment.
2. **Major Tools** - capital expenditures for major tools are driven based on specific operational needs. **GHESI** continually investigates the requirement to upgrade outdated tools and equipment and searches for newer more effective technology, combined with the most ergonomic way of accomplishing a task. Historic costs for major tools are consistent with forecasted expenditures.

Fleet / Rolling Stock

As evident from Table 5.4-53, fleet investments are planned to be very consistent over the forecast period in a similar fashion to historic expenditures. **GHESI** utilizes a levelized are strategic approach to managing assets within the fleet pool as outlined in Appendix L. Investments are based on a number of criteria which include: age of the vehicle, odometer reading, engine/power take-off ("**PTO**") hours, maintenance costs, annual vehicle test results (includes stress/electrical testing), practicality of existing vehicle including new technology available, changing emissions, weight, and road safety regulations obsoleting some existing units, and crew/other department needs. Vehicles are replaced based on an established replacement schedule that takes into account the above mentioned factors.

IT Capital

Capital investments in **IS** and **IT** infrastructure projects are selected and prioritized in order to maintain effective and efficient business processes, ensure support for disaster and pandemic business continuity and to maintain integrated and reliable enterprise solutions. Selection of projects is based on identified need in the organization, best practices in network and security systems and expert knowledge. **GHESI** utilizes a strategic approach to managing assets within the **IT** group as outlined in Appendix M.

Information Related to the Distributor's System Capability Assessment

Information related to the distributor's system capability assessment (see section 5.4.3)

As outlined in Sections 5.4.3 and 5.4.1.1, **GHESI's** distribution system is capable of meeting future demands with respect to load and generation needs. **GHESI** has not included any investments for the accommodation of **REG** type projects in the **DSP**. **GHESI's** overall distribution system capacity does not require any increases within the forecast period of 2016-2020, however; an investment to upgrade and increase capacity at the **Hydro One** Campbell **TS** or an alternative is forecasted between 2021-2023 depending on load levels and other factors including **CDM** and **DG**. Specific projects related to capacity within the service area of each load centre are monitored on a consistent basis to address load growth and/or increase to existing customer facilities.

5.4.5.2 **Material Investments (OEB Filing Req. 5.4.5.2)**

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

The following section details information related to projects/activities that meet **GHESI's** material threshold of $172,000 for the 2016 year. A list of these projects is presented below in Table 5.4-54 and detailed information, including the evaluation criteria and category specific information for each project/activity can be found in Appendix N.

Guelph Hydro Electric Systems Inc.
2016 Capital Project Summary List

Category	Project Name	Total Expenditure	Priority Ranking within Category	Page Reference
System Access				
	Apartment, Commercial, Industrial Customer Connections (CACI)	$ 646,894	1	657
	Metering Installations (CMEG)	$ 415,000	2	660
	Distribution System Modifications / Expansions for Customers (CMOD)	$ 784,249	3	663
	System Relocations Property Development (CREL)	$ 1,299,884	4	666
	Expansions for New Residential Subdivisions (CRES)	$ 1,443,261	5	669
	New Residential Service Connections (CSER)	$ 238,954	6	672
	Expansions for New Residential Townhouse Subdivisions (CTH)	$ 568,803	7	675
System Renewal				
	295 Water Street Single Phase Ug W/ Secondary Ug Cable	$ 448,000	3	678
	Alma St N / Plymouth Crt Rebuild	$ 218,000	4	683
	Alma St N/Julia Dr/Drew St Rebuild	$ 216,000	5	668
	Arrow Rd Rebuild	$ 432,000	9	693
	Fife (Wellington to Gateway) Rebuild	$ 173,000	8	700
	Imperial Rd S / Samantha Crt Rebuild	$ 247,000	7	706
	Elmira Rd S Rebuild	$ 388,000	6	711
	Westgate Dr/Lonsdale Dr/ Edinburgh Rd N Rebuild	$ 285,000	1	716
	KeatsPh2 Pole Trans Underground Rebuild	$ 986,000	2	722
	Distribution System Transformer replacement upgrades (CTRU)	$ 315,193	10	728
System Service				
	Edinburgh Rd N / Sultan St	$ 176,000	2	731
	New 5M53Cedar St (Edinburgh To Maple), Maple St, Water St	$ 500,000	3	736
	Edinburgh Rd S (Municipal To BristolWest Side)	$ 407,000	4	742
	SCADA Infrastructure (CSC)	$ 224,911	5	748
	SCADA / Remotely Operated Switches (CSW)	$ 256,248	6	751
	Arlen MTS Series Reactor***	$ 150,000	1	754
General Plant				
	Administration Building Addition***	$ 650,000	2	757
	Replacement of Single Bucket (T9)	$ 300,000	1	761
	*** Multi Year Project. Cost shown is only 2016 Expenditures			

Table 5.4-54: Material Capital Programs and Projects for 2016

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APPENDIX A: Renewable Energy Generation Investment Plan

RENEWABLE ENERGY GENERATION INVESTMENT PLAN

Per: OEB Chapter 5 Consolidated Distribution System Plan Filing Requirements – 5.1.4.2

November 26, 2014

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1. Executive Summary

In accordance with the Ontario Energy Board's (OEB) filing requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, Guelph Hydro Electric Systems Inc. (Guelph Hydro) has prepared the following Renewable Energy Generation (REG) Investment Plan.

The following sections provide a current assessment of Guelph Hydro's distribution system along with currently connected distributed generation projects. It also provides an overview of expected distributed generation project connections for 2015 through 2020.

Given the geography and primarily urban nature of Guelph Hydro's service territory, we anticipate higher numbers of solar project connection requests. It is notable that in recent years we have experienced an increasing interest in combined heat and power (CHP) projects with natural gas generators that would co-generate in parallel with our distribution system.

Since the introduction of the Feed-In-Tariff ("FIT") program by OPA in 2009, Guelph Hydro has facilitated the connection of a number of projects. As of October 2014, 275 microFIT Projects and 27 FIT Projects have been connected, with a total nameplate capacity of 8.293MW. Guelph Hydro expects to connect an additional 360 microFIT projects and 29 FIT Projects by 2020, with a total additional nameplate capacity of 8.00MW.

Overall, Guelph Hydro's distribution system is well designed, built and maintained to accept an influx of renewable generation. However, due to short circuit levels, there is a capacity restriction in one of Hydro One's transformer stations supplying Guelph Hydro. We expect to see this trend continue with other Hydro One owned transformer stations supplying Guelph Hydro because of increasing interest in CHP projects by our industrial customers. The generators used in CHP projects contribute a higher level of short circuit current compared to inverter based generation projects. Therefore, some system expansion and renewable enabling investments will be required by Hydro One to accommodate future renewable generation project connection requests.

Guelph Hydro does not expect any capital expenditures related to renewable energy generation in its Distribution System Plan. As well, no additional Operating, Maintenance and Administrative ("OM&A") costs proposed related to renewable generation connections are anticipated as Guelph Hydro is capable of processing both microFIT and FIT applications utilizing existing employees.

2. Current Assessment

In preparing this plan, Guelph Hydro has identified both existing and anticipated renewable energy generation (REG) connection requests to its distribution system. The summary of Guelph Hydro's load and REG connection forecast has been prepared by transformer station, with anticipated REG projects over 10kW distinguished from anticipated micro-FIT projects. Constraints related to the upstream Hydro One transmitter system have also been identified.

2.1 Guelph Hydro Distribution System Overview

Guelph Hydro owns, operates and maintains a relatively modern distribution system, currently serving over 53,000 customers in the City of Guelph and the Township of Guelph-Eramosa (Village of Rockwood). Guelph Hydro distributes power from seven stations; three Hydro One Networks Inc. (HONI)-owned transformer stations, one Guelph Hydro owned transformer station in the City of Guelph as well as one HONI owned distribution station and two Guelph Hydro-owned municipal stations in the Village of Rockwood.

The service territory is primarily urban, and historically has exhibited a high degree of reliability. While there are no municipal substations in Guelph, the distribution system has been built with a high degree of distribution monitoring, intelligent power factor correction, and remote switching capability.

Like many LDCs, our SCADA system provides our Control Room Operators with real-time information to monitor and operate the distribution system, through the installation of strategically located remotely operated switches, electronic faulted circuit indicators and line sensors. To further enhance operational effectiveness, Guelph Hydro has developed a robust Geographic Information System (GIS), leveraged to support other LDC enterprise systems such as Customer Information System and Work Order System. These systems provide Guelph Hydro's Control Room with additional operational support tools.

Guelph Hydro has a history of distribution system optimization through sophisticated system modeling and planning tools to optimize the efficiency of the system. We have introduced mobile computing with real-time GPS vehicle tracking, and developed an automated outage messaging system for improved internal response to system conditions. Following completion of the installation of residential and small commercial Smart Meters, Guelph Hydro developed, implemented and, is currently refining, information tools that leverage a smart meter's "last gasp" communication capability to further improve customer service through more advanced outage detection and response.

Guelph Hydro has also installed sophisticated ION 8650 revenue meters which act as a SCADA remote terminal unit (RTU) with an antenna, for projects larger than 150kW. This enables us to remotely monitor the power quality and the functionality of the generators being metered and also allows us to bring back real-time generation information. As the concentration of the renewable projects increases in the future, this information will be useful for system planning purposes.

The following table summarizes general statistics of Guelph Hydro's Distribution System.

Table 1: Guelph Hydro Distribution System Statistics

System Statistics	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Service Area (sq km)	94	94	94	94	94	94
Total Metered Customers	49,299	50,250	50,859	51,553	52,366	53,225
Number of Transformer Stations (owned by HONI)	3	3	3	3	3	3
Number of Transformer Stations (owned by Guelph Hydro)	0	0	0	1	1	1
Number of Municipal Stations (owned by HONI)	1	1	1	1	1	1
Number of Municipal Stations (owned by Guelph Hydro)	2	2	2	2	2	2
Total Circuit Length (km)	1,060	1,065	1,084	1,103	1,099	1,135
O/H Circuit (km)	427	427	430	431	427	430
U/G Circuit (km)	636	638	654	672	672	705
Number of Poles	10,748	10,921	10,874	10,946	10,715	11,163
Number of Power Transformers	2	2	2	4	4	4
System Peak - Summer (MW)	268	286	297	294	303	280
System Peak - Winter (MW)	246	254	254	254	268	270
Total Energy Purchased (annual MWh)	1,504	1,641	1,696	1,742	1,737	N/A

2.2 Existing Distributed Generation Connections to the Distribution System

Guelph Hydro has connected a significant number of micro-FIT and FIT projects to the distribution system along with providing connection to non-renewable generators. As of October-2014, the total number of renewable generation projects connected to Guelph Hydro's distribution system is 303, with an installed capacity of 8.293MW. Based on information obtained from the OPA, Guelph Hydro's total renewable generation, in terms of capacity, accounts for 0.7% of the provincial total. The following table summarizes this information on a year-to-year basis.

Table 2: Existing Renewable Distributed Generation Connections

Number of Renewables by Year	*<2011*	*2012*	*2013*	*2014*	*Total*
Micro Generation (<= 10 kW)	86	83	73	34	***276***
Small Generation (<= 250 kW)	2	18	7	0	***27***
Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	***0***
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	0	***0***
Total	***88***	***101***	***80***	***34***	***303***

Table 3: Existing Renewable Distributed Generation Connection in MW

Renewables by Year [MW]	*<2011*	*2012*	*2013*	*2014(YTD)*	*Total*
Micro Generation (<= 10 kW)	0.59	0.655	0.578	0.296	***2.119***
Small Generation (<= 250 kW)	0.35	4.335	1.489	0	***6.174***
Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	***0***
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	0	***0***
Total	**0.94**	**4.99**	**2.067**	**0.296**	***8.293***

Table 4: Existing Non-Renewable Distributed Generation Connections

Other Distributed Generation by Year	*<2011*	*2012*	*2013*	*2014*	*Total*
Micro Generation (<= 10 kW)	2	0	0	0	***2***
Small Generation (<= 250 kW)	0	0	0	0	***0***
Small Generation (> 250 kW,<= 500 kW)	1	0	0	0	***1***
Mid-Size Generation (> 500 kW, <= 10 MW)	2	0	0	0	***2***
Total	***5***	***0***	***0***	***0***	***5***

Table 5: Existing Non-Renewable Distributed Generation Connection in MW

Other Distributed Generation by Year [MW]	*<2011*	*2012*	*2013*	*2014*	*Total*
Micro Generation (<= 10 kW)	0.005	0	0	0	***0.005***
Small Generation (<= 250 kW)	0	0	0	0	***0***
Small Generation (> 250 kW,<= 500 kW)	0.4	0	0	0	***0.4***
Mid-Size Generation (> 500 kW, <= 10 MW)	4.2	0	0	0	***4.2***
Total	**4.605**	**0**	**0**	**0**	***4.605***

To-date Guelph Hydro has reviewed 165 pre-FIT Consultation requests (renewals not included) for a total capacity of 60.665MW. Of those reviewed, 20 requests had no capacity available, for a total of 4.579MW. These projects would have been supplied from the Campbell TS BY Bus that, in any event, is unable to accept any further generation because the short circuit capacity threshold has been reached. Out of the 145 remaining projects, only 31 were able to obtain an OPA FIT contract, of which 27 projects were connected as of October 2014. Six more projects, with a nameplate capacity of 0.875MW, are still in the process of seeking Notification to Proceed (NTP) from the OPA. Moreover, Guelph Hydro has capacity for 23 FIT projects, with a nameplate capacity of 4.245MW, which are pending approval of an OPA FIT contract under FIT 3.0.

With respect to micro-FIT projects, Guelph Hydro has reviewed 452 projects, of which 149 projects were cancelled by the customer, even though they were able to acquire an OPA micro-FIT contract. Over the course of five years, we have connected 275 projects with a nameplate capacity of 2.119MW.

Apart from micro-FIT and FIT projects, Guelph Hydro has also connected two RESOP solar projects and three Co-generation projects with their respective nameplate capacity of 0.005MW and 4.6MW.

Although non-renewable generation project information is not required as part of the Chapter 5 Filing Requirement with regards to the OPA's letter of comment; it is provided to illustrate the entire picture and keep OPA informed of the market trends.

2.3 Distribution System Distributed Generation Capacity Assessment

Since their inception, distribution systems, including monitoring and protection elements were planned, designed and constructed to serve loads. They were not intended to facilitate the connection and management of a larger number of distributed generators. As such, the amount of generation capacity to be connected to the distribution system will be constrained by a variety of engineering factors such as supply feeder ampacity, power quality and equipment ratings, as well as limits on reverse power flow and short circuit capacity at the transformer stations and substations.

It is anticipated that initially, the connection of small-scale inverter-based renewable generation will not impose many limitations, but over time a larger concentration of micro-generators, or several medium-sized generators on the same distribution feeder will have a noticeable impact on the distribution system and upstream elements. Large scale projects will have an immediate impact and will require detailed study and analysis to understand the impact of the proposed connection. With increased generation penetration levels, load transfer capability will be severely limited between

feeders from different transformer stations, as the system parameters change. This will trigger the generators to be tripped as they are no longer on the feeders that have the proper protections; meaning that the load that was supplemented by the distributed generators will increase the demand from the distribution feeders.

Generation capacity availability is not only based on short-circuit capacity or thermal limits at the station, but is also based on feeder loading to ensure that there is enough short circuit capacity at the stations when there are potential feeder load transfers under construction, maintenance and emergency situations. Guelph Hydro's application of feeder loading design parameters and good utility practice will ensure operational flexibility for load switching operations for both emergency and construction purposes.

The available generation capacity of a feeder is, to some degree, a function of the load capacity of the feeder under both normal and load transfer conditions. Consequently, constraints on renewable generation connections are expected to result from limitations of reverse power flow and short circuit capacity at the transformer stations. The typical three-to-five year planning process for mid-sized projects generally provides Guelph Hydro with an adequate timeframe to plan for required expansions to accommodate mid-sized load or generation additions.

Table 6 shows the transformer station and substation generation connection limitations and includes both existing and in-progress generator connections. There is currently an 8MW combined heat and power (CHP) project in the process of connecting to a feeder from Campbell TS BY Bus, which will result in reaching the short circuit capacity threshold for that Dual Element Spot Network (DESN). The City of Guelph's–Community Energy Initiative aims to have 100MW of co-generation capacity installed in the city by 2031. This has resulted in a growing interest among large industrial customers to install CHP equipment in Guelph.

Guelph Hydro is also aware that some industrial customers are interested in installing CHP plants and are in the process of obtaining OPA approvals. If these projects proceed, they will consume the balance of the remaining Campbell TS JQ and ZE Bus generation connection capacity.

As a result of the aforementioned projects, station upgrades may be required at Campbell TS and Arlen MTS in order to accommodate additional future generation projects.

Table 6: Transformer Station Generation Connections and Limitations

Station	Bus	Existing FIT Connections (MW)	Existing micro-FIT Connections (MW)	Existing other Distributed Generation Connections (MW)	Distributed Generation Connections – In Progress (MW)	Thermal Limit (MW)	Short Circuit Limit (MVA)	Remaining Thermal Limit (MW)	Remaining Short Circuit Capacity (MVA)
Hydro One Owned Campbell TS	*BY*	*2.484*	*0.2284*	*0.003*	*8.0*	*13.4**	*59.5**	*2.69*	*2.98*
	JQ	*1.994*	*0.2805*	*-*	*-*	*15.3**	*59.5**	*13.03*	*56.09*
	ZE	*1.246*	*0.2077*	*2.8*	*-*	*15.0**	*30.8**	*10.75*	*14.62*
	Total	**5.724**	**0.7166**	**2.803**	**8.0**	**43.7**	**149.8***	**26.46**	**73.69**
Hydro One Owned Cedar TS	*BY*	*-*	*0.4501*	*0.002*	*-*	*17.3**	*112.5**	*16.86*	*111.84*
	ZE	*-*	*0.4942*	*-*	*-*	*6.4**	*137.8**	*5.91*	*137.06*
	JQ	*-*	*0.2506*	*1.4*	*-*	*35.3**	*152.4**	*33.65*	*145.15*
	Total	**0**	**1.1949**	**1.402**	**0**	**59.0***	**402.7***	**56.42**	**394.05**
Hydro One Owned Hanlon TS	**BY**	**0.45**	**0.166**	**0**	**0**	**29.6***	**132***	**28.98**	**131.08**
Guelph Hydro Owned Arlen MTS	**BY**	**0**	**0.010**	**0**	**10.2**[1]	**33.0**	26.1	33.0	26.1[1]
Hydro One Owned Rockwood DS	**Station**	**0**	**0.00**	**0**	**0**	**3.8***	-	3.8	-
Guelph Hydro Owned Rockwood MS1	**Station**	**0**	**0.032**	**0**	**0**	**2.5**	-	2.468	-
Guelph Hydro Owned Rockwood MS2	**Station**	**0**	**0.00**	**0**	**0**	**2.5**	-	2.5	-
Total		**6.174**	**2.119**	**4.205**	**18.2**	**174.1**	**710.6**	**-**	

*Information obtained from Hydro One website.

1) If the Hanlon Creek, 10.2MW CHP project were to go ahead, then all of Arlen MTS SCC capacity would be taken, otherwise, there is still 26.1 MVA of short circuit capacity.

3. Forecast Distributed Generation Connections to the Distribution System

Guelph Hydro notes that, while the filing requirements specifically focus on renewable energy generation connections under the FIT and microFIT programs, it is understood that LDCs are to facilitate connection of all generators to the distribution system, including non-renewable generation projects (landfill gas, energy from waste, gas and etc.). A fully developed and integrated distribution system will assist in facilitating both renewable and non-renewable generator connections.

Based on current information, the following tables summarize the anticipated distributed generation connections. It also details non-renewable generation projects that are in the process of connecting, as well as projects that are in the preliminary stage of preparing and submitting documents for OPA approval. OPA's plan to procure 150MW and 50MW of renewable generation capacity under FIT and micro-FIT program per year, for the period of 2014-2018 was also considered. Guelph Hydro has also noted an increasing interest in Net Metering and CHP projects.

In the following tables, for micro-FIT projects, an average generator size of 8kW is assumed based on existing connections. For FIT projects, the capacity requests from Pre-FIT assessments have been included. For other distributed generation project connections, ten Net Metering projects are estimated per year, as there are a significant number of consultations for capacity requests being received. Guelph Hydro is aware that plans are in place for at least ten homes to be built in 2015 as a pilot project for Net Metering. In addition, we are also aware of two CHP projects that have OPA approval with combined generation capacity of 11MW. Preliminary work is being done for three CHP projects to be submitted for OPA approval, with a combined generation capacity of 13MW. Guelph Hydro currently has capacity to accommodate connection to all of the above projects listed in the tables.

Depending on the timing of the CHP projects request for connection impact assessment, station upgrades may be required to facilitate the connection of the generation projects; most notably, at Arlen MTS if the 10.2 MW Hanlon creek project were to go ahead. Projects wishing to connect to Campbell TS BY Bus, have been failing the DAT test.

Table 7: Forecast Renewable Distributed Generation Connections

Number of Renewables by Year	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Micro Generation (<= 10 kW)	60	60	60	60	60	60	***360***
Small Generation (<= 250 kW)	6	3	5	5	5	5	***29***
Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	0	0	***0***
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	0	0	0	***0***
Total	***66***	***63***	***65***	***65***	***65***	***65***	***389***

Table 8: Forecast Renewable Generation Connection in MW

Renewables by Year [MW]	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Micro Generation (<= 10 kW)	0.48	0.48	0.48	0.48	0.48	0.48	***2.88***
Small Generation (<= 250 kW)	0.875	0.4	0.89	1.25	0.94	0.765	***5.12***
Small Generation (> 250 kW,<= 500 kW)	0	0	0	0	0	0	***0***
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	0	0	0	***0***
Total	***1.355***	***0.88***	***1.37***	***1.73***	***1.42***	***1.245***	***8.00***

Table 9: Forecast Non-Renewable Distributed Generation Connections

Other Distributed Generation by Year	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Micro Generation (<= 10 kW)	10	10	10	10	10	10	***60***
Small Generation (<= 250 kW)	0	0	0	0	0	0	***0***
Small Generation (> 250 kW,<= 500 kW)	0	1	0	0	0	0	***1***
Mid-Size Generation (> 500 kW, <= 10 MW)	1	0	1	2	0	0	***4***
Total	***11***	***11***	***12***	***12***	***10***	***10***	***65***

Table 10: Forecast Non-Renewable Distributed Generation Connections in MW

Other Distributed Generation by Year	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Micro Generation (<= 10 kW)	0.08	0.08	0.08	0.08	0.08	0.08	***0.48***
Small Generation (<= 250 kW)	0	0	0	0	0	0	***0***
Small Generation (> 250 kW,<= 500 kW)	0	0.8	0	0	0	0	***0.8***
Mid-Size Generation (> 500 kW, <= 10 MW)	8.0	0	4.0	9.0	0	0	***21***
Total	***8.08***	***0.88***	***4.08***	***9.08***	***0.08***	***0.08***	***22.28***

4. Planning and Consultation

Guelph Hydro has consulted with the OPA on numerous occasions in an effort to keep both groups up to date of the REG developments as well as to review the available thermal and short circuit current limitations for several of the stations in Guelph Hydro's service area.

Frequent updates are provided by Guelph Hydro's Conservation and Demand Management group about customers interested in installing generation, either to supplement their demand, or under the FIT program. The above mentioned avenues provide a long-term outlook of the market trends and help us in terms of system planning.

Guelph Hydro has also participated in several Regional Infrastructure Planning meetings with the OPA and other LDCs from the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area. Although the main focus of the meetings has been on load growth and system expansion projects; generation, both non-renewable and renewable, have also been discussed. Increasing interest in large CHP projects in the Guelph area will have a big impact in terms of the overall load growth within certain geographic areas.

5. Investments to Facilitate Renewable Energy Generation

Guelph Hydro has reviewed the need for capital and OM&A investments related to the connection of REG projects as it applies to the expansion of the distribution system and renewable enabling improvements. Based on this review and historic trends within our service territory, Guelph Hydro does not expect any REG investments in both areas for the period of 2015-2020. From an OM&A perspective, no additional OM&A expenses are anticipated as Guelph Hydro is able to process both microFIT and FIT applications using existing employees.

Guelph Hydro shall fully comply with its responsibility under the Distribution System Code as it relates to distribution system expansion and renewable Enabling Improvements to the distribution system to support REG projects.

APPENDIX B: Renewable Energy Generation Plan Letter to IESO (OPA)

Guelph Hydro
Electric Systems Inc.

November 28, 2014

Ms. Miriam Heinz
Regulatory Coordinator

The Ontario Power Authority
120 Adelaide Street West, Suite 1600
Toronto, ON, M5H 1T1

Dear Ms. Miriam:

RE: Guelph Hydro Electric Systems Inc. (ED-2002-0565)
Renewable Energy Generation Investments Plan

In accordance with the Ontario Energy Board's (OEB) *"Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5"*, revised on March 28, 2014, attached is Guelph Hydro Electric Systems Inc.'s submission on the Renewable Energy Generation ("REG") investments identified in Guelph Hydro's five-year Distribution System Plan.

Guelph Hydro's Cost of Service ("COS") application for 2016 rates is due on April 24, 2015 and its Distribution System Plan is part of this application.

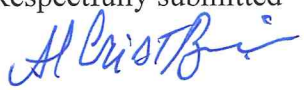
Guelph Hydro is requesting that the OPA provide a letter commenting on the information included in REG submission no less than 30 days in advance of its COS application deadline (i.e. no later than March 24, 2015).

The person to be contacted if the OPA staff has questions about the content of Guelph Hydro's information during the review period is:

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Guelph Hydro
Electric Systems Inc.

Respectfully submitted



Cristina Birceanu

Director of Regulatory Affairs
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APPENDIX C: IESO Comment Letter to GHESI on REG Investments Plan

IESO Letter of Comment

Guelph Hydro Electric Systems Inc.

Renewable Energy Generation Investments Plan

Date: January 23, 2015

ieso
Independent Electricity System Operator

Introduction

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

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("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.

Guelph Hydro Electric Systems Inc. – Distribution System Plan

On November 28, 2014 Guelph Hydro Electric Systems Inc. ("Guelph Hydro") provided its Renewable Energy Generation Investments Information ("Plan") to the former Ontario Power Authority[2] as part of its 5-year Distribution System Plan. The IESO has reviewed Guelph Hydro's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

Guelph Hydro indicates that as of October 2014, it has connected 276 microFIT projects totalling 2,119 kW of capacity, and 27 FIT projects, totalling 6,174 kW of capacity. According to the IESO's information, as of November 2014, the OPA offered contracts to 279 microFIT projects totalling 2,100 kW of capacity. The OPA has also offered contracts to 34 FIT projects representing a capacity of 7,163 kW, of which 27 FIT projects have come into service. The renewable energy generation connections information in Guelph Hydro's Plan is therefore reasonably consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.
[2] Ibid.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

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

As an active member of the Kitchener-Waterloo-Cambridge-Guelph ("KWCG") Working Group, Guelph Hydro has been involved in a coordinated regional electricity planning study for the KWCG area since 2010. Over the last couple of years, the KWCG Working Group, consisting of staff from the former OPA, IESO, Hydro One Networks Inc., Kitchener-Wilmot Hydro Inc., Waterloo North Hydro Inc., Cambridge & North Dumfries Hydro Inc. and Guelph Hydro Electric Systems Inc., has held a number of planning meetings to discuss the electricity supply and reliability needs and the development of integrated solutions in the KWCG area. In 2013, the KWCG regional planning study was transitioned to align with the formalized Ontario Energy Board regional planning process. Consequently the KWCG Working Group is developing an Integrated Regional Resource Plan ("IRRP"), which is to be completed in April 2015.

In addition to being involved in the regional planning process, Guelph Hydro has consulted with the OPA on numerous occasions to coordinate distributed generation capacity assessment and to review capacity availability at the various transformer stations in the Guelph Hydro service area.

The IESO looks forward to continuing to work with Guelph Hydro to complete the IRRP for the KWCG area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

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APPENDIX D: 2014 Asset Condition Assessment

GUELPH HYDRO ELECTRIC SYSTEMS INC.
2014 ASSET CONDITION ASSESSMENT

December 11, 2014

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Contents of this report shall not be disclosed
without authority of client.
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GUELPH HYDRO ELECTRIC SYSTEMS INC.
2014 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418757-RA-0001-R00

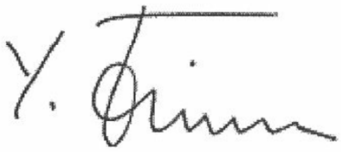
December 11, 2014

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Dated: Dec 11, 2014

To: Guelph Hydro Electric Systems Inc.

Revision History

Revision Number	Date	Comments	Approved

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I INTRODUCTION

Guelph Hydro Electric Systems Inc. (GHESI) is a local distribution company that provides electricity to over 50,000 residential, commercial, and industrial customers in Guelph and Rockwood, Ontario.

Guelph Municipal Holdings, which in turn is 100% owned by the City of Guelph, wholly owns GHESI. Activities, performance standards, and rates are regulated by the Ontario Energy Board.

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

In early 2013, GHESI selected and engaged Kinectrics to perform an Asset Condition Assessment (ACA) on GHESI's key distribution assets. Kinectrics was again tasked with performing an ACA for GHESI in 2014. This report presents the results of the 2014 ACA.

The Asset Condition Assessment Report presents the findings and recommendations of the 2014 ACA. The methodologies used in this assessment are detailed in the Kinectrics report "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment".

I.1 Scope of Work

The assets in this study are categorized as follows:

- Substation Transformers
- Circuit Breakers
- Pole Mounted Transformers
- Pad Mounted Transformers
- Submersible Transformers
- Vault Transformers
- Overhead Switches
  - LIS
  - SCADA Switches
- Pad Mounted Switches
  - Live Front SG
  - Solid Dielectric SG
  - Switching Cubicles
- Cables
  - Primary
  - Secondary
- Lines
  - 1 Phase Primary
  - 3 Phase Primary
  - Secondary

- Poles
  - Wood Poles
  - Concrete Poles
  - Composite Poles
- Vault
- Manholes

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

I.2 **Deliverables**

The deliverable in this study is a Report. For each asset category the following are included (IV Appendix A: Results and Findings for Each Asset Category: Section 1 – Section 21):

- 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

II RESULTS

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table II-1. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. For each group the Health Index Distribution and average Health Index are shown. Also given is the average age of each group.

It can be seen from the results that pole mounted transformers are in the worst condition. Although the average HI of pole mounted transformers is 78%, 12% of the assets are in poor or very poor condition.

Manholes and vaults are, also of concern. While the average Health Index for these asset categories are 87% and 89% respectively, approximately 10% of manholes are in poor or very poor condition and around 10% of vaults are in poor or very poor condition. It should be noted, however, that more than half of the assets in this study's sample pool were assets inspected and subsequently assessed because they were suspect units or in areas that made them more prone to degradation. The samples are not likely to be representative of the entire vault and manhole populations. It is probable that the remainders of the vault and manhole populations are, on average, in better condition than the samples.

It is also worth noting that 6% of switching cubicles are in poor or very poor condition.

For reference, a graphical comparison between the 2012 and 2014 assessments are shown in Figure II-2.

Condition Based Flagged for Action Plan

The condition-based action plan for the first year and the flagged for action strategy is shown for each asset group in Table II-2. Table II-3 and Table II-4 show the 20 year action plan and levelized action plan. The same information is shown graphically on Figure II-3 and Figure II-4.

It is important to note that the plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for replacement. While the Flagged for Action Plan can be used as a guide or input to GHESI's asset management strategy, it is not expected that it be followed directly or as the final deciding factor in sustainment and capital decisions. There are numerous other factors and considerations that will influence GHESI's asset management decisions.

The most significant asset, in terms of quantities flagged for action, is pole mounted transformers. Eighty seven (87) pole mounted transformers are flagged for action in the first year; this represents 4.8% of the population. Also of significance are the 48 pad mounted transformers (1.3% of the population) and 39 wood poles (0.4% of the population) are flagged for action in the first year.

Table II-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution				
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)
Substation Transformers		4	4	93%	0%	0%	0%	0%	100%
Circuit Breakers		18	18	100%	0%	0%	0%	0%	100%
Pole Mounted Transformers		1824	1821	78%	2%	11%	21%	25%	42%
Pad Mounted Transformers		3825	3825	88%	< 1%	1%	10%	26%	62%
Submersible Transformers		42	42	86%	0%	5%	19%	14%	62%
Vault Transformers		81	81	91%	0%	0%	2%	17%	80%
Overhead Switches	LIS	361	361	97%	0%	0%	0%	5%	95%
	SCADA	94	94	84%	0%	5%	10%	26%	60%
Pad Mounted Switches	Live Front SG	88	88	87%	0%	1%	2%	30%	67%
	Solid Dielectric SG	11	11	99%	0%	0%	0%	0%	100%
	Switching Cubicles	77	77	91%	4%	3%	0%	9%	84%
Cables	Primary	679	679	95%	< 1%	< 1%	7%	2%	91%
	Secondary	1127	1123	97%	< 1%	< 1%	1%	4%	94%
Lines	1 Phase Primary	99	99	99%	0%	0%	0%	< 1%	99%
	3 Phase Primary	329	329	100%	0%	0%	0%	0%	99%
	Secondary	459	458	98%	0%	0%	< 1%	< 1%	99%
Poles	Wood Poles	10105	9564	86%	< 1%	< 1%	5%	39%	55%
	Concrete Poles	881	881	83%	0%	0%	< 1%	79%	21%
	Composite Poles	180	180	88%	0%	0%	0%	0%	100%
Vault		469	105	89%	< 1%	10%	7%	< 1%	82%
Manholes		275	62	87%	2%	8%	5%	24%	61%

Figure II-1 Graphical Health Index Results Summary

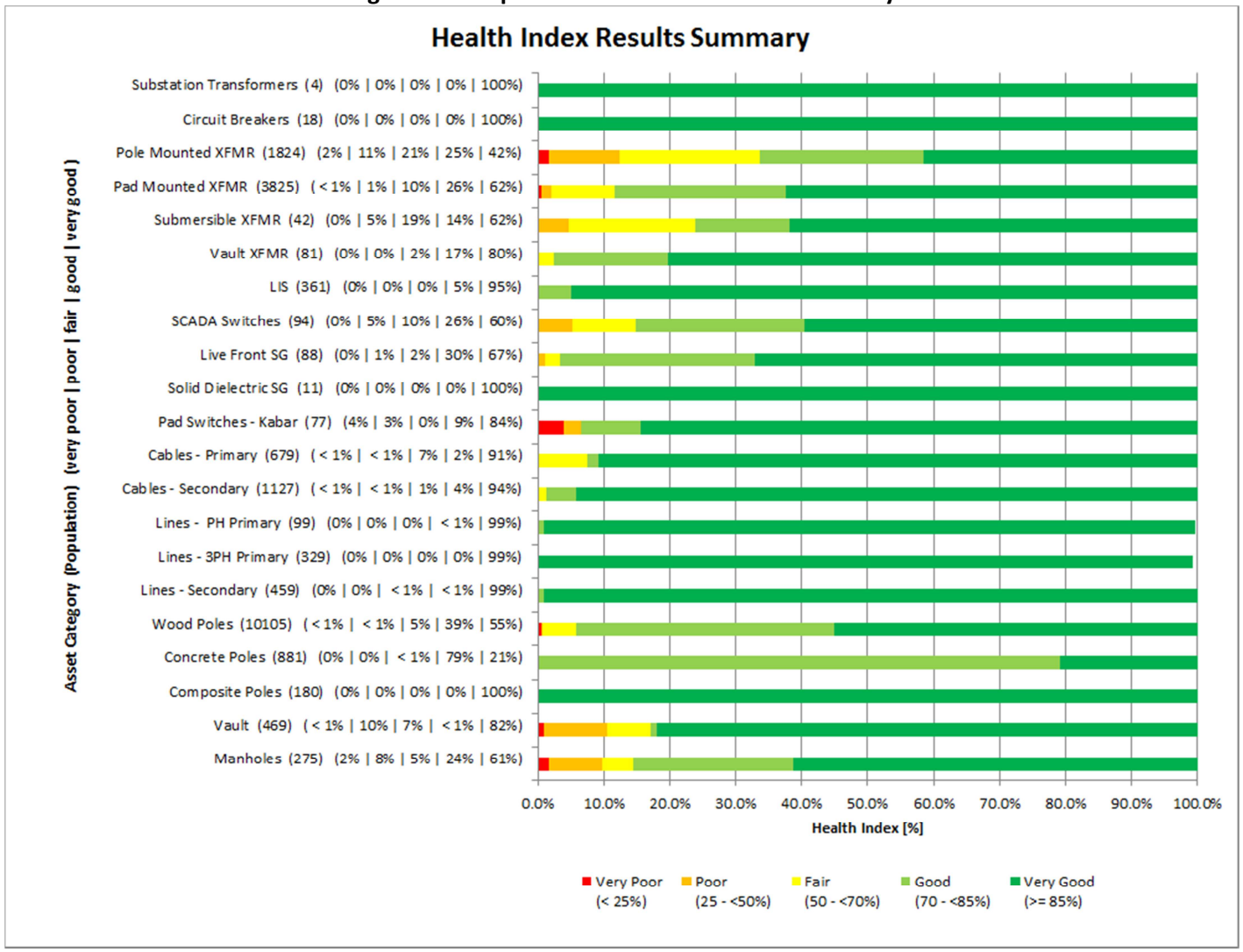


Figure II-2 2012 and 2014 Health Index Results Summary



Table II-2 Year 1 Optimal Condition-Based Flagged for Action Plan and Action Strategy

Asset Category		Condition-Based Action Plan for Year 1		Action Strategy
		Number of Units	Percentage of Population	
Substation Transformers		0	0.0%	proactive
Circuit Breakers		0	0.0%	proactive
Pole Mounted Transformers		87	4.8%	reactive
Pad Mounted Transformers		48	1.3%	reactive
Submersible Transformers		1	2.4%	reactive
Vault Transformers		0	0.0%	reactive
Overhead Switches	LIS	0	0.0%	reactive
	SCADA	0	0.0%	reactive
Pad Mounted Switches	Live Front SG	0	0.0%	reactive
	Solid Dielectric SG	0	0.0%	reactive
	Switching Cubicles	3	3.9%	reactive
Cables*	Primary	5	0.7%	reactive
	Secondary	5	0.4%	reactive
Lines*	1 Phase Primary	0	0.0%	reactive
	3 Phase Primary	0	0.0%	reactive
	Secondary	1	0.2%	reactive
Poles	Wood Poles	39	0.4%	proactive
	Concrete Poles	0	0.0%	proactive
	Composite Poles	0	0.0%	proactive
Vault		4	0.9%	reactive
Manholes		2	0.7%	reactive

*data in terms of conductor-km

Table II-3 Twenty-Year Condition-Based Flagged for Action Plan

Asset Category		Flagged for Action Plan (number of units)																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Circuit Breakers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers		87	73	63	53	45	43	42	35	37	35	34	33	30	30	28	29	29	28	30	24
Pad Mounted Transformers		48	42	39	35	37	38	38	38	43	42	43	41	43	46	46	50	51	51	56	53
Submersible Transformers		1	0	1	0	0	0	0	0	0	2	1	2	2	1	0	1	1	1	0	0
Vault Transformers		0	0	0	0	0	0	0	0	0	0	0	0	1	1	3	2	1	1	1	2
Overhead Switches	LIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
	SCADA	0	0	0	1	1	1	0	1	0	2	1	1	1	1	1	1	1	2	1	1
Pad Mounted Switches	Live Front SG	0	1	0	0	0	0	1	0	0	0	0	0	1	1	2	3	4	4	4	4
	Solid Dielectric SG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Switching Cubicles	3	2	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	1	0
Cables*	Primary	5	5	6	6	7	7	7	8	7	9	8	8	9	9	9	9	9	10	10	11
	Secondary	5	6	7	7	8	8	9	11	11	11	13	14	15	15	17	17	19	19	20	21
Lines*	1 Phase Primary	0	0	1	0	0	1	0	1	0	1	0	1	0	1	1	0	1	1	1	1
	3 Phase Primary	0	0	1	0	0	1	0	1	0	1	0	1	0	1	1	0	1	1	1	1
	Secondary	1	1	1	1	1	1	2	2	2	2	3	2	3	2	3	2	3	3	3	4
Poles	Wood Poles	39	13	7	10	13	14	20	25	29	37	39	51	59	67	79	87	99	112	127	143
	Concrete Poles	0	0	0	0	0	0	1	1	1	2	3	4	5	6	8	10	13	16	21	24
	Composite Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault		4	4	3	4	3	3	2	3	2	3	2	3	2	3	3	2	3	3	4	3
Manholes		2	1	1	1	1	0	1	0	0	1	0	0	0	1	0	0	0	1	0	0

*data in terms of conductor-km

Table II-4 Twenty-Year Levelized Condition-Based Flagged for Action Plan

Asset Category		Levelized Flagged for Action Plan (number of units)																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Circuit Breakers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers		87	73	63	53	45	43	42	36	36	35	34	33	29	29	29	29	30	27	27	28
Pad Mounted Transformers		44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Submersible Transformers		0	0	1	0	1	0	0	1	0	1	1	2	2	0	1	0	1	0	1	0
Vault Transformers		0	0	1	0	0	1	0	0	1	0	0	1	0	0	0	2	1	2	1	2
Overhead Switches	LIS	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1
	SCADA	1	0	1	1	1	1	0	1	1	1	1	1	1	0	1	1	1	1	1	0
Pad Mounted Switches	Live Front SG	1	1	1	2	1	1	1	2	1	1	1	2	1	1	1	2	1	1	1	2
	Solid Dielectric SG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Switching Cubicles	3	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0	1	0	0	1
Cables*	Primary	8	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Secondary	13	12	12	13	13	12	13	13	12	13	13	12	13	13	12	13	13	12	13	13
Lines*	1 Phase Primary	1	0	0	1	0	1	0	1	0	1	1	0	1	0	1	0	1	0	1	1
	3 Phase Primary	1	0	0	1	0	1	0	1	0	1	1	0	1	0	1	0	1	0	1	1
	Secondary	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	3
Poles	Wood Poles	54	53	53	54	53	54	53	54	53	54	53	54	53	54	53	54	53	54	53	54
	Concrete Poles	6	5	6	6	5	6	6	6	5	6	6	6	5	6	6	6	5	6	6	6
	Composite Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault		4	4	3	4	2	3	3	3	2	3	3	3	2	3	3	3	2	3	3	3
Manholes		2	0	0	1	0	1	0	0	1	0	1	0	1	0	0	1	0	1	0	0

*data in terms of conductor-km

Figure II-3 Graphical Twenty-Year Flagged for Action Plan

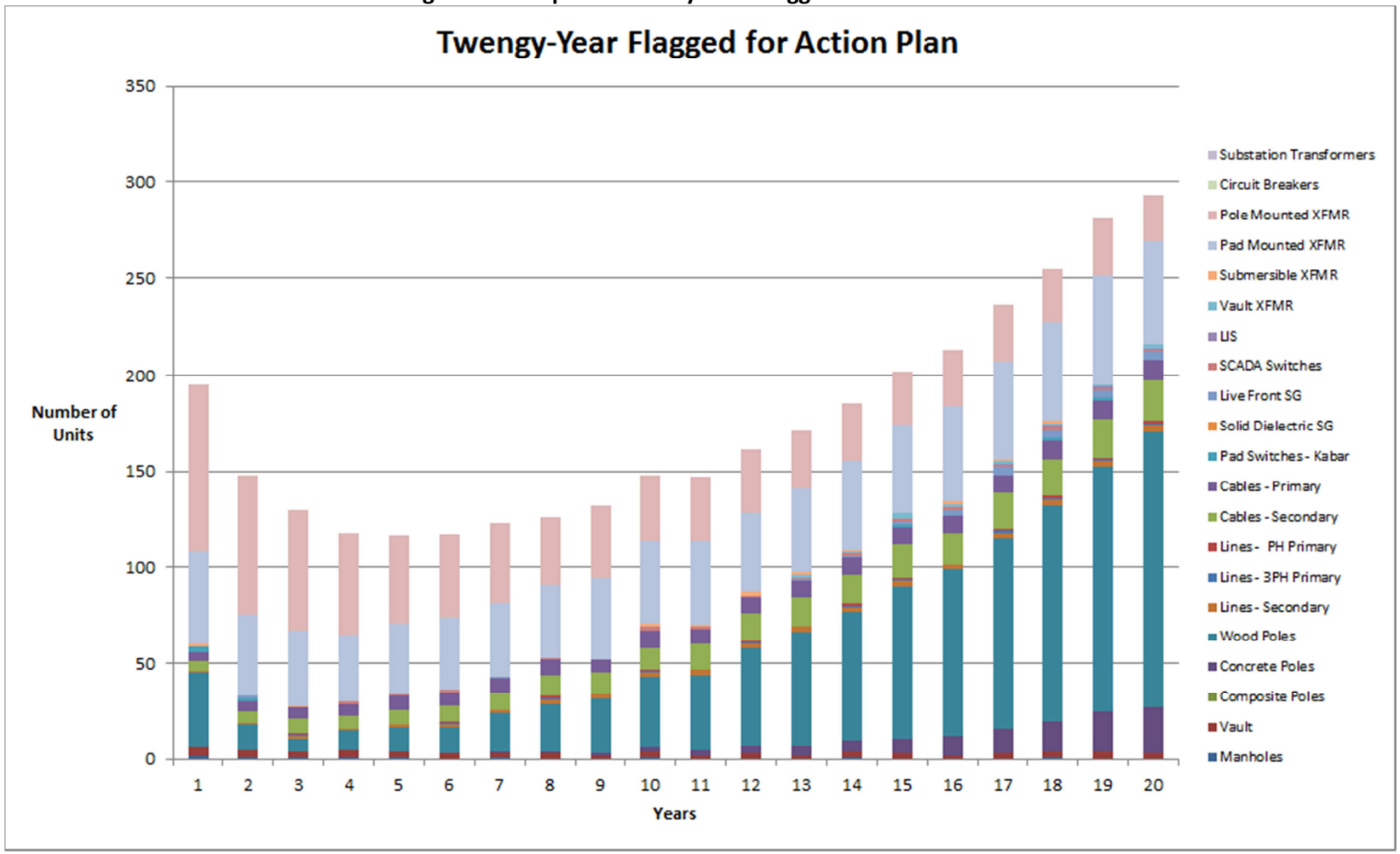
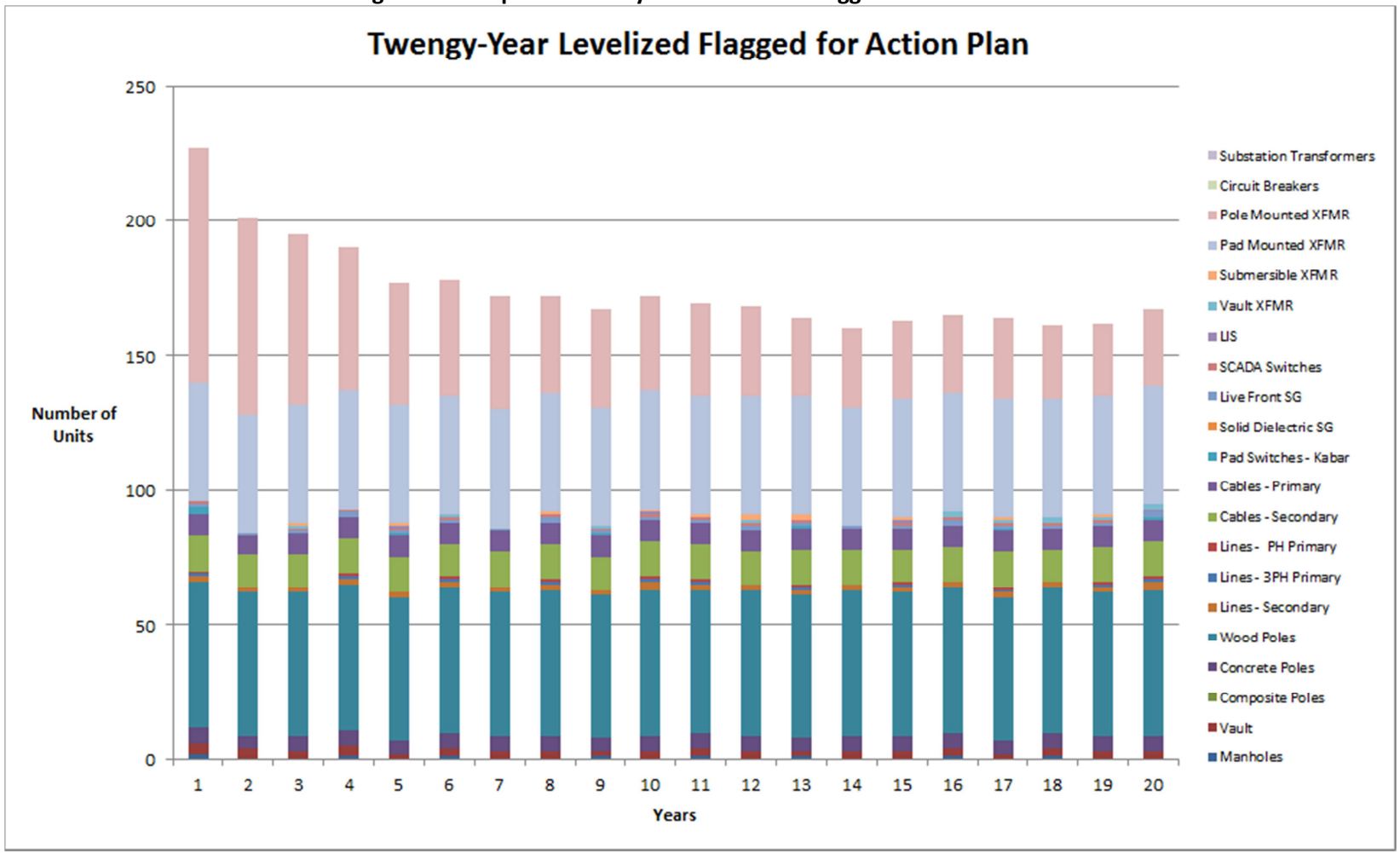


Figure II-4 Graphical Twenty-Year Levelized Flagged for Action Plan



Data Assessment Results

Data assessment includes determining the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of condition parameter data currently defined in its Health Index formula. The data gaps for each asset category are shown in Table II-5. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any asset in an asset category. The more minimal the data gaps, the higher the quality of available condition data and Health Index formulas.

Table II-5 Average DAI of All Asset Categories

Asset Category		Average DAI	Sample Size (% of Population)
Substation Transformers		94%	100%
Circuit Breakers		8%	100%
Pole Mounted Transformers		22%	100%
Pad Mounted Transformers		53%	100%
Submersible Transformers		26%	100%
Vault Transformers		96%	100%
Overhead Switches	LIS	20%	100%
	SCADA	25%	100%
Pad Mounted Switches	Live Front SG	62%	100%
	Solid Dielectric SG	59%	100%
	Switching Cubicles	60%	100%
Cables	Primary	21%	100%
	Secondary	21%	100%
Lines	1 Phase Primary	21%	100%
	3 Phase Primary	21%	100%
	Secondary	21%	100%
Poles	Wood Poles	78%	95%
	Concrete Poles	84%	100%
	Composite Poles	95%	100%
Vault		22%	22%
Manholes		22%	23%

The most important data, namely age, inspection records, oil quality and dissolved gas analysis tests, were available for all substation transformers. As such, the average DAI for this asset category is 94%. Winding Doble tests and more specific information related to transformer cooling would improve the HI formula.

Because age was the only data available for breakers, the average DAI is only 8%. The gaps include information on breaker operating mechanism, contacts, interrupter, and insulation.

Age, loading data, and number of customers are available for all distribution transformers. No other data was available for pole mounted and submersible transformers. The average DAI for these asset categories are 22% and 26% respectively. Gaps include inspection data related to exterior tank condition, and transformer connection and insulation. Detailed inspection data was available only for approximately 39% of all pad mounted transformers. The overall DAI for this asset category is 53%. Because detailed inspection data was available for most vault transformers, the average DAI for this category is 96%.

Data for LIS and SCADA switches include age and number of operations. Gaps include indication of whether a unit has been maintained, inspection data related to operating mechanism, interrupter, insulation, and switch condition. Because such data was not available, the average DAIs for LIS and SCADA switches were only 20% and 25% respectively.

Age and inspection records are available for most pad mounted switchgear, solid dielectric switchgear, and switching cubicles. The average DAI for these asset categories are 62%, 59%, and 60% respectively.

Age was the only data available for primary and secondary cables. Data related to splices and terminations, maintenance records, fault history, and loading were not available. As such, the DAIs for both primary and secondary cables is only 21%.

Overhead lines (single phase, three phase, and secondary) had only age data available. The DAIs for all three asset categories is 21%. Data gaps include information on repairs and splices and corrective maintenance records.

Age and inspection records are available for all pole types. Additionally pole strength is available for wood poles. The DAI for wood, concrete, and composite poles are 78%, 84%, and 95% respectively.

Inspection data related to wall, floor, and ceiling conditions was collected for vaults and manholes. However, only 22% of vaults and 22% of manholes were inspected. As such, the average DAIs were only 22% and 22% respectively.

In summary, the following asset categories had fairly high data availability indicators: substation transformers, vault transformers, and poles. Circuit breakers, lines and cables had only age available.

III CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for GHESI's key distribution assets, namely substation transformers, circuit breakers, distribution transformers (pole mounted, pad mounted, submersible, vault), overhead switches (LIS, SCADA), pad mounted switches (live front, solid dielectric, pad switches), cables (primary, secondary), lines (1 phase primary, 3 phase primary, secondary), poles (wood, concrete, composite), vaults, and manholes.

2. At 78%, pole mounted transformers have the lowest average HI of all asset classes. Further, 12% of the assets are in poor or very poor condition.

3. Manholes and vaults are, also of concern. While the average Health Index for these asset categories are 87% and 89% respectively, approximately 10% of manholes are in poor or very poor condition and around 10% of vaults are in poor or very poor condition.

   It should be noted, however, that more than half of the assets in this study's sample pool were assets inspected and subsequently assessed because they were suspect units or in areas that made them more prone to degradation. The samples are not likely to be representative of the entire vault and manhole populations. It is probable that the remainders of the vault and manhole populations are, on average, in better condition than the samples.

4. It is also worth noting that 6% of switching cubicles are in poor or very poor condition.

5. The most significant asset, in terms of quantities flagged for action, is pole mounted transformers. Eighty seven (87) pole mounted transformers are flagged for action in the first year; this represents 4.8% of the population.

6. Also of significance are that the following are flagged for action in the first year:
   - 48 pad mounted transformers (1.3% of the population)
   - 37 wood poles (0.4% of the population)

7. It is important to note that the flagged for action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence GHESI's asset management process.

8. Availability of data is as follows:
   - Substation transformers, vault transformers, live front pad mounted switchgear, and poles had good condition data available for most units. As such, these asset categories had fairly high data availability indicators.
   - While good condition data is being collected for pad mounted transformers, such inspection data was only available for 40% of the population.
   - Pole mounted, submersible transformers, and overhead switches had service information and age, however no inspection records were available.

- Age and inspection records were available for all pad mounted switch categories (live front, solid dielectric, and switching cubicles).
- The percentage of vaults and manholes that have been inspected have both increased to 22% of their respective populations.
- Circuit breakers, lines and cables had only age data available.

9. The data gaps for all asset categories, if applicable, were identified. It is recommended that efforts be made to close the data gaps in a prioritized manner.

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IV APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

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1 Substation Transformers

1.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Substation Transformers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Substation Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Insulation	11	Oil Quality	3	Table 1-2
		Oil DGA	6	Table 1-3
Cooling	1	Fan	1	Table 1-6
Sealing & Connection	2	Oil Conservator	1	Table 1-6
		Physical Check	1	Table 1-6
		Oil Leak	1	Table 1-6
Service Record	6	Loading	5	Table 1-5
		Age	3	Figure 1-1

1.1.2 Condition Parameter Criteria

Oil Quality

Table 1-2 Substation 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%	

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

$$\text{For example if all data is available, overall Factor} = \frac{\sum Score_i \times Weight_i}{12}$$

Oil DGA

Table 1-3 Substation 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 ≥ 500 ppm and CO2 ≥ 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 ≥ 500 ppm and CO2 ≥ 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 Doble Test

Table 1-4 Substation Transformers Winding Doble 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%

Age

Assume that the failure rate for Substation 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 95% 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.

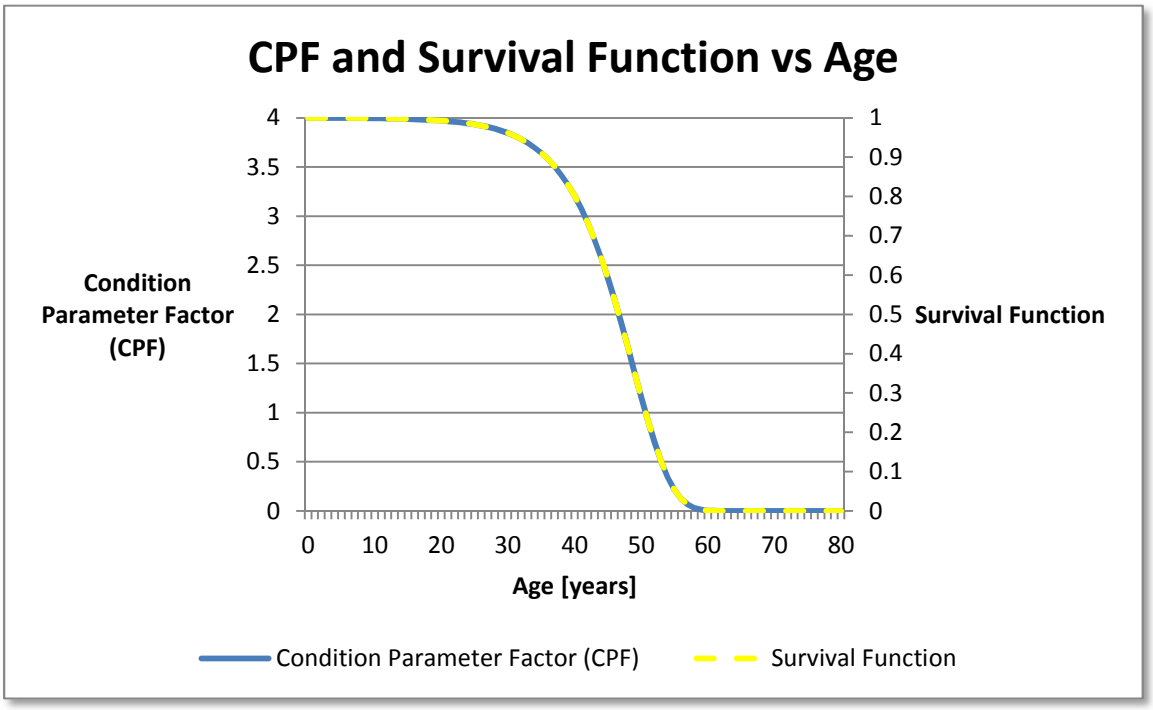


Figure 1-1 Substation Transformers Age Condition Criteria

Loading History

Table 1-5 Substation Transformers Loading History

Data: S1, S2, S3, …, SN recorded data
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Sub-Factor Score = $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Sub-Factor Score should be multiplied by 0.6 to show the effect of overheating.

Okay or Not Okay

Table 1-6 Substation Transformers Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

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 9 years.

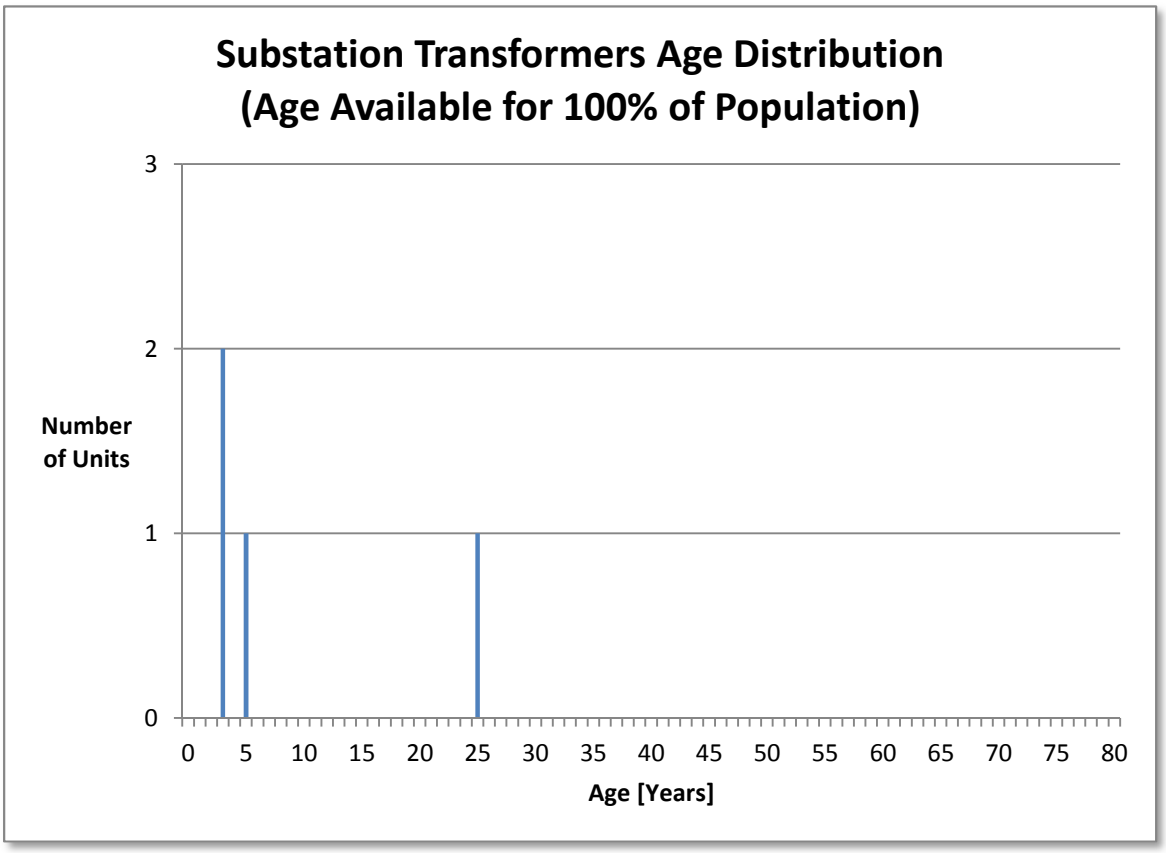


Figure 1-2 Substation Transformers Age Distribution

1.3 Health Index Results

There are 4 in-service Substation Transformers at GHESI. Of these, 4 units had sufficient data for assessment.

The average Health Index for this asset group is 93%. None were in poor or very poor condition.

The Health Index Distribution is shown in Figure 1-3 through Figure 1-5.

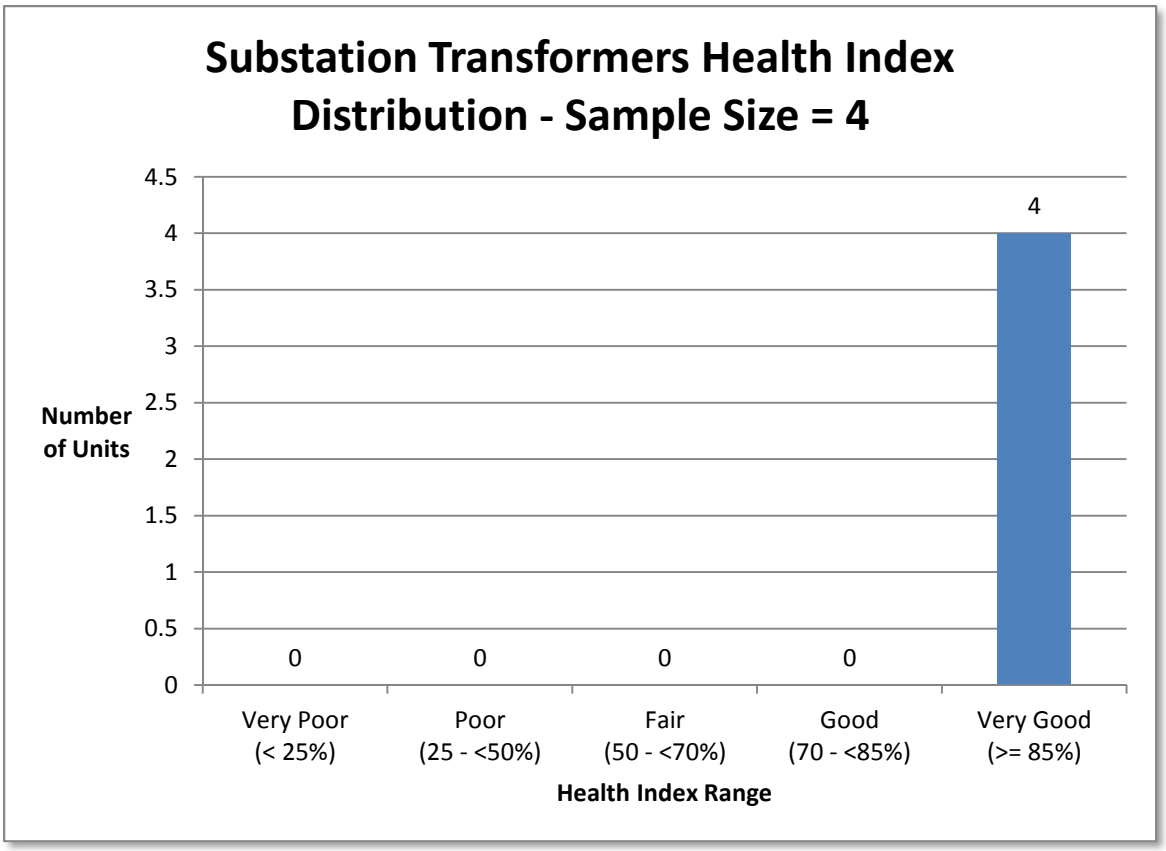


Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

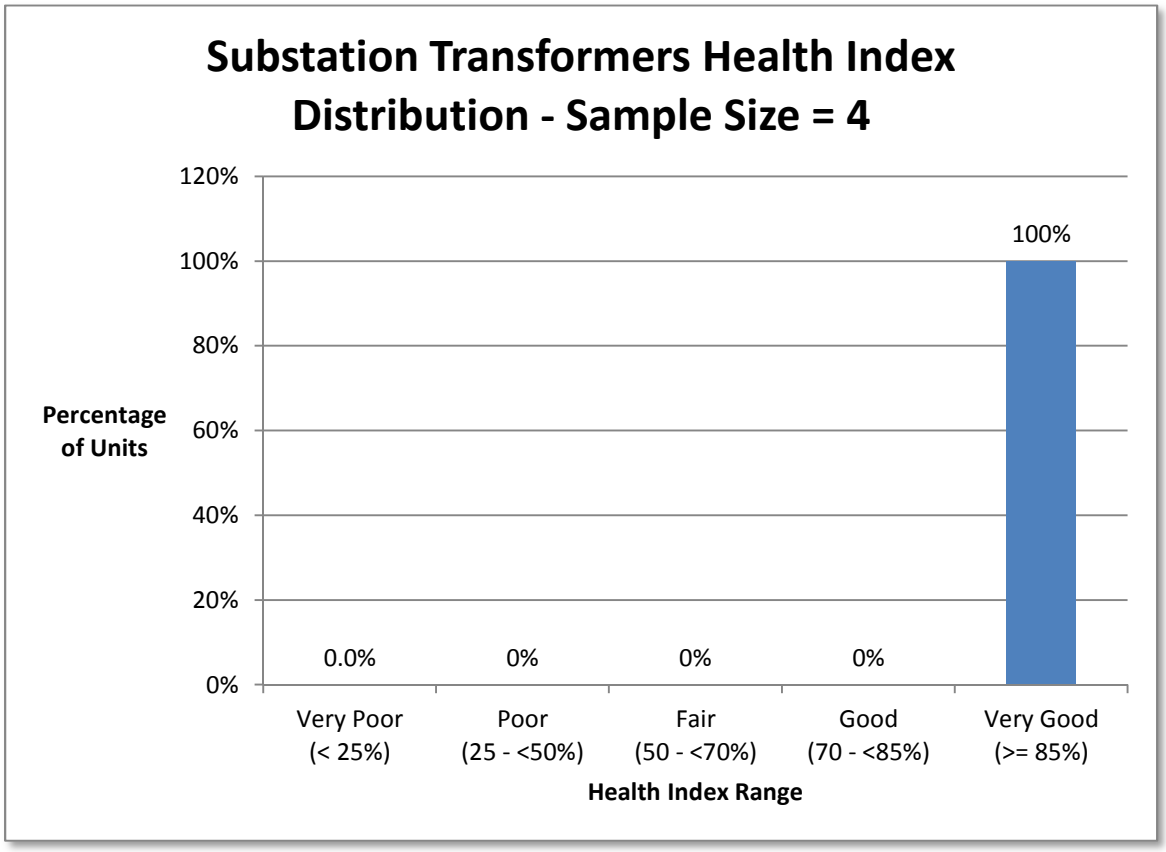


Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

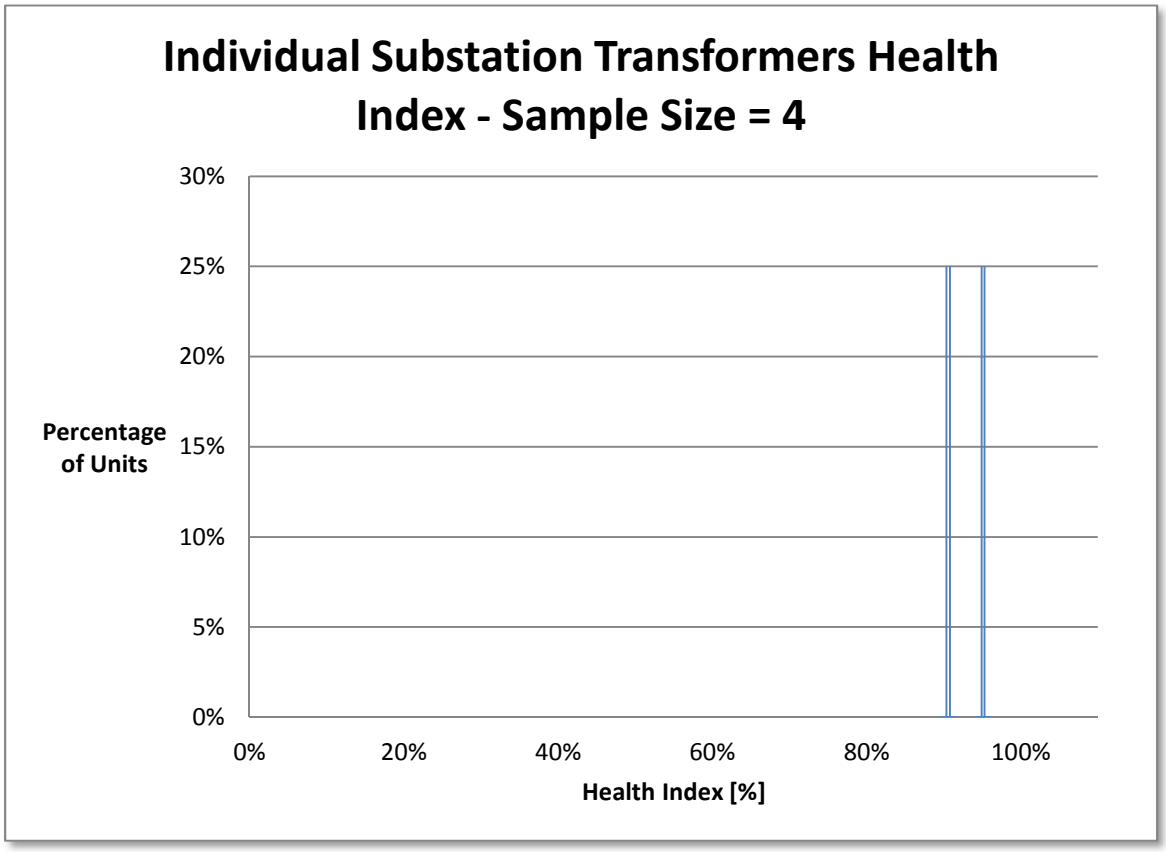


Figure 1-5 Substation Transformers Health Index Distribution by Value (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 1-7 Health Index Results for Each Substation Transformers Unit

Transformer	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category
Arlen T1	3	91%	**90.3%**	Very Good
Rockwood MS-2	5	95%	**90.8%**	Very Good
Rockwood MS-1	25	99%	**94.9%**	Very Good
Arlen T2	3	91%	**95.3%**	Very Good

1.4 Condition-Based Flagged for Action Plan

Based on transformer condition, no units are flagged for action in the next 20 years.

1.5 Data Analysis

1.5.1 Data Gap

The data available for Substation Transformers includes age, inspection results, oil quality, dissolved gas analysis. Although much of the critical data, namely oil quality and DGA, are available and included in the Health Index formula, additional data may be collected and used to improve the Health Index formulation. These are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Winding Doble Test	Insulation	☆ ☆ ☆	Transformer windings	Power/dissipation factor indicating insulation deterioration	On-site measurement test
Cooling	Cooling	☆ ☆ ☆	Cooling oil	Abnormal oil flow	Visual Inspection / On-site Reading / IR Scans
				Abnormal oil pump motor	
			Radiator	Plugged radiator	
			Valves	Broken valves	
			Transformer tank	High top oil temperature	
			Winding	High winding temperature	
Primary and Secondary Connector	Sealing & Connection	☆	Cable connection	Defects due to installation	Visual inspection
			Pothead		
Main Tank Desiccant		☆	Transformer tank breather	Desiccant seal failure	Visual inspection

1.5.2 Data Availability Distribution

The average DAI for Substation Transformers is 94%. All units had age, oil and DGA tests, as well as inspection results.

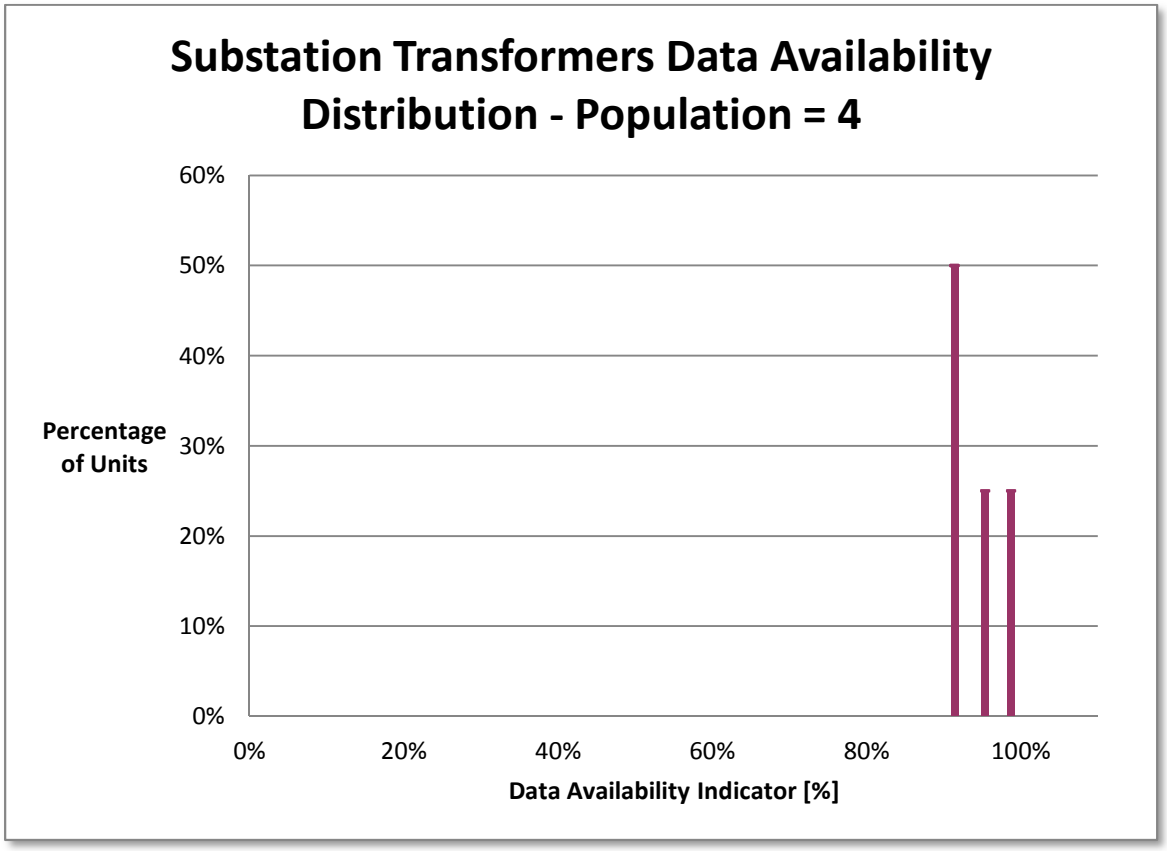


Figure 1-6 Substation Transformers Data Availability Distribution

2 Breakers

2.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Breakers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Breakers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	14	Lubrication	1	
		Linkage	1	
		cabinet	1	
Contact Performance	7	Trip Time	1	
		Closing Time	1	
		Contact Wear	1	
Arc Extinction	5	Arc Extinction Mechanism	1	
Insulation	2	Insulation	1	
Service Record	5	Overall Condition	1	
		Age	1	Figure 2-1

2.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Breakers 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 95% 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.

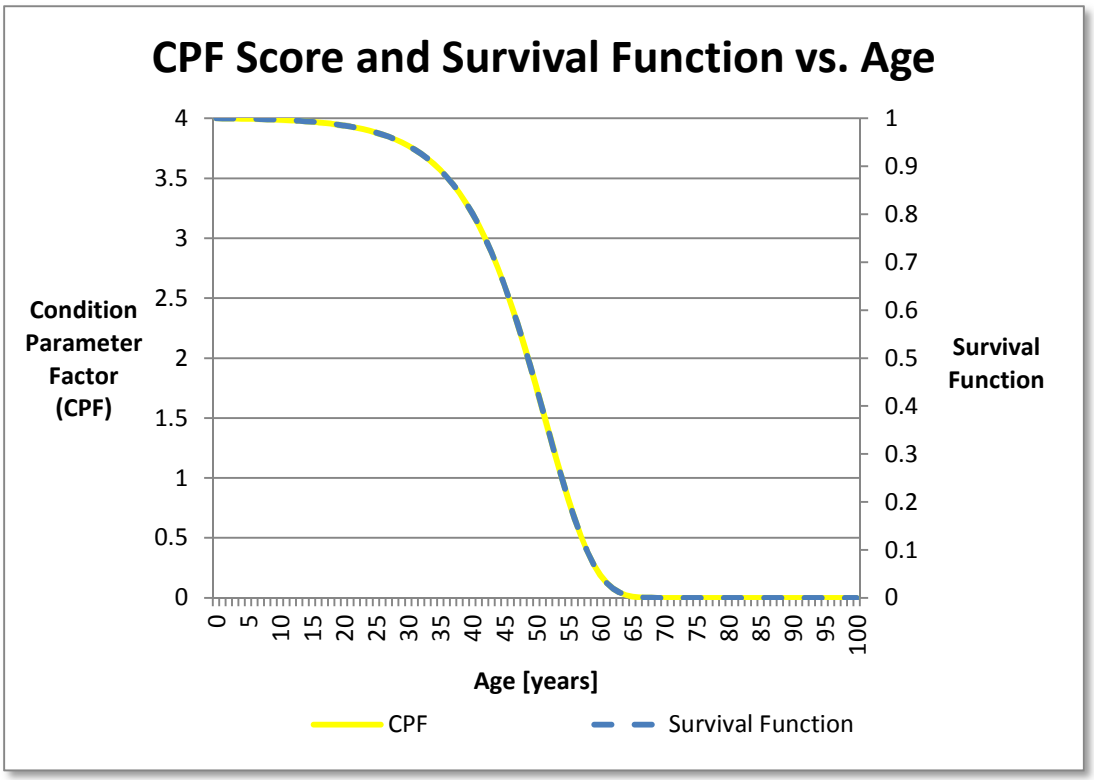


Figure 2-1 Breakers Age Condition Criteria

2.2 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 3 years.

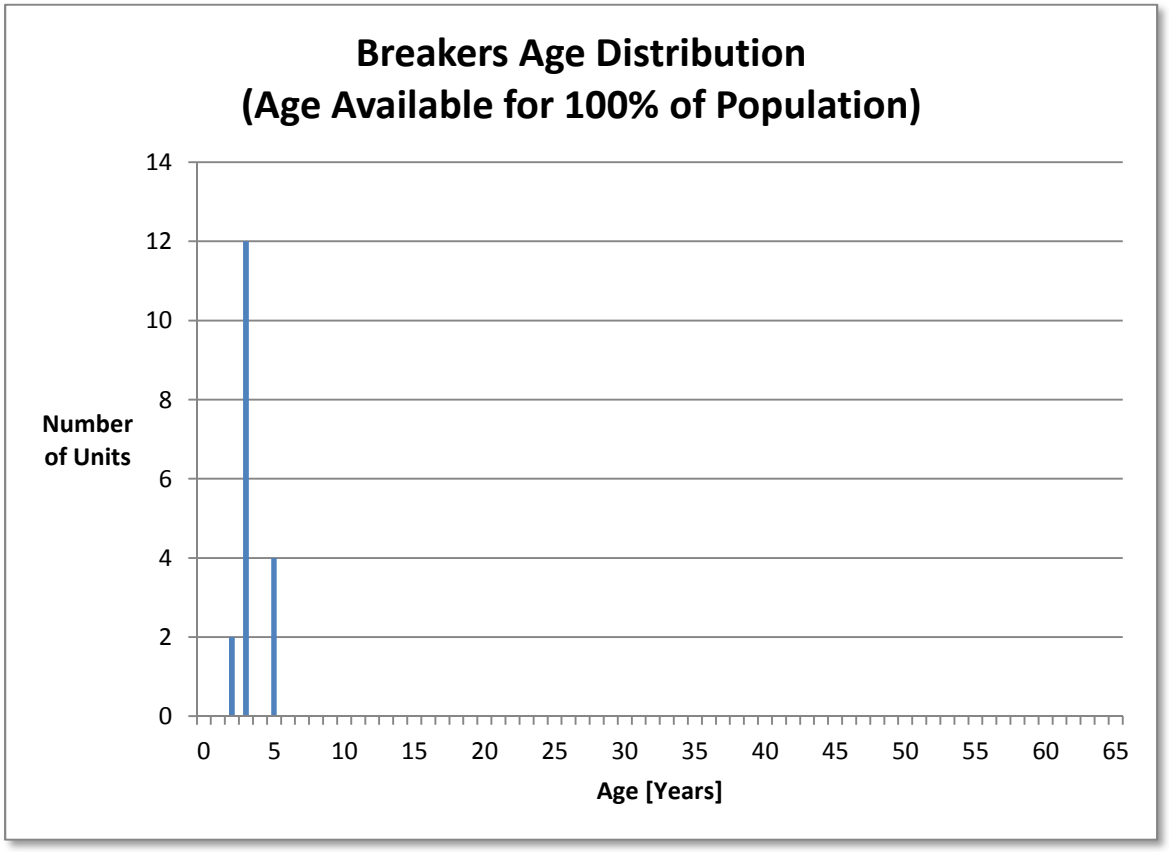


Figure 2-2 Breakers Age Distribution

2.3 Health Index Results

There are 18in-service Breakers at GHESI. Of these, 18 units had sufficient data for assessment.

The average Health Index for this asset group is 100%. None were found to be in poor or very poor condition.

The Health Index Distribution is shown in Figure 2-3 through Figure 2-5.

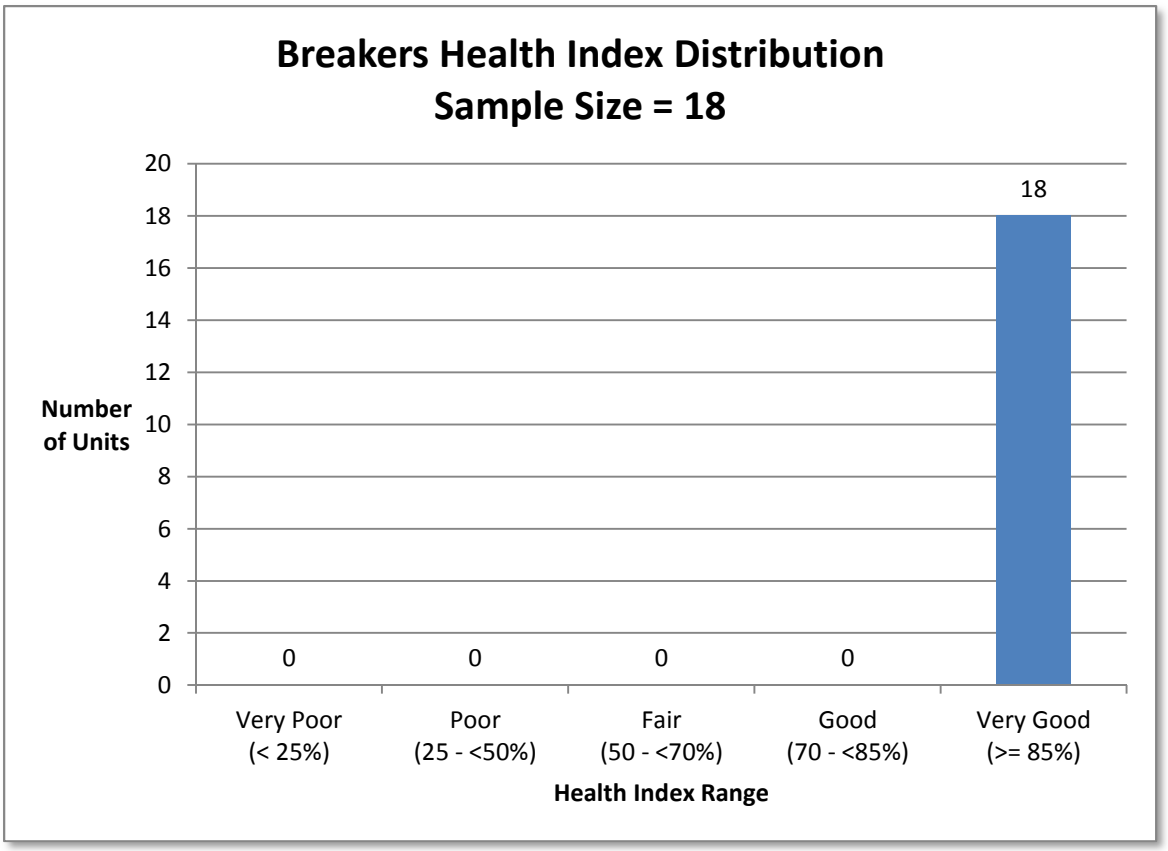


Figure 2-3 Breakers Health Index Distribution (Number of Units)

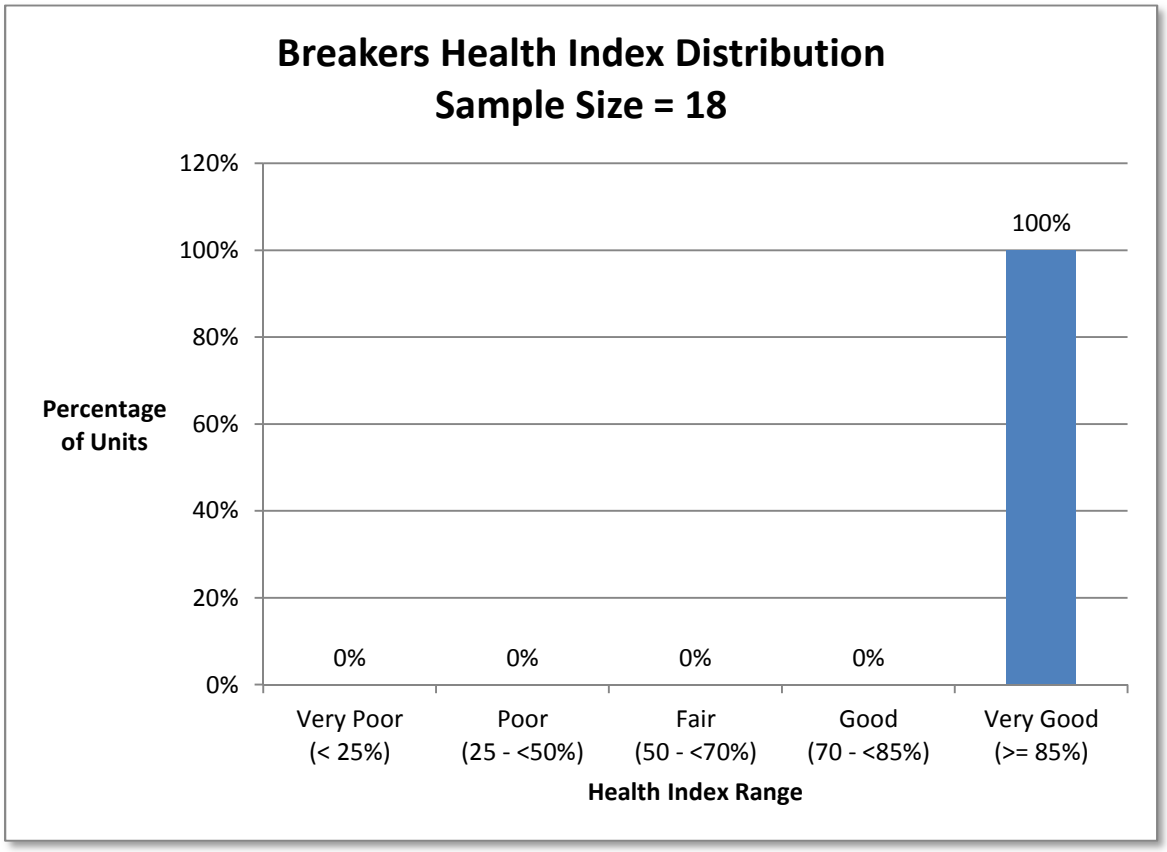


Figure 2-4 Breakers Health Index Distribution (Percentage of Units)

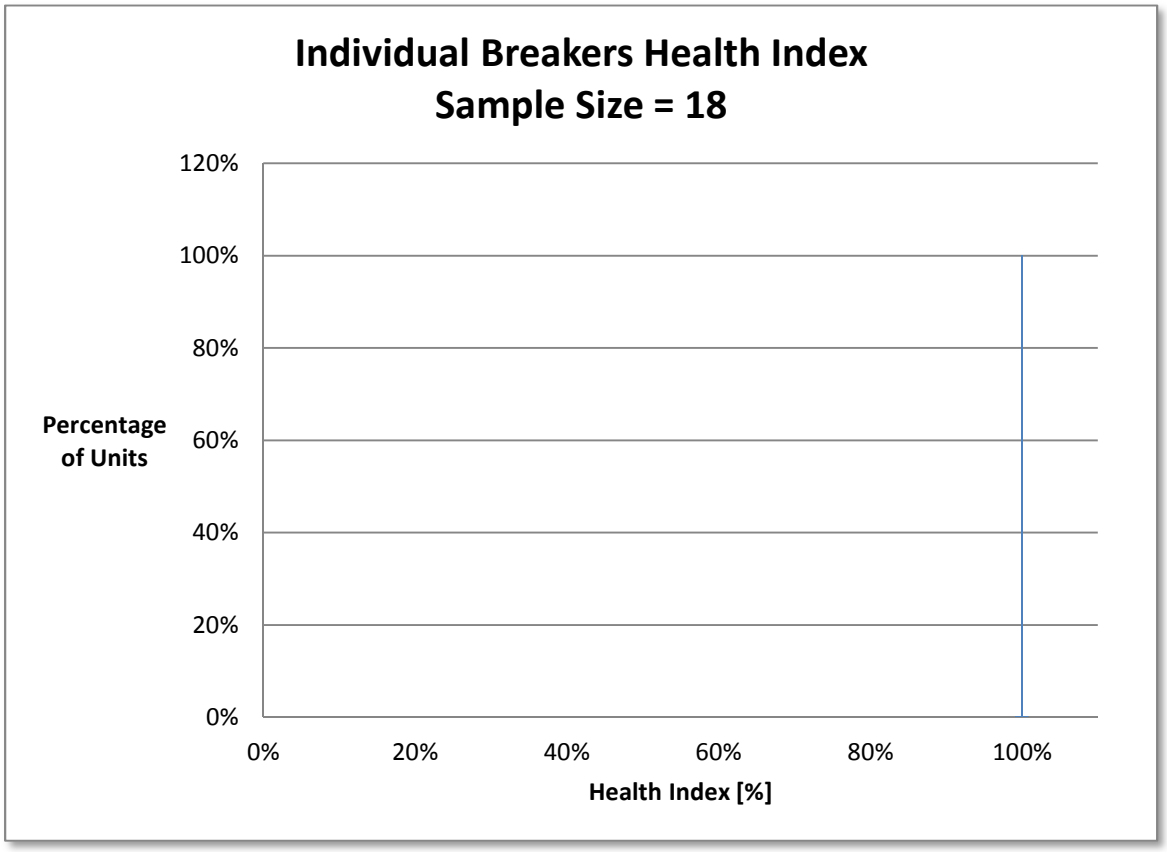


Figure 2-5 Breakers Health Index Distribution by Value (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 2-2 Health Index Results for Each Breakers Unit

Transformer	Station Number	Age	Data Availability	Health Index	Health Index Category
32	MS2-F3	5	8%	**99.9%**	Very Good
35	MS2-T1B	5	8%	**99.9%**	Very Good
36	MS2-F2	5	8%	**99.9%**	Very Good
37	MS2-F1	5	8%	**99.9%**	Very Good
41	T1B	3	8%	**99.9%**	Very Good
42	7356F12	3	8%	**99.9%**	Very Good
43	7356F13	3	8%	**99.9%**	Very Good
44	7356F11	3	8%	**99.9%**	Very Good
45	7356F14	3	8%	**99.9%**	Very Good
72	YB	3	8%	**99.9%**	Very Good
73	T2Y	3	8%	**99.9%**	Very Good
74	BY	3	8%	**99.9%**	Very Good
90	7356F21	3	8%	**99.9%**	Very Good
91	7356F22	3	8%	**99.9%**	Very Good
92	7356F23	3	8%	**99.9%**	Very Good
93	7356F24	3	8%	**99.9%**	Very Good
108	T2L6	2	8%	**100.0%**	Very Good
109	T1L5	2	8%	**100.0%**	Very Good

2.4 Condition-Based Replacement Plan

Based on breaker condition, no units are flagged for action in the next 20 years.

2.5 Data Analysis

2.5.1 Data Gaps

The data available for Breakers was age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Linkage	Operating Mechanism	★ ★ ★	Operating system	Mechanical part and linkage issue	Visual inspection
Lubrication		★ ★ ★	Lubricants	Lubricant ageing	Visual inspection
Cabinet		★	Control cabinet	Cable termination issue	Visual inspection
				Door sealing gasket issue	
				Space heater issue	
				Metallic surface corrosion	
Closing Time	Contact Performance	★	Breaker performance	Time from energizing the opening circuit to fully closed	Measurement / Testing
Trip Time		★	Breaker performance	Duration of current interruption	Measurement / Testing
Arcing Contact		★ ★	Arcing contact	Arcing contact wear	Measurement / Testing
SF6 Leak	Arc Extinction	★ ★	SF6 Breaker Poles	Gas density drop	On-site reading (Using SF6 gas density monitor)
Vacuum Bottle		★ ★	Vacuum CB	Vacuum status check	On-site test (Through hi-pot test)
Dielectric Test	Insulation	★ ★	Insulation	Insulation issue	Measurement / Testing

2.5.2 Data Availability Distribution

The average DAI for Breakers is 8% because all breakers were had age.

The data availability distribution for the population is shown in Figure 2-6.

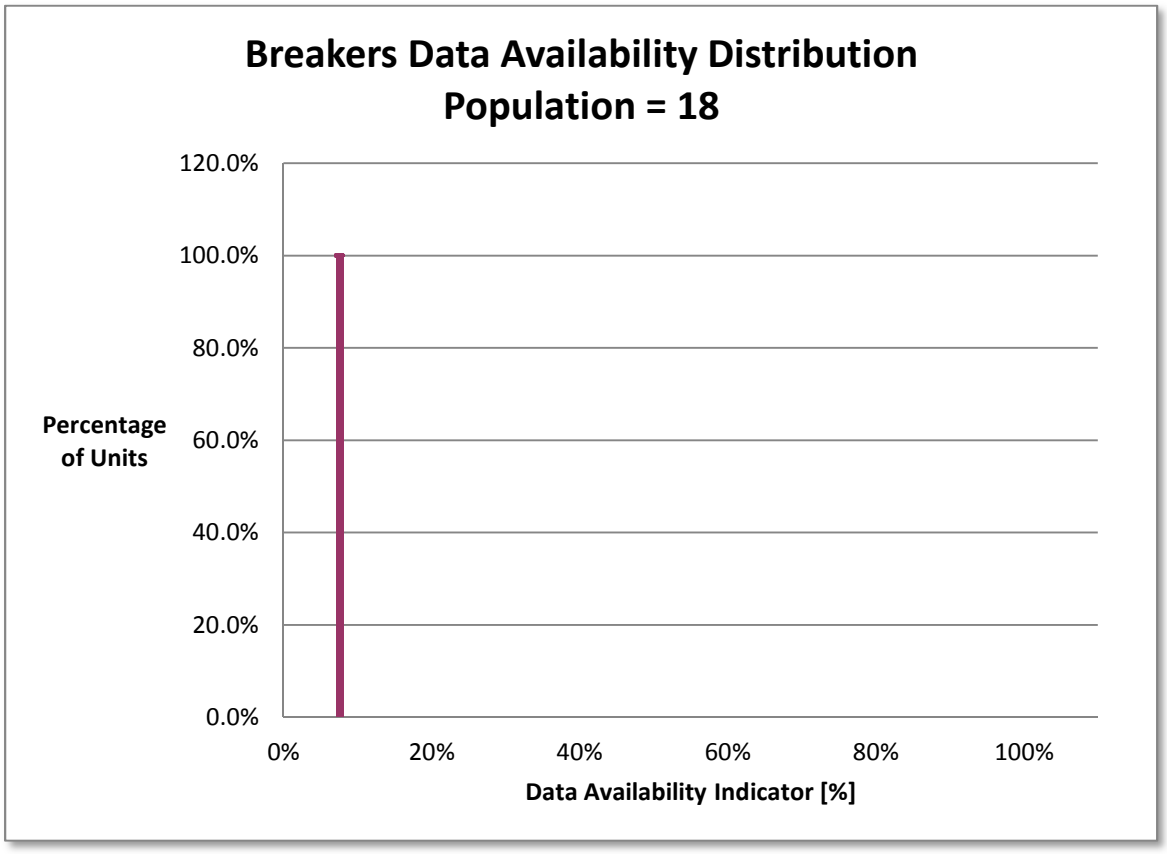


Figure 2-6 Breakers Data Availability Distribution

3 Pole Mounted Transformers

3.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Pole Mounted Transformers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Pole Mounted Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	1	
Connection and Insulation	4	Oil Leak	5	
		Connection	2	
		Grounding	1	
		Bushing	2	
Service Record	3	Number of Customers	1	Table 3-2
		Age	2	Figure 3-1
		Loading	2	Table 3-3
		Overall Condition	2	

3.1.2 Condition Parameter Criteria

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 failure (P_f) for this asset are 20% and 95% 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:

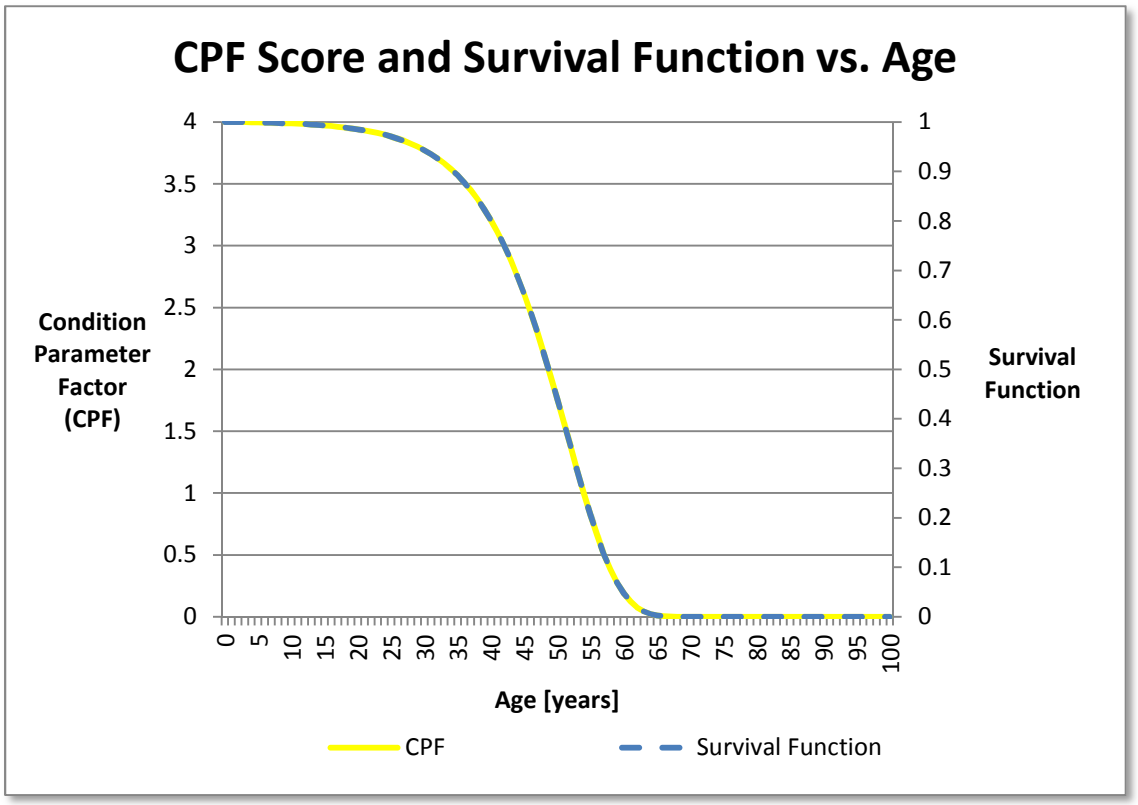


Figure 3-1 Pole Mounted Transformers Age Condition Criteria

Number of Customers

Table 3-2 Pole Mounted Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	Transformer Size <= 100 kVA	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{\textit{Annual Peak Load}}{\textit{Nameplate Rating}}$$

Table 3-3 Pole Mounted Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

3.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 66% of the population. The average age was found to be 21 years.

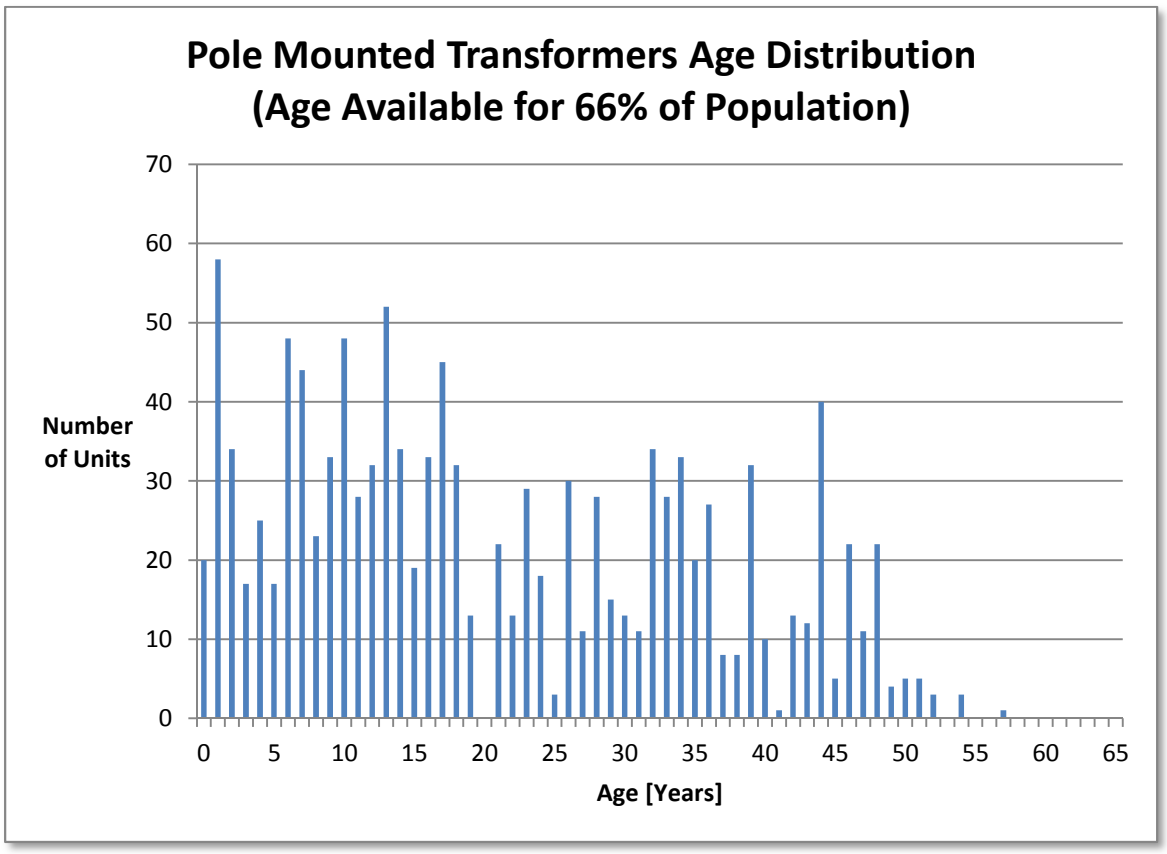


Figure 3-2 Pole Mounted Transformers Age Distribution

3.3 Health Index Results

There are 1824 in-service Pole Mounted Transformers at GHESI. There were 1821 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 78%. Approximately 12% of the units were found to be in poor condition.

The Health Index Results are as follows:

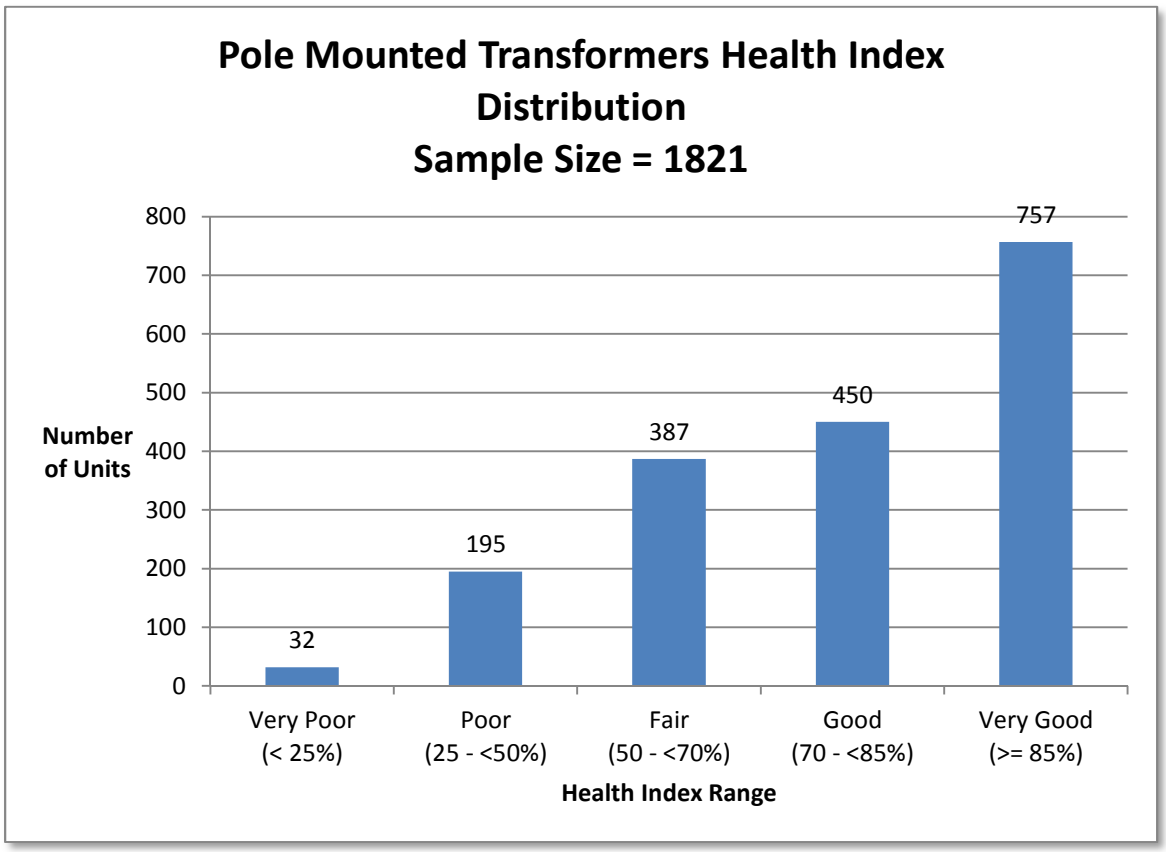


Figure 3-3 Pole Mounted Transformers Health Index Distribution (Number of Units)

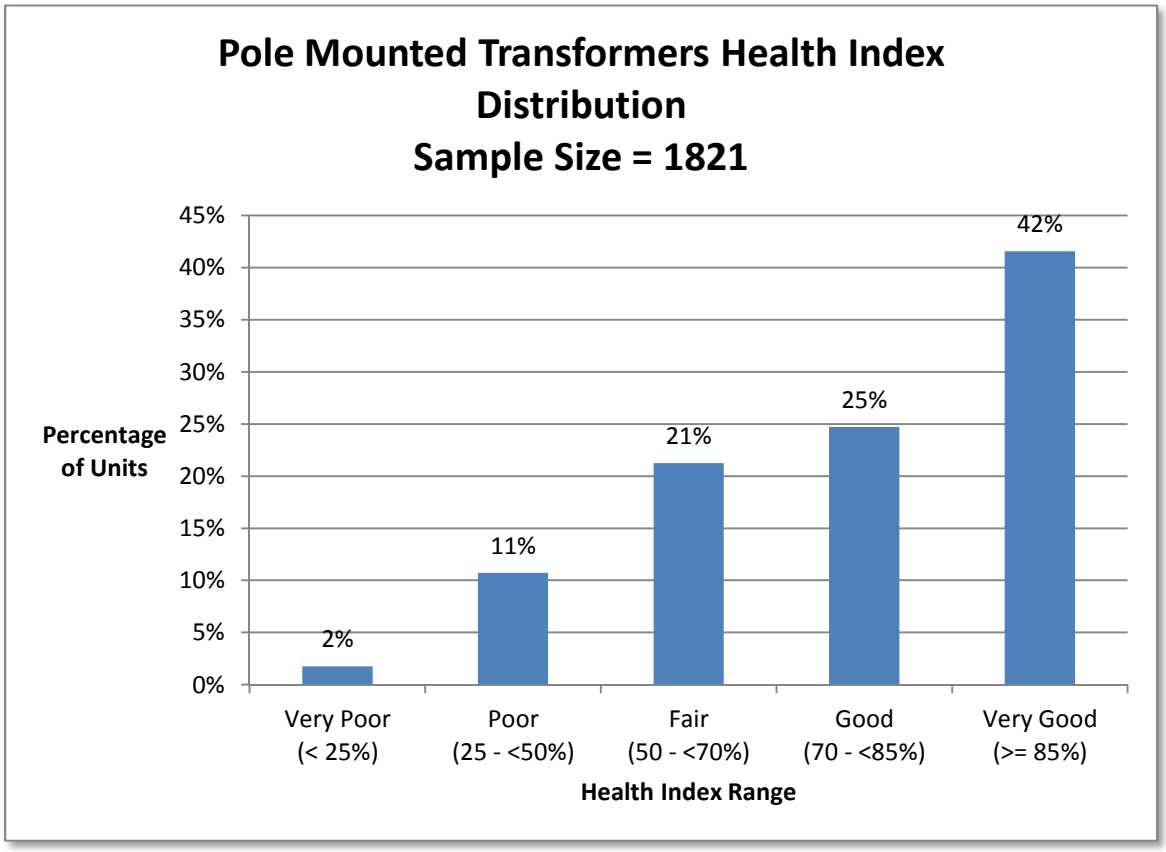


Figure 3-4 Pole Mounted Transformers Health Index Distribution (Percentage of Units)

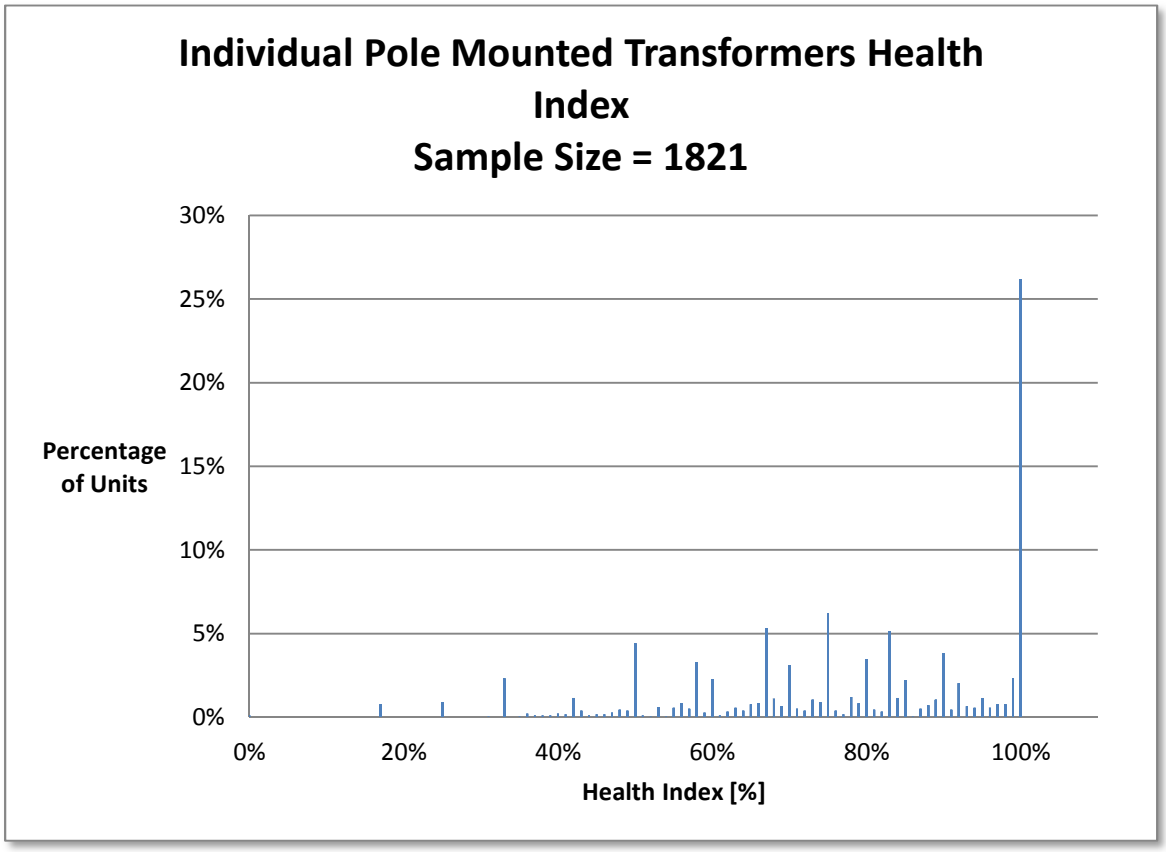


Figure 3-5 Pole Mounted Transformers Health Index Distribution by Value (Percentage of Units)

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 asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

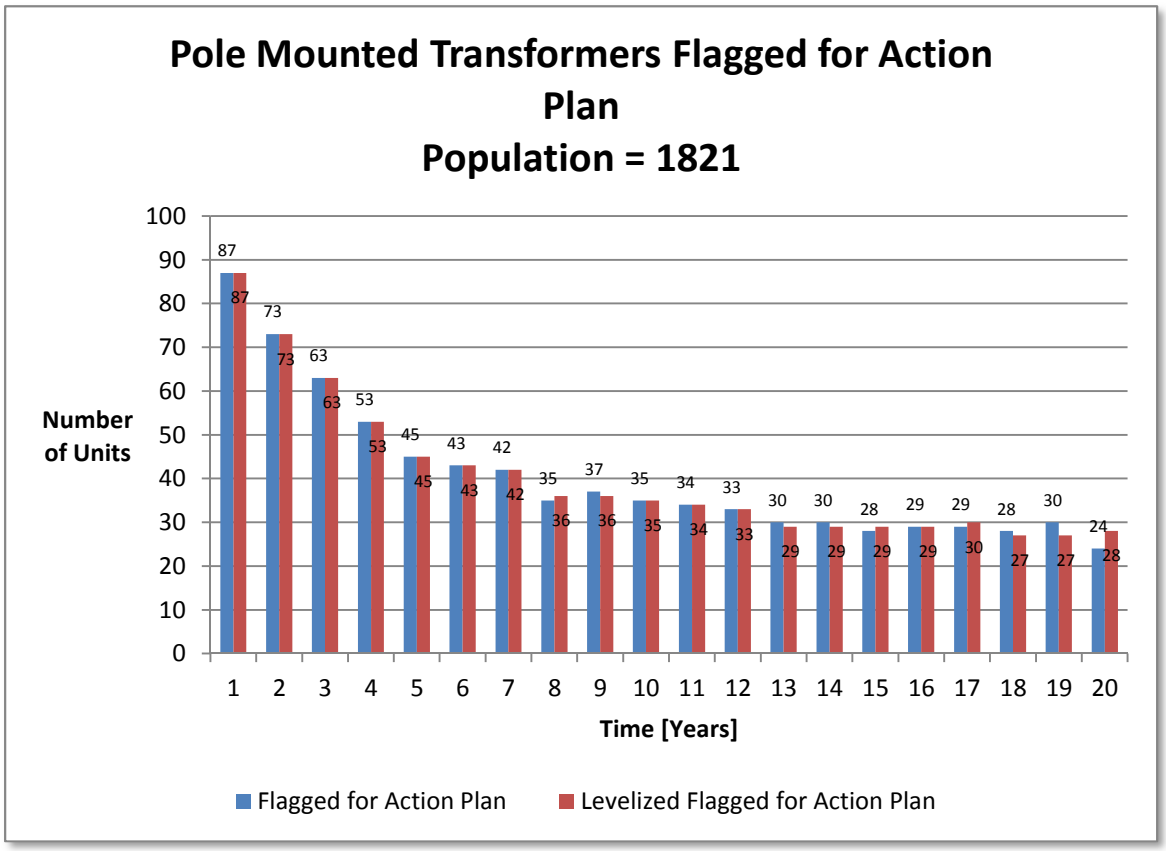


Figure 3-6 Pole Mounted Transformers Condition-Based Flagged for Action Plan

3.5 Data Analysis

3.5.1 Data Gap

The data available for Pole Mounted Transformers is age, loading, and number of customers. The data gaps, which are primarily from inspections, are as follows:

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		☆ ☆	Porcelain	Crack / Dirt	Visual inspection
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation record

3.5.2 Data Availability Distribution

Because inspection data was not available for this asset category, the average DAI for Pole Mounted Transformers is 22%.

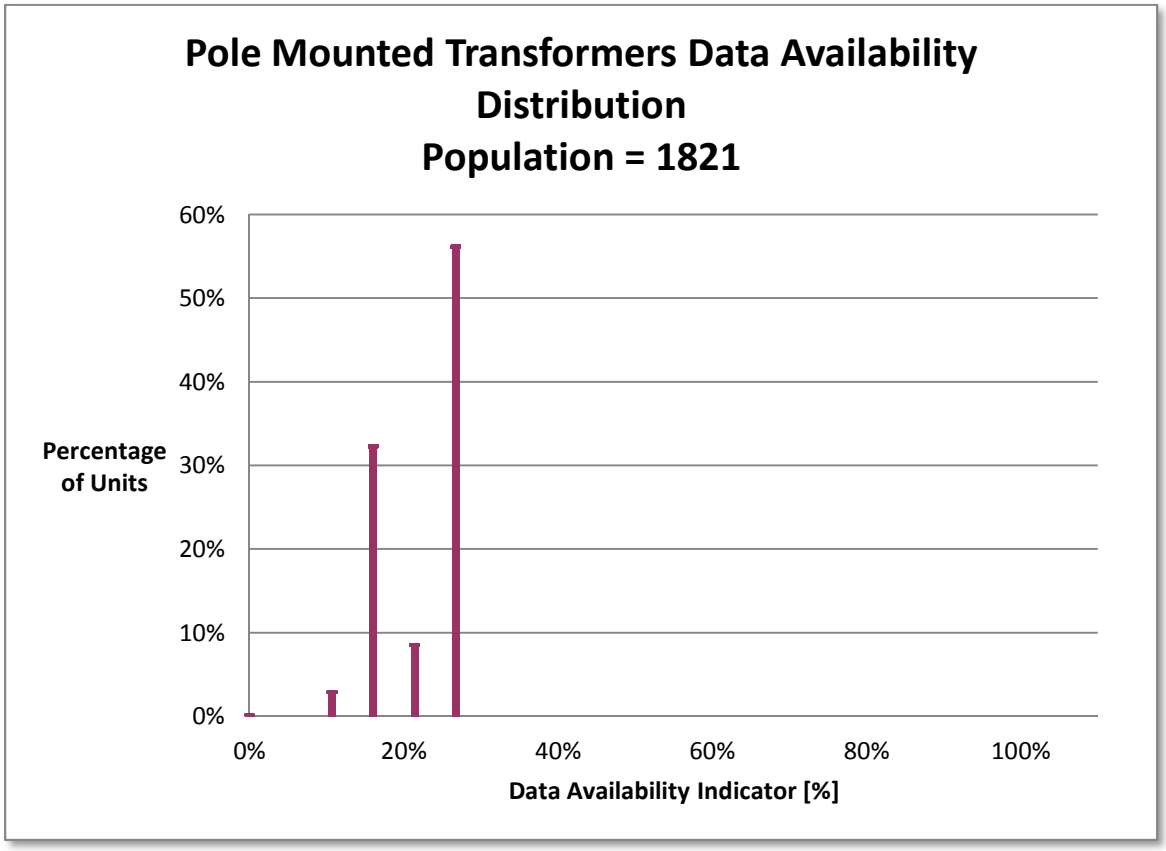


Figure 3-7 Pole Mounted Transformers Data Availability Distribution

4 Pad Mounted Transformers

4.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Pad Mounted Transformers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Pad Mounted Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	3	Corrosion	2	Table 4-4
		Access	1	Table 4-4
		Base	1	Table 4-4
Connection and Insulation	5	Oil Leak	1	Table 4-4
		Connection	2	Table 4-4
		Barrier	2	Table 4-4
		Elbow	2	Table 4-4
		Stress Cone	2	Table 4-4
		Bushing	2	Table 4-4
Service Record	5	Overall Condition	2	Table 4-4
		Number of Customers	1	Table 4-2
		Age	2	Figure 4-1
		Loading	2	Table 4-3
De-Rating		Livefront	70%	

4.1.2 Condition Parameter Criteria

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 40 and 60 years the probability of failure (P_f) for this asset are 20% and 95% 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:

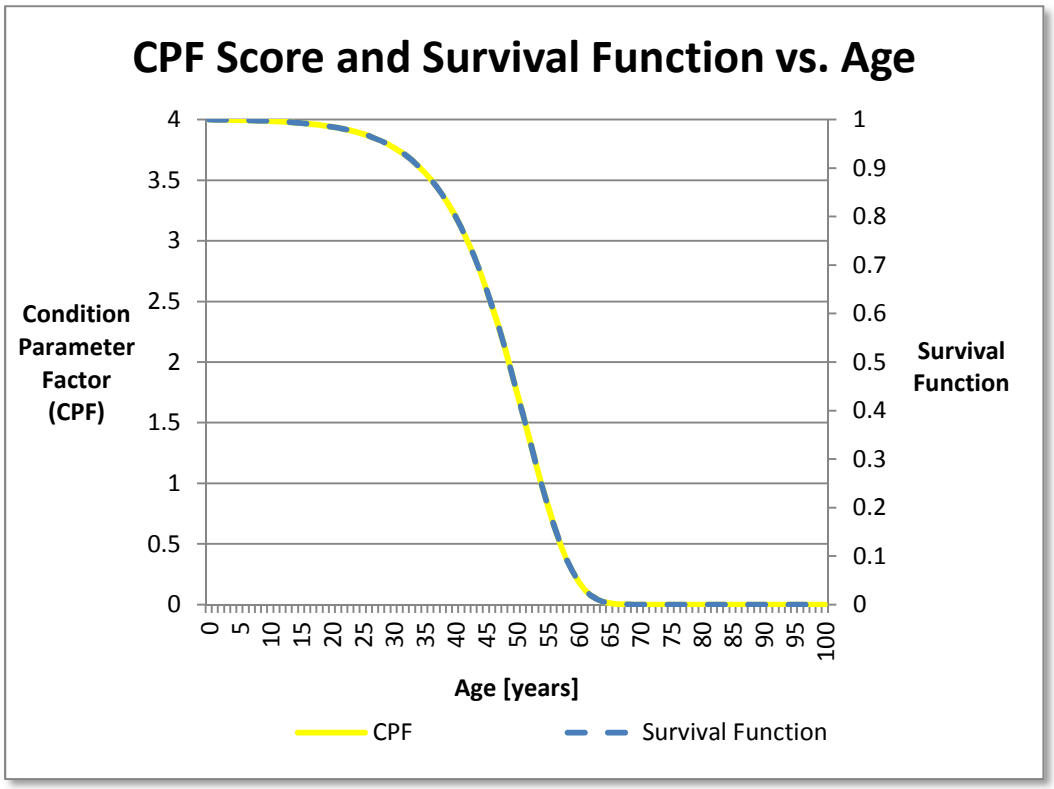


Figure 4-1 Pad Mounted Transformers Age Condition Criteria

Number of Customers

Table 4-2 Pad Mounted Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	Transformer Size <= 100 kVA	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{\textit{Annual Peak Load}}{\textit{Nameplate Rating}}$$

Table 4-3 Pad Mounted Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

Okay or Not Okay

Table 4-4 Pad Mounted Transformers Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

4.2 Age Distribution

The age distribution is shown in the figure below. Age was available for only 79% of the population. The average age was found to be 16 years.

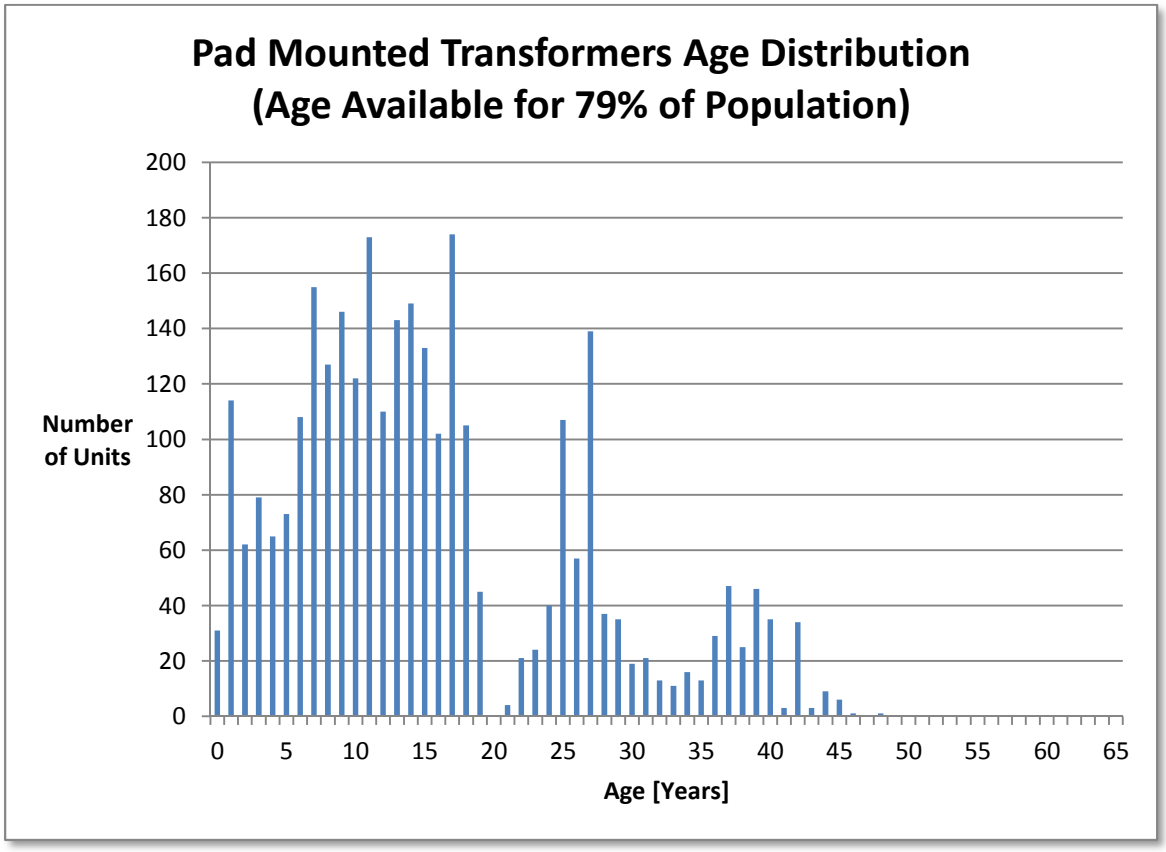


Figure 4-2 Pad Mounted Transformers Age Distribution

4.3 Health Index Results

There are 3825 in-service Pad Mounted Transformers at GHESI. There were 3825 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 88%. Approximately 2% of the units were found to be in poor condition.

The Health Index Results are as follows:

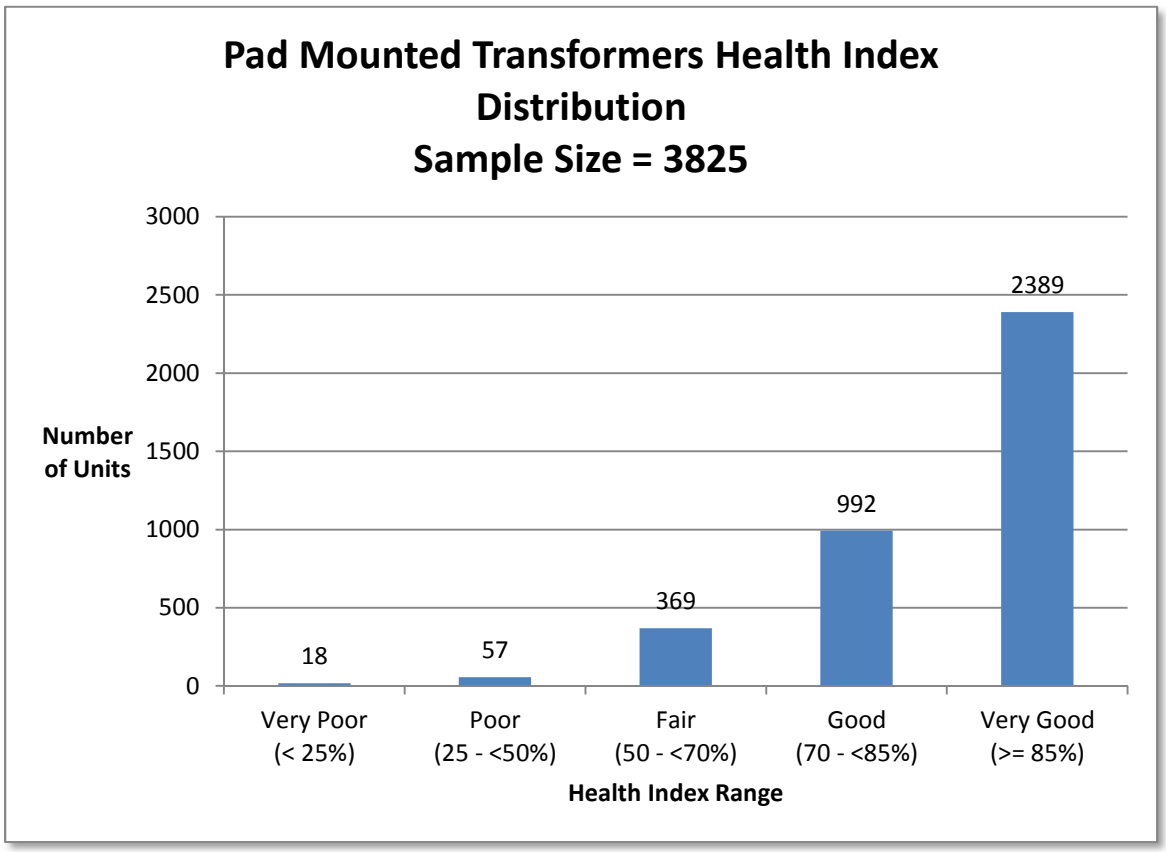


Figure 4-3 Pad Mounted Transformers Health Index Distribution (Number of Units)

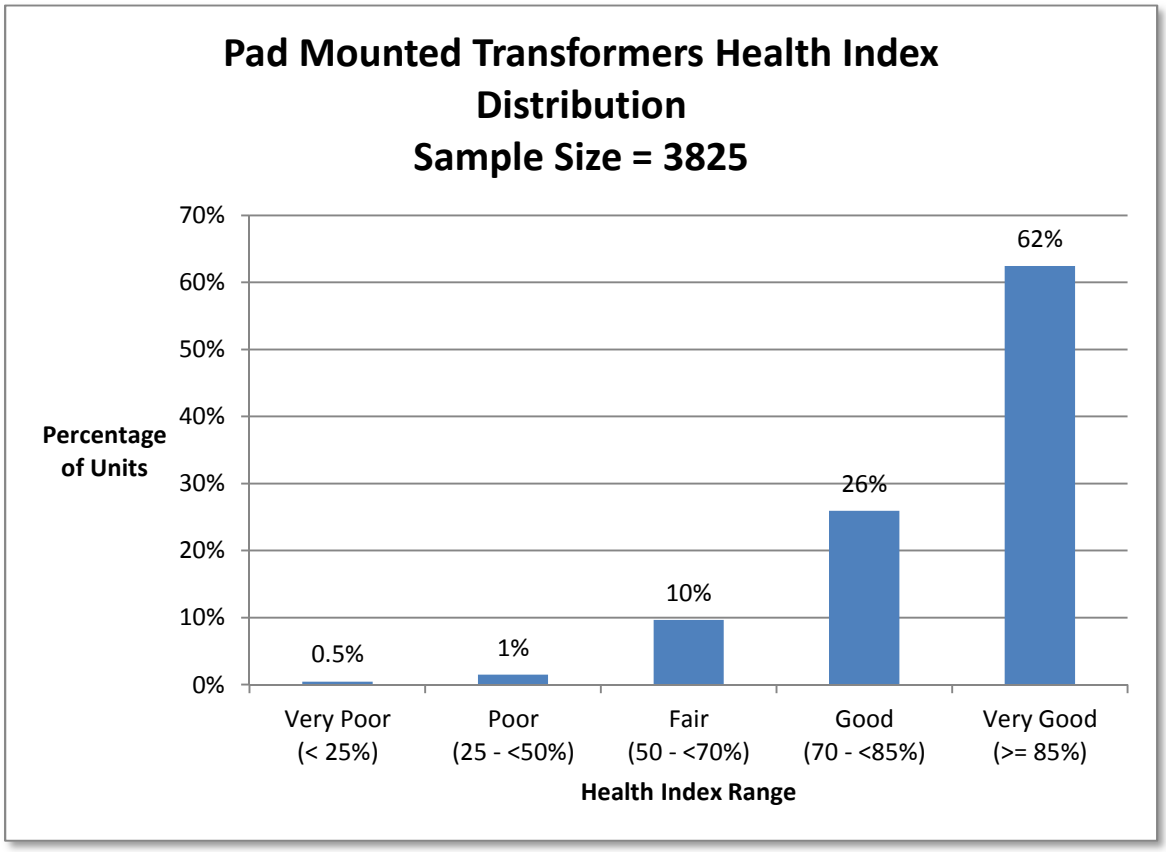


Figure 4-4 Pad Mounted Transformers Health Index Distribution (Percentage of Units)

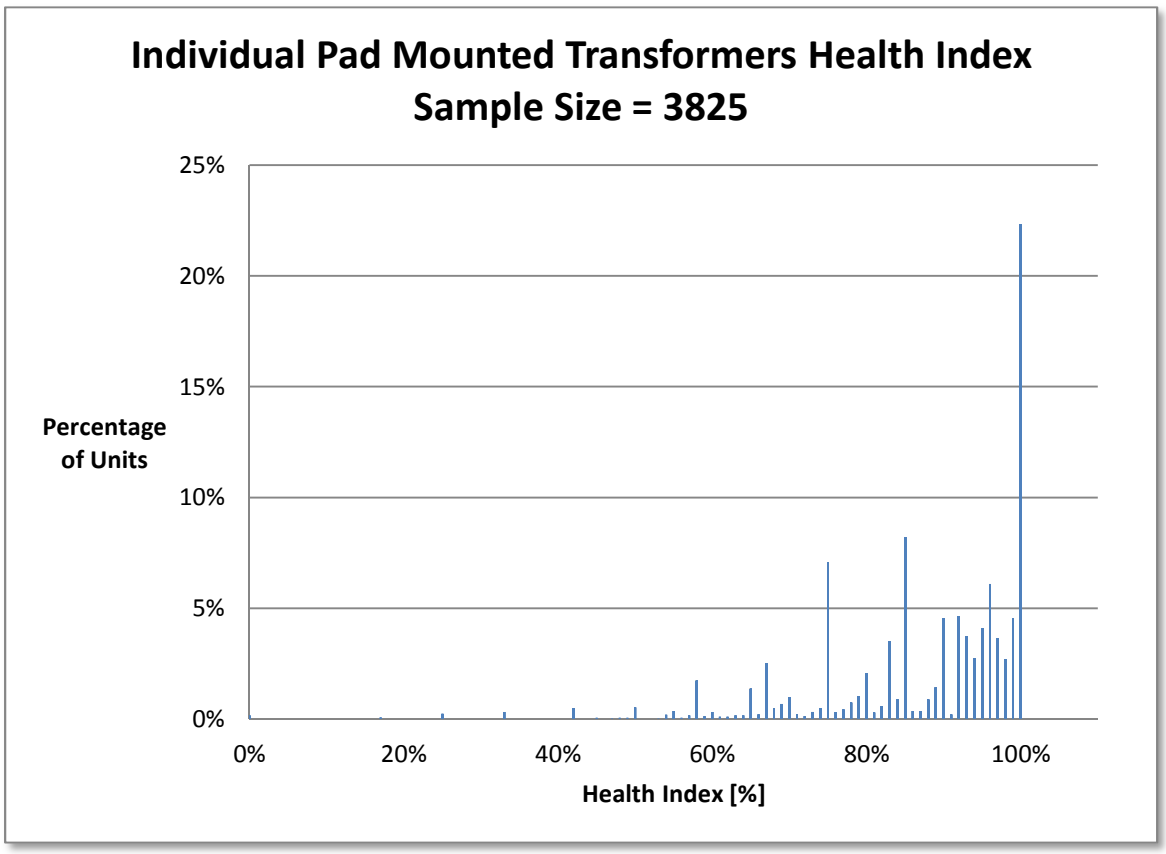


Figure 4-5 Pad Mounted Transformers Health Index Distribution by Value (Percentage of Units)

4.4 Condition-Based Flagged for Action Plan

As it is assumed that Pad Mounted Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

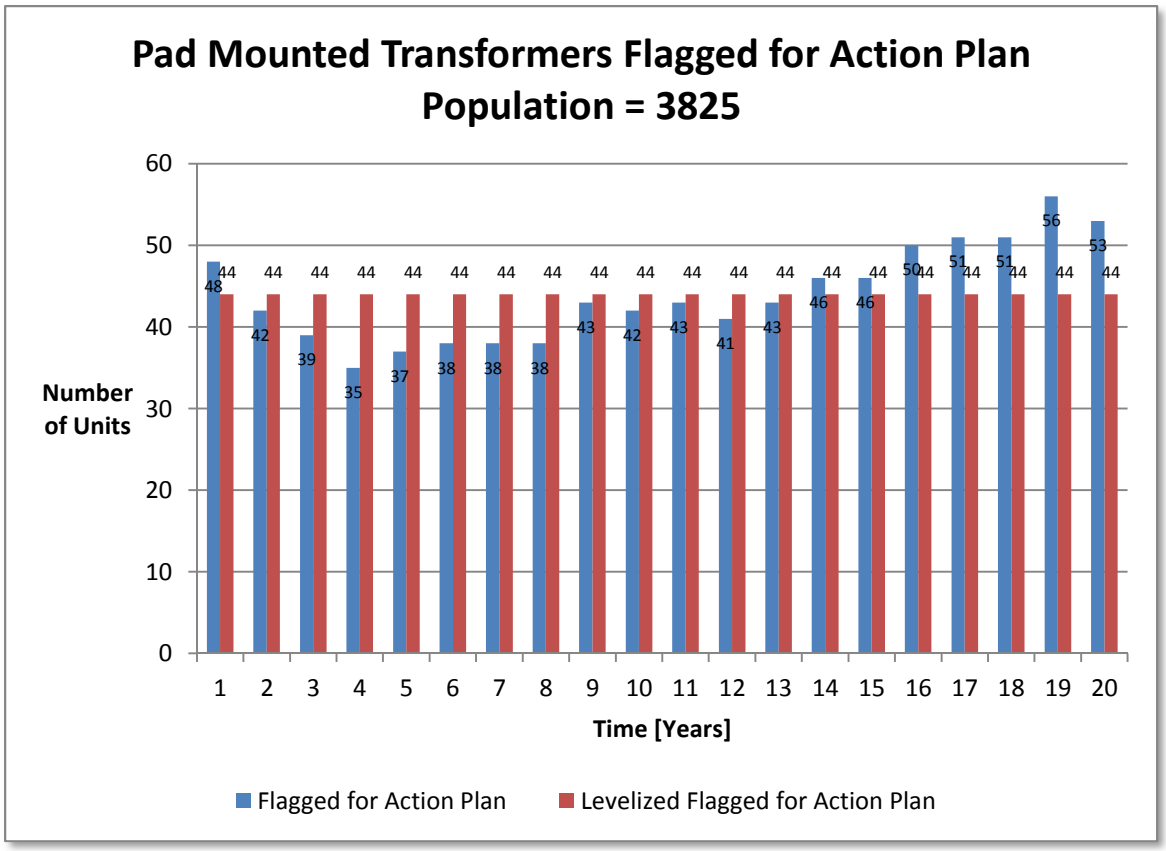


Figure 4-6 Pad Mounted Transformers Condition-Based Flagged for Action Plan

4.5 Data Analysis

4.5.1 Data Gap

The data available for Pad Mounted Transformers are age, number of customers, loading, and inspection records. No data gaps were identified.

4.5.2 Data Availability Distribution

Because not all units had inspection data available, the average DAI for Pad Mounted Transformers is 53%.

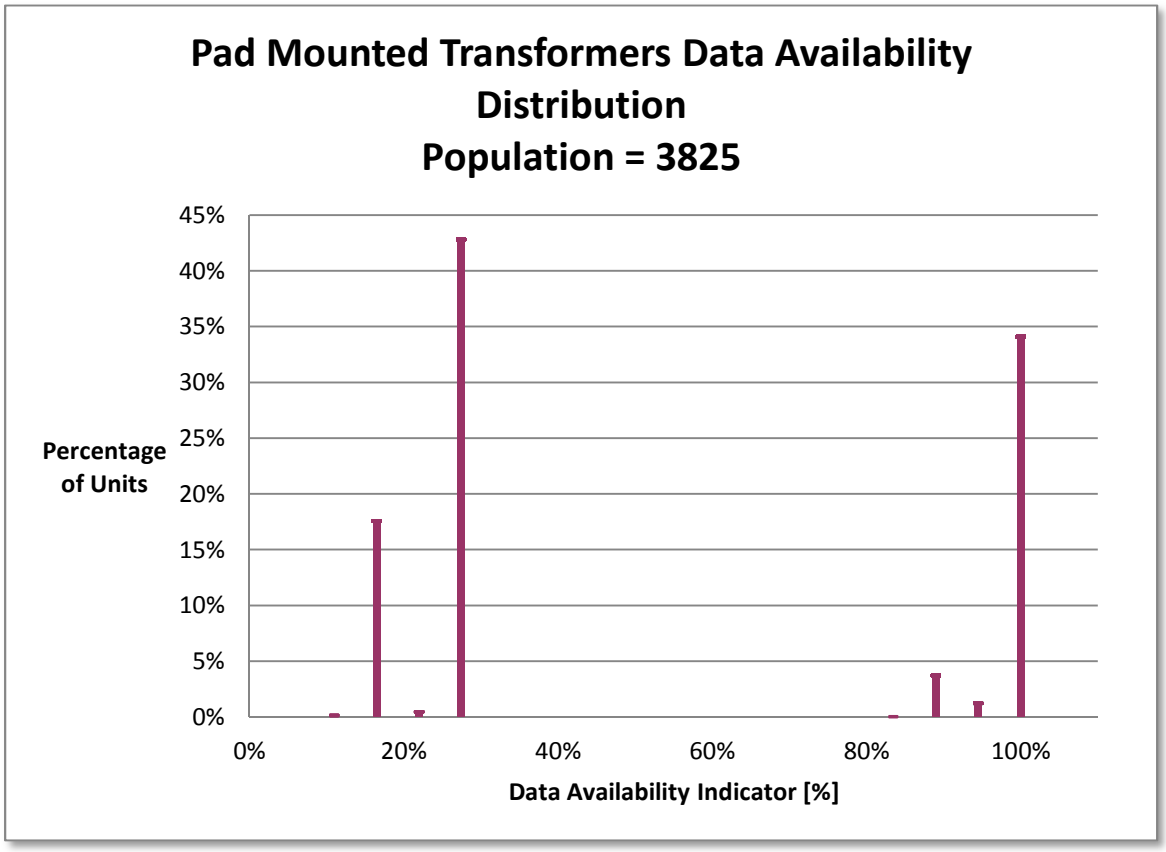


Figure 4-7 Pad Mounted Transformers Data Availability Distribution

5 Submersible Transformers

5.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Submersible Transformers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Submersible Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	1	
Connection and Insulation	1	Oil Leak	1	
Service Record	1	Number of Customers	1	Table 5-2
		Age	2	Figure 5-1
		Loading	2	Table 5-3
		Overall	2	

5.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Submersible 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 40 years the probability of failure (P_f) for this asset are 20% and 95% 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:

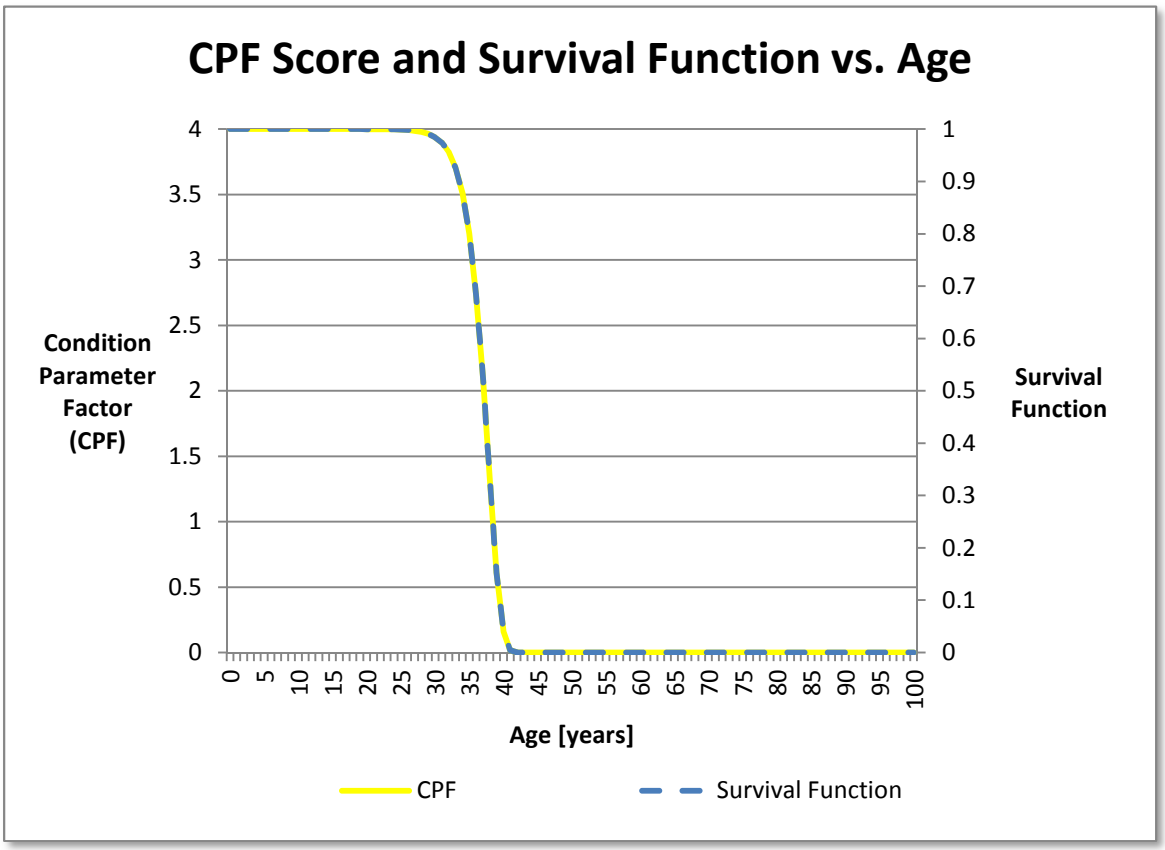


Figure 5-1 Submersible Transformers Age Condition Criteria

Number of Customers

Table 5-2 Submersible Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	Transformer Size <= 100 kVA	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{Annual\ Peak\ Load}{Nameplate\ Rating}$$

Table 5-3 Submersible Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

5.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 48% of the population. The average age was found to be 16 years.

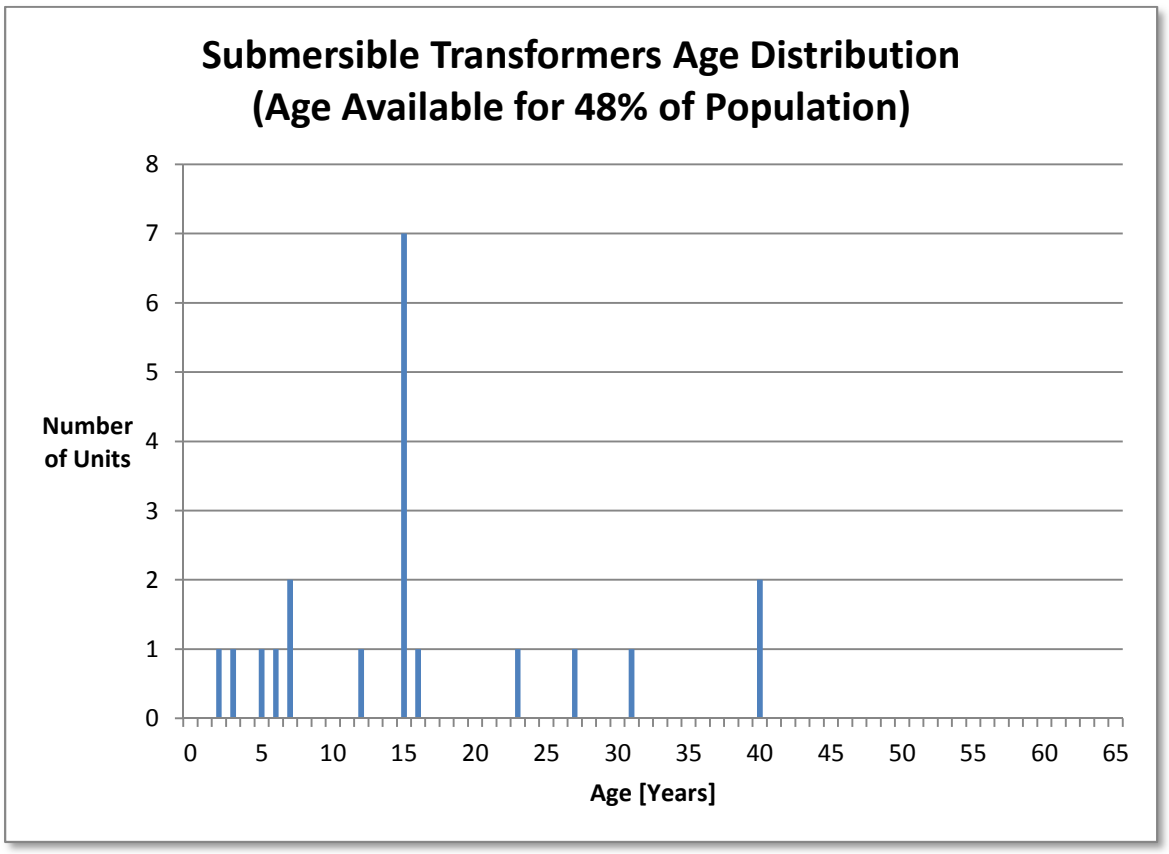


Figure 5-2 Submersible Transformers Age Distribution

5.3 Health Index Results

There are 42 in-service Submersible Transformers at GHESI. There were 42 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 86%. Approximately 5% of the units were found to be in poor condition.

The Health Index Results are as follows:

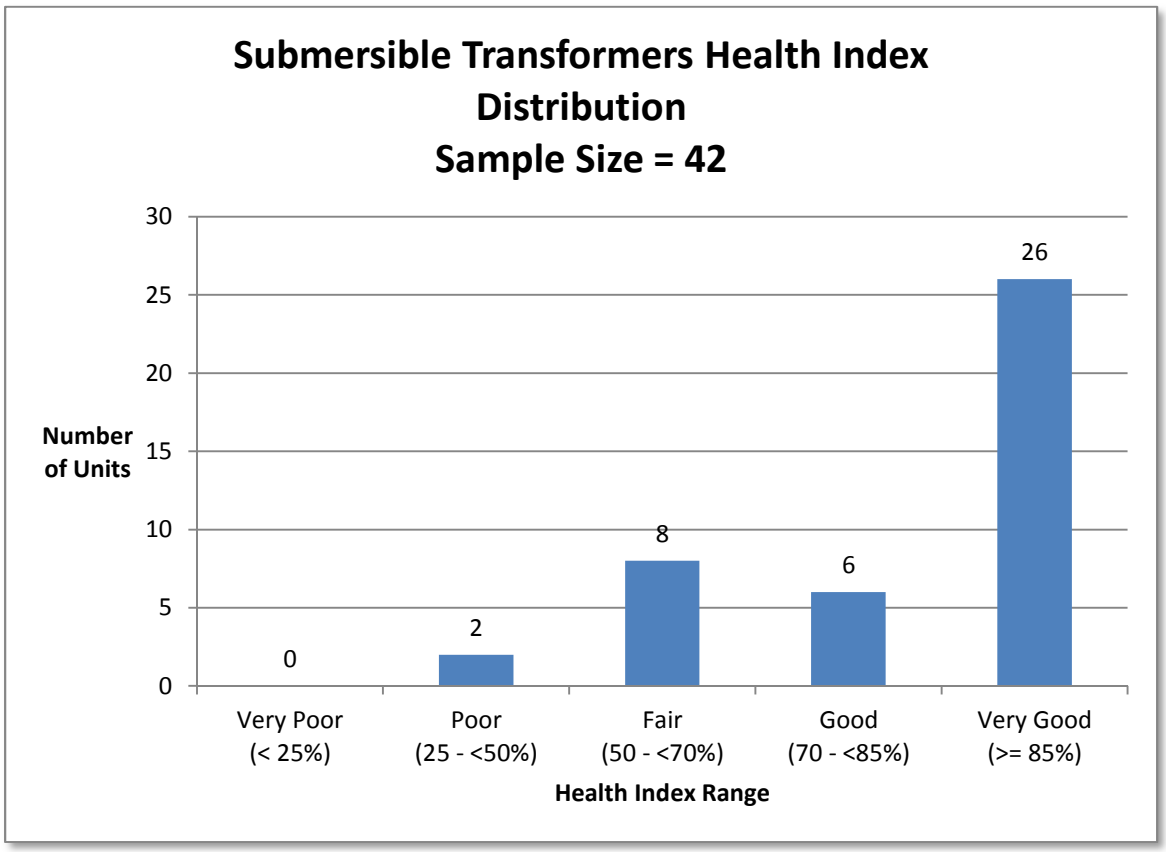


Figure 5-3 Submersible Transformers Health Index Distribution (Number of Units)

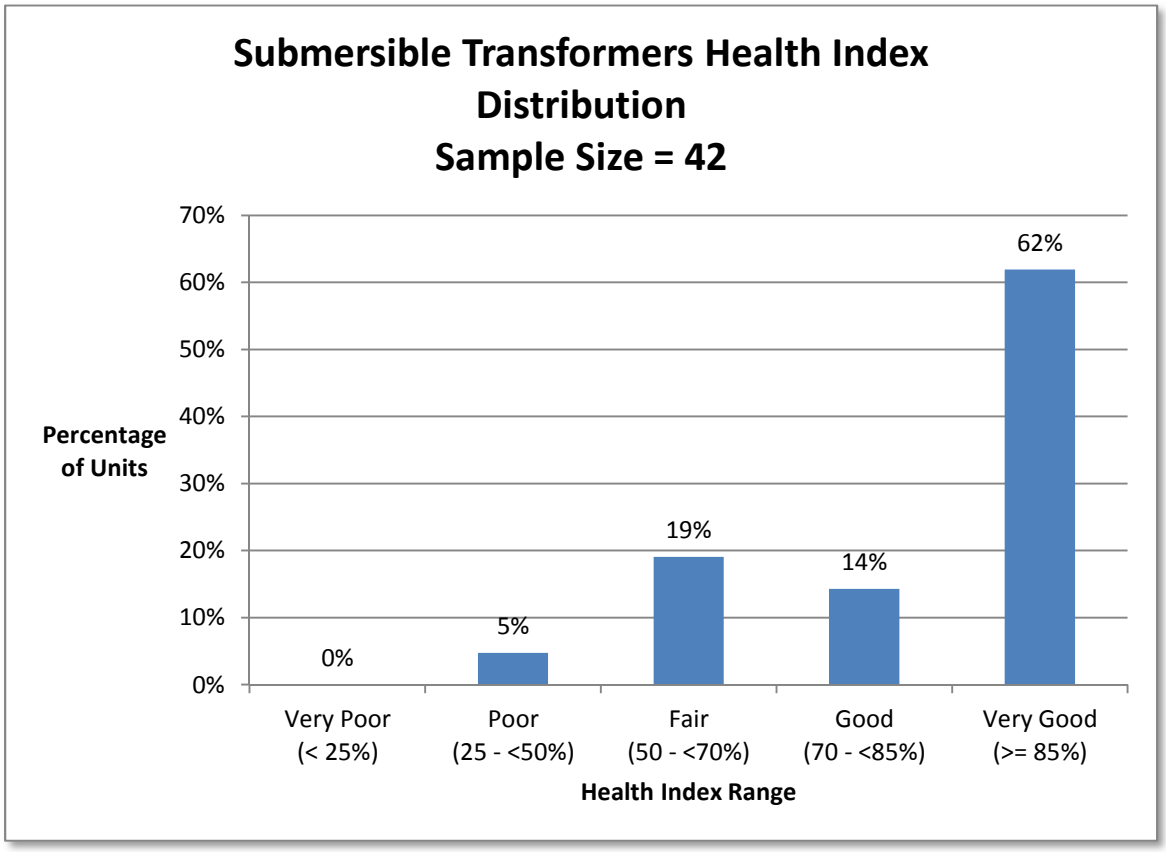


Figure 5-4 Submersible Transformers Health Index Distribution (Percentage of Units)

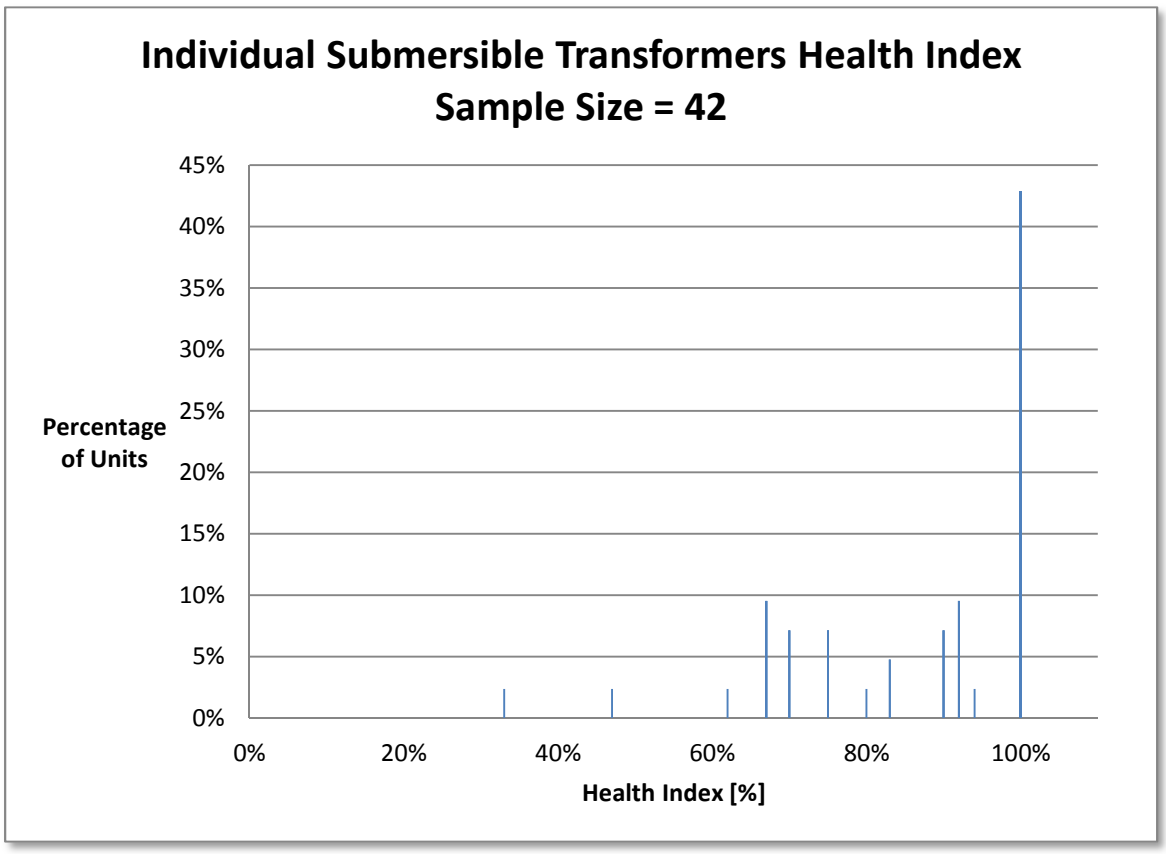


Figure 5-5 Submersible Transformers Health Index Distribution by Value (Percentage of Units)

5.4 Condition-Based Flagged for Action Plan

As it is assumed that Submersible Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

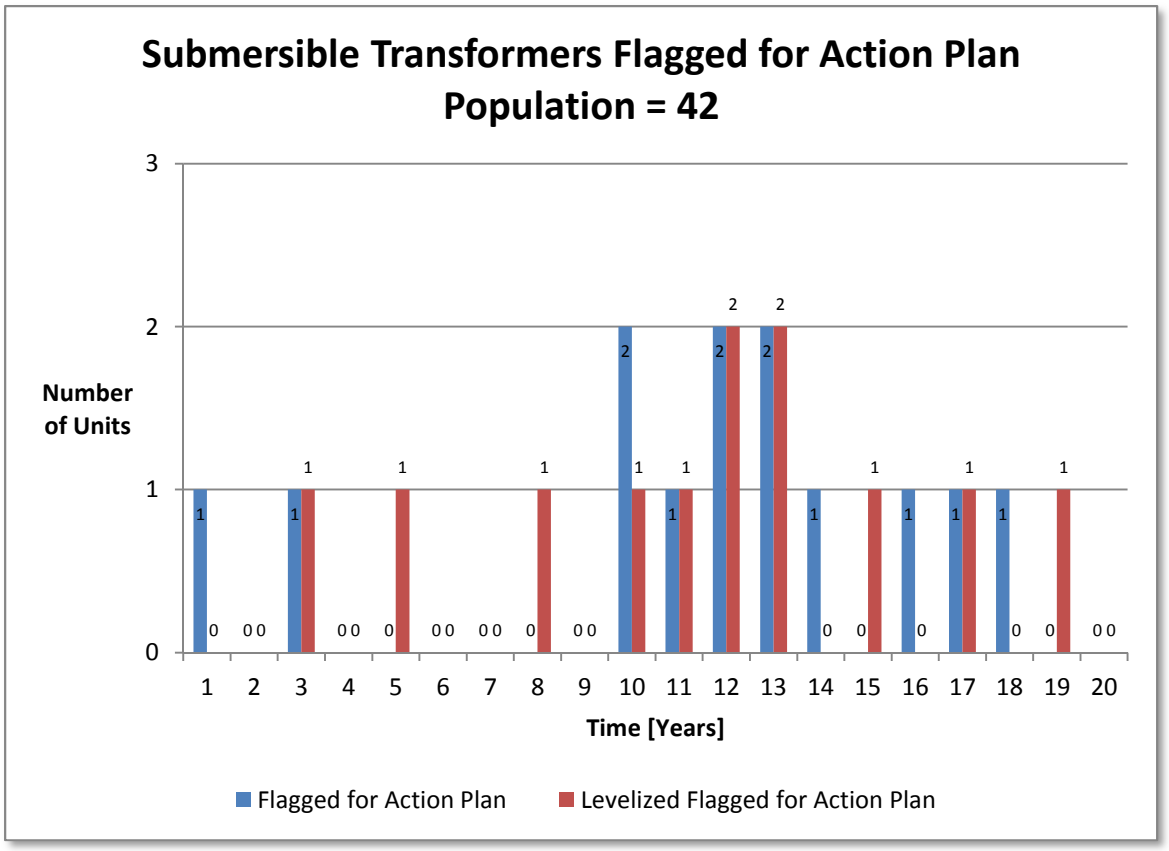


Figure 5-6 Submersible Transformers Condition-Based Flagged for Action Plan

5.5 Data Analysis

5.5.1 Data Gap

The data available for Submersible Transformers includes age, number of customers, and loading. The data gaps, which are mainly from inspections, are as follows:

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
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation record

5.5.2 Data Availability Distribution

Because inspection data was not available, the average DAI for Submersible Transformers is 26%.

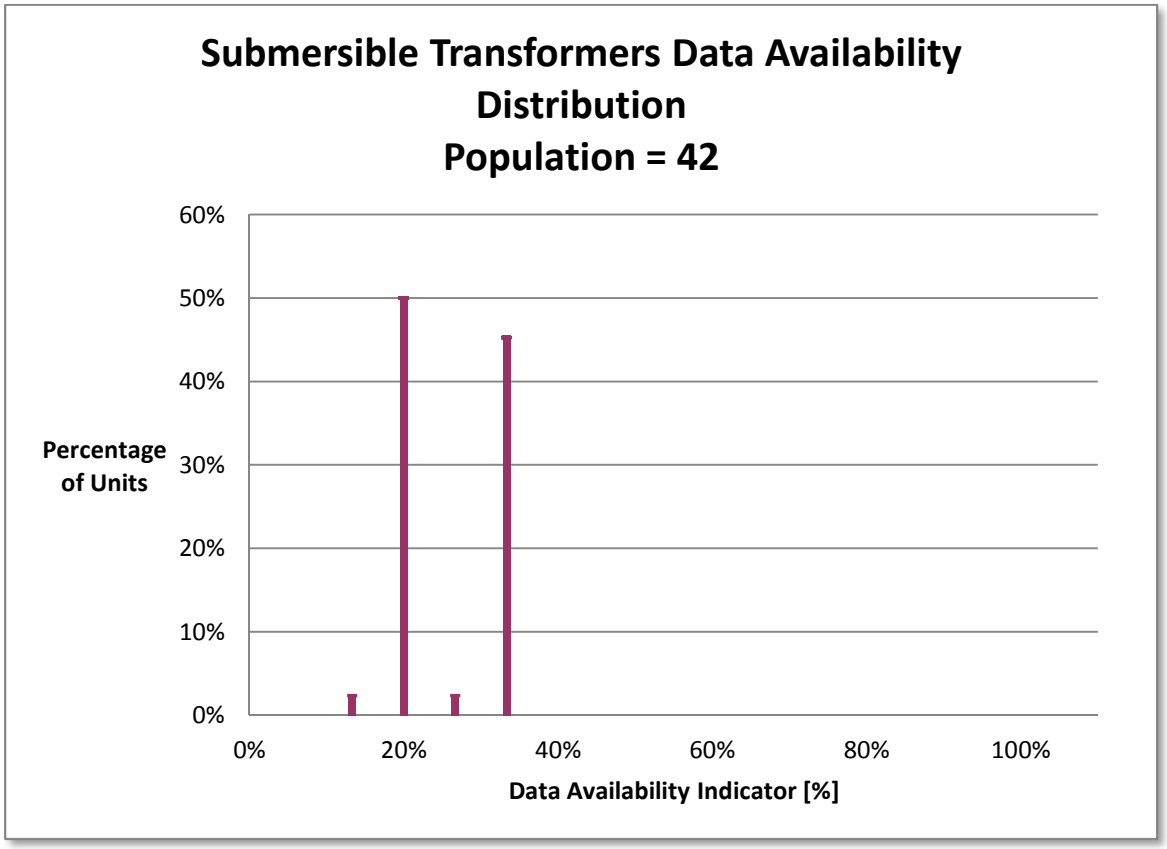


Figure 5-7 Submersible Transformers Data Availability Distribution

6 Vault Transformers

6.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Vault Transformers. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Vault Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	7	Corrosion	3	Table 6-4
		Access	1	Table 6-4
		Housekeeping	5	Table 6-4
Connection and Insulation	5	Oil Leak	2	Table 6-4
		Grounding	1	Table 6-4
		Elbow	3	Table 6-4
		Stress Cone	3	Table 6-4
		Bushing	3	Table 6-4
Service Record	**5**	Overall Condition	2	Table 6-4
		Number of Customers	1	Table 6-2
		Age	2	Figure 6-1
		Loading	2	Table 6-3

6.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Vault 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 40 years the probability of failure (P_f) for this asset are 20% and 95% 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:

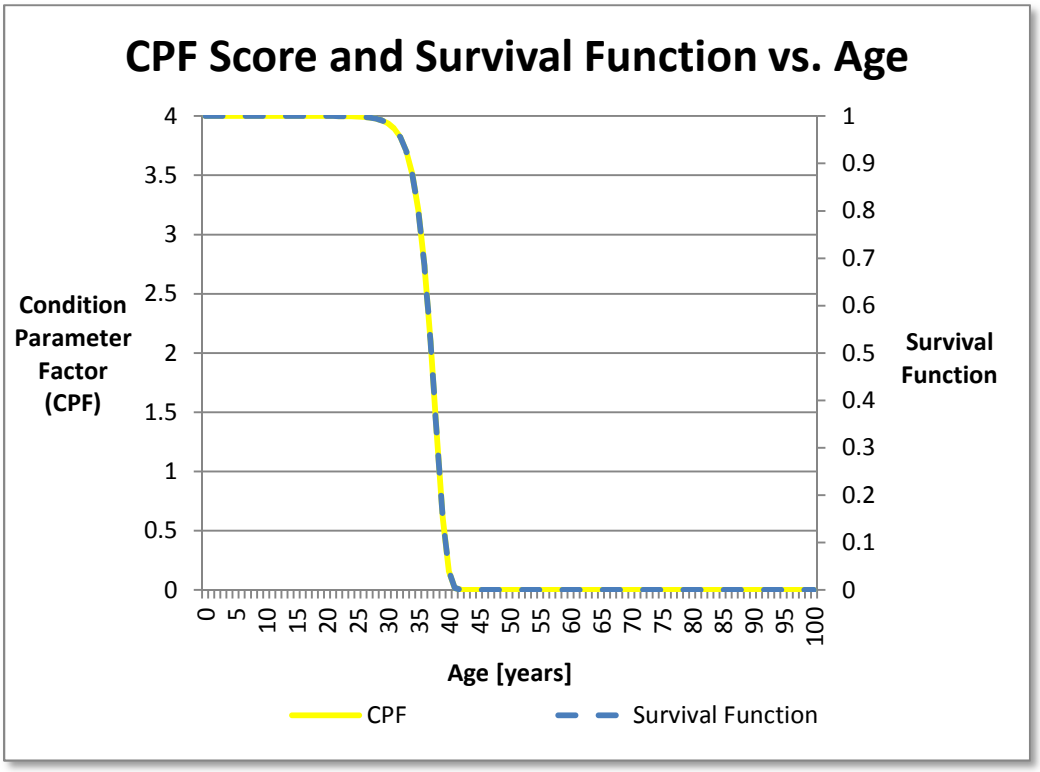


Figure 6-1 Vault Transformers Age Condition Criteria

Number of Customers

Table 6-2 Vault Transformers Number of Customers Description and Score

Number of Customers	Score
0-9	4
10-19	3
20-39	2
40+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{\textit{Annual Peak Load}}{\textit{Nameplate Rating}}$$

Table 6-3 Vault Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

Okay or Not Okay

Table 6-4 Vault Transformers Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

6.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 69% of the population. The average age was found to be 26 years.

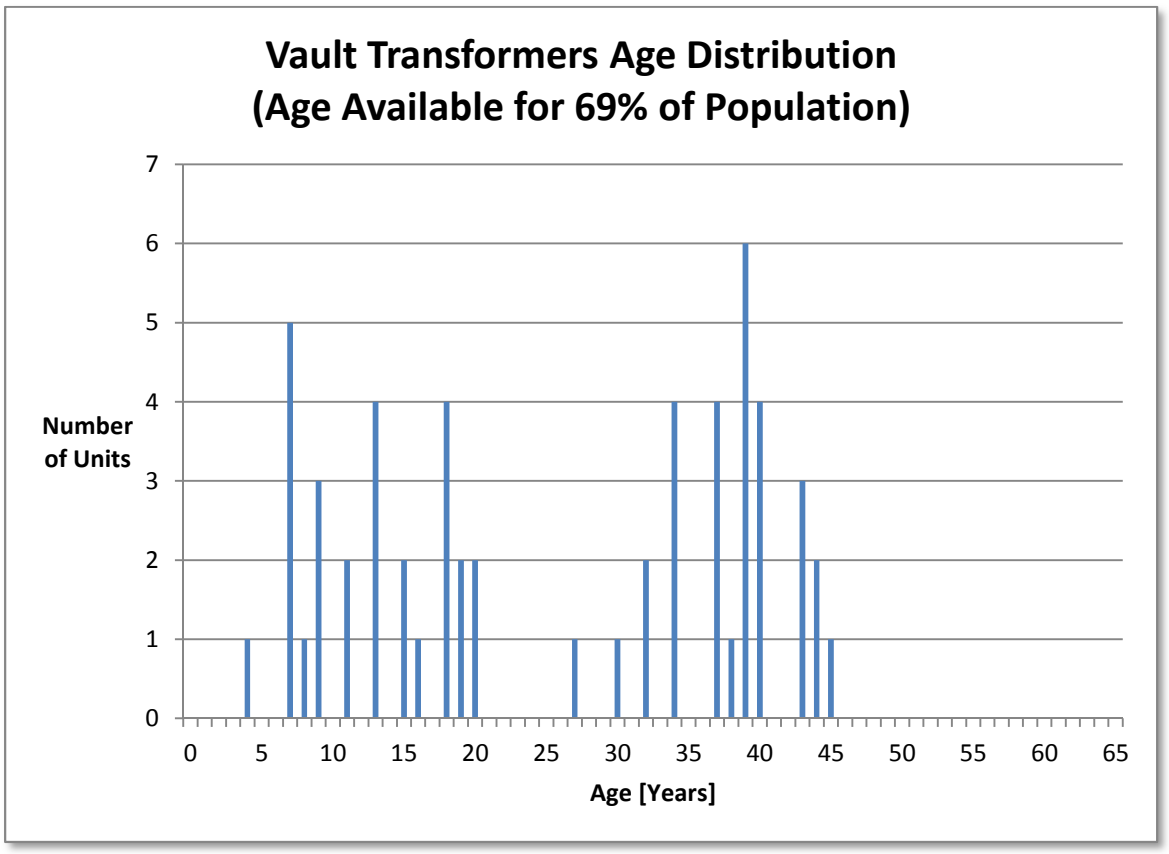


Figure 6-2 Vault Transformers Age Distribution

6.3 Health Index Results

There are 81 in-service Vault Transformers at GHESI. There were 81 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 91%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

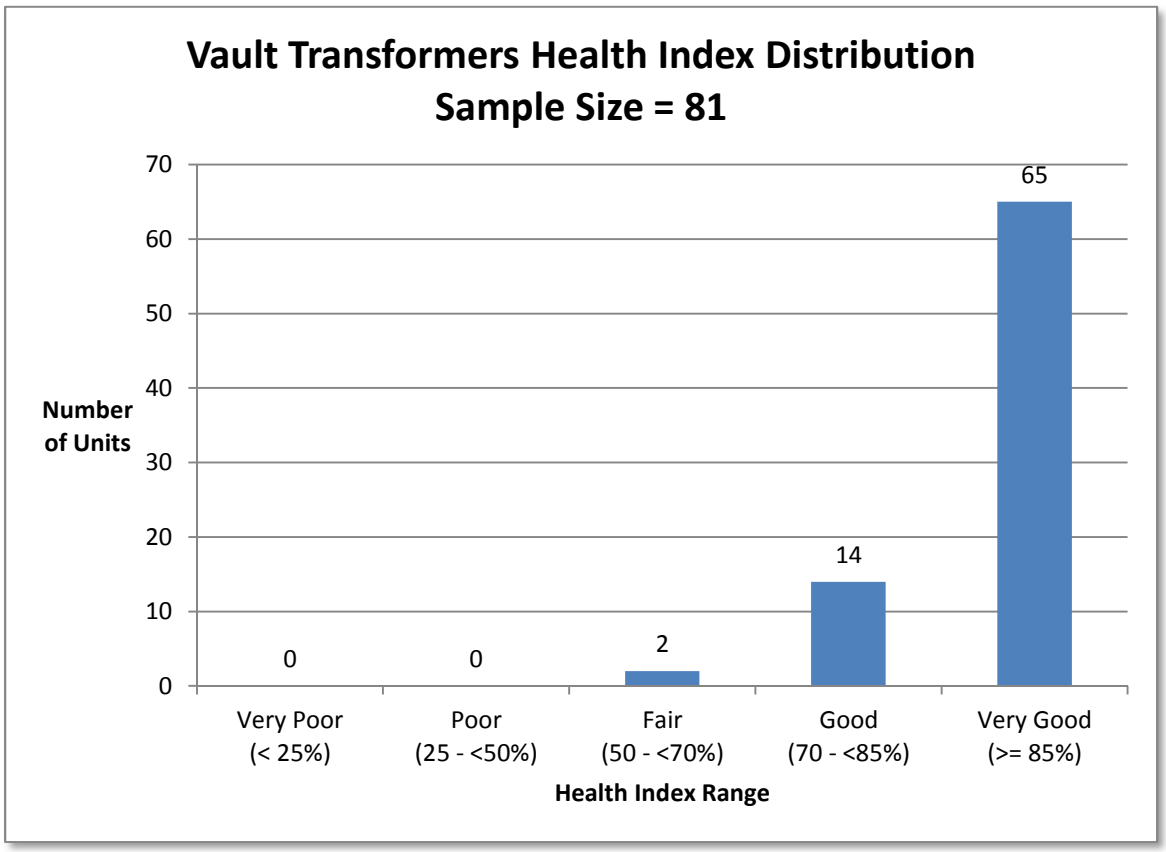


Figure 6-3 Vault Transformers Health Index Distribution (Number of Units)

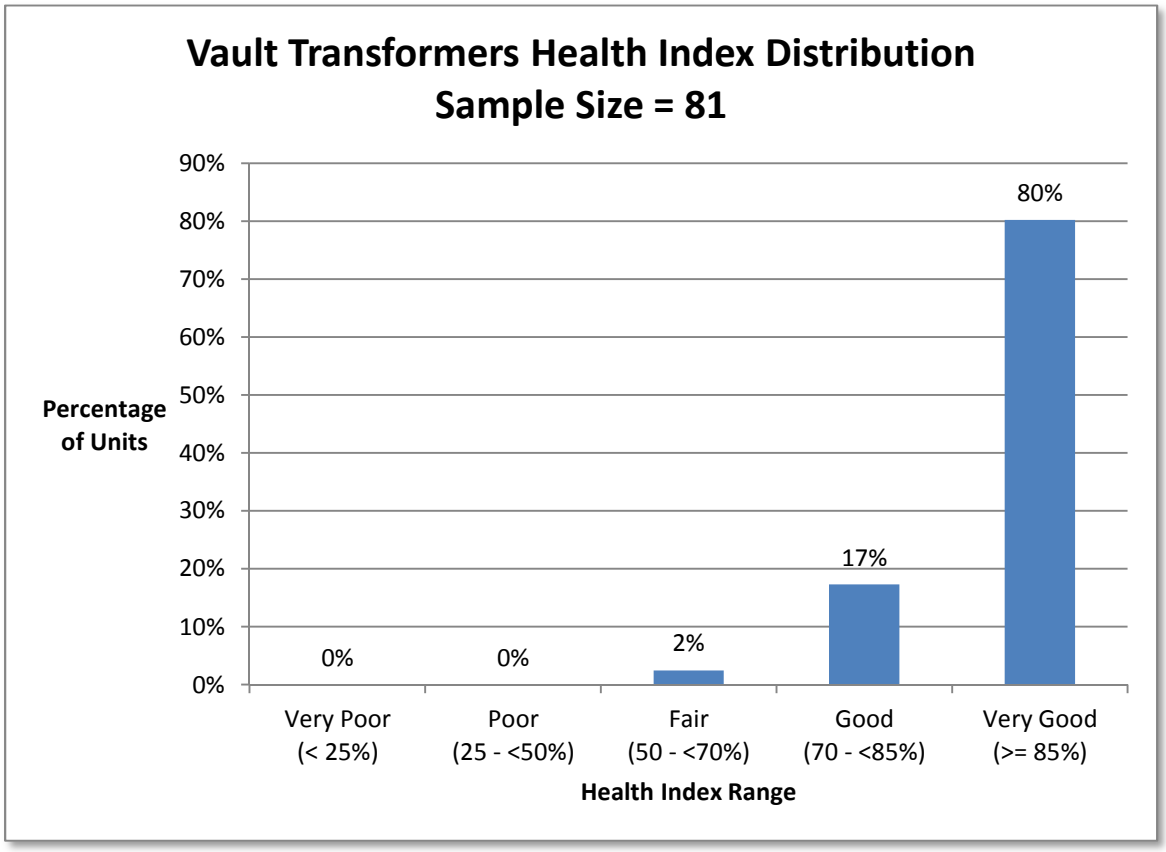


Figure 6-4 Vault Transformers Health Index Distribution (Percentage of Units)

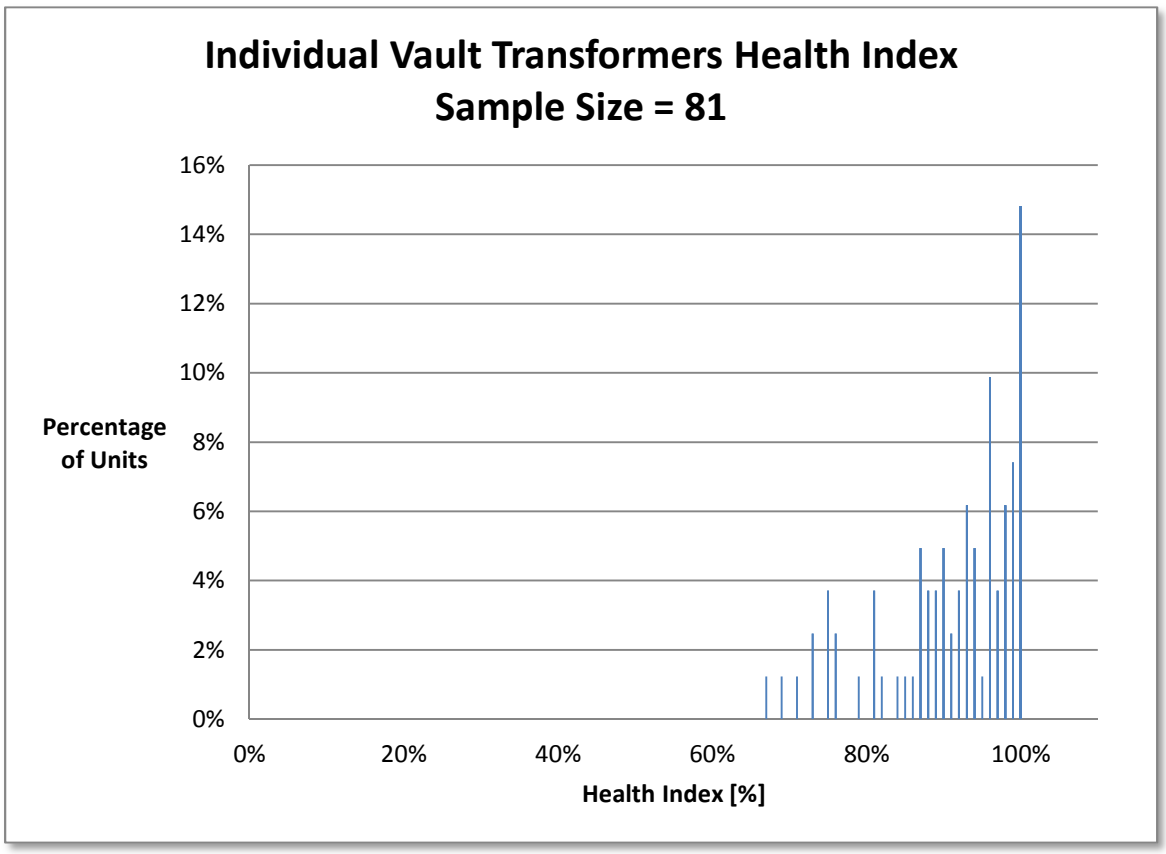


Figure 6-5 Vault Transformers Health Index Distribution by Value (Percentage of Units)

6.4 Condition-Based Flagged for Action Plan

As it is assumed that Vault Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

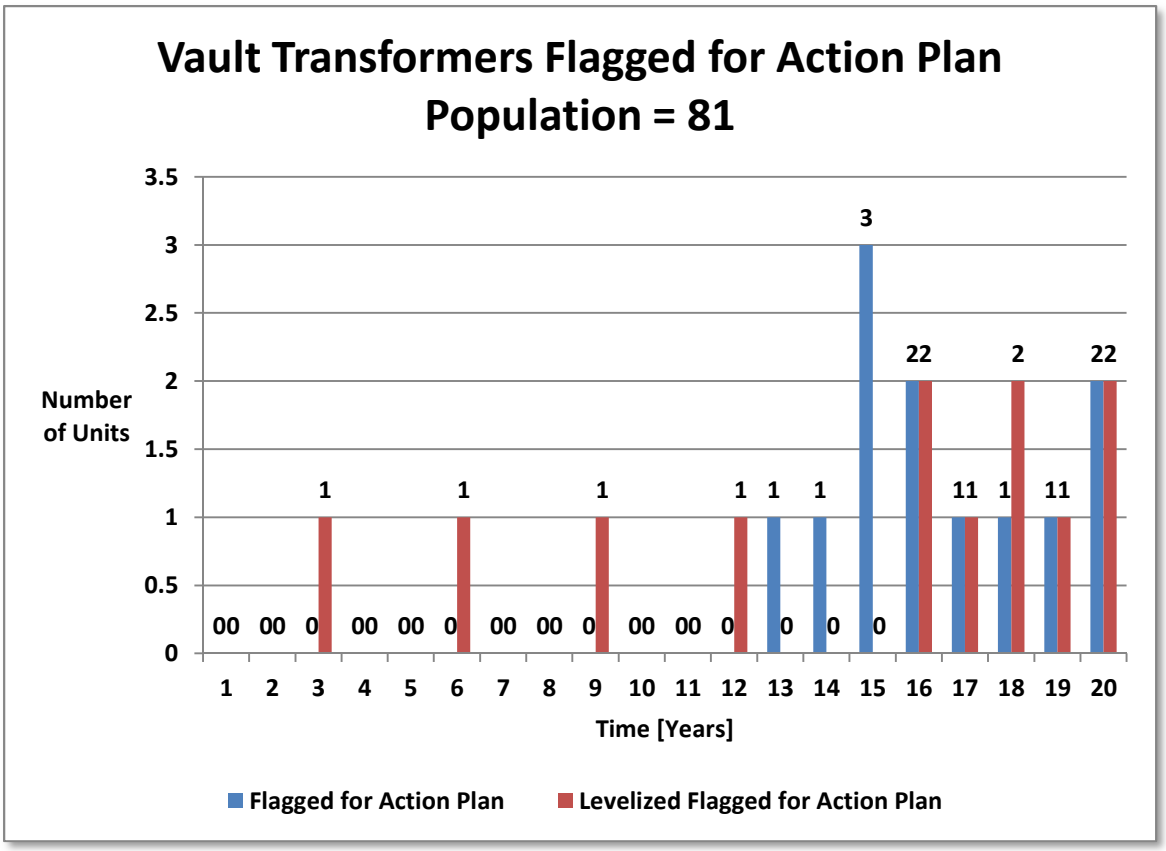


Figure 6-6 Vault Transformers Condition-Based Flagged for Action Plan

6.5 Data Analysis

6.5.1 Data Gap

The data available for Vault Transformers includes age, loading, number of customers, and inspection records. There are no data gaps for this asset category.

6.5.2 Data Availability Distribution

The average DAI for Vault Transformers is 96%.

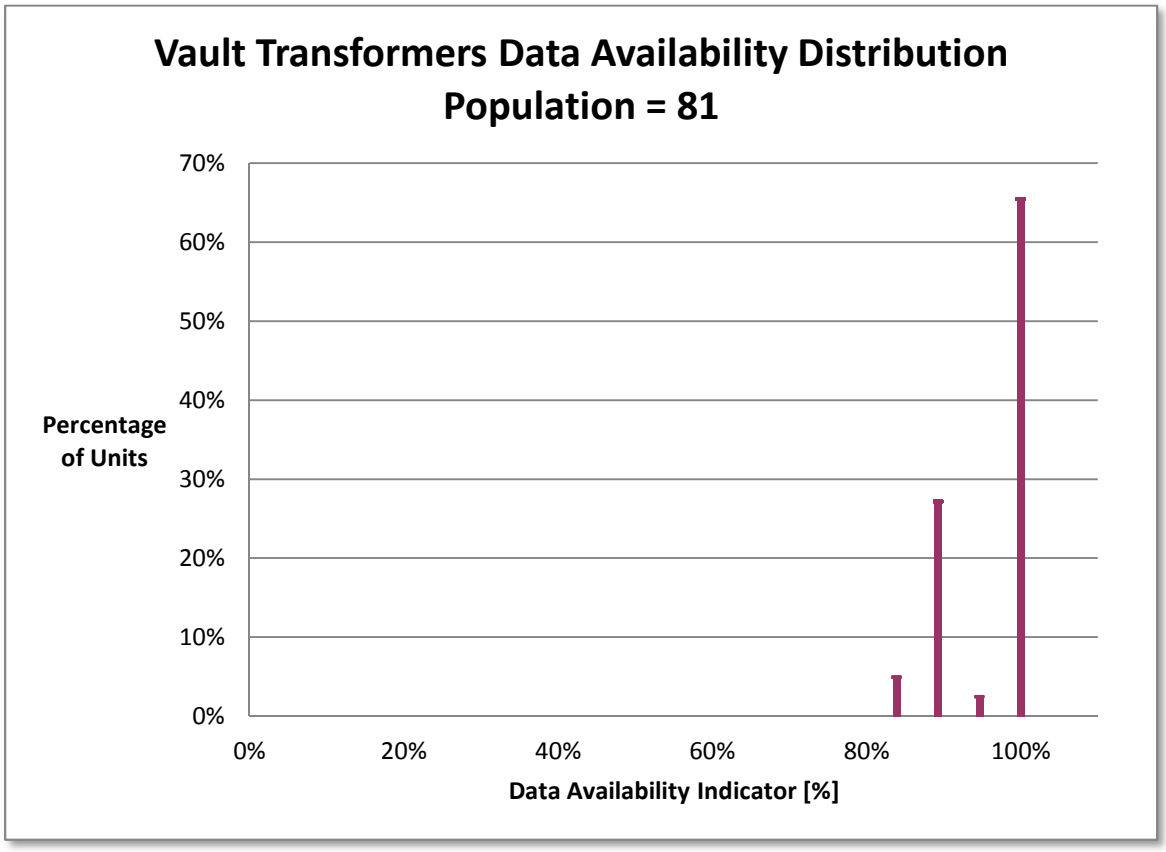


Figure 6-7 Vault Transformers Data Availability Distribution

7 Load Interrupting Switches

7.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Load Interrupting Switches (LIS). The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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 Load Interrupting Switches Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	13	Mechanism, Switch Mounting	1	
Arc Extinction	4	Arc Horn, Interrupter	1	
Insulation	2	Insulator	1	
Switch	6	Switch	1	
Maintenance	1	Maintained	0	Table 7-2
Service Record	9	Age	1	Figure 7-2
		Number of Operations*	1	Table 7-3

*This parameter refers to the number of operations in the past 5 years (not the lifetime total operations)

7.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Load Interrupting Switches 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 failure (P_f) for this asset are 20% and 95% 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:

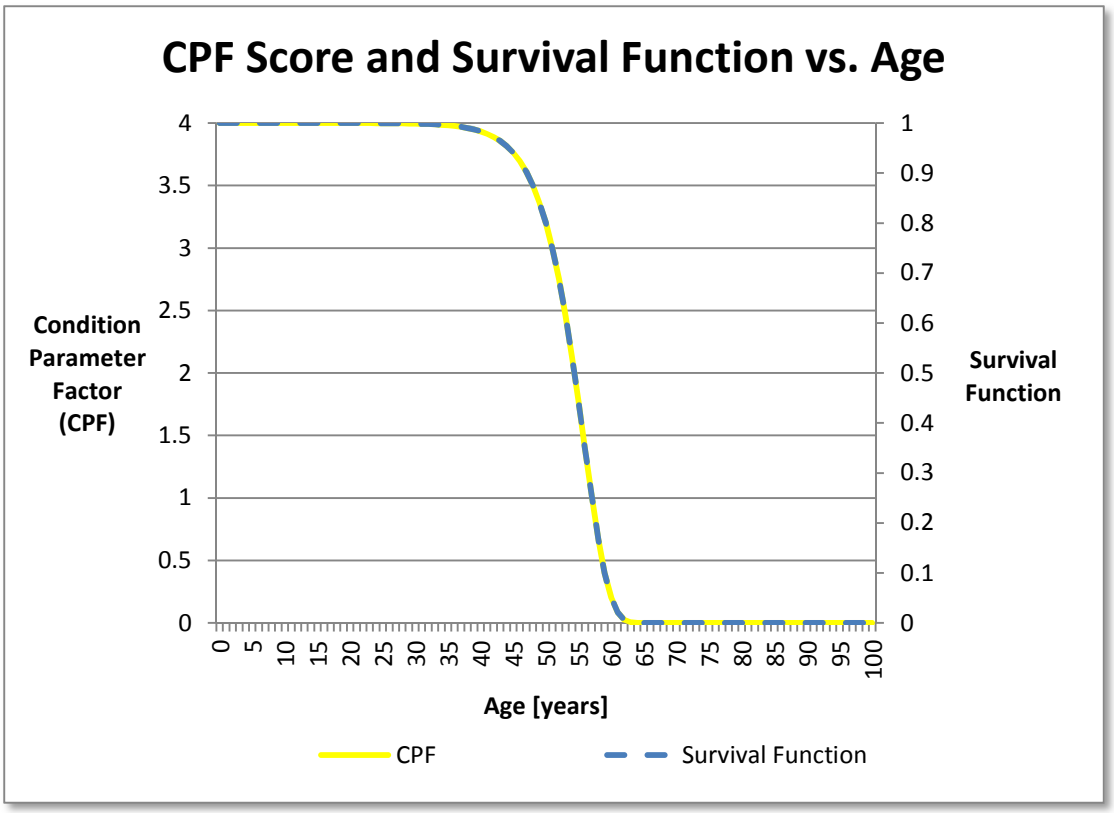


Figure 7-1 Load Interrupting Switches Age Condition Criteria

Maintenance Record

Table 7-2 Load Interrupting Switches Maintenance Record Description and Score

Recently Maintained	Score
NO	0
YES	4

Number of Operations

Table 7-3 Load Interrupting Switches Number of Operations Description and Score

Total Number of Operations (past 5 years)	Score
0*	3
1 – 4	4
5 - 9	3
10 - 19	2
20 - 29	1
30+	0

*If a unit has not been operated within the last 5 years it is unknown if the switch will operate as required. As such, the score is reduced to 3

7.2 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 15 years.

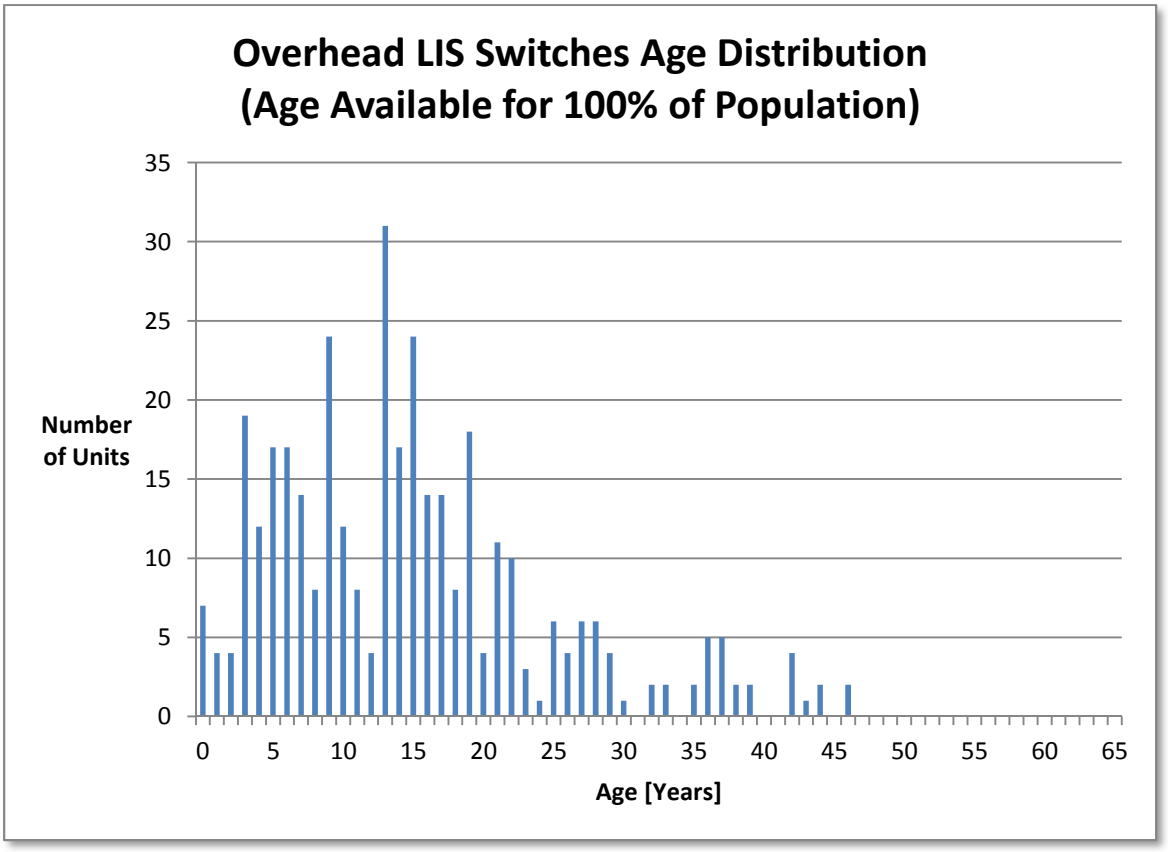


Figure 7-2 Load Interrupting Switches Age Distribution

7.3 Health Index Results

There are 361 in-service Load Interrupting Switches at GHESI. There were 361 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 97%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

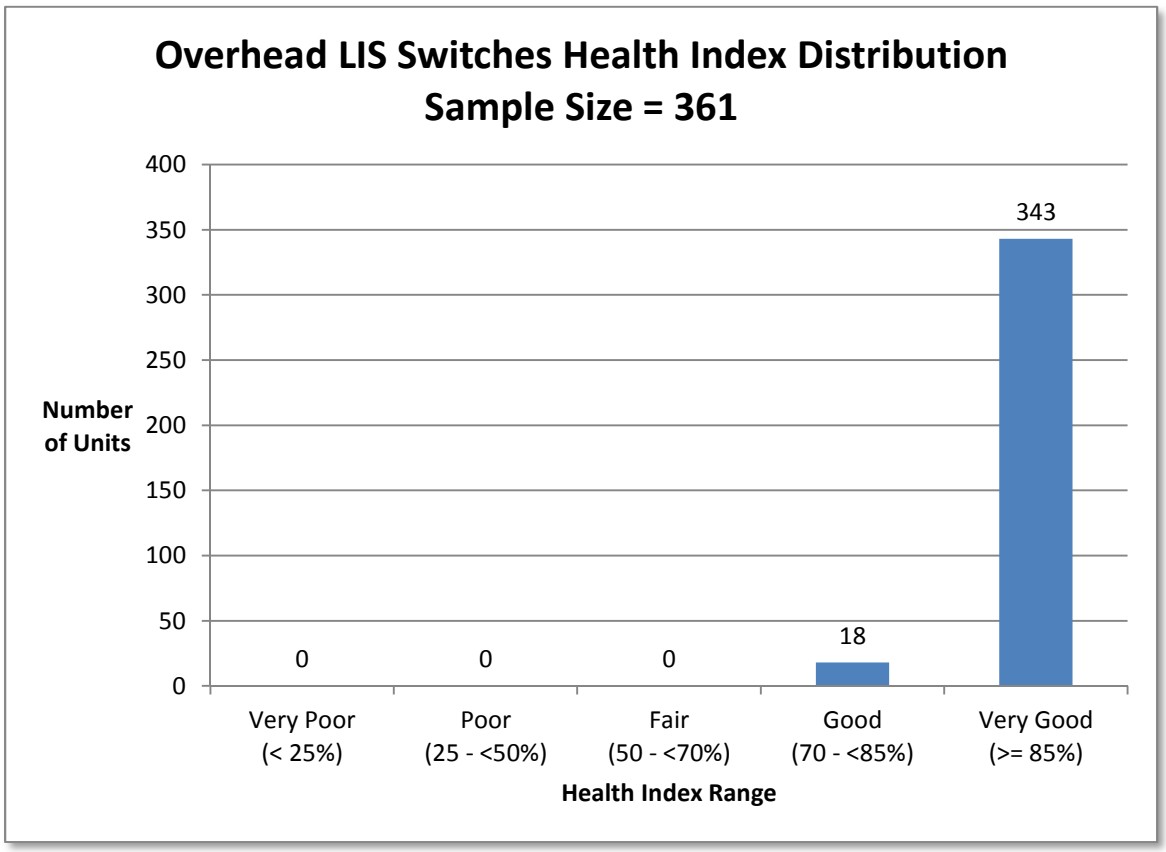


Figure 7-3 Load Interrupting Switches Health Index Distribution (Number of Units)

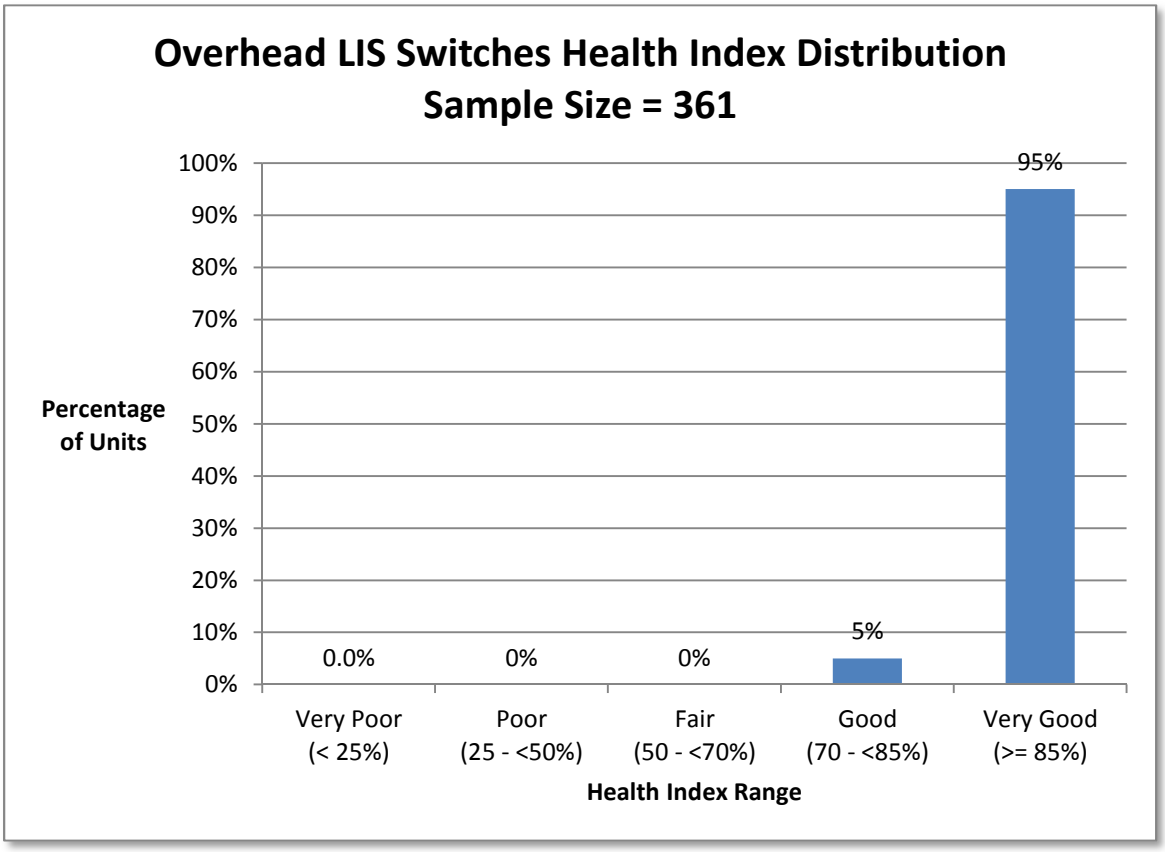


Figure 7-4 Load Interrupting Switches Health Index Distribution (Percentage of Units)

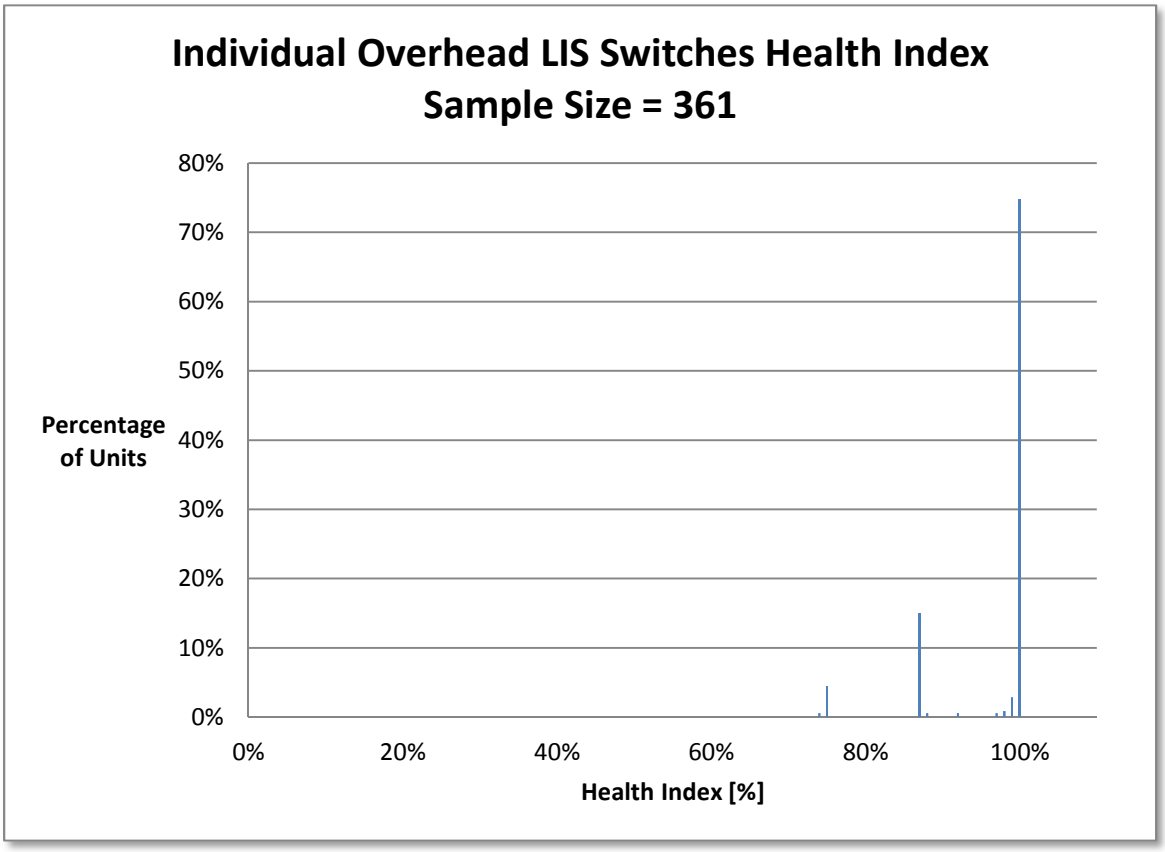


Figure 7-5 Load Interrupting Switches Health Index Distribution by Value (Percentage of Units)

7.4 Condition-Based Flagged for Action Plan

As it is assumed that Load Interrupting Switches are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

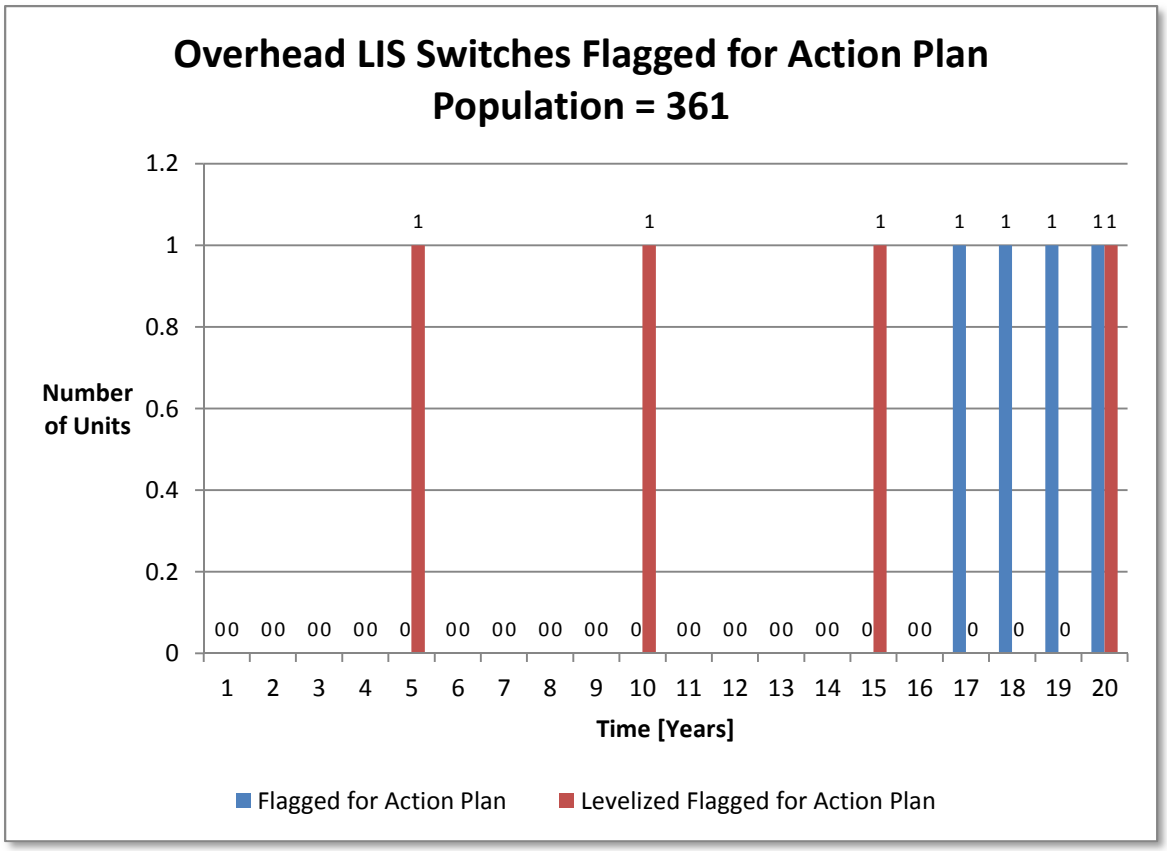


Figure 7-6 Load Interrupting Switches Condition-Based Flagged for Action Plan

7.5 Data Analysis

7.5.1 Data Gap

The data available for Load Interrupting Switches includes age and number of operations. The data gaps, which are primarily from visual inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	☆	Support insulator	Crack	On-site visual inspection
Switch Condition	**Switch**	☆☆☆	Blade	Blade condition	On-site visual inspection

7.5.2 Data Availability Distribution

Because no inspection data was available, the average DAI for Load Interrupting Switches is 20%.

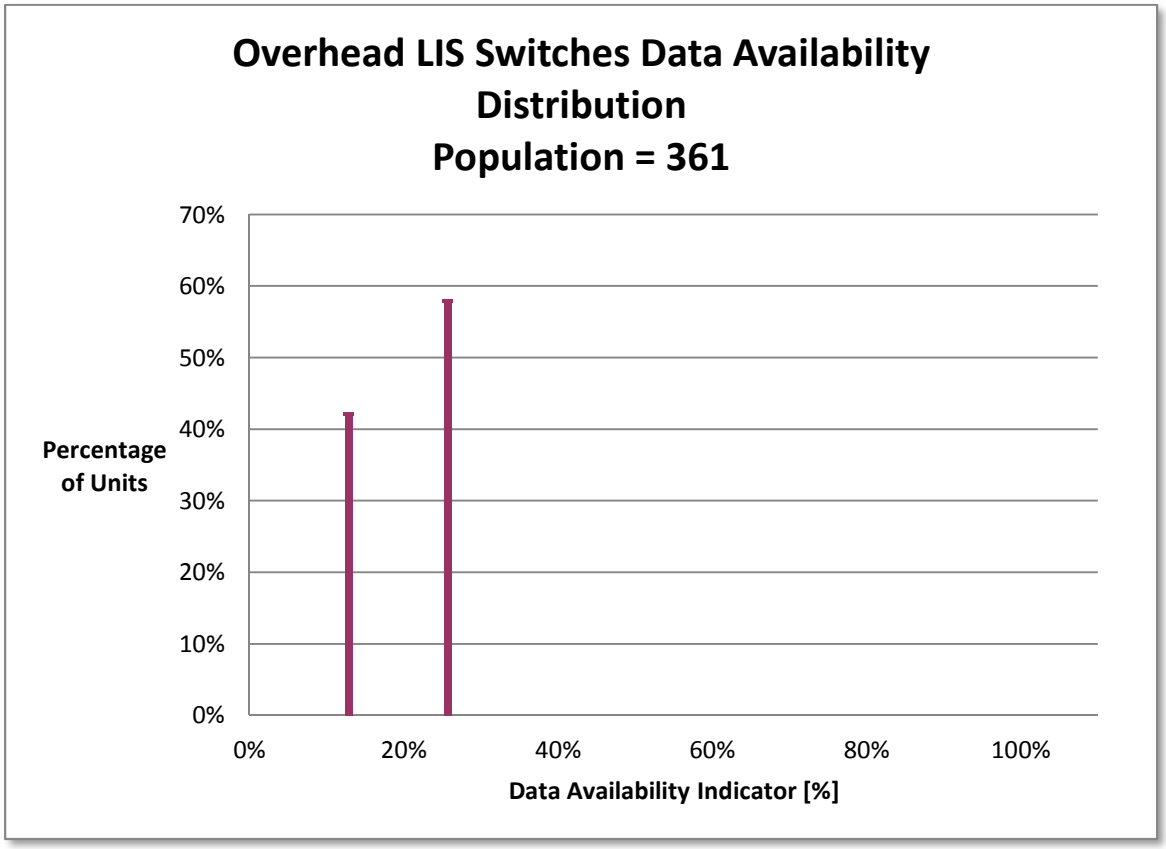


Figure 7-7 Load Interrupting Switches Data Availability Distribution

8 SCADA Switches

8.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI SCADA Switches. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

8.1.1 Condition and Sub-Condition Parameters

Table 8-1 SCADA Switches Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	13	Mechanism, Switch Mounting	1	
Arc Extinction	4	Arc Horn, Interrupter	1	
Insulation	2	Insulator	1	
Switch	6	Switch	1	
Maintenance	1	Maintained	1	Table 8-2
Service Record	9	Age	1	Figure 8-2
		Number of Operations*	1	Table 8-3

*This parameter refers to the number of operations in the past 5 years (not the lifetime total operations)

8.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for SCADA Switches 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 45 and 60 years the probability of failure (P_f) for this asset are 20% and 95% 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:

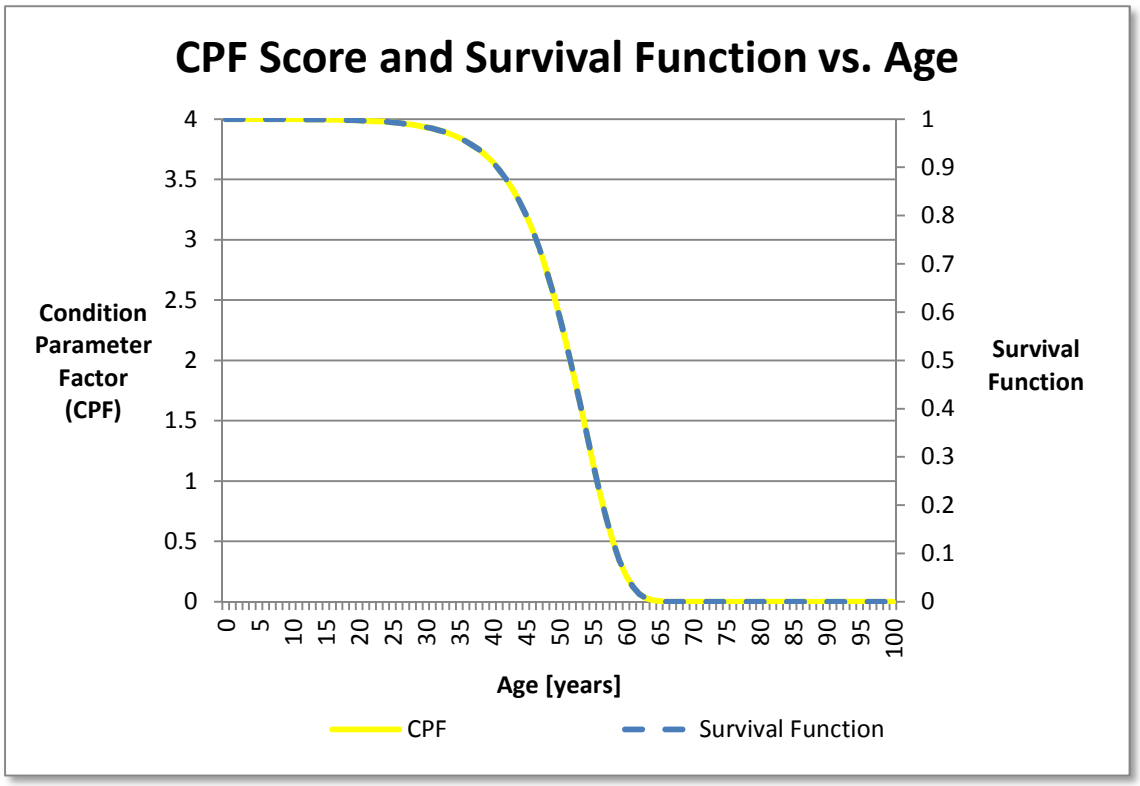


Figure 8-1 SCADA Switches Age Condition Criteria

Maintenance Record

Table 8-2 SCADA Switches Maintenance Record Description and Score

Recently Maintained	Score
NO	0
YES	4

Number of Operations

Table 8-3 SCADA Switches Number of Operations Description and Score

Total Number of Operations (past 5 years)	Score
0*	3
1 – 4	4
5 - 9	3
10 - 19	2
20 - 29	1
30+	0

*If a unit has not been operated within the last 5 years it is unknown if the switch will operate as required. As such, the score is reduced to 3

8.2 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 9 years.

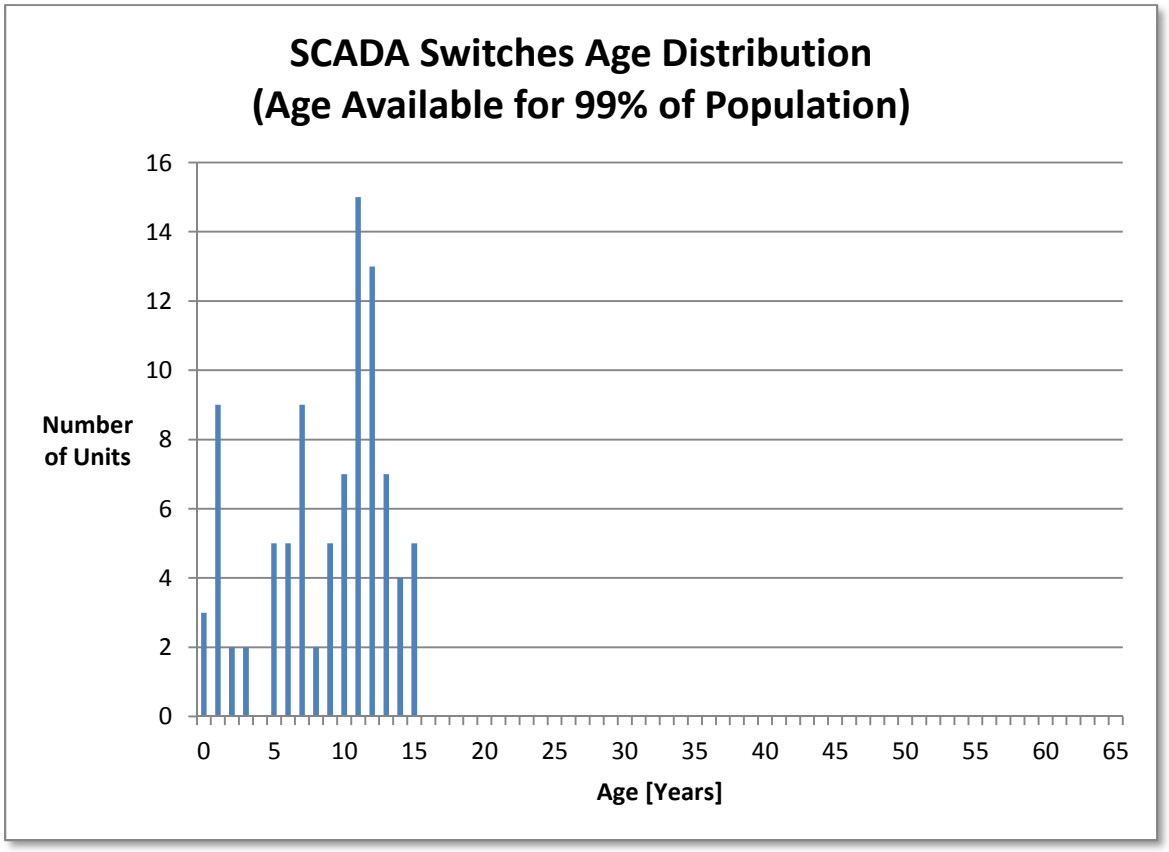


Figure 8-2 SCADA Switches Data Availability Distribution

8.3 Health Index Results

There are 94 in-service SCADA Switches at GHESI. There were 94 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 84%. Approximately 5% of the units were found to be in poor condition.

The Health Index Results are as follows:

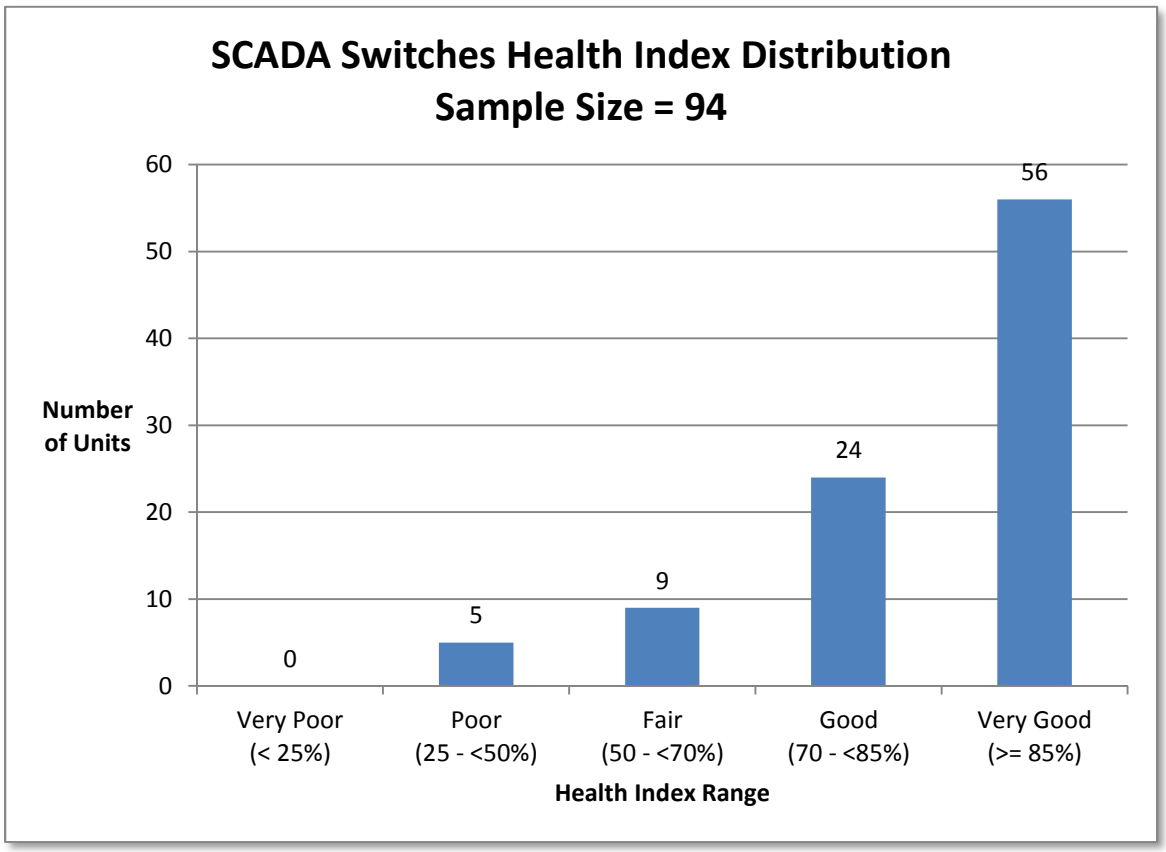


Figure 8-3 SCADA Switches Health Index Distribution (Number of Units)

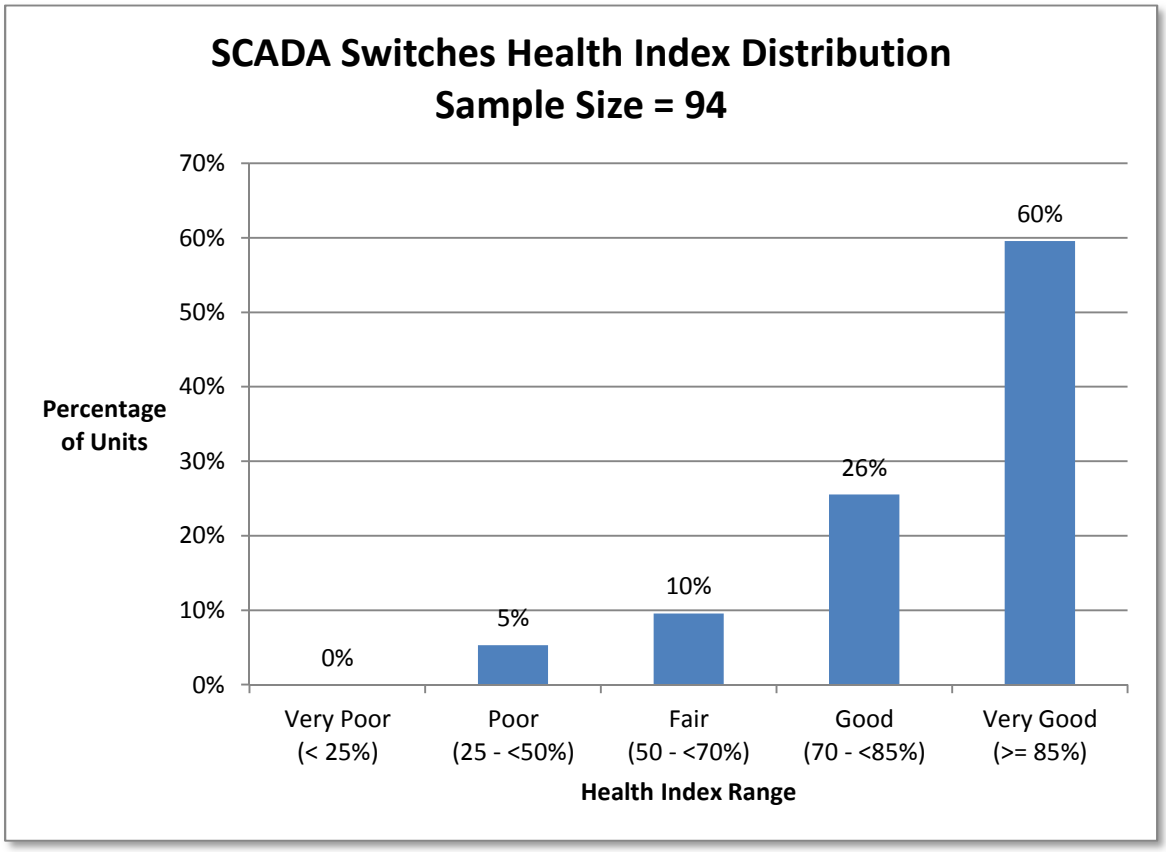


Figure 8-4 SCADA Switches Health Index Distribution (Percentage of Units)

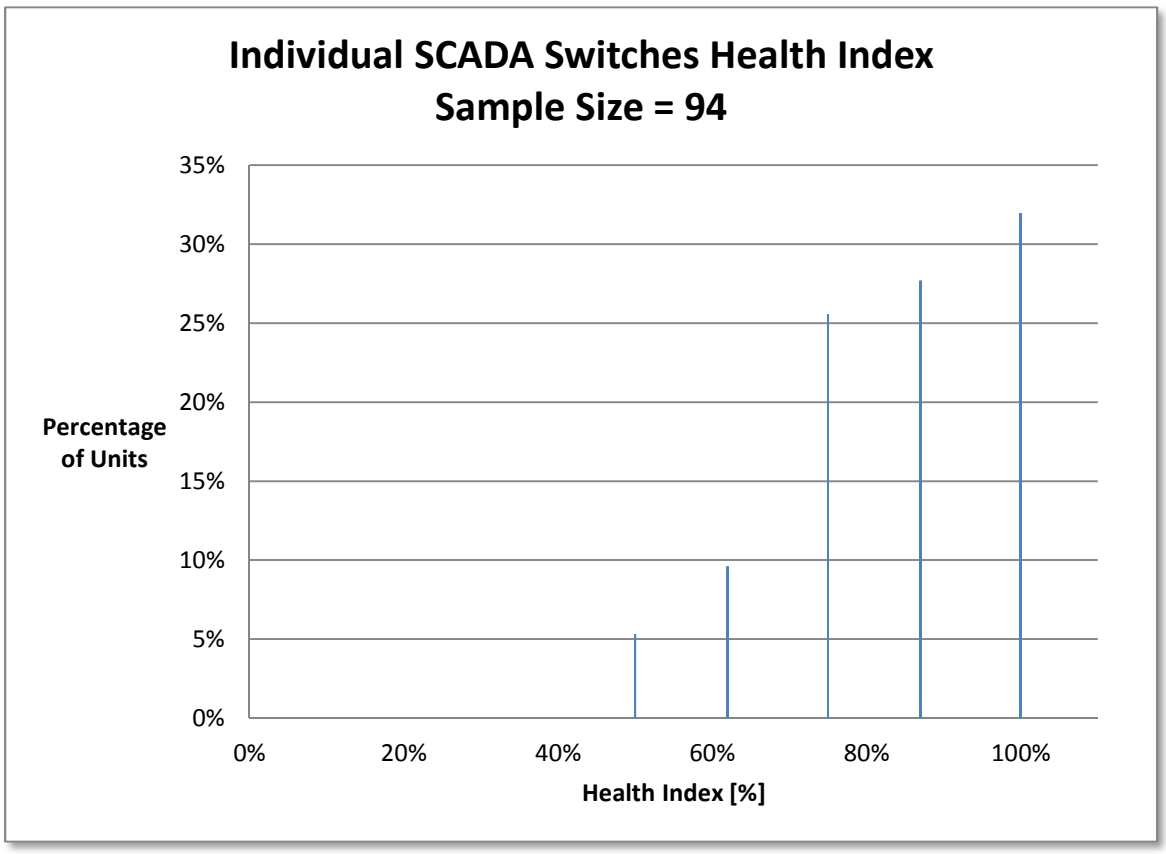


Figure 8-5 SCADA Switches Health Index Distribution by Value (Percentage of Units)

8.4 Condition-Based Flagged for Action Plan

As it is assumed that SCADA Switches are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

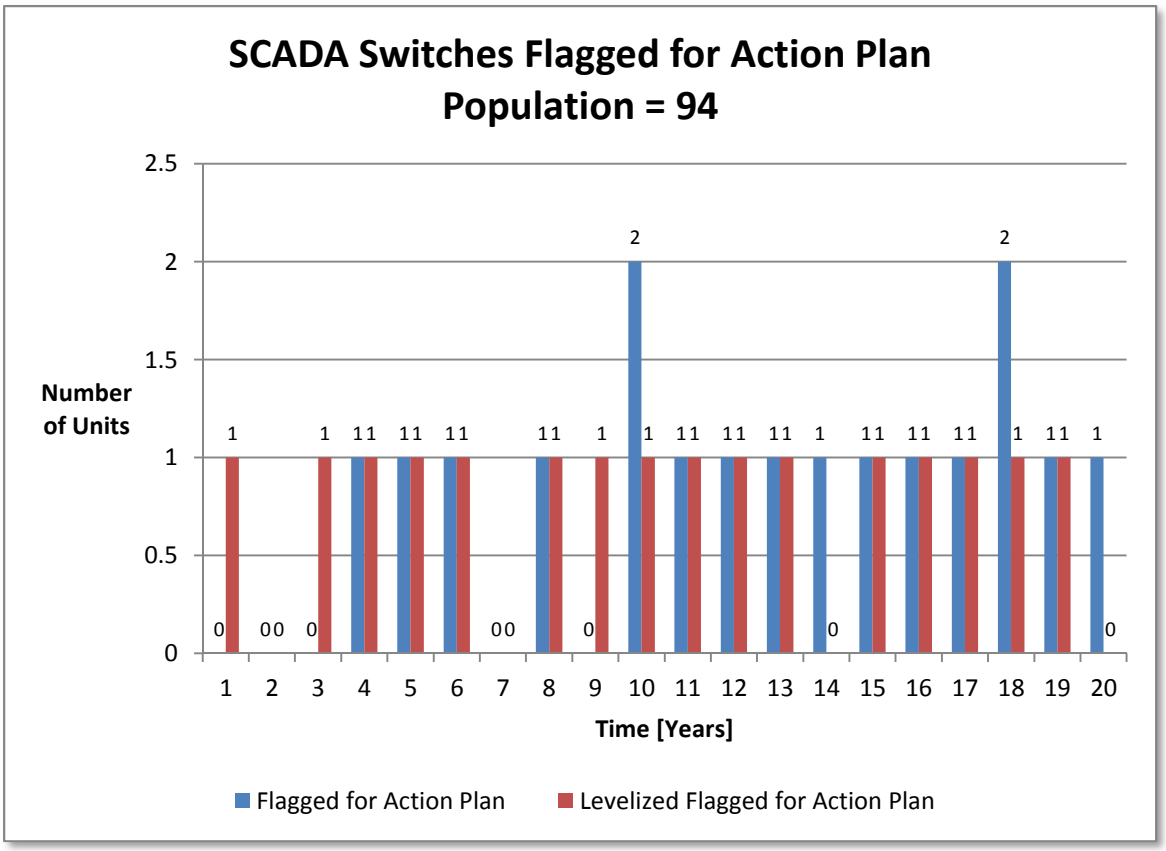


Figure 8-6 SCADA Switches Condition-Based Flagged for Action Plan

8.5 Data Analysis

8.5.1 Data Gap

The data available for SCADA Switches includes age, number of operations, and an indicator of whether the switch has been inspected or not. The data gaps, which are primarily from visual inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	☆	Support insulator	Crack	On-site visual inspection
Switch Condition	**Switch**	☆☆☆	Blade	Blade condition	On-site visual inspection

8.5.2 Data Availability Distribution

Because there were no inspection records, the average DAI for SCADA Switches is 25%.

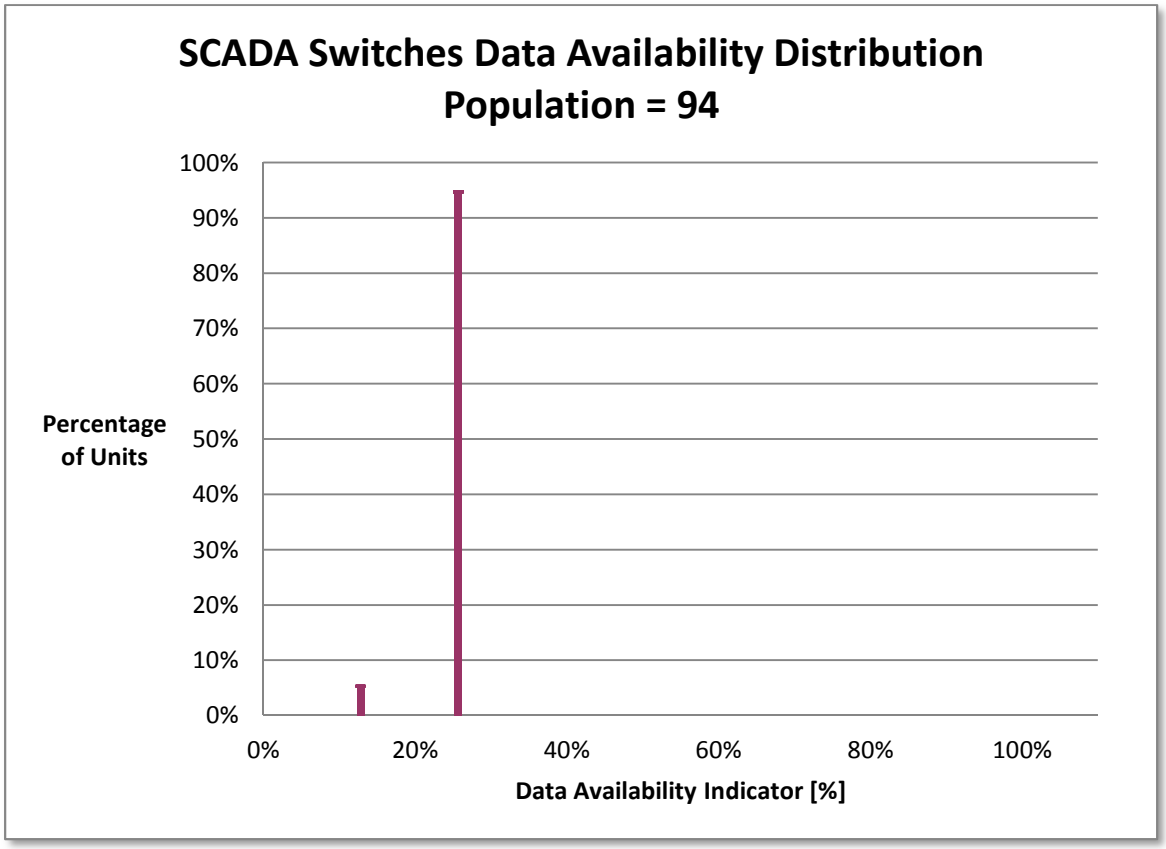


Figure 8-7 SCADA Switches Data Availability Distribution

9 Live Front Switchgear

9.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Live Front Switchgear. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Live Front Switchgear Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	Table 9-2
		Access	1	Table 9-2
		Base	2	Table 9-2
		Moisture	2	Table 9-2
Switch/Fuse Condition	1	Switch/Fuse Condition	1	
Insulation / Termination	1	Insulation	1	Table 9-2
		Termination	1	Table 9-2
Service Record	3	Overall Condition	4	Table 9-3
		Dry Ice	1	Table 9-4
		Safety Problem	1	Table 9-2
		Hot Spots	1	Table 9-2
		Age	3	Figure 9-1

9.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Live Front Switchgear 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 30 and 40 years the probability of failure (P_f) for this asset are 20% and 95% 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:

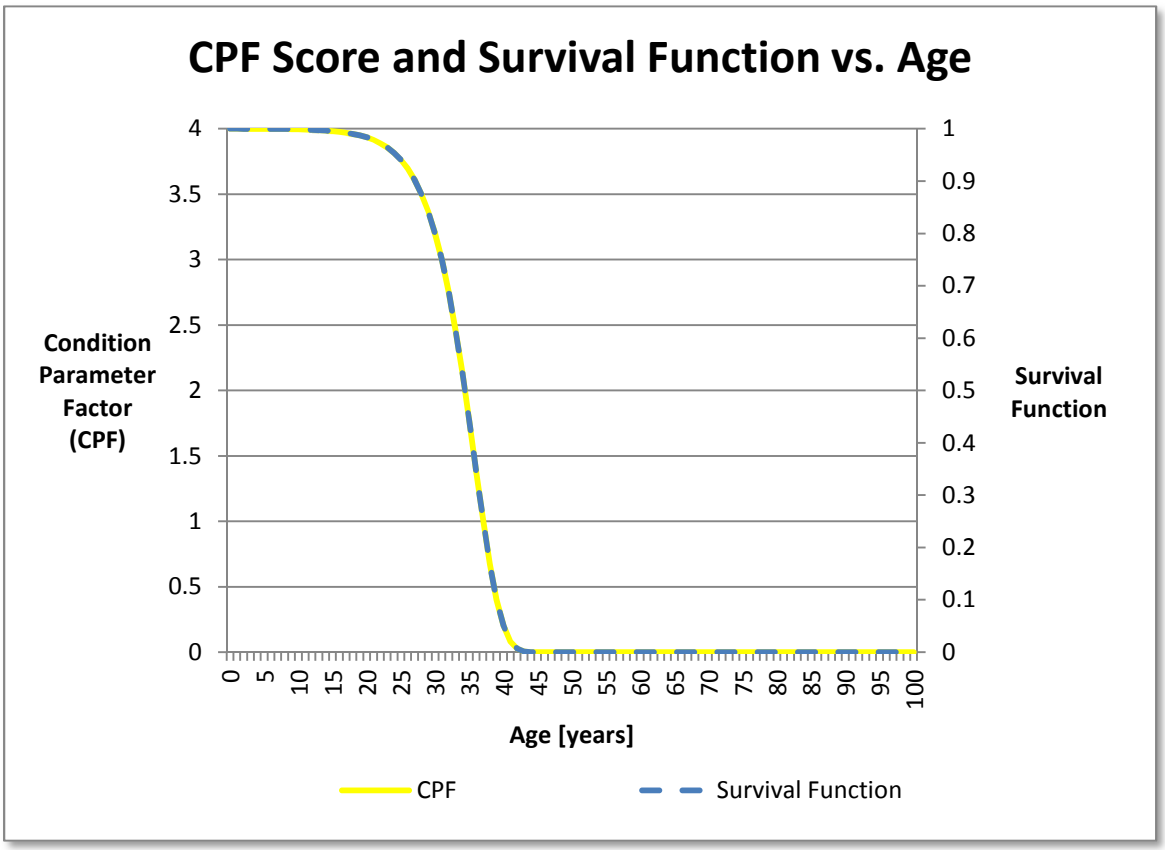


Figure 9-1 Live Front Switchgear Age Condition Criteria

Okay or Not Okay

Table 9-2 Live Front Switchgear Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Status

Table 9-3 Live Front Switchgear Status Description and Score

Status	Score
PROBLEM	0
NO PROBLEM	4
FIXED	3

Dry Ice

Table 9-4 Live Front Switchgear Dry Ice Description and Score

Dry Ice Complete	Score
Complete	4
Not Complete	0

9.2 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 14 years.

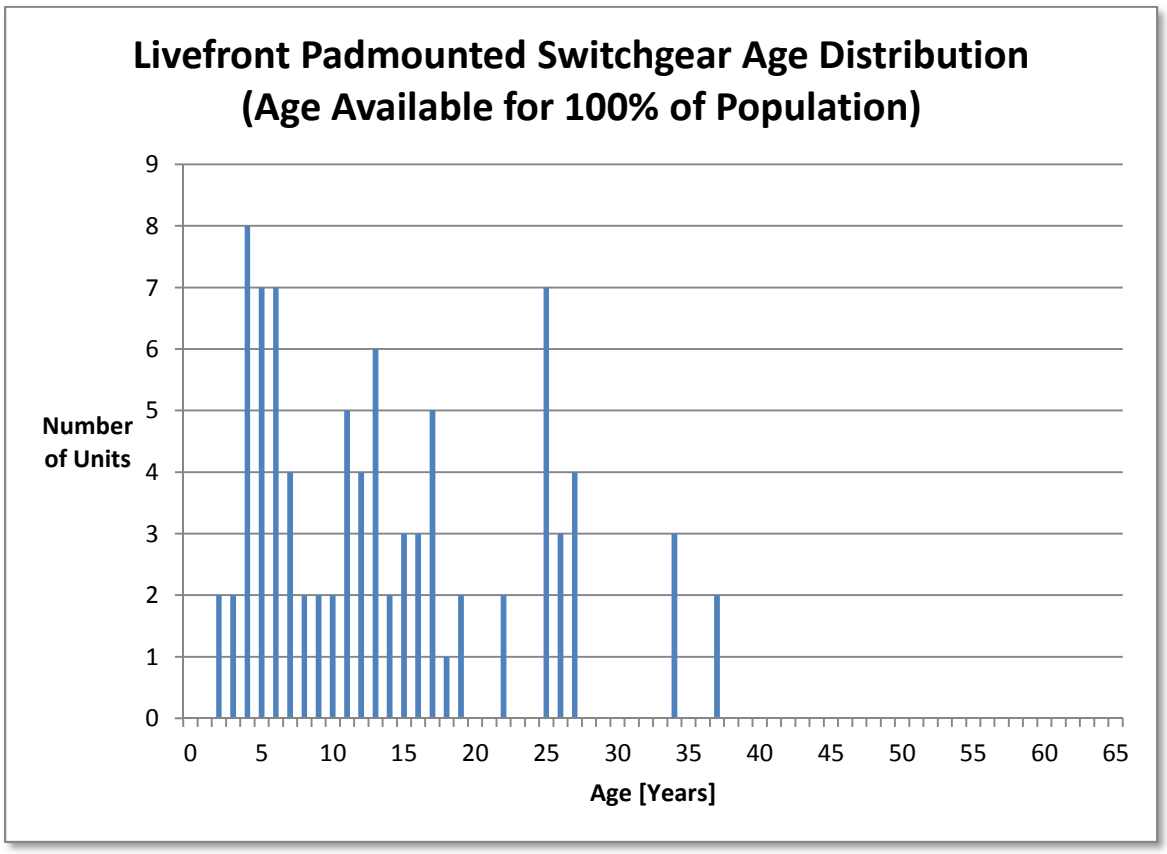


Figure 9-2 Live Front Switchgear Age Distribution

9.3 Health Index Results

There are 88 in-service Live Front Switchgear at GHESI. There were 88 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 87%. About 1% of the units were found to be in poor condition.

The Health Index Results are as follows:

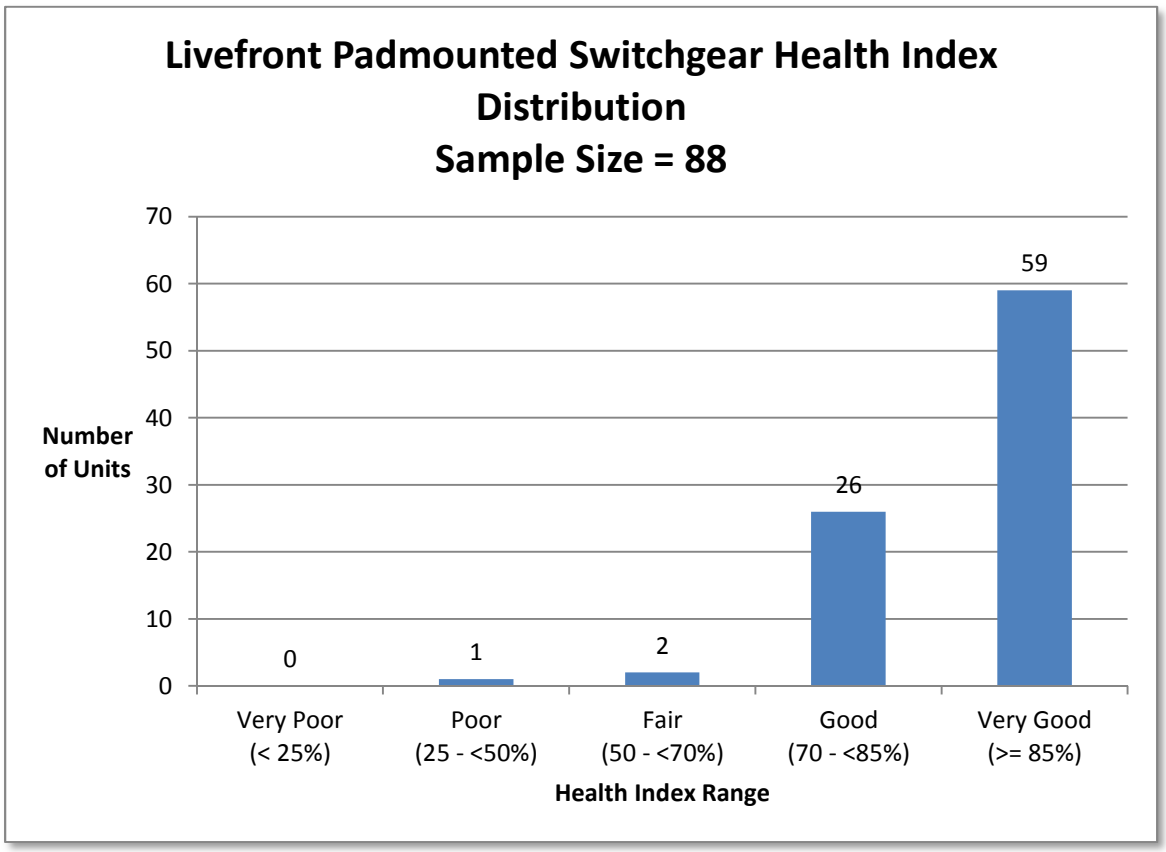


Figure 9-3 Live Front Switchgear Health Index Distribution (Number of Units)

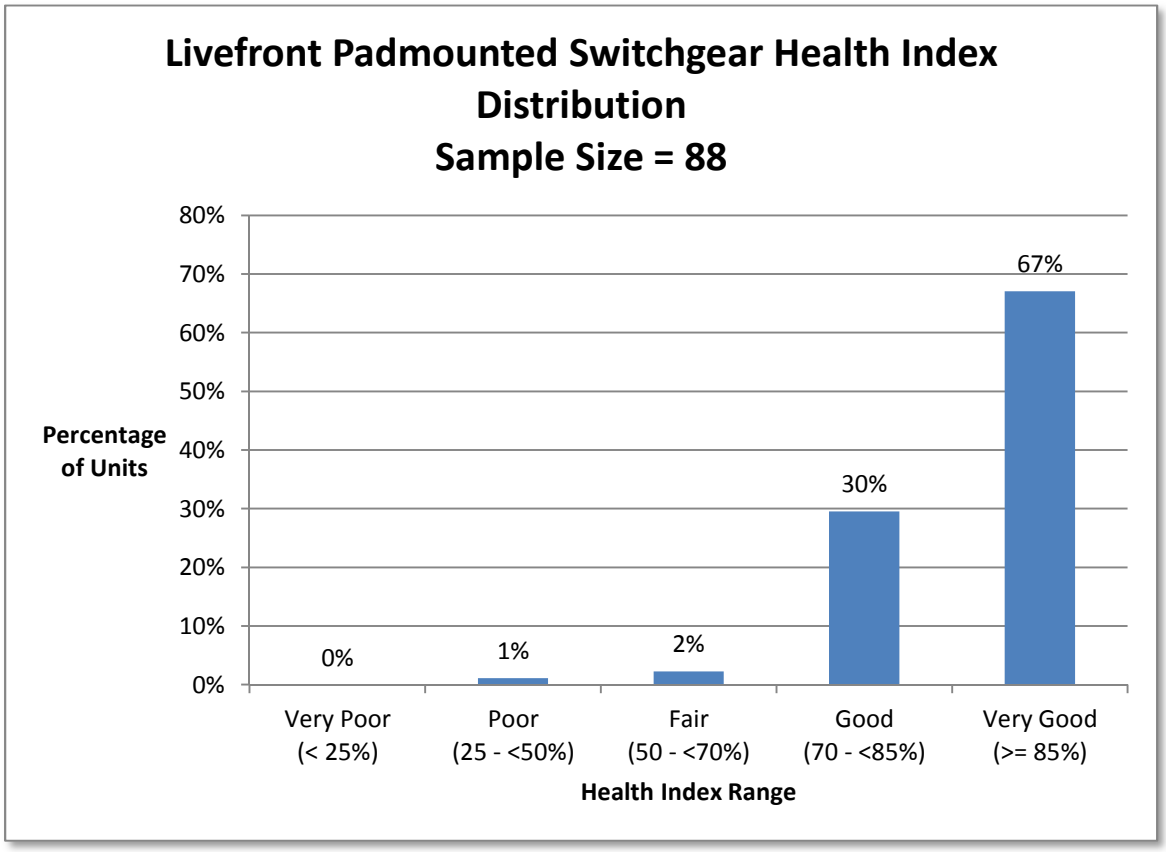


Figure 9-4 Live Front Switchgear Health Index Distribution (Percentage of Units)

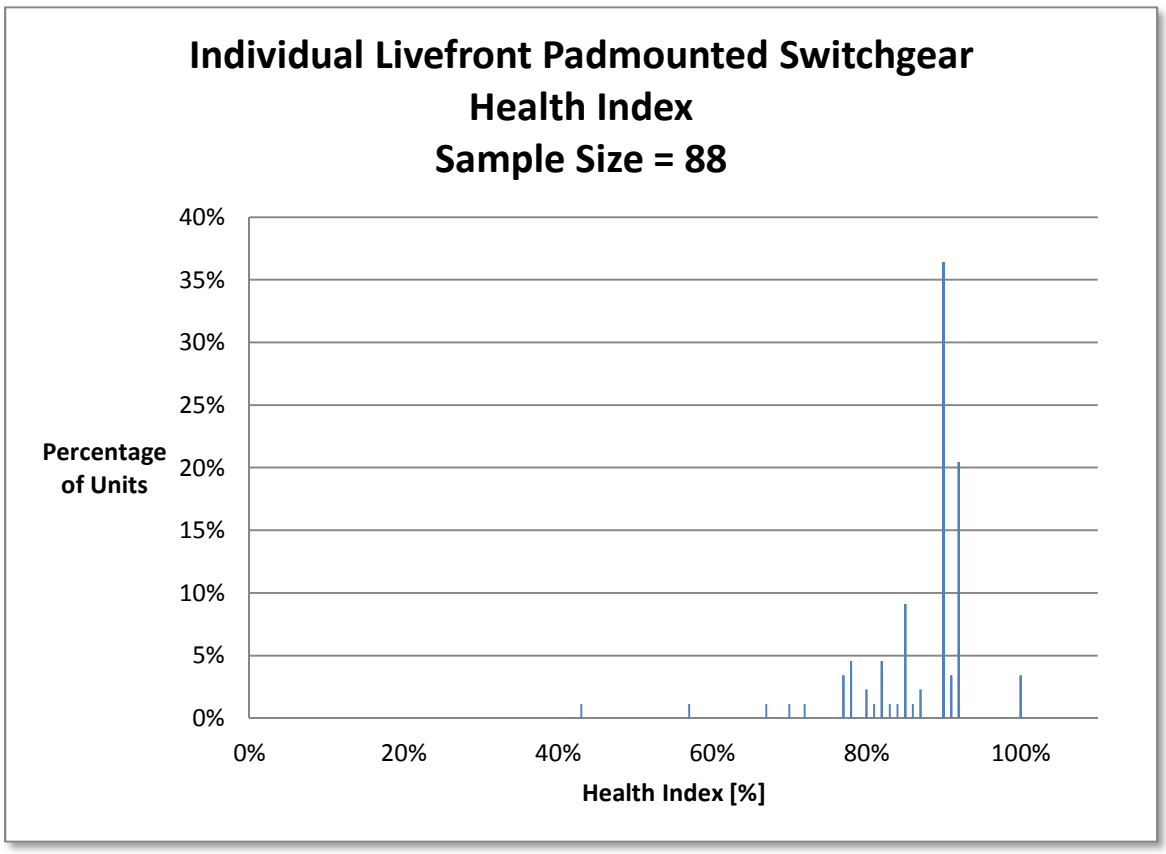


Figure 9-5 Live Front Switchgear Health Index Distribution by Value (Percentage of Units)

9.4 Condition-Based Flagged for Action Plan

As it is assumed that Live Front Switchgear are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

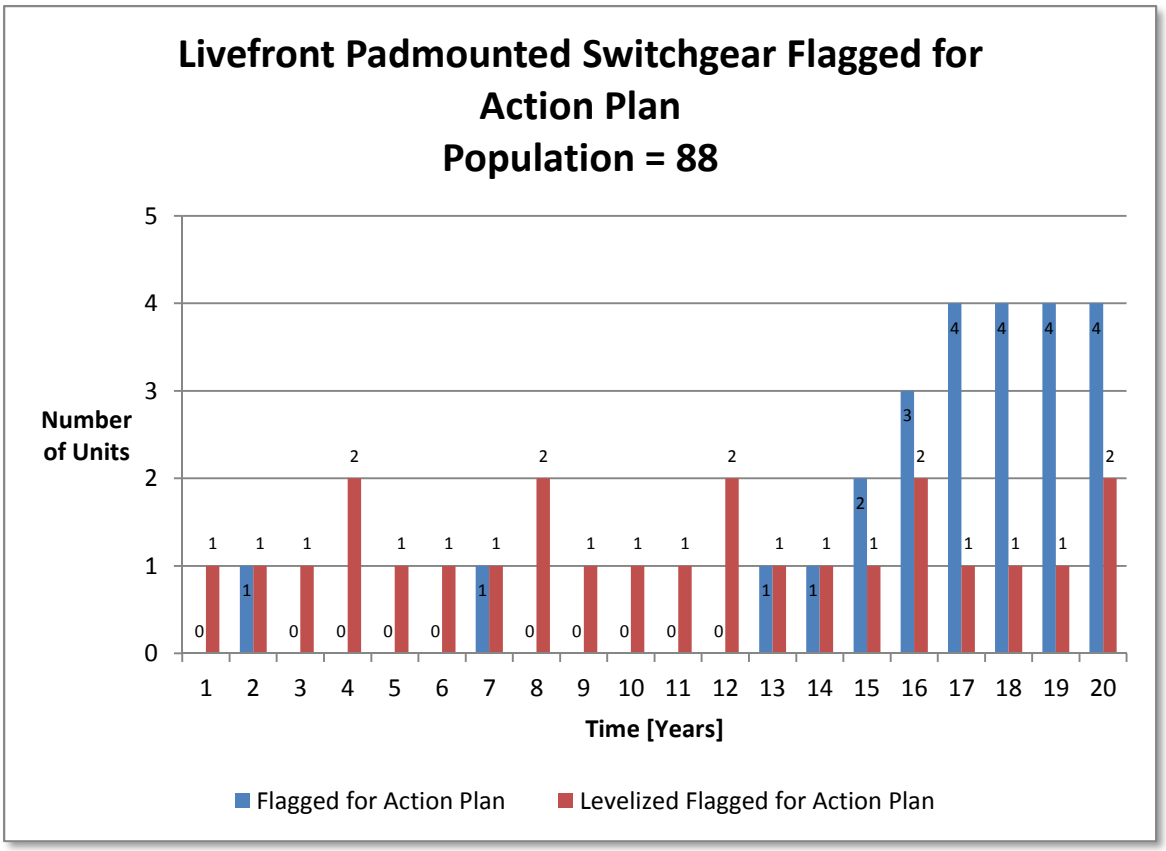


Figure 9-6 Live Front Switchgear Condition-Based Flagged for Action Plan

9.5 Data Analysis

The data available for Live Front Switchgear are age and inspection records. Data gaps identified for this asset class 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	Insulation / Termination	☆☆	Connection	Poor connection / hot spots	Visual inspection or IR scan

9.5.1 Data Availability Distribution

The data availability was generally good; the average DAI for Live Front Switchgear is 62%.

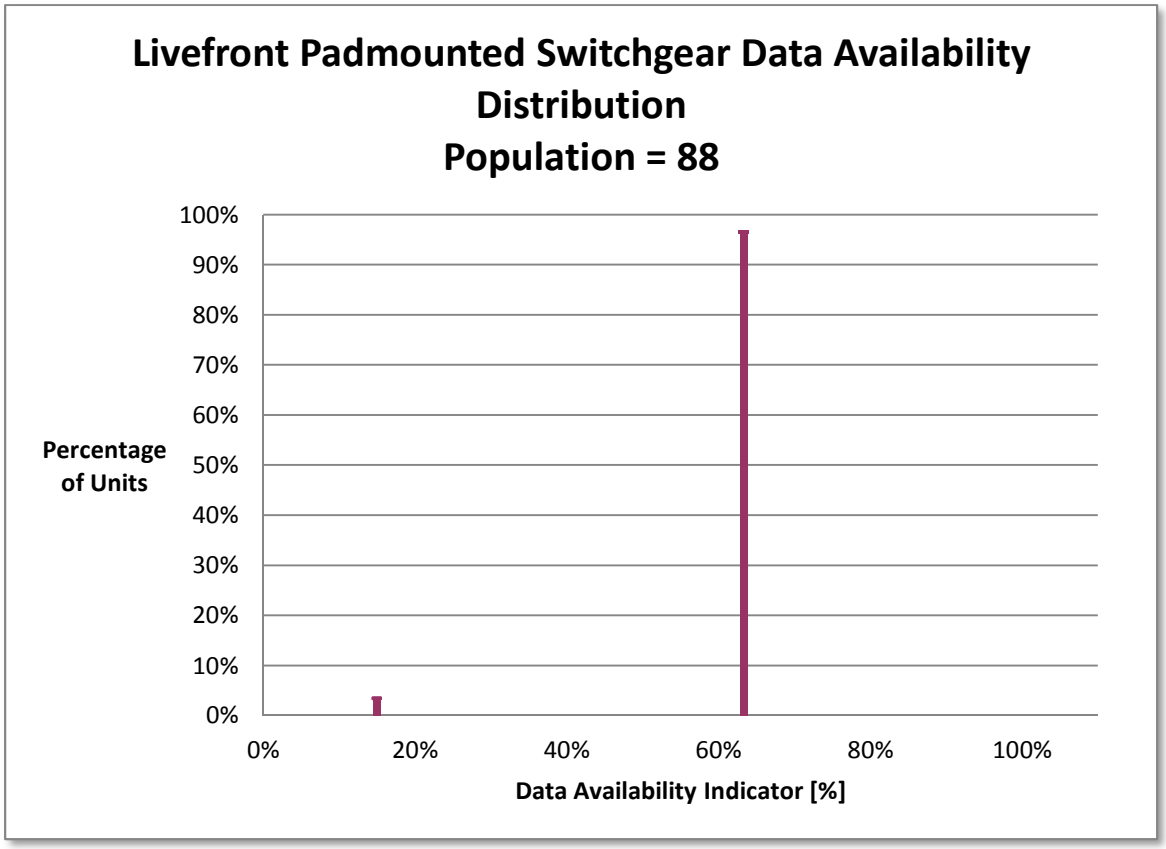


Figure 9-7 Live Front Switchgear Data Availability Distribution

10 Solid Dielectric Switchgear

10.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Solid Dielectric Switchgear. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

10.1.1 Condition and Sub-Condition Parameters

Table 10-1 Solid Dielectric Switchgear Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	Table 10-2
		Access	1	Table 10-2
		Base	2	Table 10-2
		Moisture	2	Table 10-2
Insulation / Termination	1	Insulation	1	Table 10-2
		Termination	1	Table 10-2
Service Record	3	Overall Condition	4	Table 10-2
		Safety Problem	1	Table 10-2
		Hot Spots	1	Table 10-2
		Age	3	Figure 10-1

10.1.2 Condition Parameter Criteria

Okay or Not Okay

Table 10-2 Solid Dielectric Switchgear Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Age

Assume that the failure rate for Solid Dielectric Switchgear 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 30 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

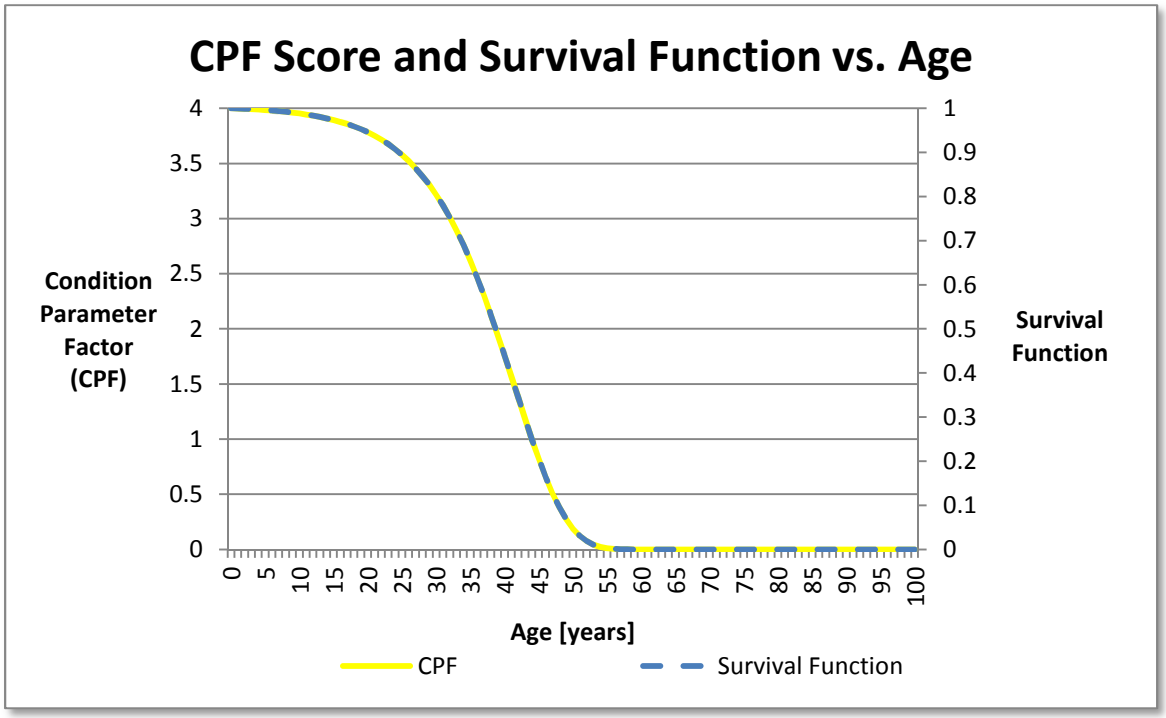


Figure 10-1 Solid Dielectric Switchgear Age Condition Criteria

10.2 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 2 years.

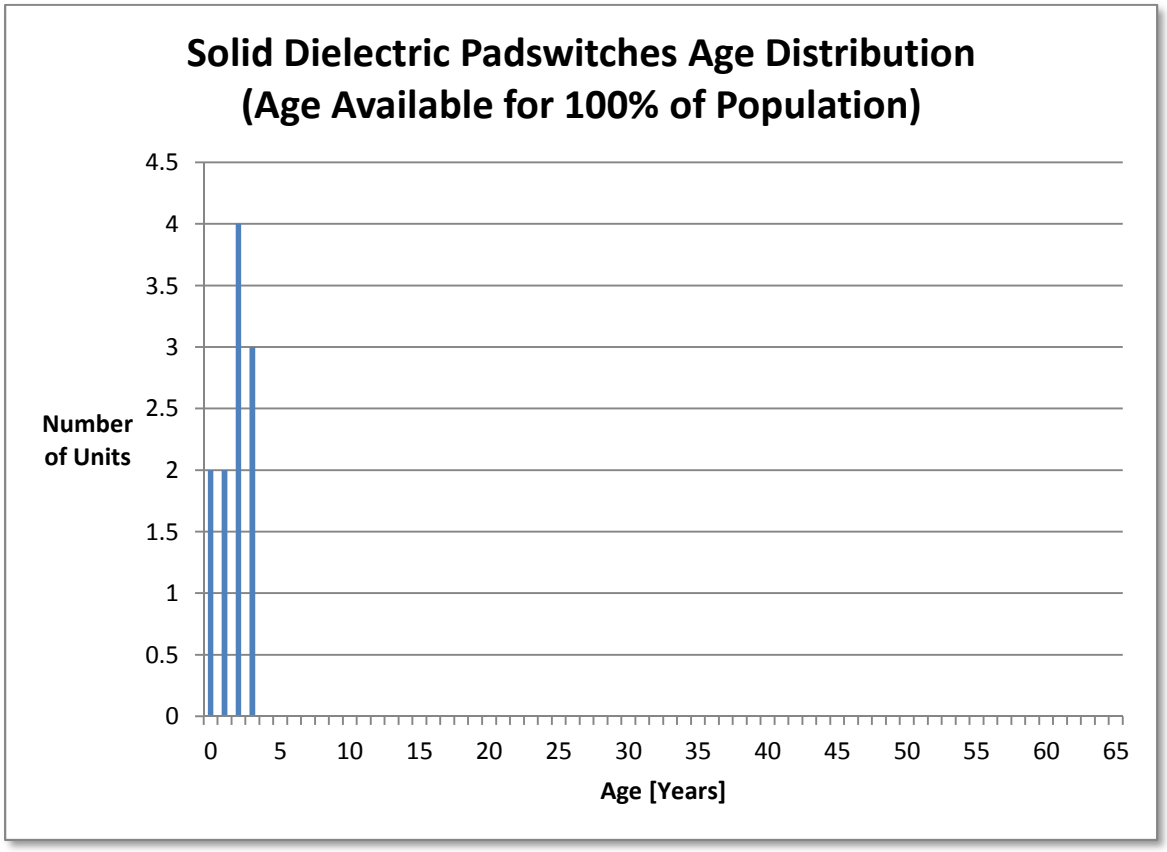


Figure 10-2 Solid Dielectric Switchgear Age Distribution

10.3 Health Index Results

There are 11 in-service Solid Dielectric Switchgear at GHESI. There were 11 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 99%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

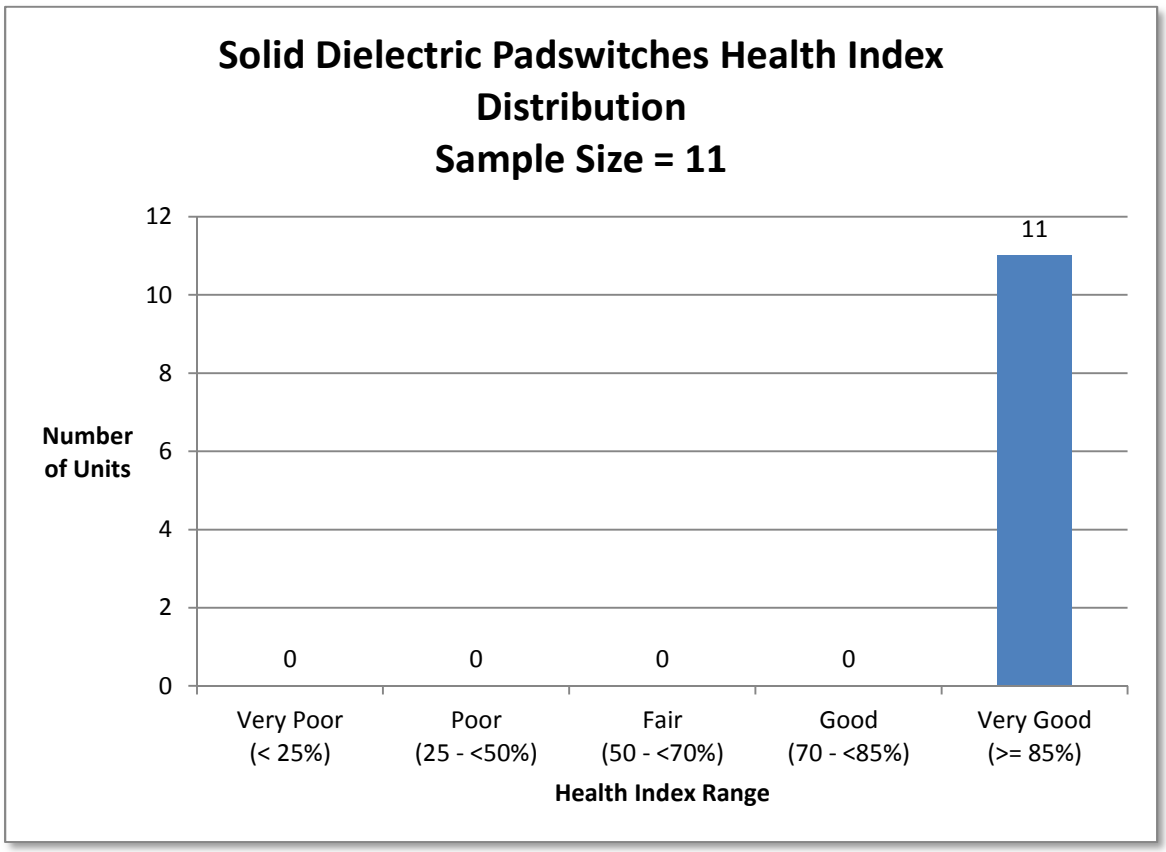


Figure 10-3 Solid Dielectric Switchgear Health Index Distribution (Number of Units)

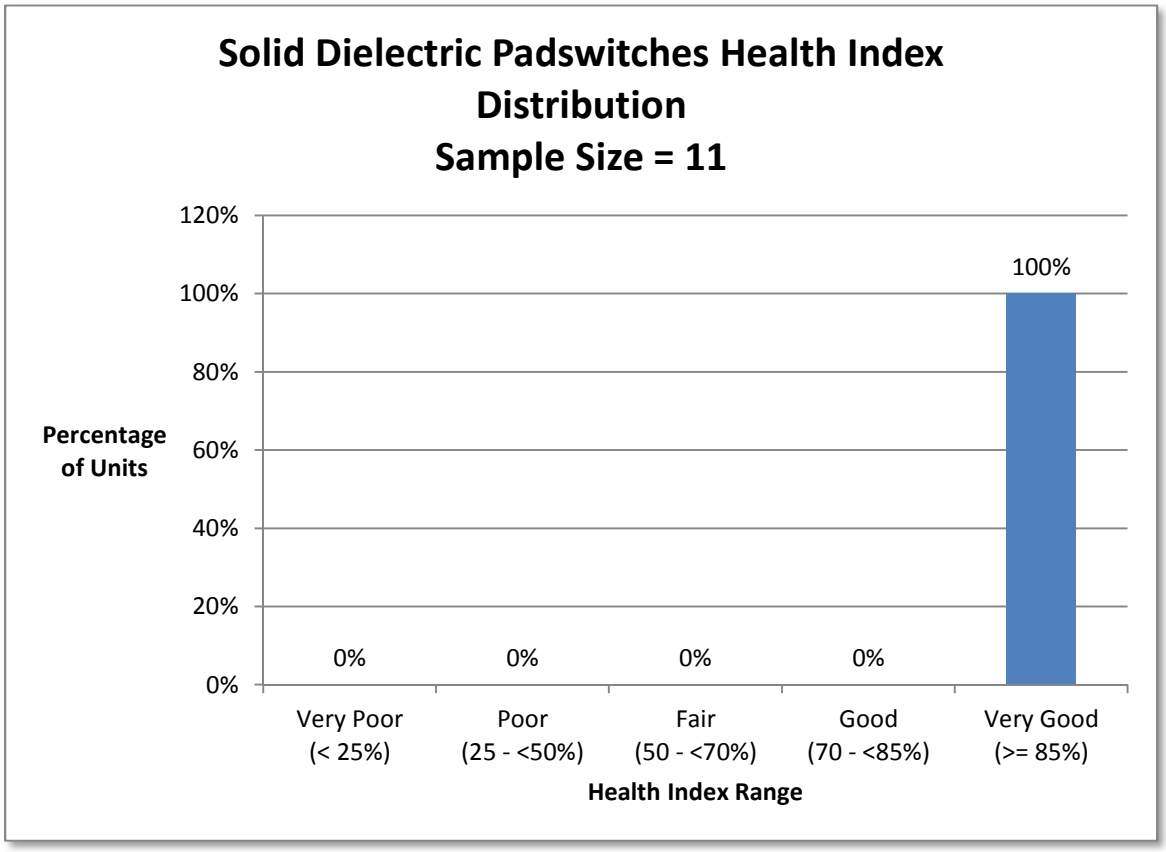


Figure 10-4 Solid Dielectric Switchgear Health Index Distribution (Percentage of Units)

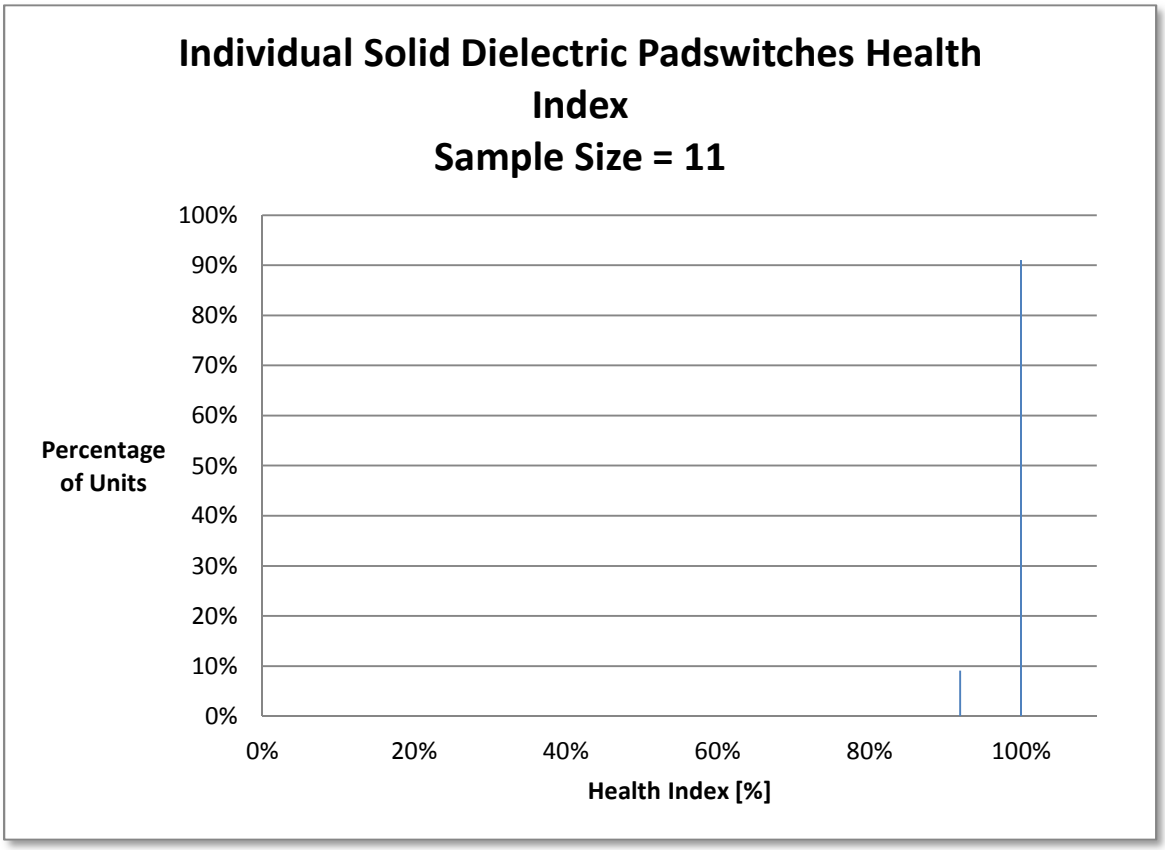


Figure 10-5 Solid Dielectric Switchgear Health Index Distribution by Value (Percentage of Units)

10.4 Condition-Based Flagged for Action Plan

As it is assumed that Solid Dielectric Switchgear are reactively addressed, the flagged for action plan is based on asset failure rate f(t). No units are flagged for action in the next 20 years.

10.5 Data Analysis

10.5.1 Data Gap

There are no data gaps for this asset category.

10.5.2 Data Availability Distribution

The average DAI for Solid Dielectric Switchgear is 59%.

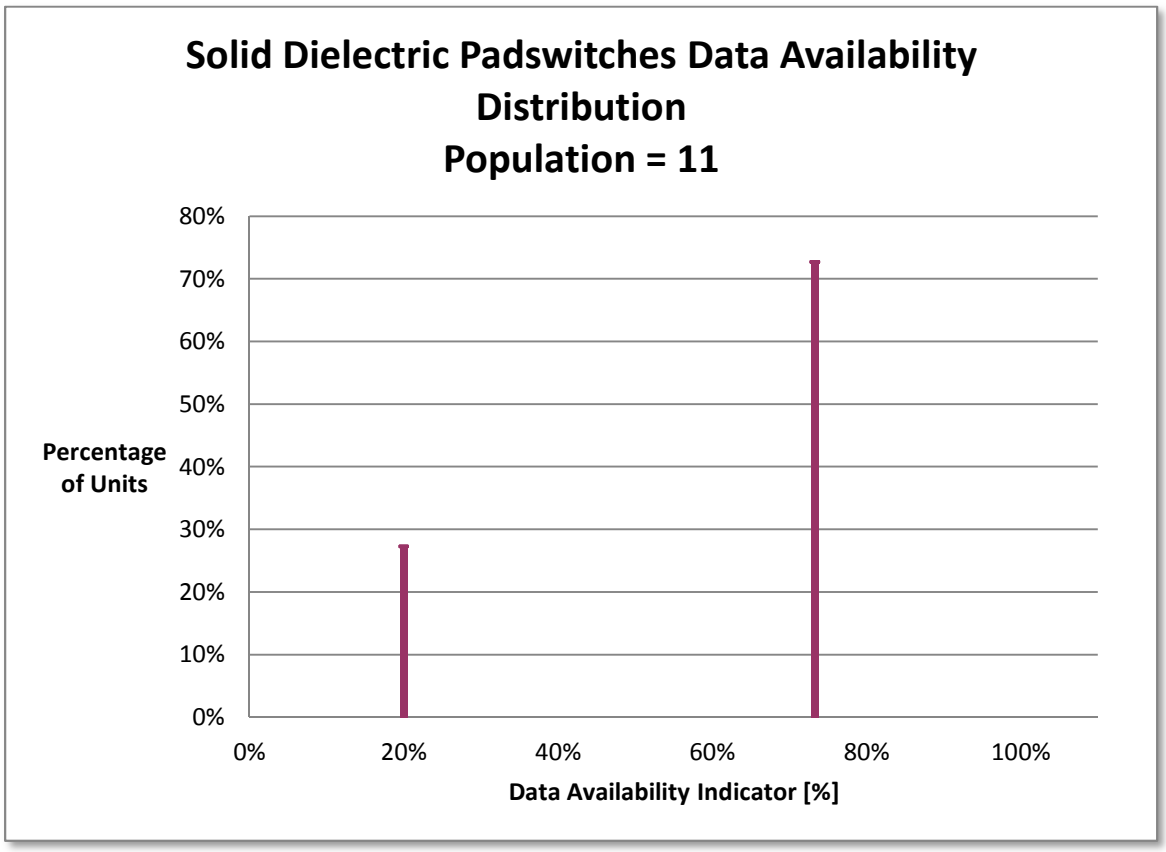


Figure 10-6 Solid Dielectric Switchgear Data Availability Distribution

11 Switching Cubicles

11.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Switching Cubicles. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

11.1.1 Condition and Sub-Condition Parameters

Table 11-1 Switching Cubicles Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	Table 11-2
		Access	1	Table 11-2
		Base	2	Table 11-2
Insulation / Termination	1	Elbows	1	Table 11-2
		Connection	1	Table 11-2
		Bushing	1	Table 11-2
		Barrier	1	Table 11-2
		Safety Problem	1	Table 11-2
		Age	3	Figure 11-1

11.1.2 Condition Parameter Criteria

Okay or Not Okay

Table 11-2 Switching Cubicles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Age

Assume that the failure rate for Switching Cubicles 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 30 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

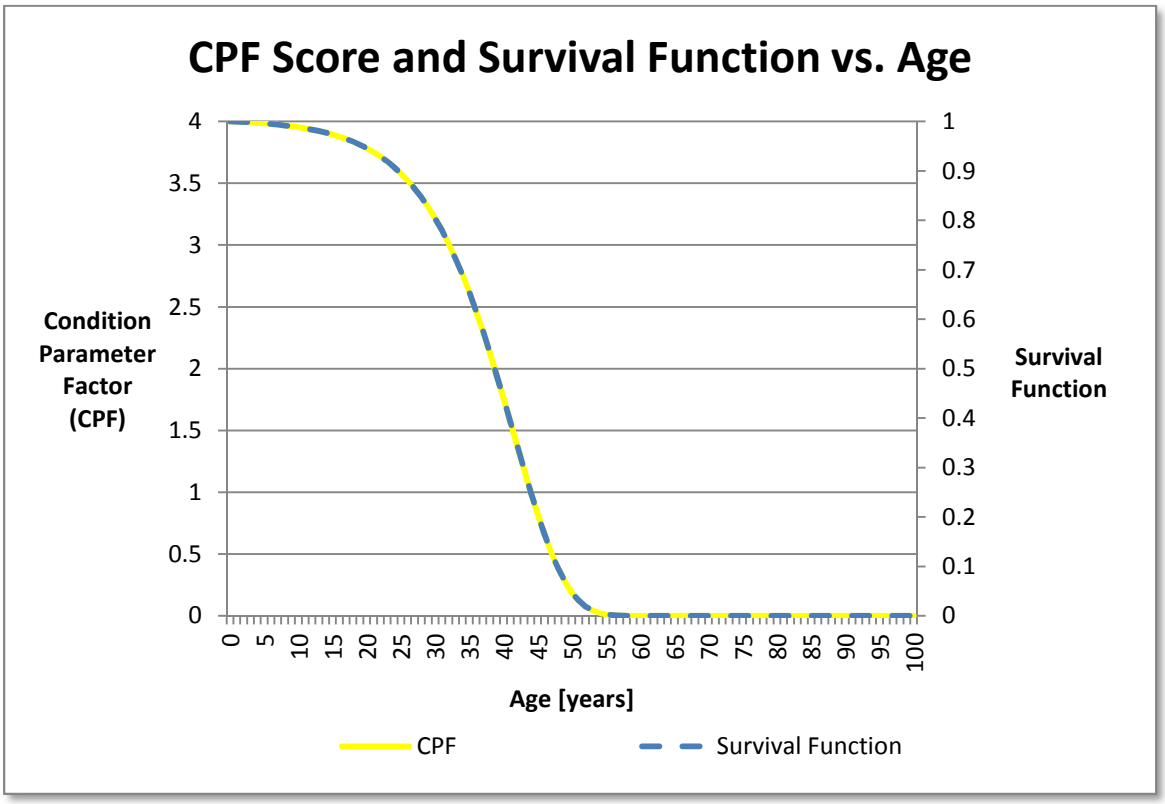


Figure 11-1 Switching Cubicles Age Condition Criteria

11.2 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 15 years.

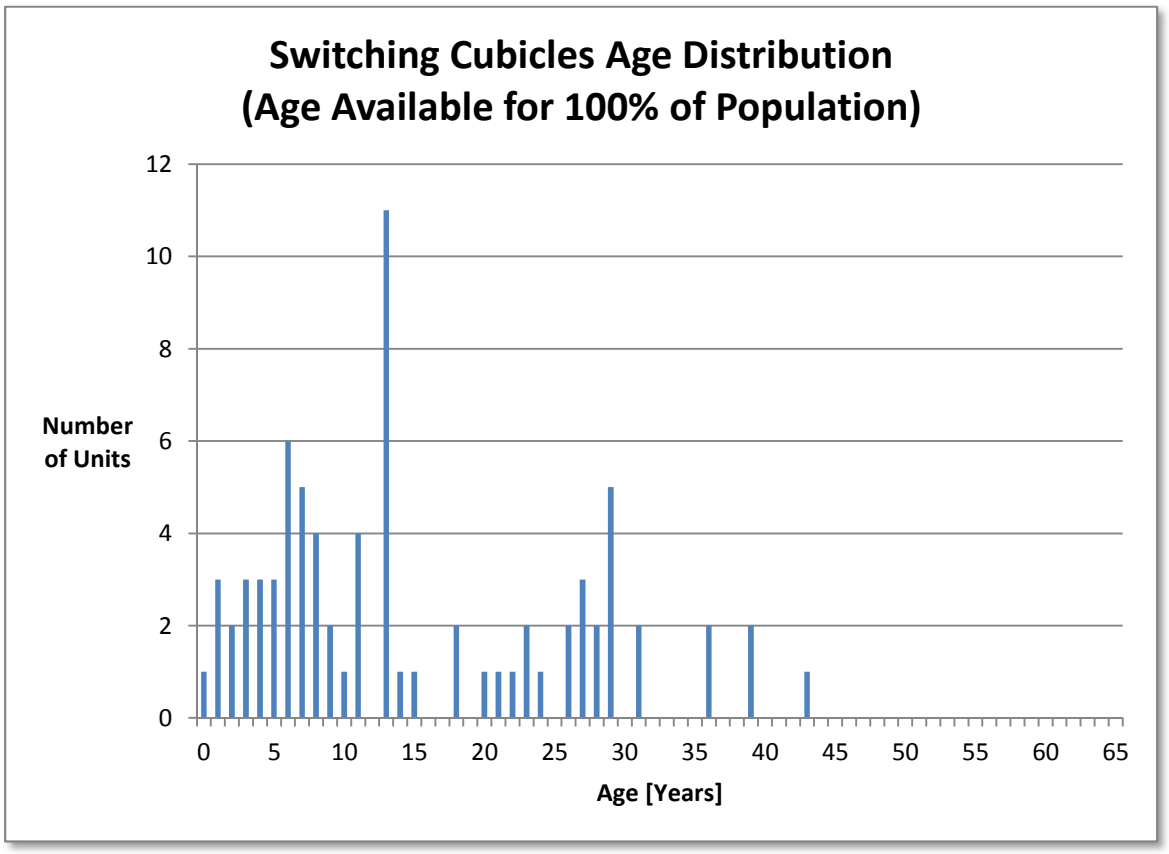


Figure 11-2 Switching Cubicles Age Distribution

11.3 Health Index Results

There are 77 in-service Switching Cubicles at GHESI. There were 77 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 91%. Approximately 6% of the units were found to be in poor condition.

The Health Index Results are as follows:

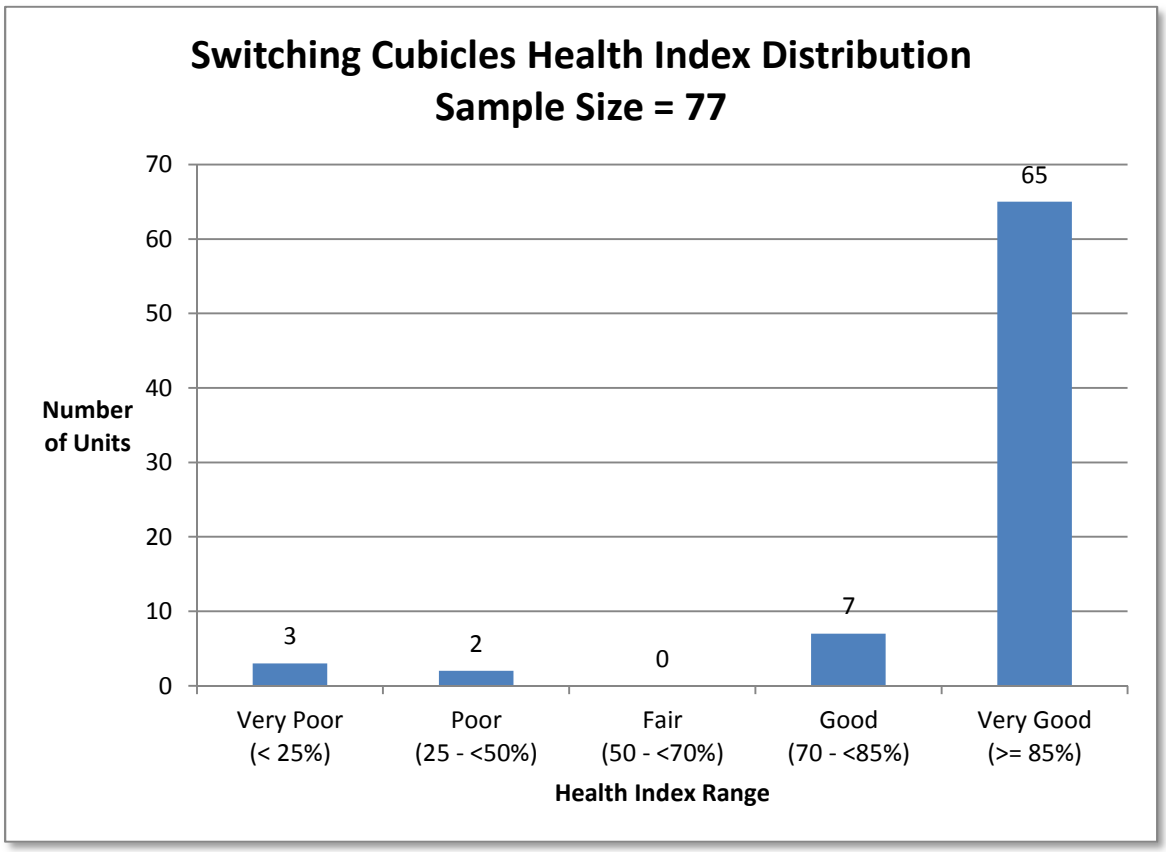


Figure 11-3 Switching Cubicles Health Index Distribution (Number of Units)

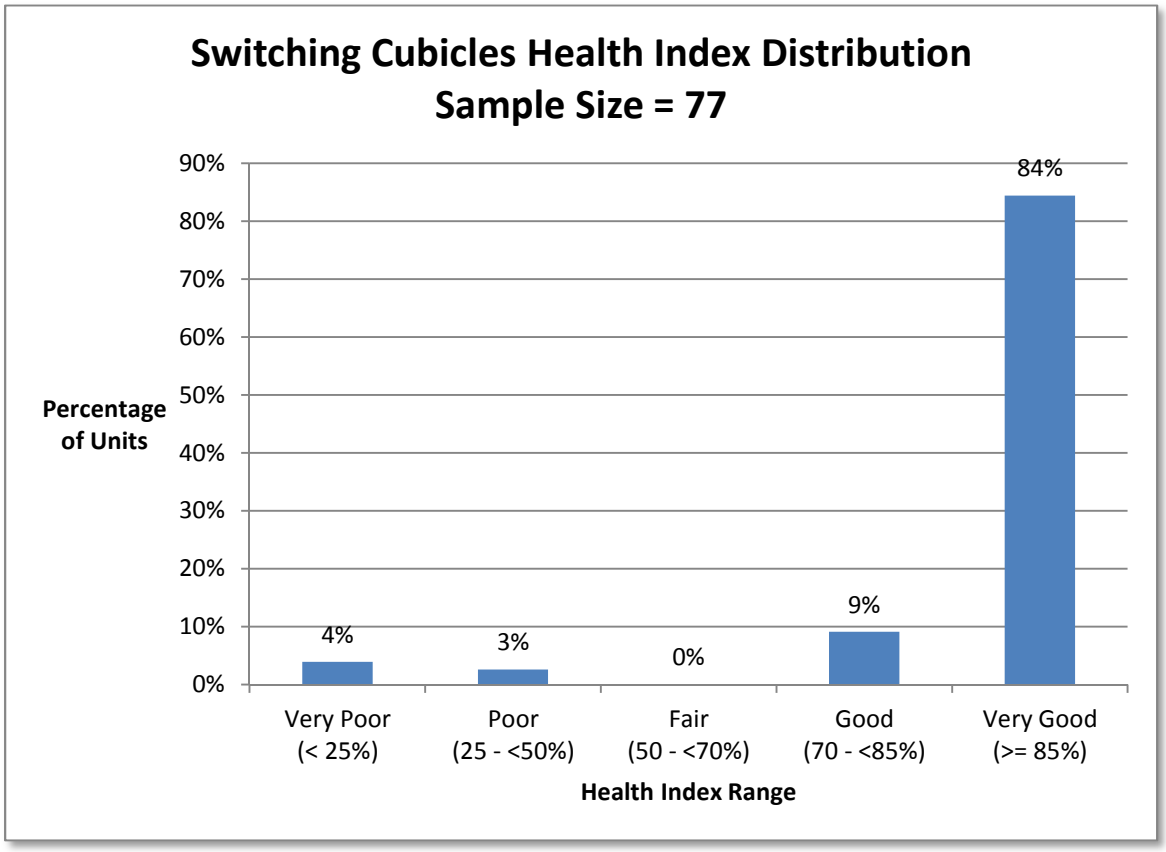


Figure 11-4 Switching Cubicles Health Index Distribution (Percentage of Units)

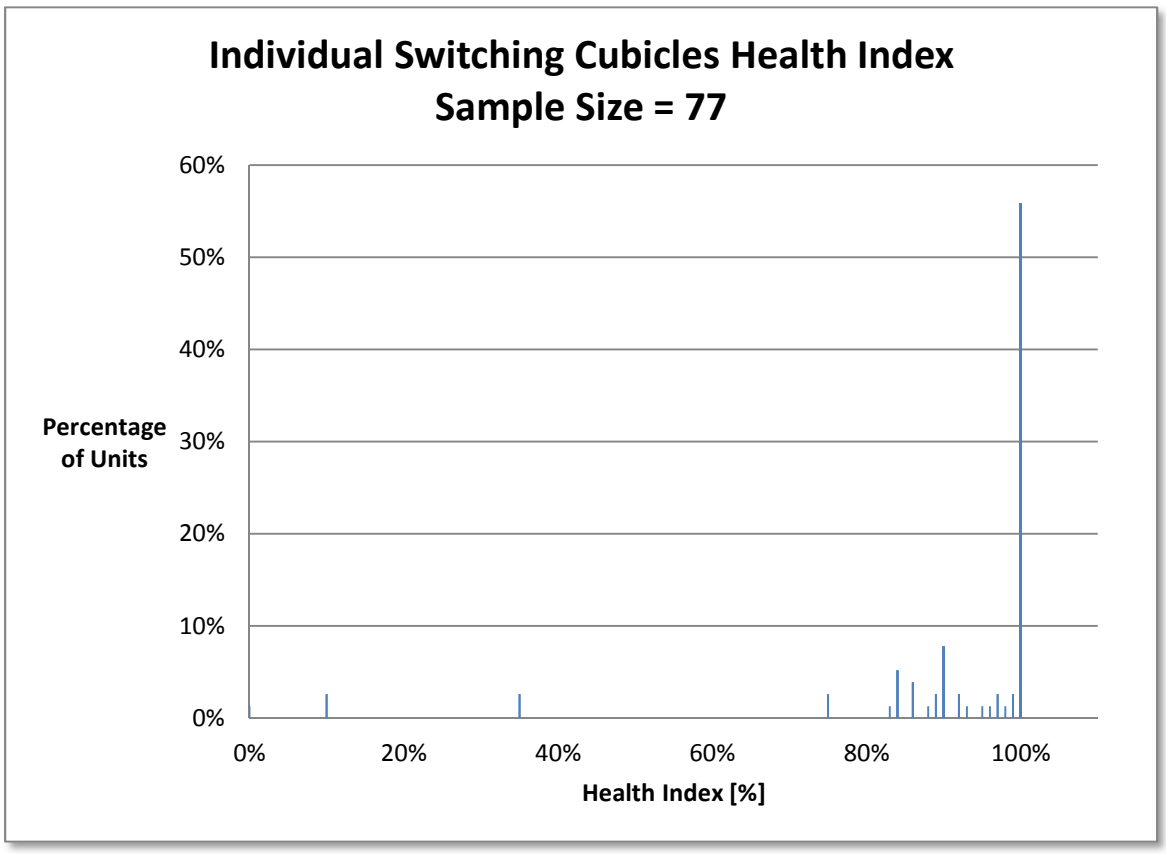


Figure 11-5 Switching Cubicles Health Index Distribution by Value (Percentage of Units)

11.4 Condition-Based Flagged for Action Plan

As it is assumed that Switching Cubicles are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

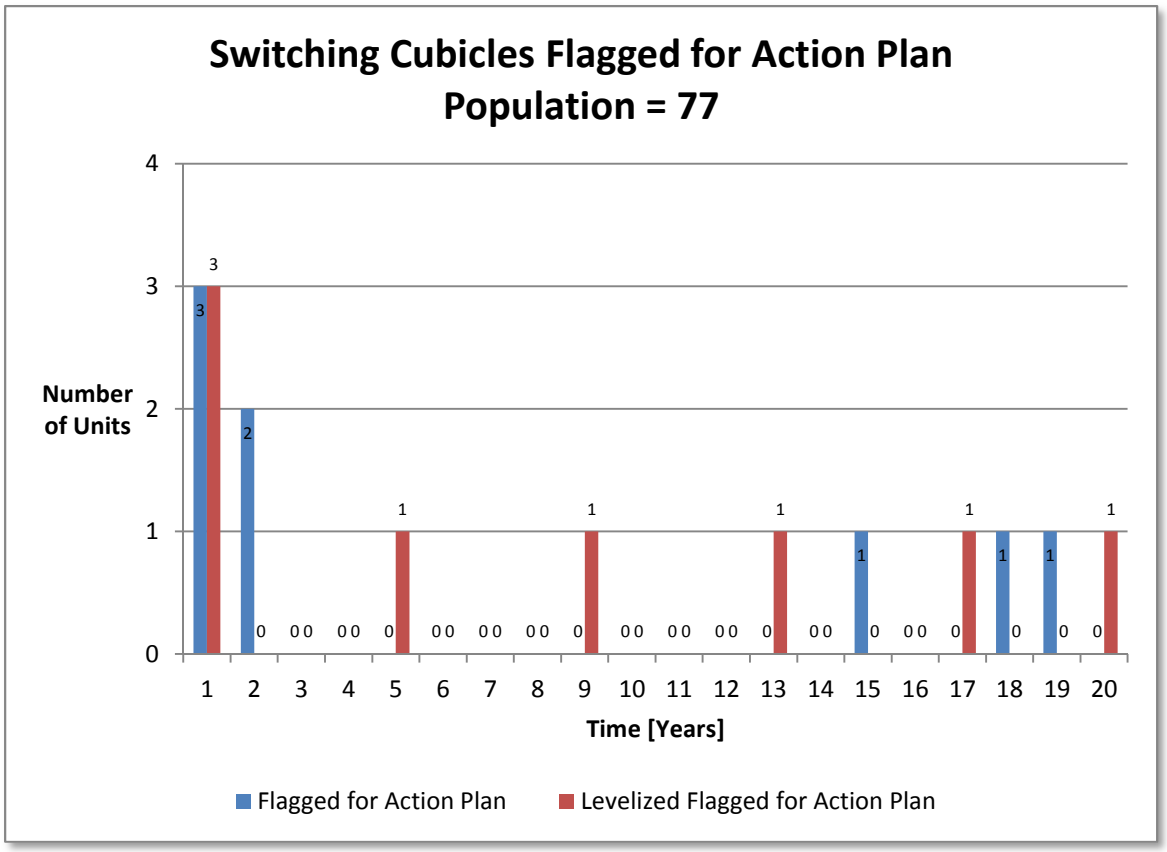


Figure 11-6 Switching Cubicles Condition-Based Flagged for Action Plan

11.5 Data Analysis

11.5.1 Data Gap

There are no data gaps for this asset category.

11.5.2 Data Availability Distribution

The average DAI for Switching Cubicles is 60%.

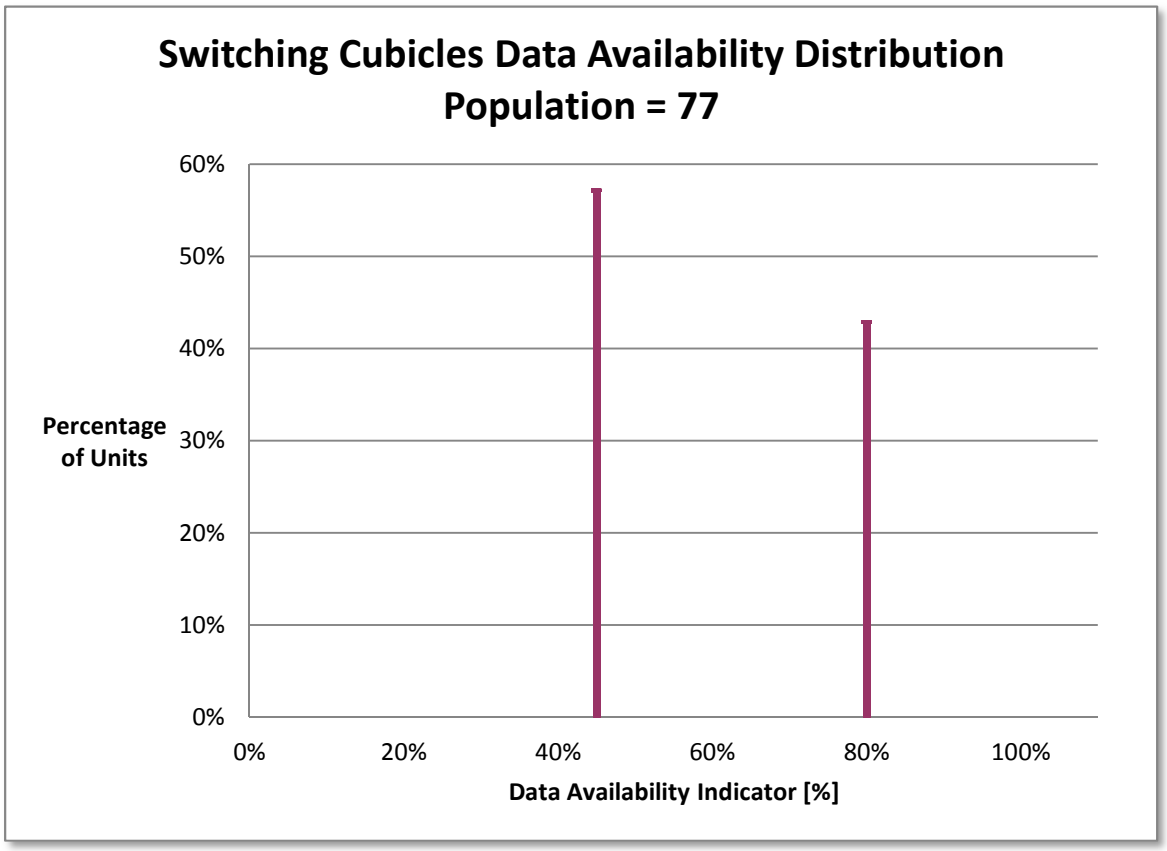


Figure 11-7 Switching Cubicles Data Availability Distribution

12 Primary Cables

12.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Primary Cables. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

12.1.1 Condition and Sub-Condition Parameters

Table 12-1 Primary Cables Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Splices and Terminations	1	
		Overall Corrective Maintenance Counts	1	
Operation Condition	3	Loading	1	
Service Record	4	5 Year Fault Rate	4	
		Age	3	Figure 12-2
De-Rating Factor		Pre 1980 vintage	80%	

12.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Primary 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 and 40 years the probability of failure (P_f) for this asset are 20% and 95% 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:

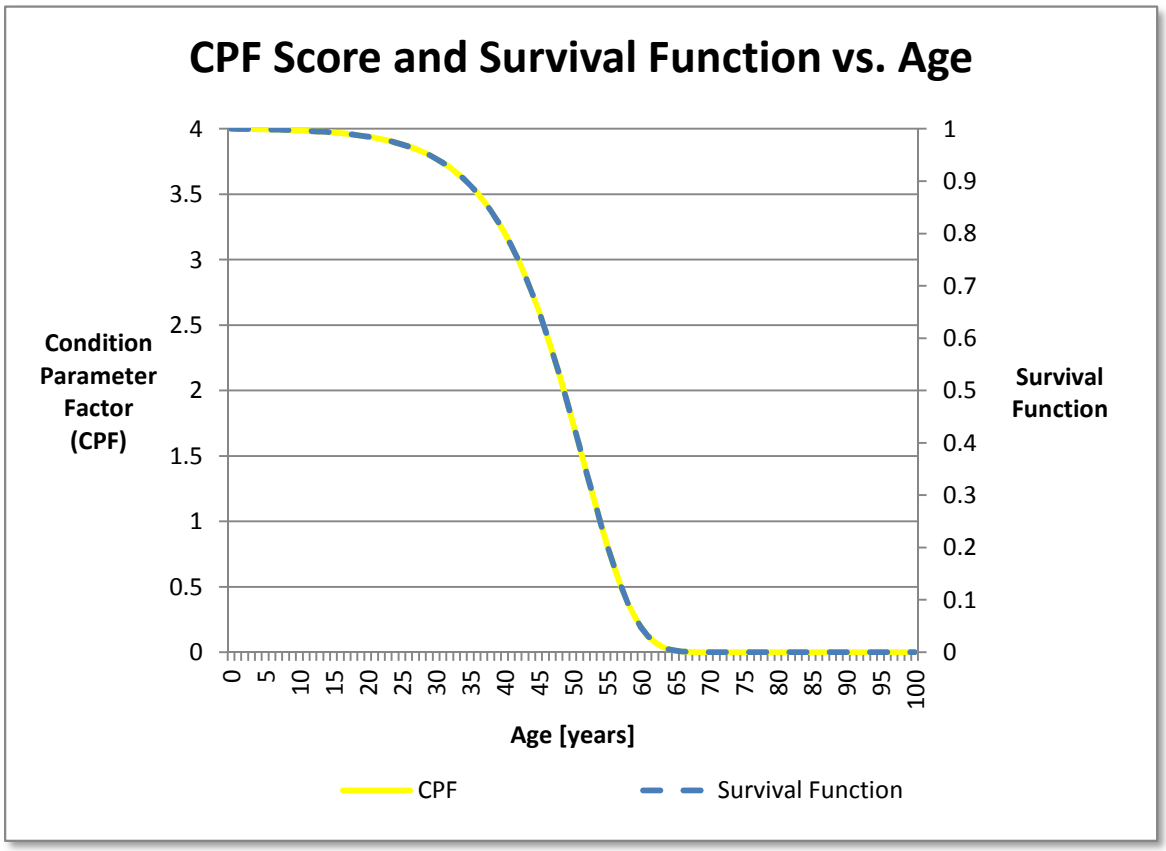


Figure 12-1 Primary Cables Age Condition Criteria

12.2 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 17 years.

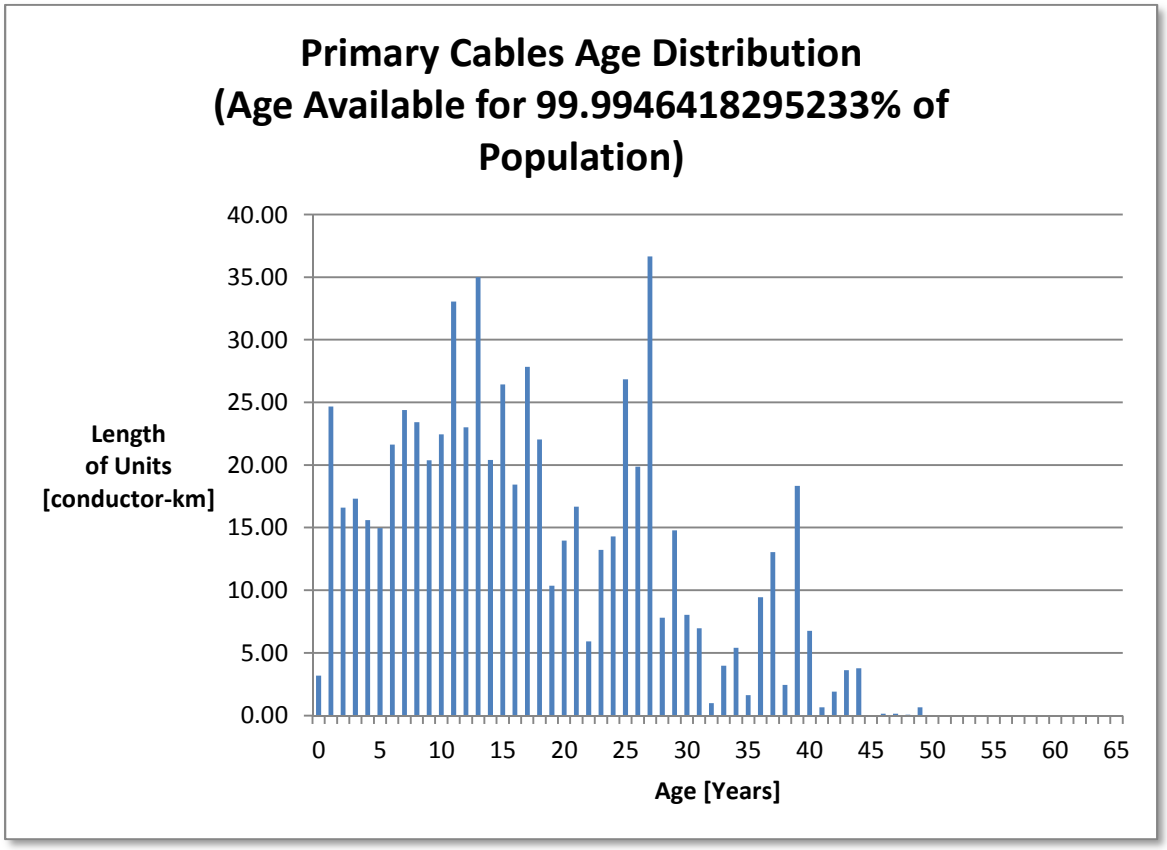


Figure 12-2 Primary Cables Age Distribution

12.3 Health Index Results

There are 679 conductor-km of in-service Primary Cables at GHESI. There were 679 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 95%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

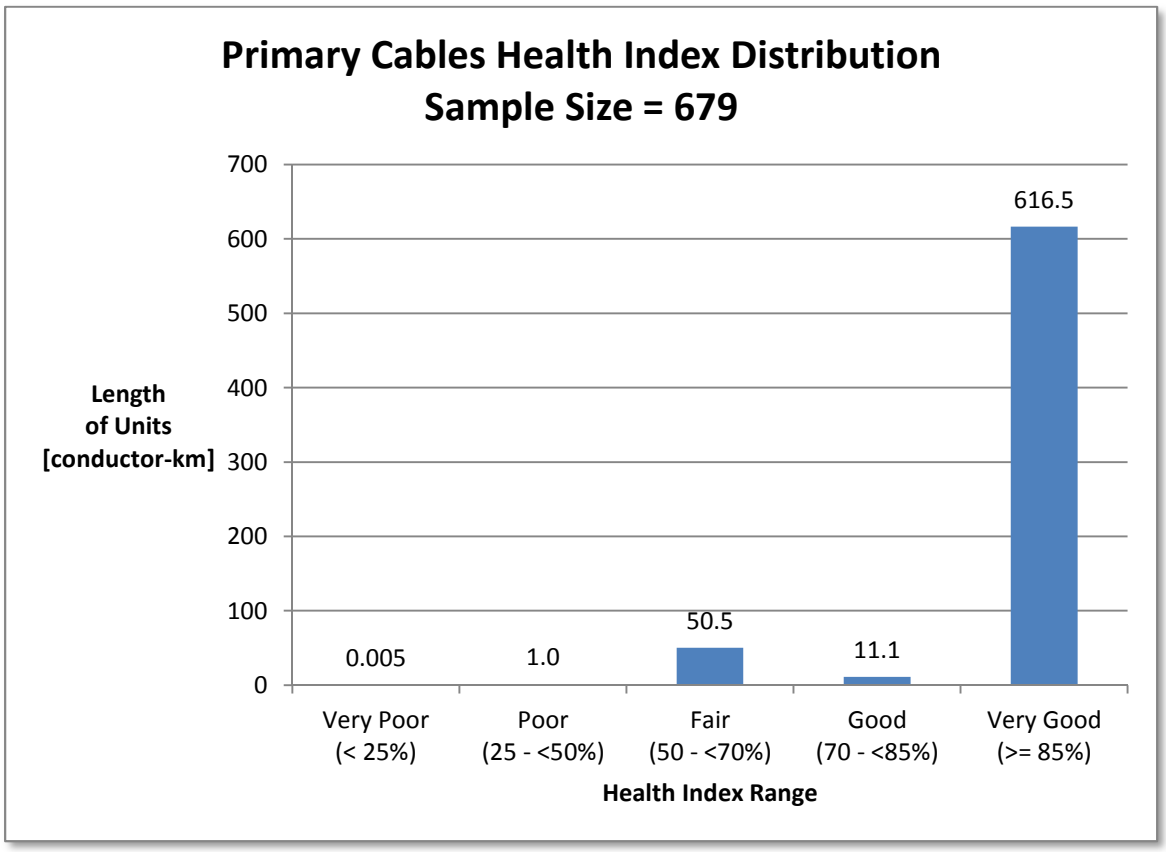


Figure 12-3 Primary Cables Health Index Distribution (Number of Units)

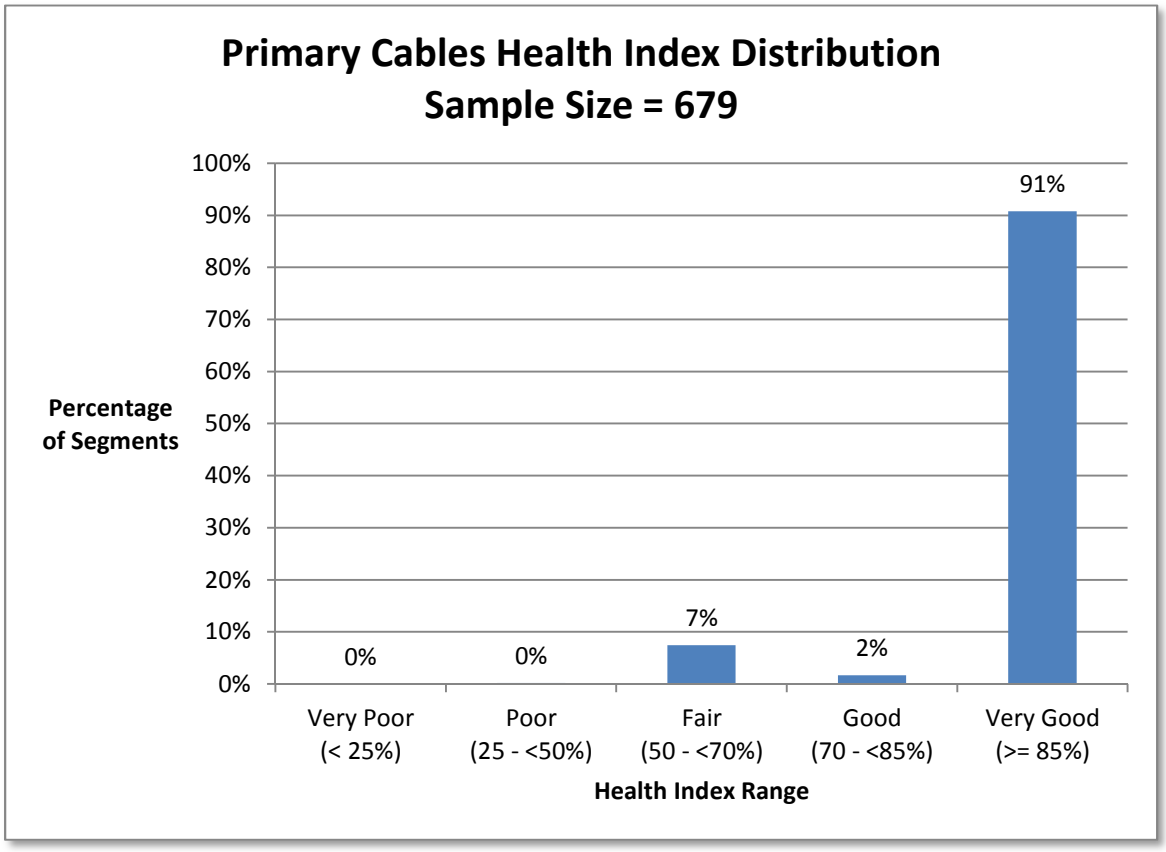


Figure 12-4 Primary Cables Health Index Distribution (Percentage of Units)

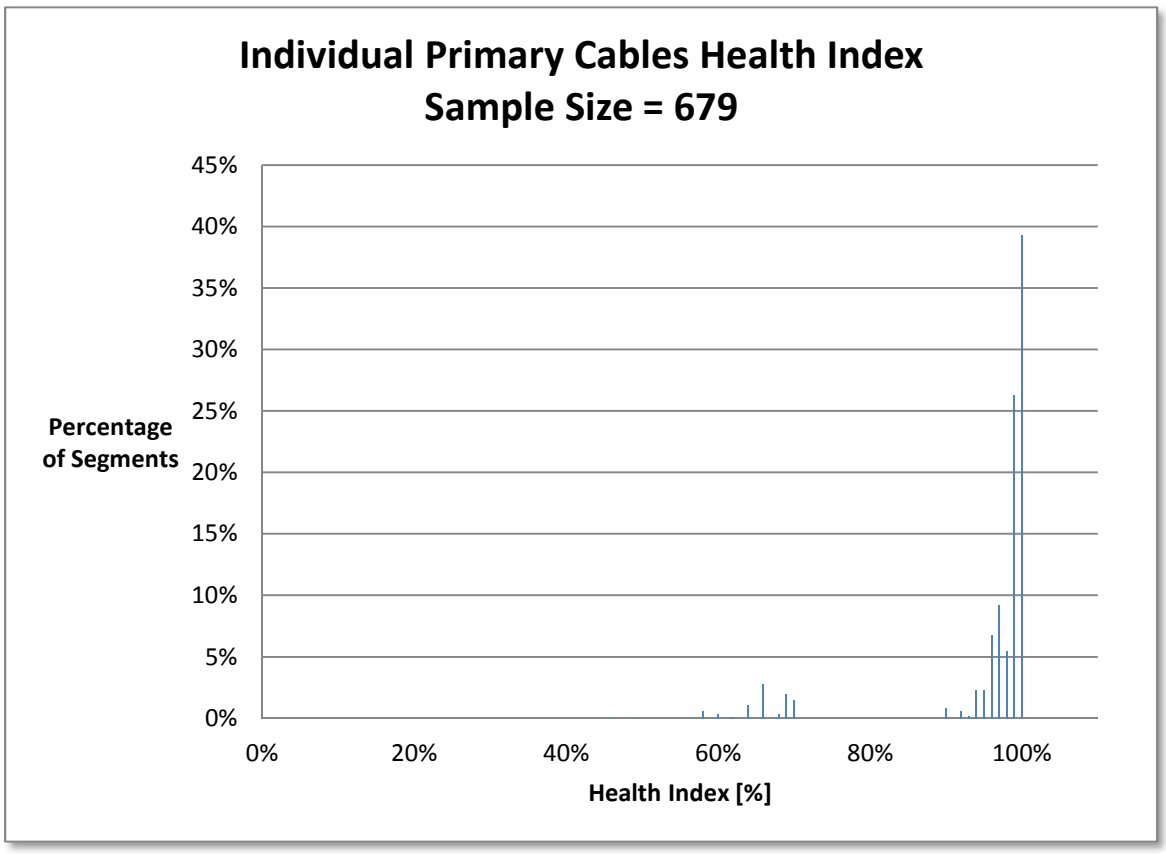


Figure 12-5 Primary Cables Health Index Distribution by Value (Percentage of Units)

12.4 Condition-Based Flagged for Action Plan

As it is assumed that Primary Cables are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

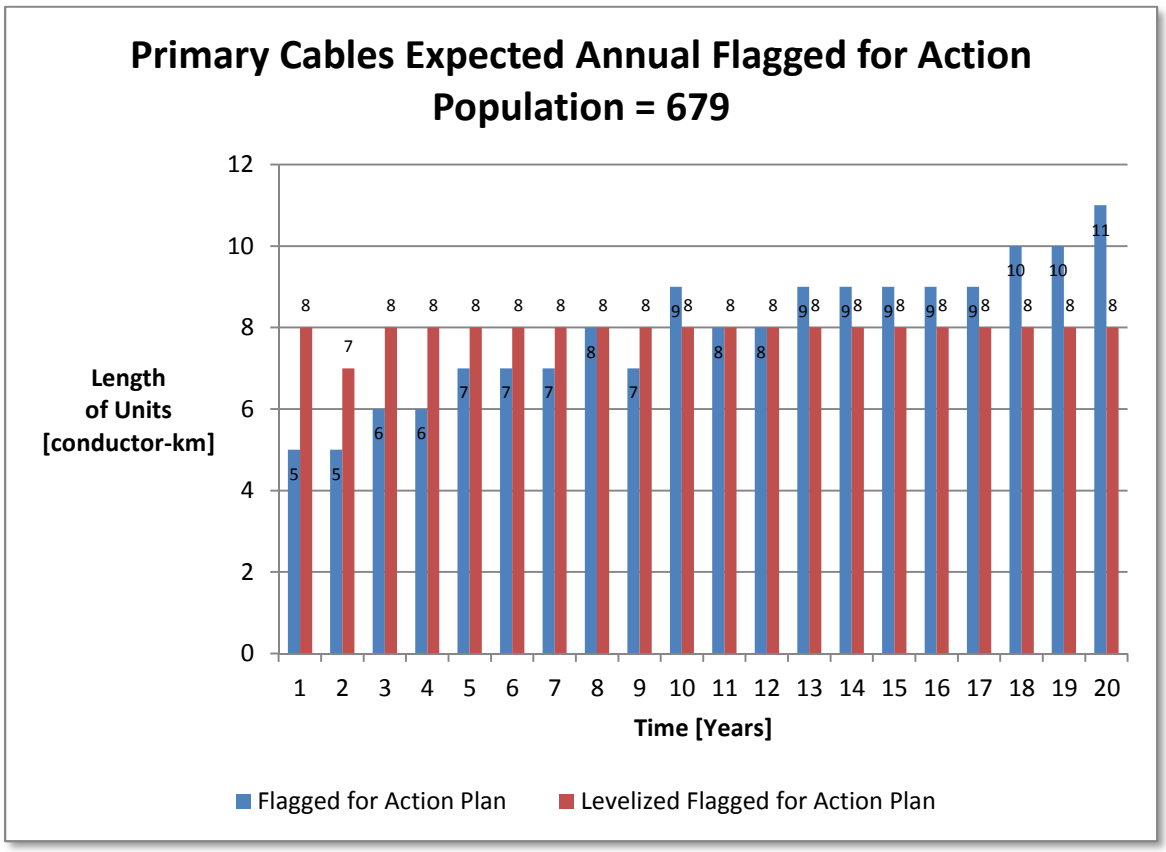


Figure 12-6 Primary Cables Condition-Based Flagged for Action Plan

12.5 Data Analysis

12.5.1 Data Gap

Only age was available for Primary Cables.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	☆☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		☆☆	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Loading	Operation Condition	☆☆☆	Cable segment	Loading History: e.g. hourly peak Loads	Operation record

12.5.2 Data Availability Distribution

Because only age was available, the average DAI for Primary Cables is 21%.

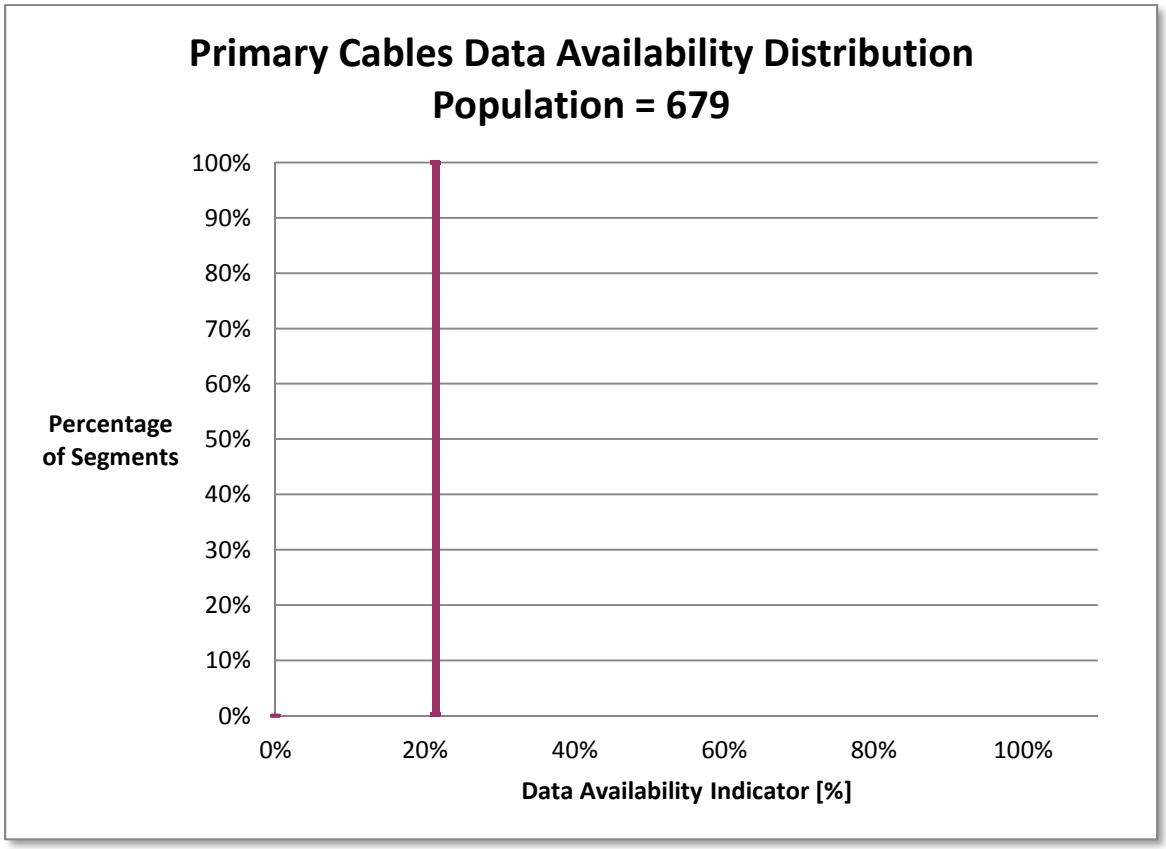


Figure 12-7 Primary Cables Data Availability Distribution

13 Secondary Cables

13.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Secondary Cables. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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”.

13.1.1 Condition and Sub-Condition Parameters

Table 13-1 Secondary Cables Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Splices and Terminations	1	
		Overall Corrective Maintenance Counts	1	
Operation Condition	3	Loading	1	
Service Record	4	5 Year Fault Rate	4	
		Age	3	Figure 13-1

13.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Secondary 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 and 40 years the probability of failure (P_f) for this asset are 20% and 95% 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:

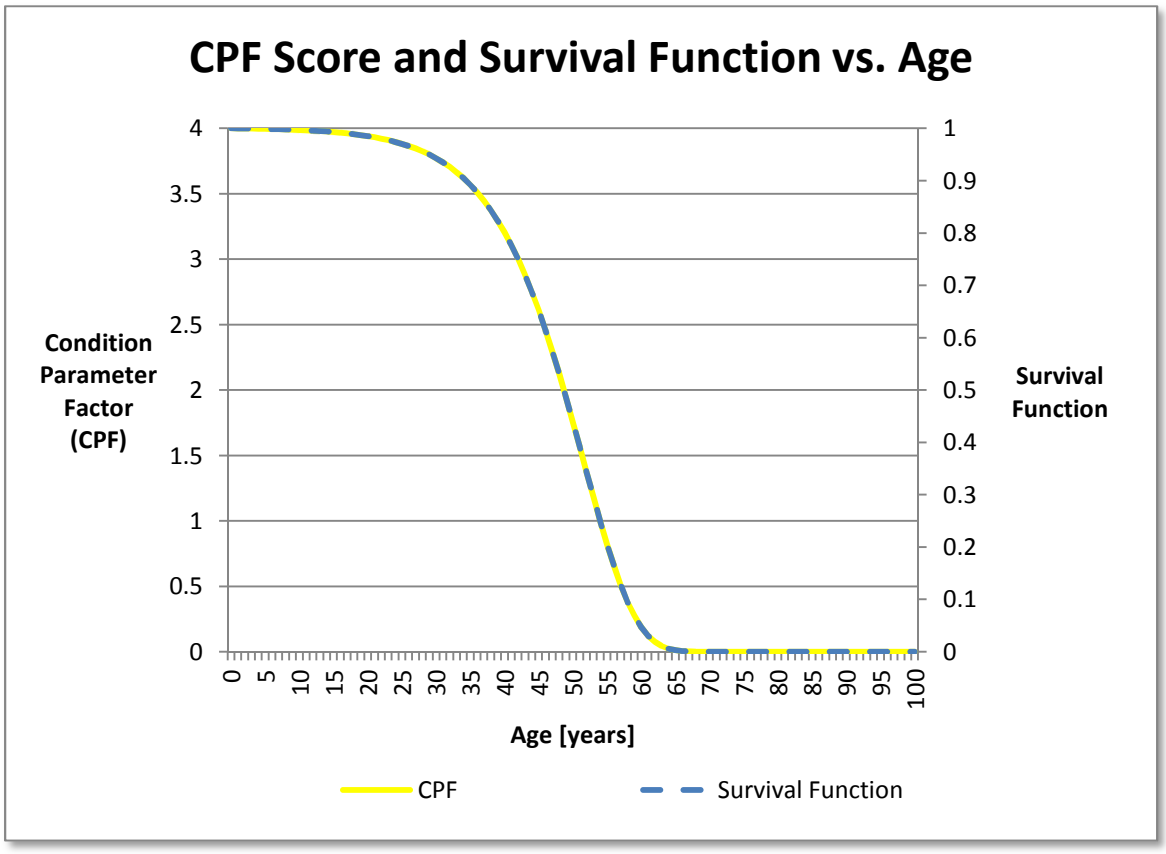


Figure 13-1 Secondary Cables Age Condition Criteria

13.2 Age Distribution

The age distribution is shown in the figure below. Age was available for nearly 100% of the population. The average age was found to be 18 years.

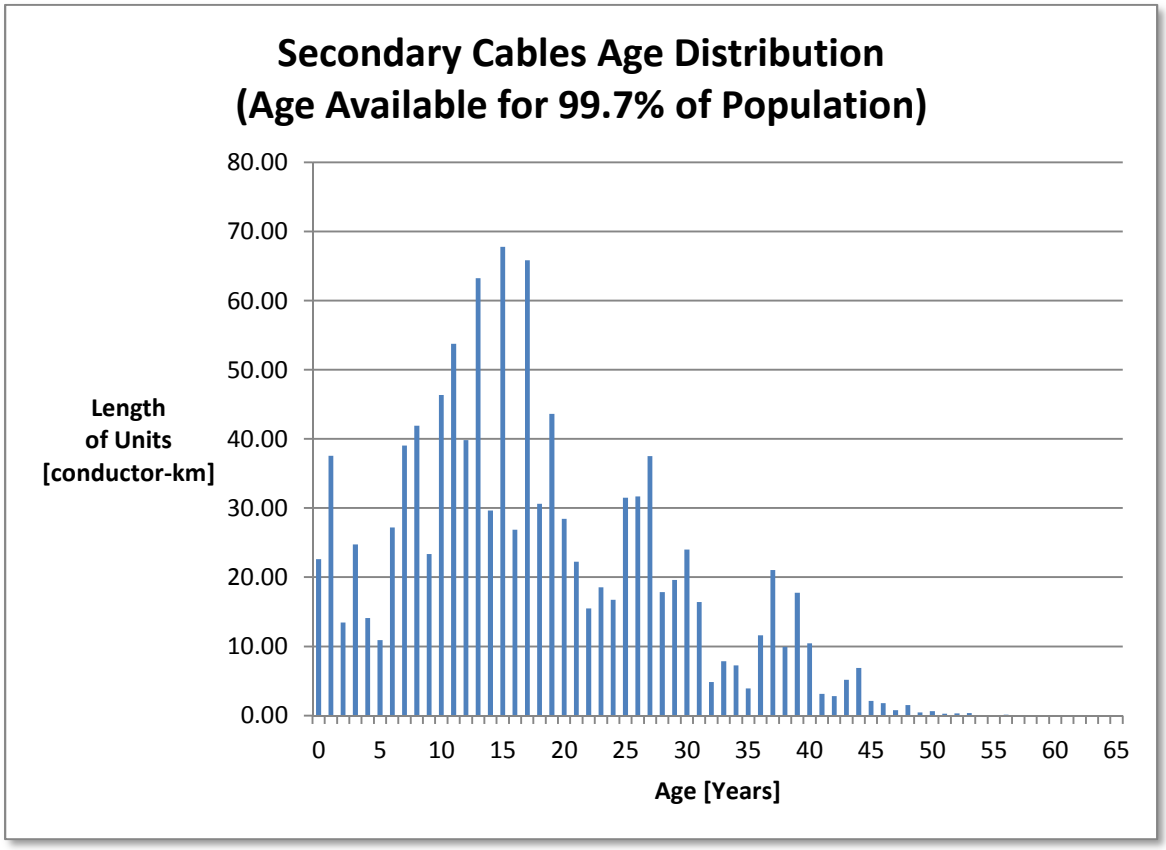


Figure 13-2 Secondary Cables Age Distribution

13.3 Health Index Results

There are 1127 conductor-km of in-service Secondary Cables at GHESI. There was 1123 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 97%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

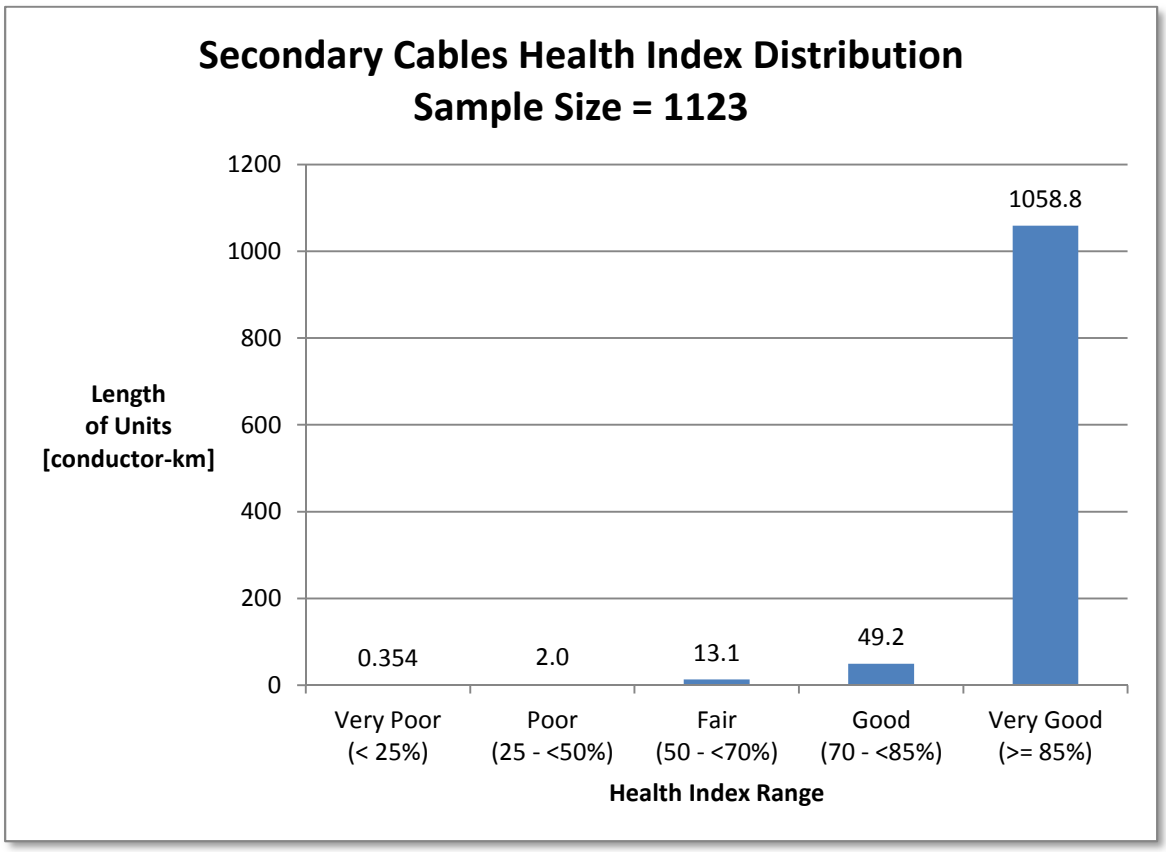


Figure 13-3 Secondary Cables Health Index Distribution (Number of Units)

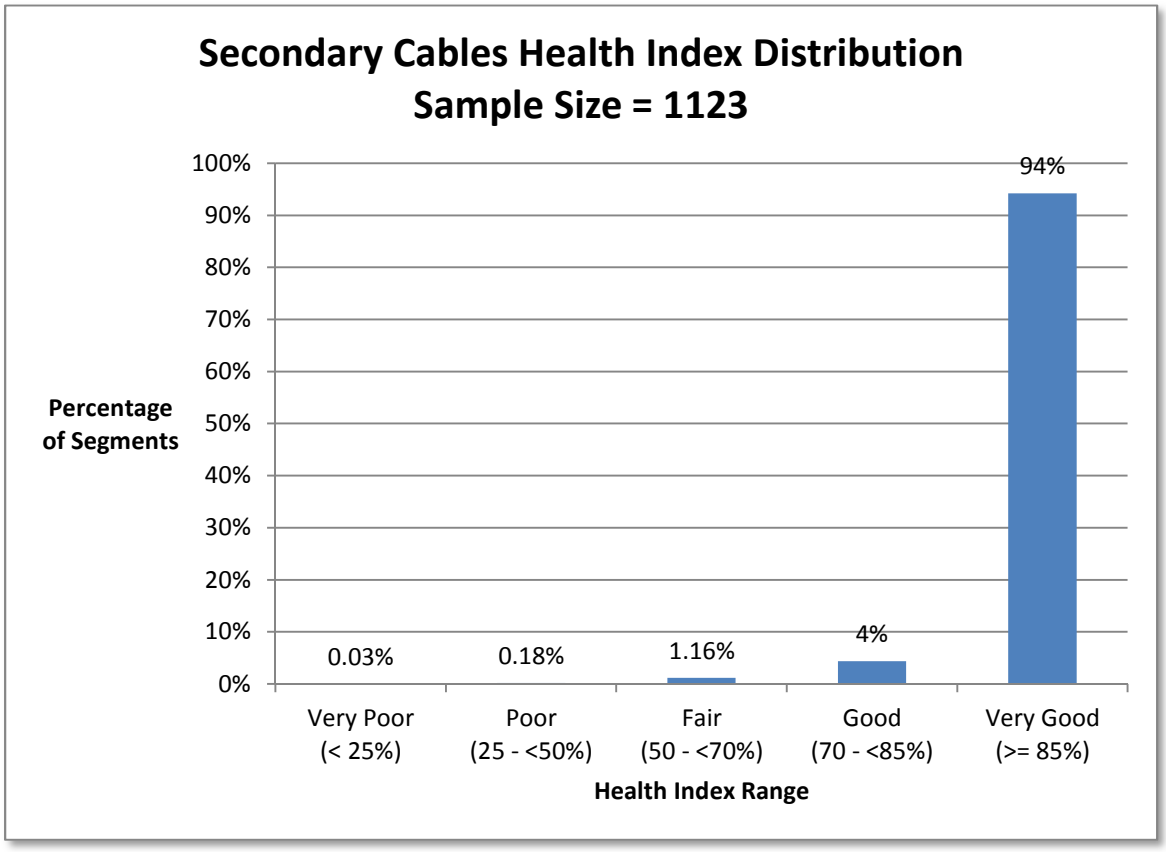


Figure 13-4 Secondary Cables Health Index Distribution (Percentage of Units)

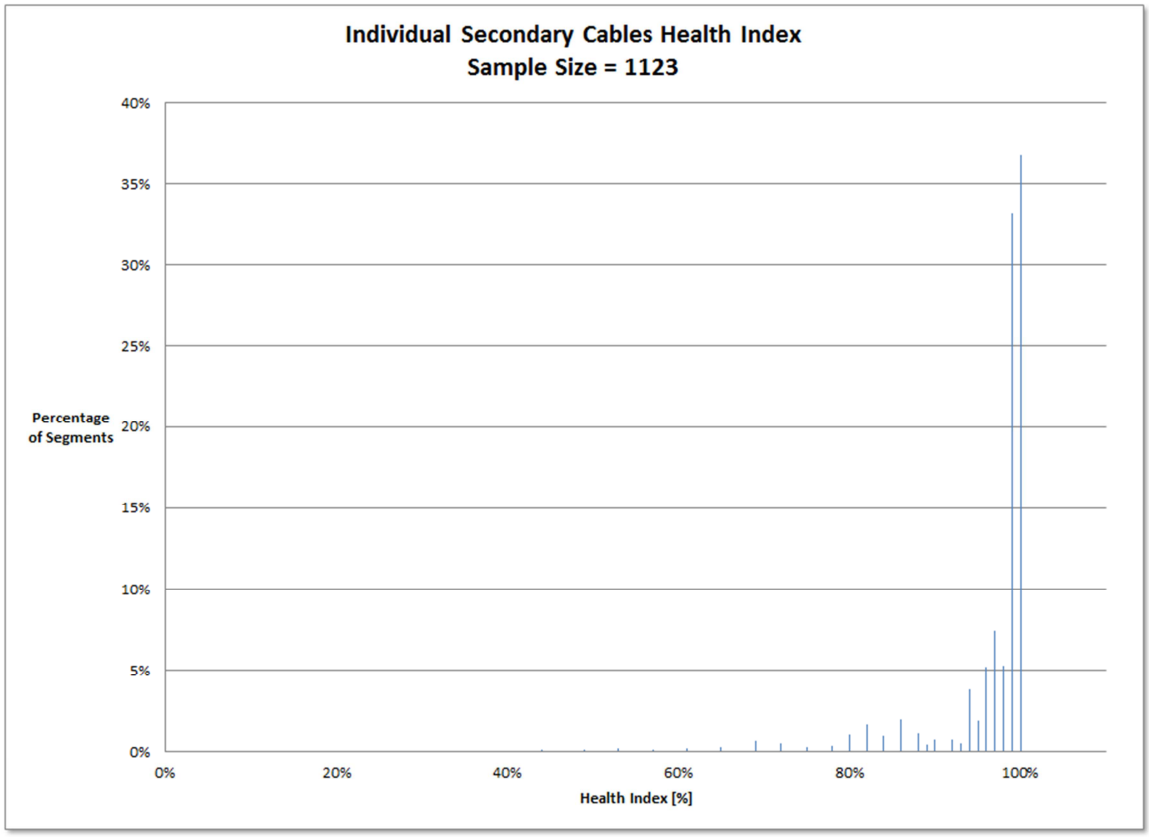


Figure 13-5 Secondary Cables Health Index Distribution by Value (Percentage of Units)

13.4 Condition-Based Flagged for Action Plan

As it is assumed that Secondary Cables are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

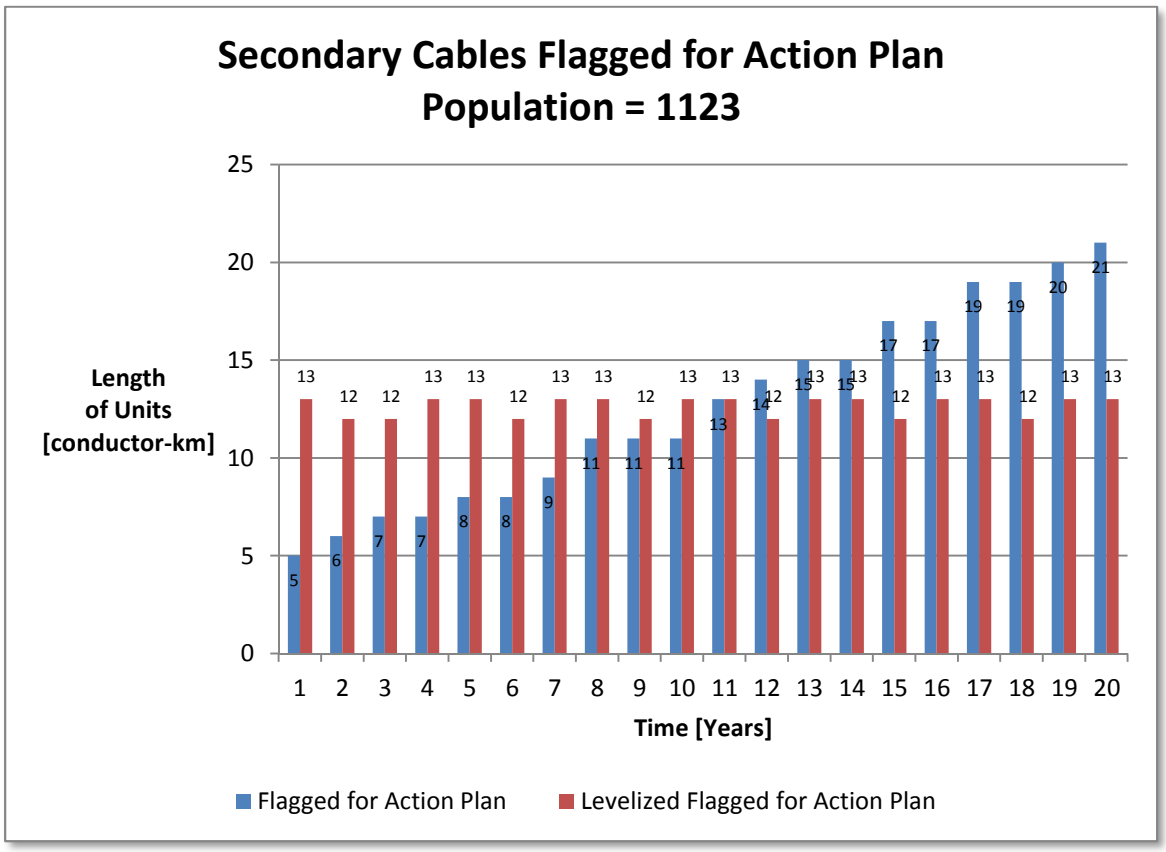


Figure 13-6 Secondary Cables Condition-Based Flagged for Action Plan

13.5 Data Analysis

13.5.1 Data Gap

Only age was available for Secondary Cables.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	☆☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		☆☆	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Loading	Operation Condition	☆☆☆	Cable segment	Loading History: e.g. hourly peak Loads	Operation record

13.5.2 Data Availability Distribution

Because only age was available, the average, the average DAI for Secondary Cables is 21%.

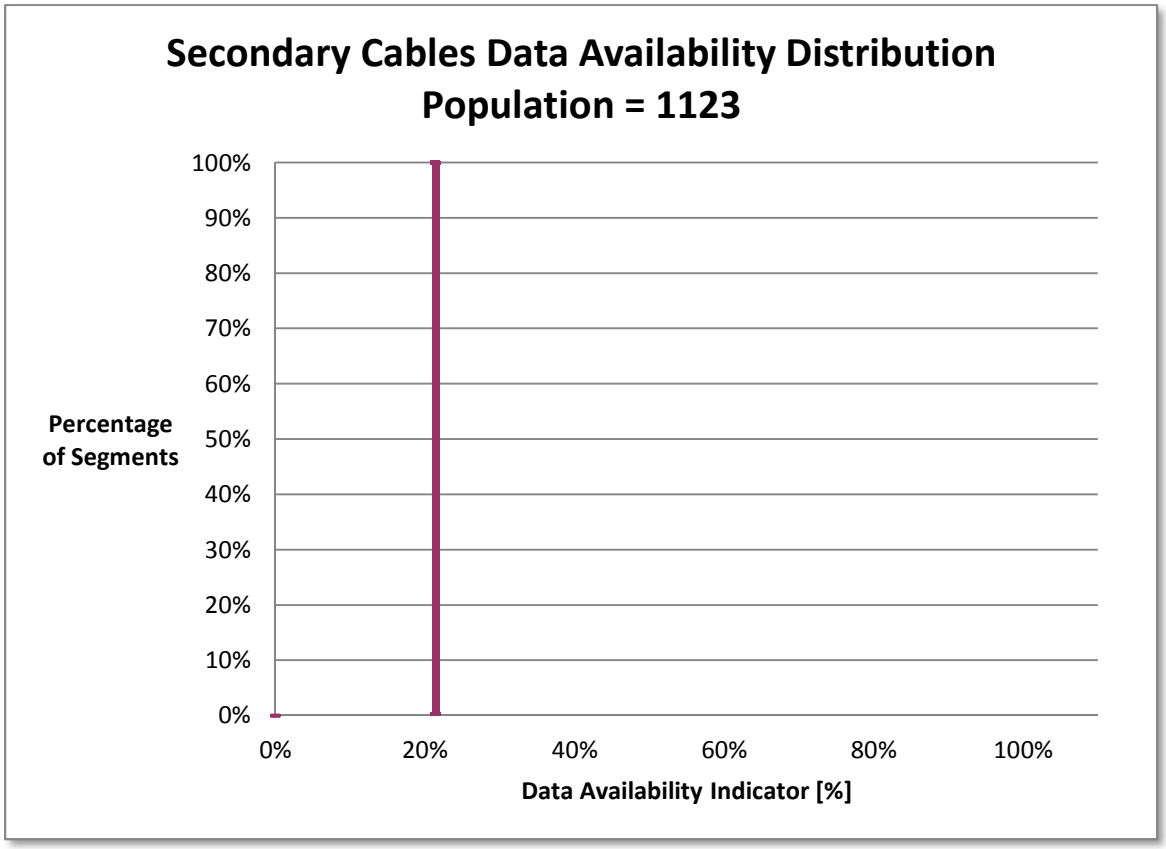


Figure 13-7 Secondary Cables Data Availability Distribution

14 Single Phase Primary Lines

14.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Single Phase Primary Lines. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

14.1.1 Condition and Sub-Condition Parameters

Table 14-1 Single Phase Primary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 14-1

14.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Single Phase Primary Lines 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 and 60 years the probability of failure (P_f) for this asset are 20% and 95% 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:

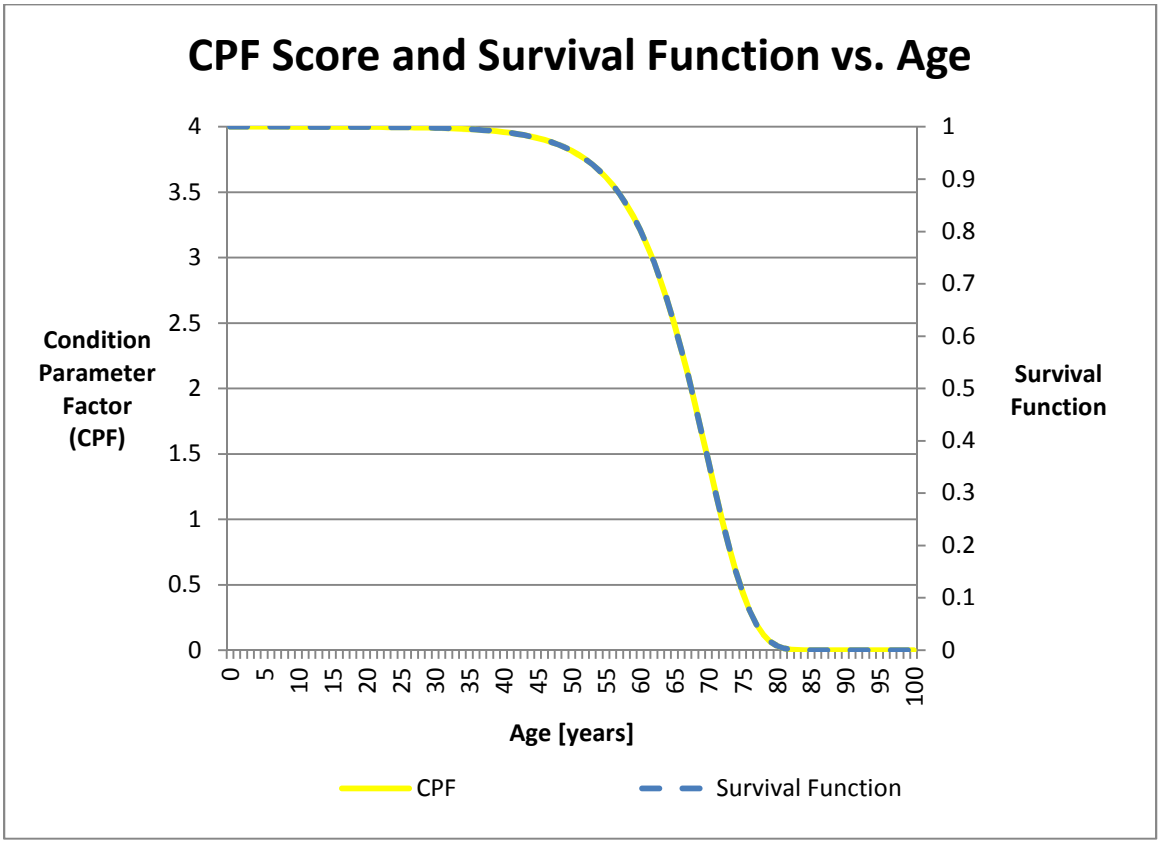


Figure 14-1 Single Phase Primary Lines Age Condition Criteria

14.2 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 29 years.

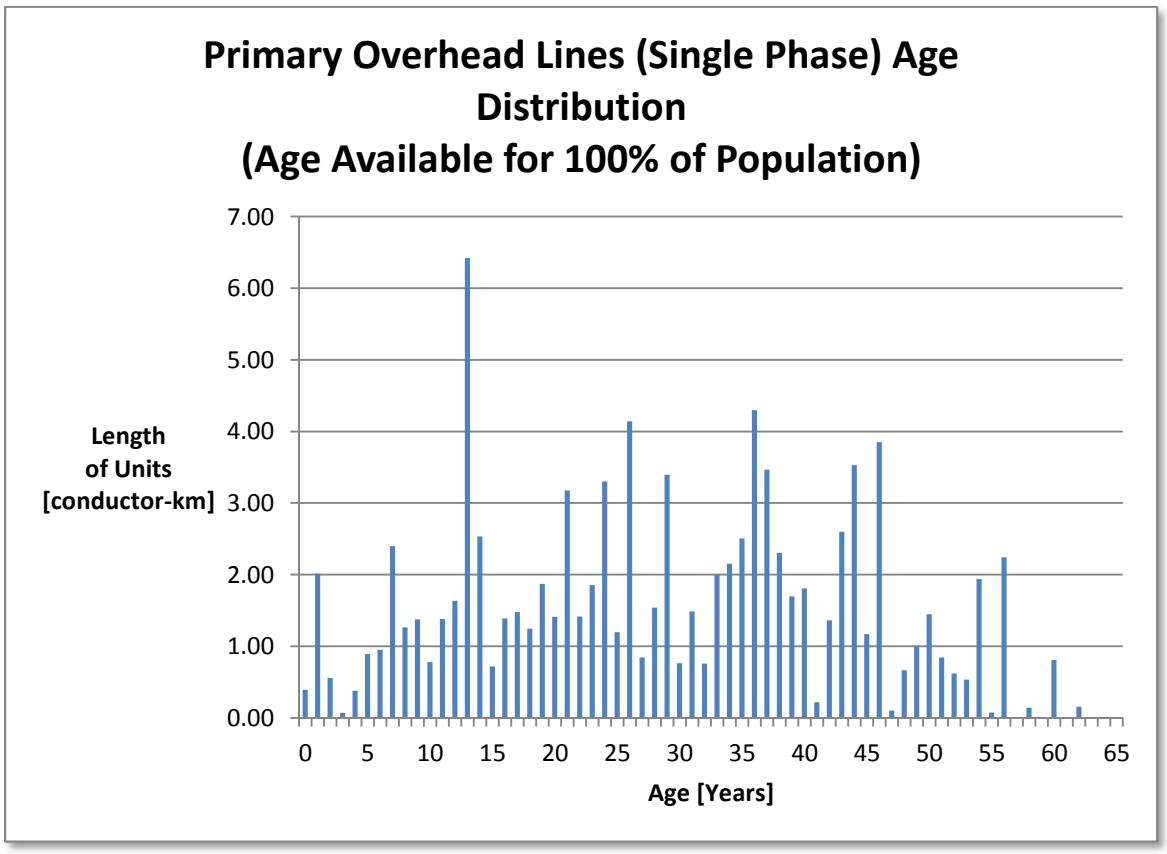


Figure 14-2 Single Phase Primary Lines Age Distribution

14.3 Health Index Results

There are 99 conductor-km of in-service Single Phase Primary Lines at GHESI. There were 99 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 99%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

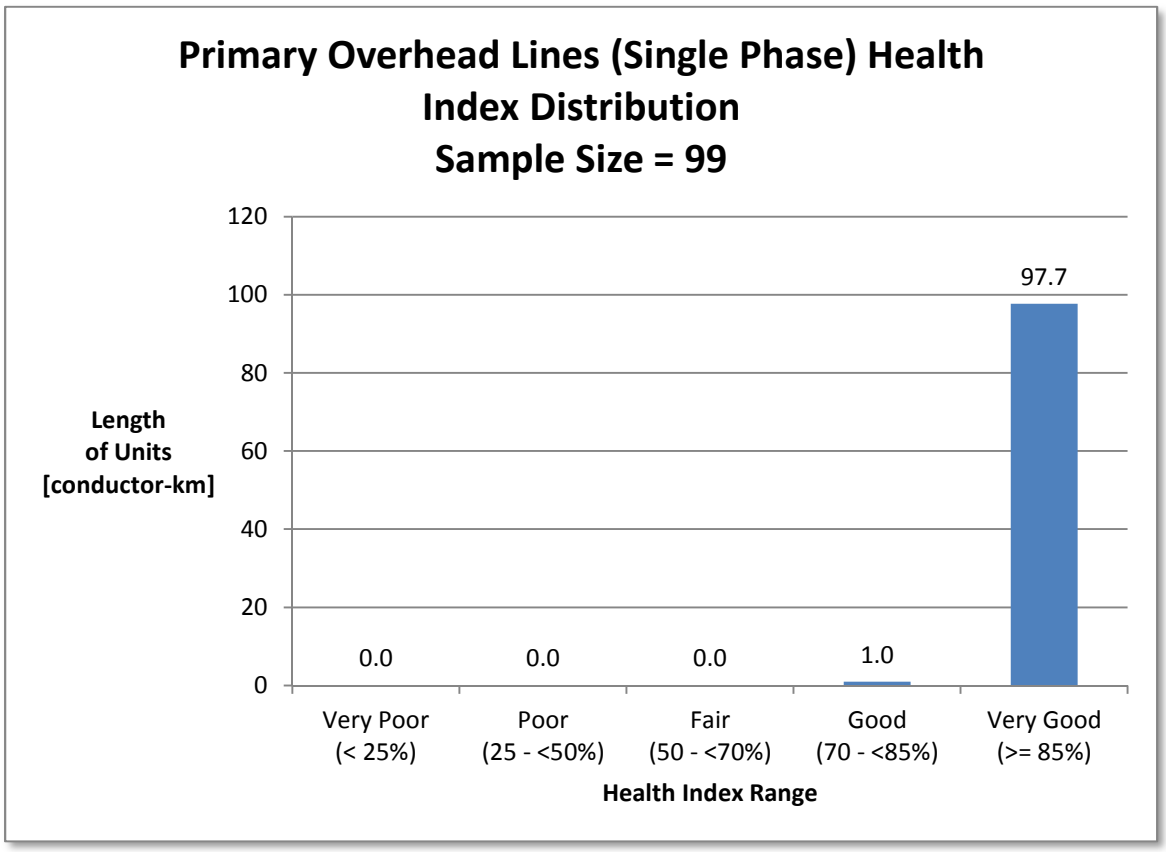


Figure 14-3 Single Phase Primary Lines Health Index Distribution (Number of Units)

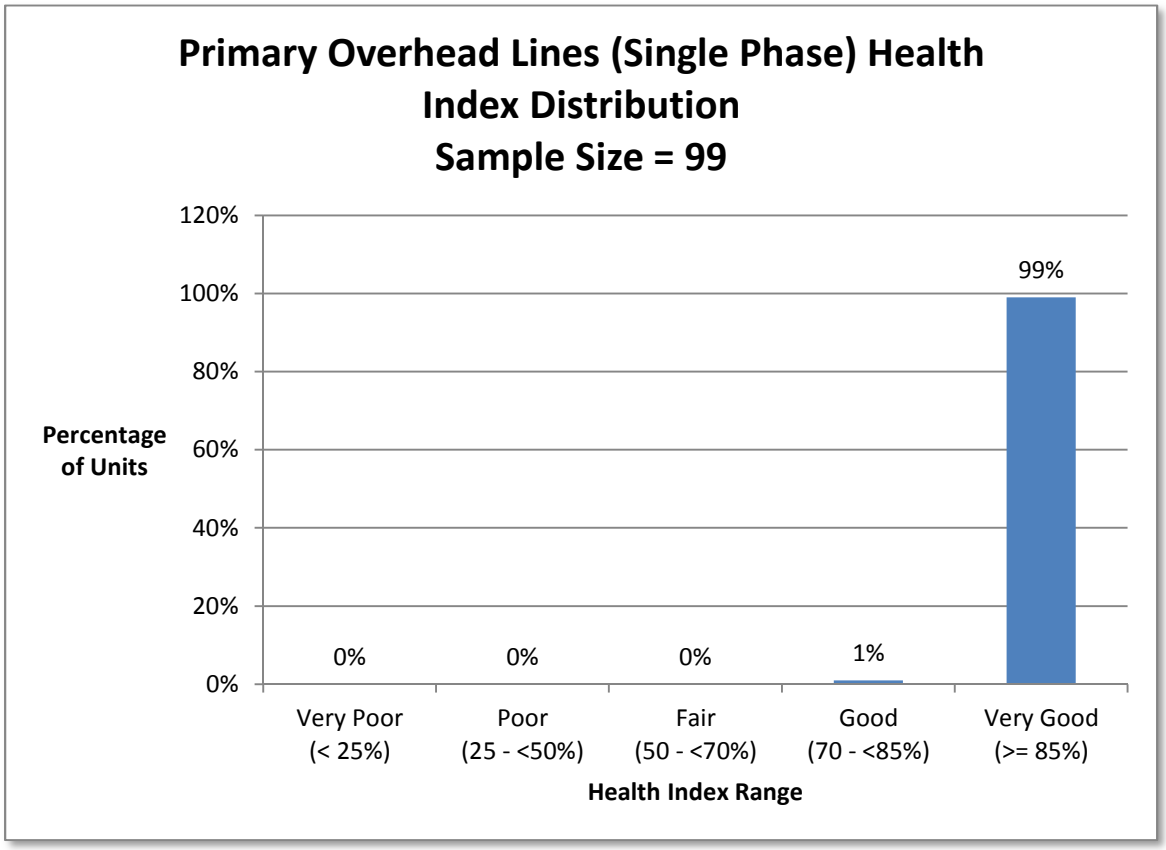


Figure 14-4 Single Phase Primary Lines Health Index Distribution (Percentage of Units)

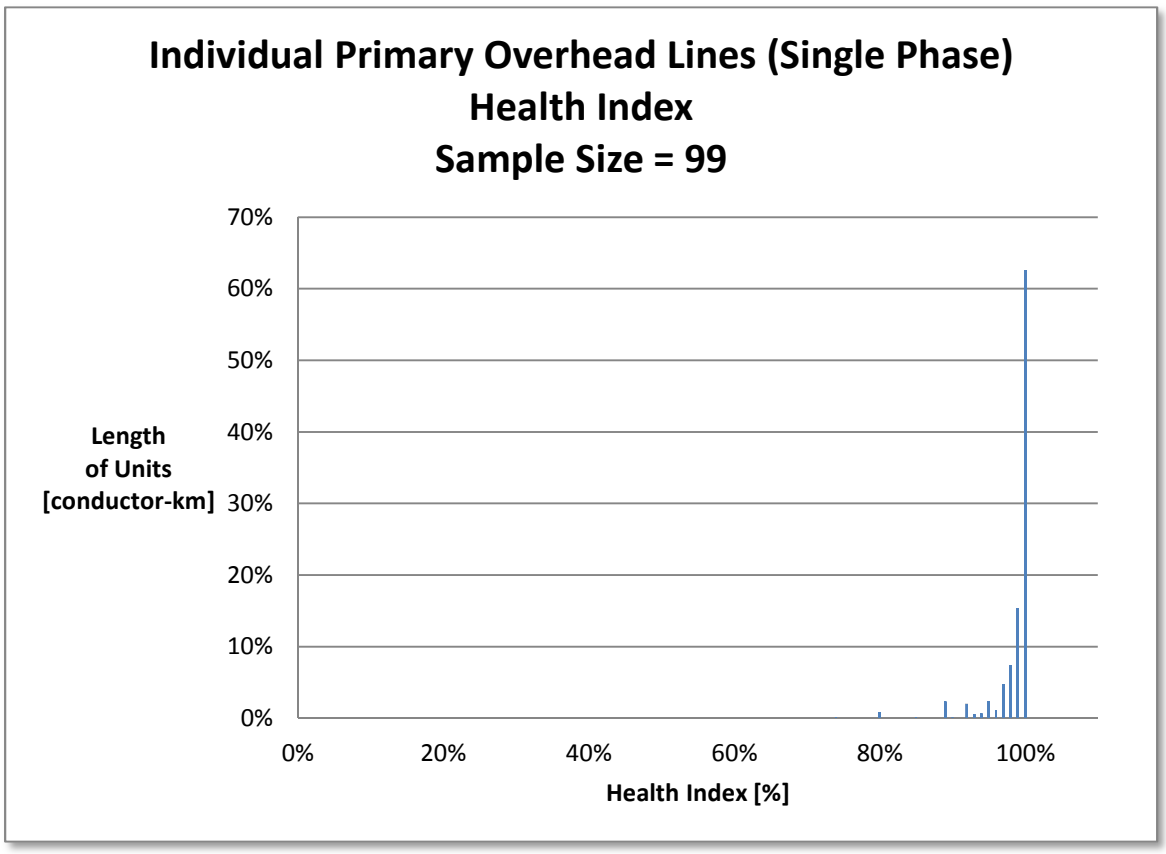


Figure 14-5 Single Phase Primary Lines Health Index Distribution by Value (Percentage of Units)

14.4 Condition-Based Flagged for Action Plan

As it is assumed that Single Phase Primary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

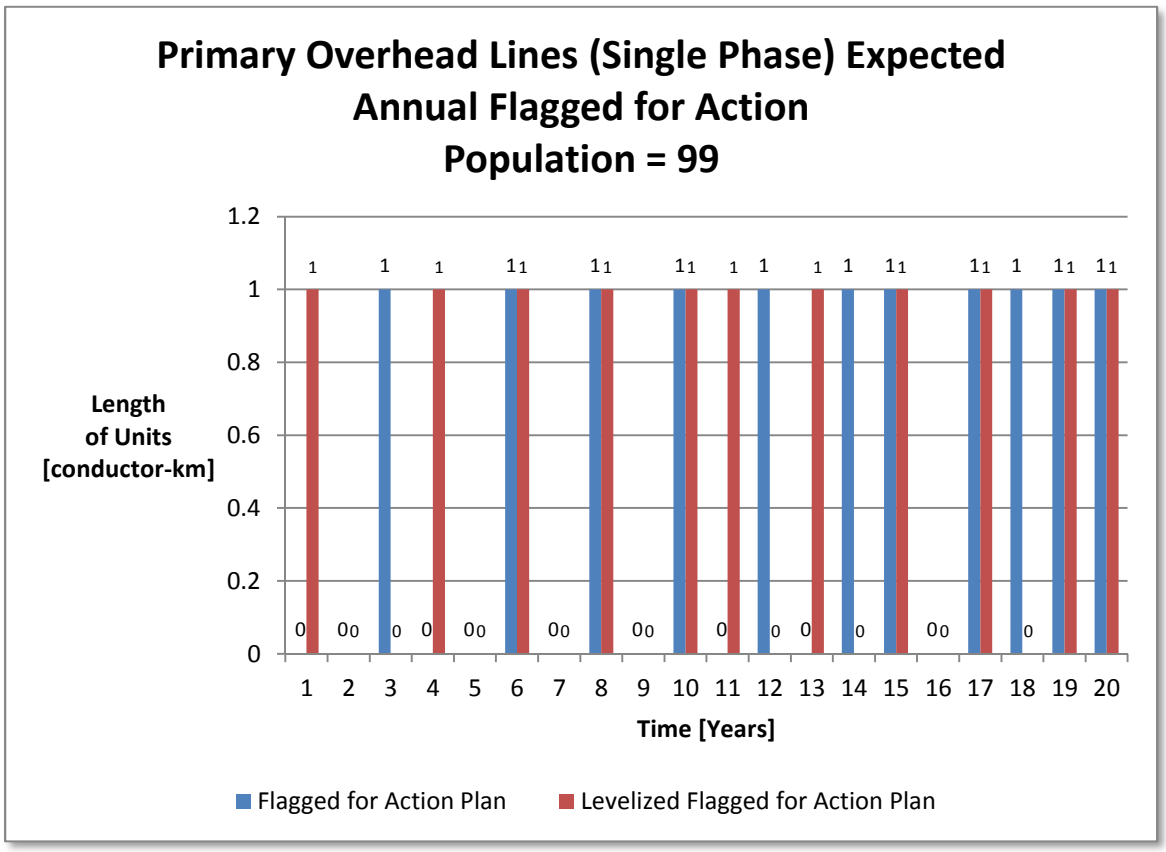


Figure 14-6 Single Phase Primary Lines Condition-Based Flagged for Action Plan

14.5 Data Analysis

14.5.1 Data Gap

Age was the only data available for Single Phase Primary Lines. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	☆☆	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		☆☆	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

14.5.2 Data Availability Distribution

The average DAI for Single Phase Primary Lines is 21%.

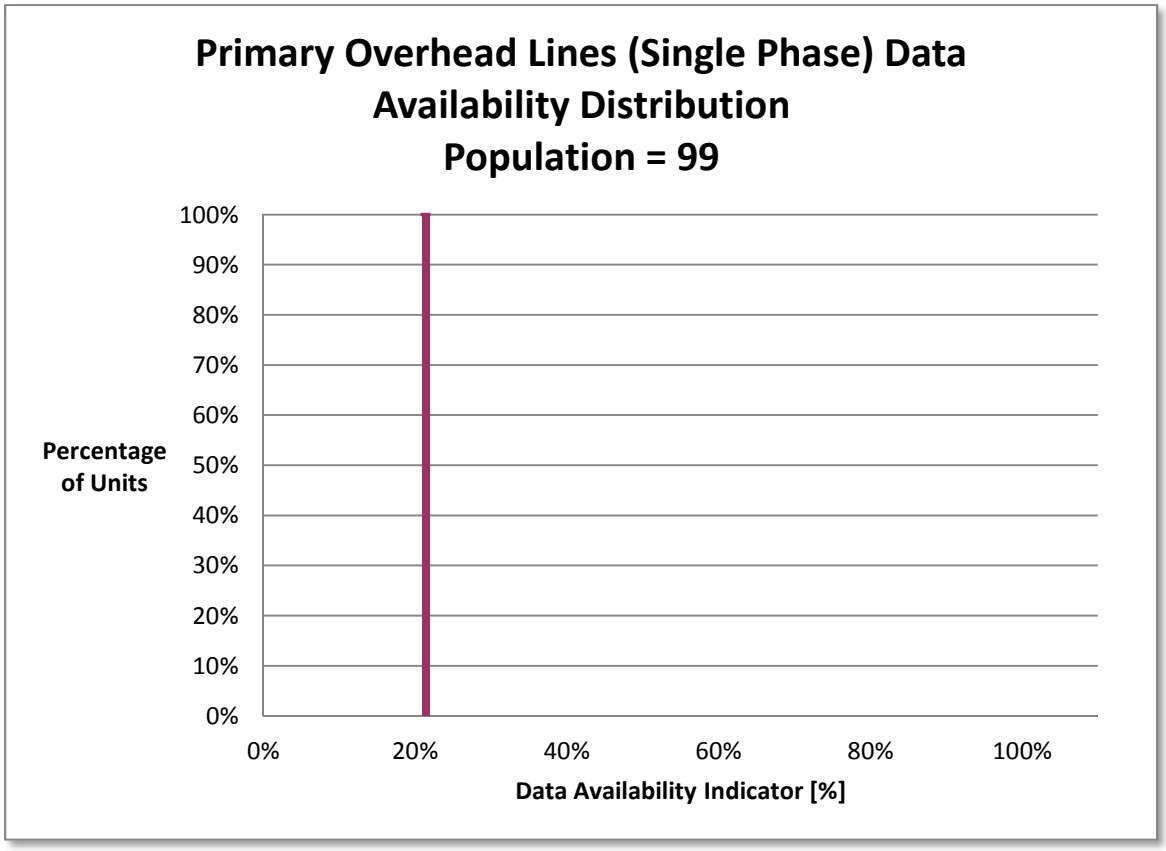


Figure 14-7 Single Phase Primary Lines Data Availability Distribution

15 Three Phase Primary Lines

15.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Three Phase Primary Lines. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

15.1.1 Condition and Sub-Condition Parameters

Table 15-1 Three Phase Primary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 15-1

15.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Three Phase Primary Lines 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 and 60 years the probability of failure (P_f) for this asset are 20% and 95% 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:

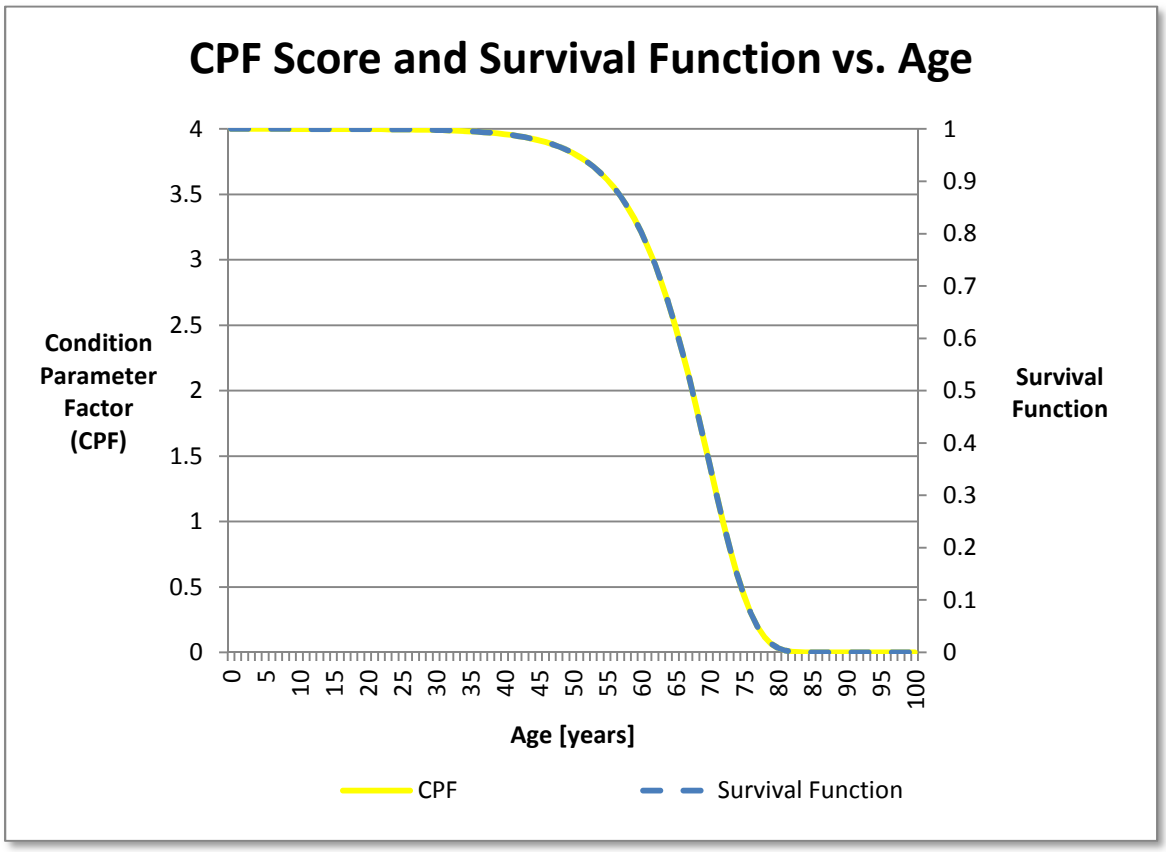


Figure 15-1 Three Phase Primary Lines Age Condition Criteria

15.2 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 20 years.

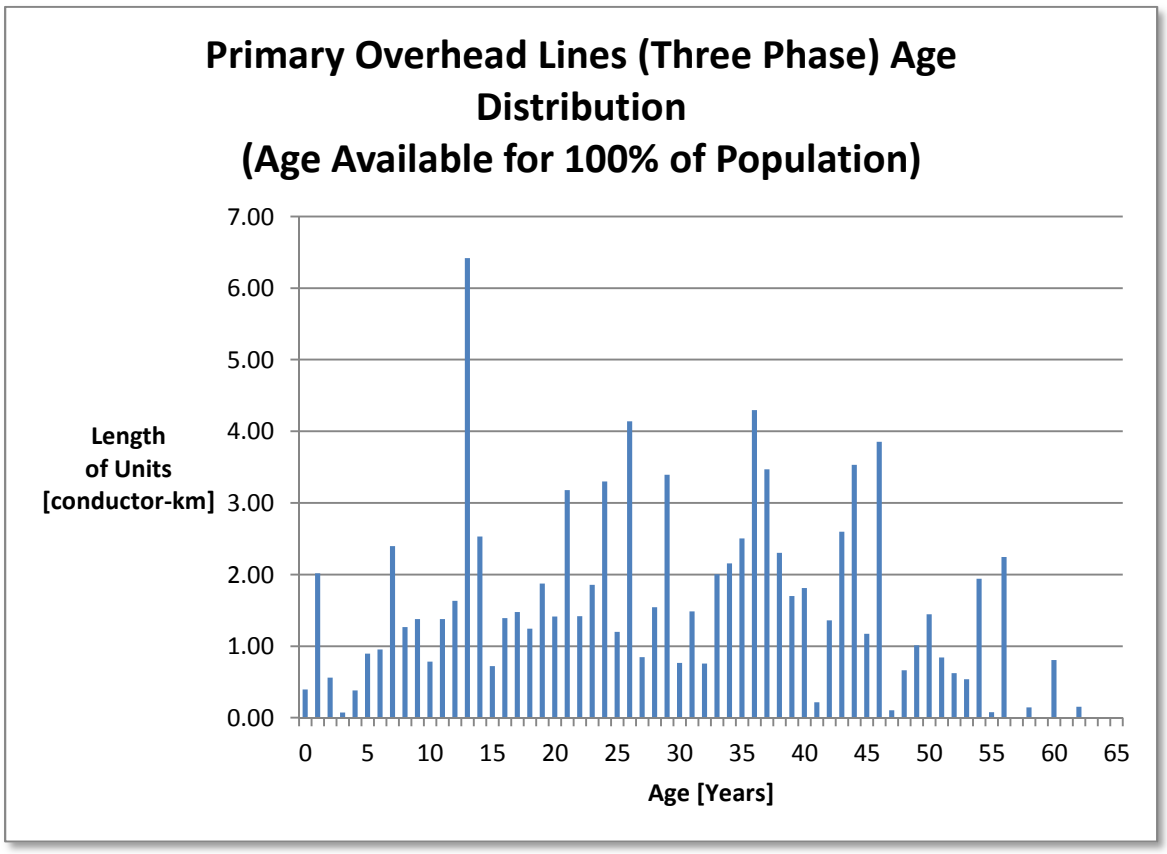


Figure 15-2 Three Phase Primary Lines Age Distribution

15.3 Health Index Results

There are 329 conductor-km of in-service Three Phase Primary Lines at GHESI. There were 329 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is nearly 100%. Almost none were found to be in poor condition.

The Health Index Results are as follows:

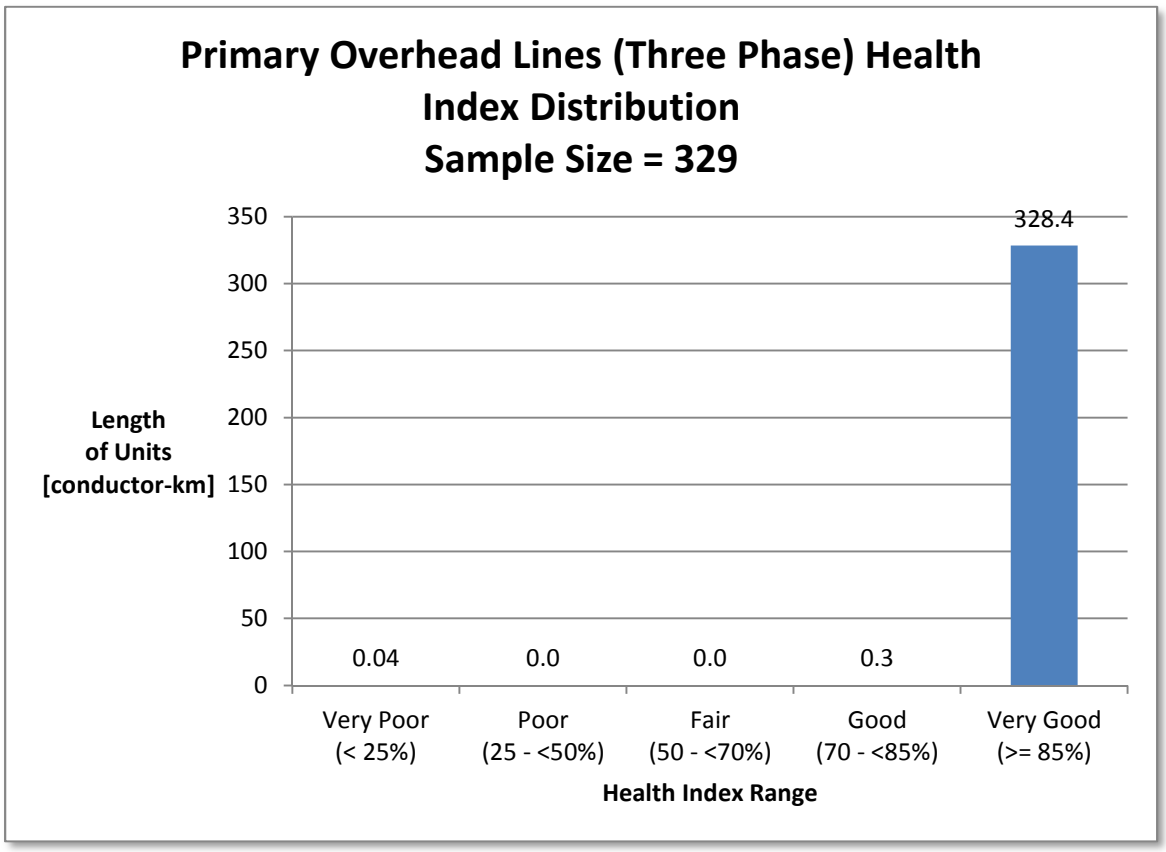


Figure 15-3 Three Phase Primary Lines Health Index Distribution (Number of Units)

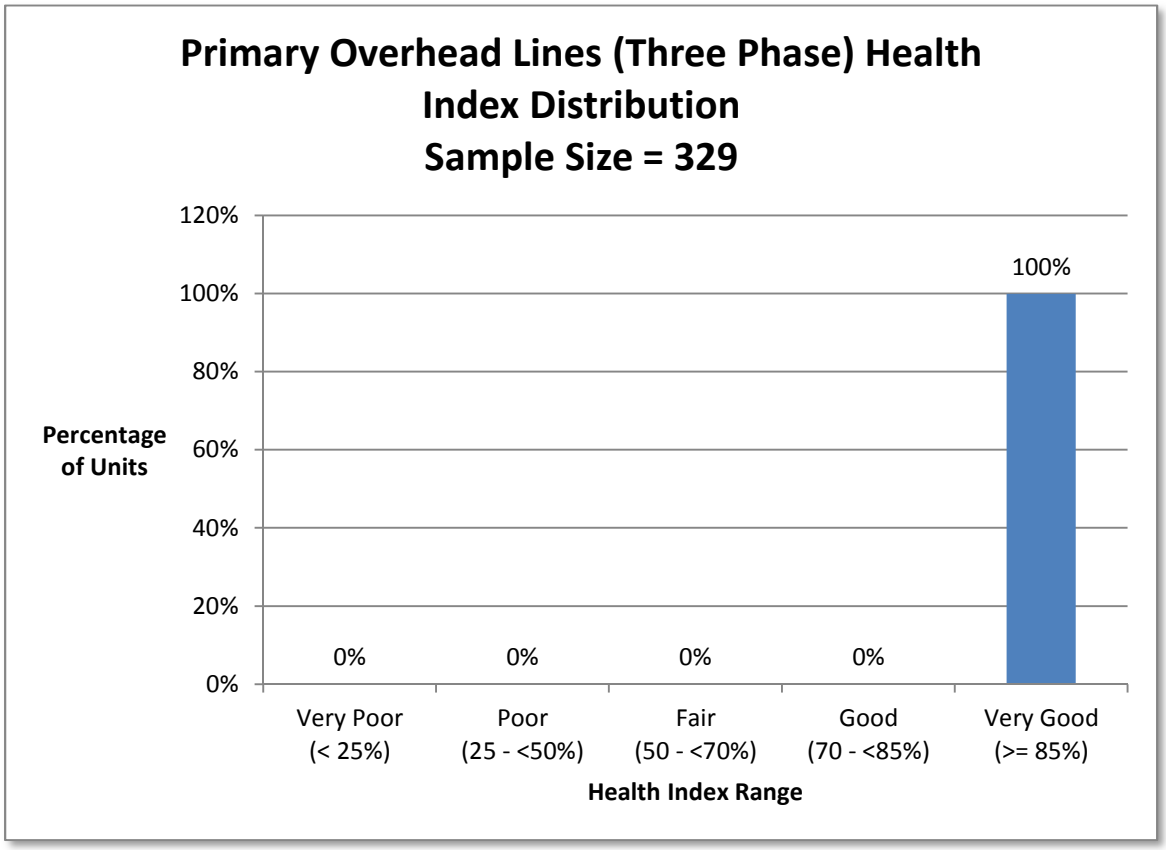


Figure 15-4 Three Phase Primary Lines Health Index Distribution (Percentage of Units)

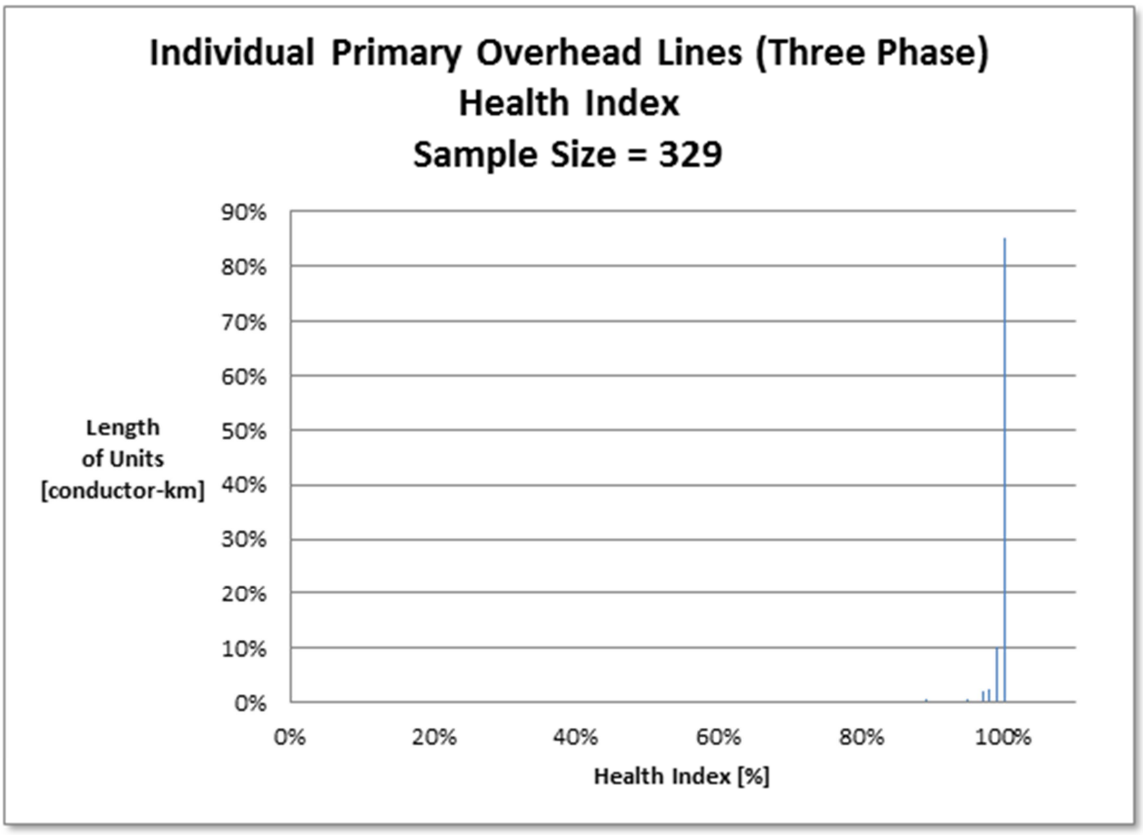


Figure 15-5 Three Phase Primary Lines Health Index Distribution by Value (Percentage of Units)

15.4 Condition-Based Flagged for Action Plan

As it is assumed that Three Phase Primary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

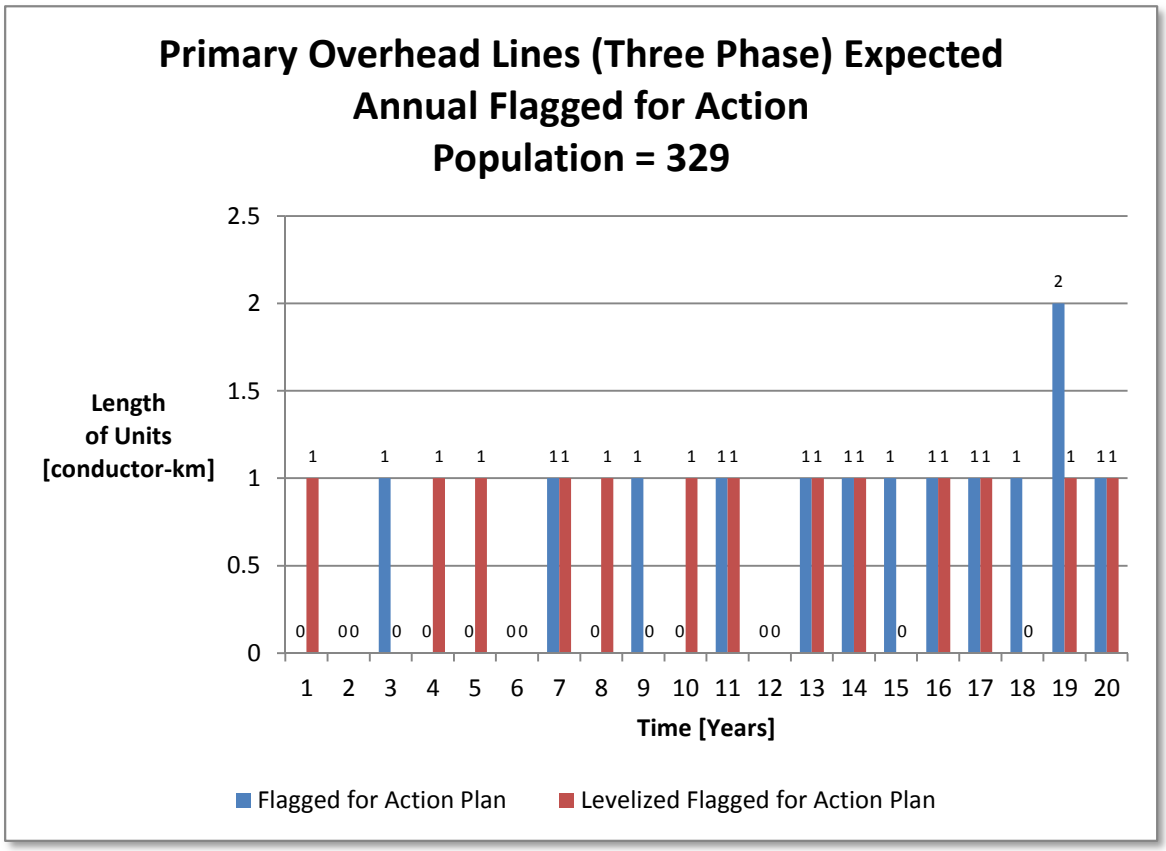


Figure 15-6 Three Phase Primary Lines Condition-Based Flagged for Action Plan

15.5 Data Analysis

15.5.1 Data Gap

The data available for Three Phase Primary Lines was age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	✯ ✯	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		✯ ✯	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

15.5.2 Data Availability Distribution

The average DAI for Three Phase Primary Lines is 21%.

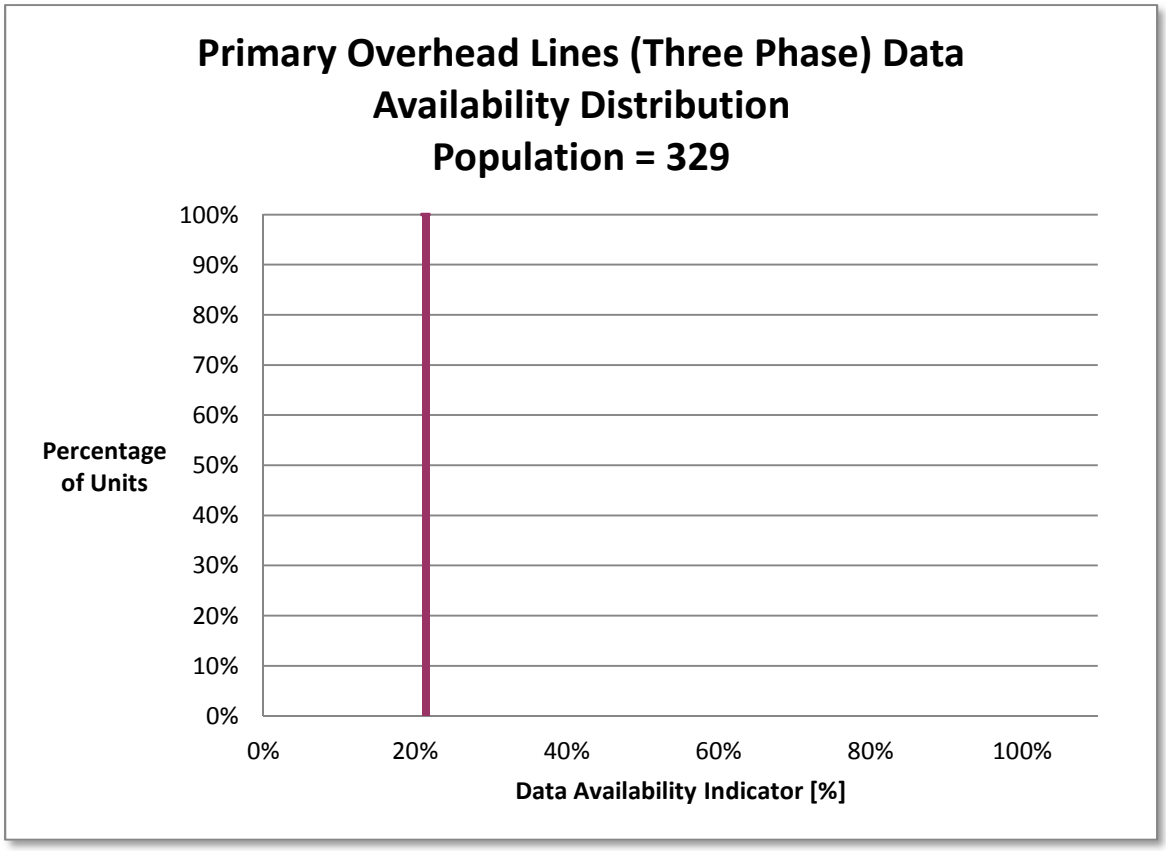


Figure 15-7 Three Phase Primary Lines Data Availability Distribution

16 Secondary Lines

16.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Secondary Lines. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

16.1.1 Condition and Sub-Condition Parameters

Table 16-1 Secondary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 16-1

16.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Secondary Lines 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 and 60years the probability of failure (P_f) for this asset are 20% and 95% 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:

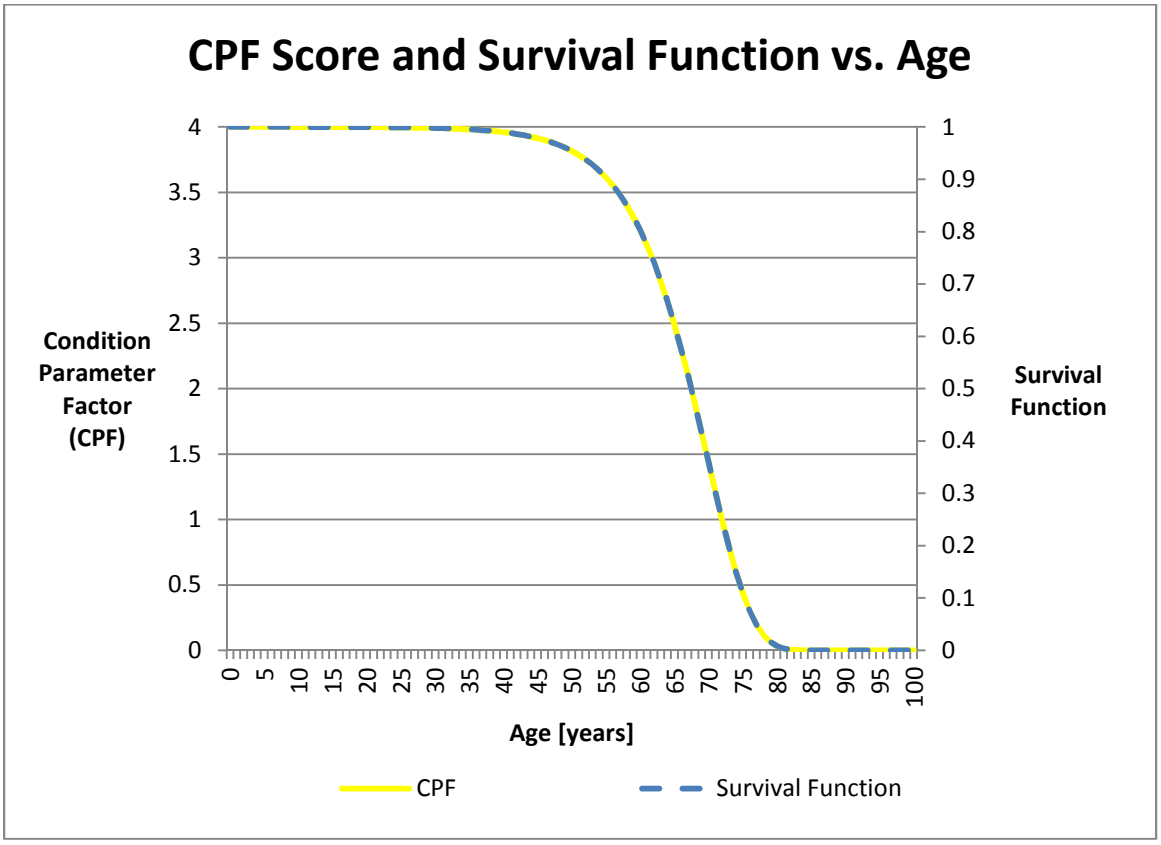


Figure 16-1 Secondary Lines Age Condition Criteria

16.2 Age Distribution

The age distribution is shown in the figure below. Age was available for nearly 100% of the population. The average age was found to be 29 years.

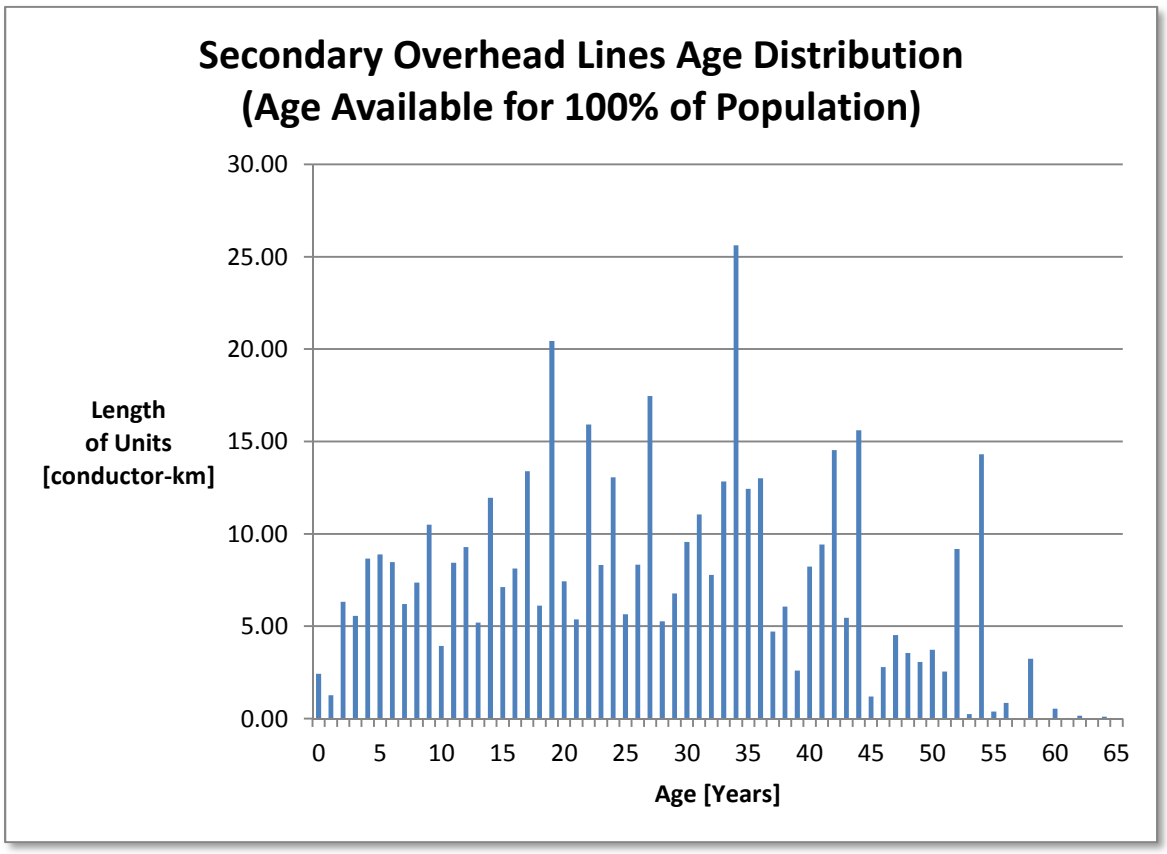


Figure 16-2 Secondary Lines Age Distribution

16.3 Health Index Results

There are 459 conductor-km of in-service Secondary Lines at GHESI. There were 458 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 98%. None were found to be in poor condition.

The Health Index Results are as follows:

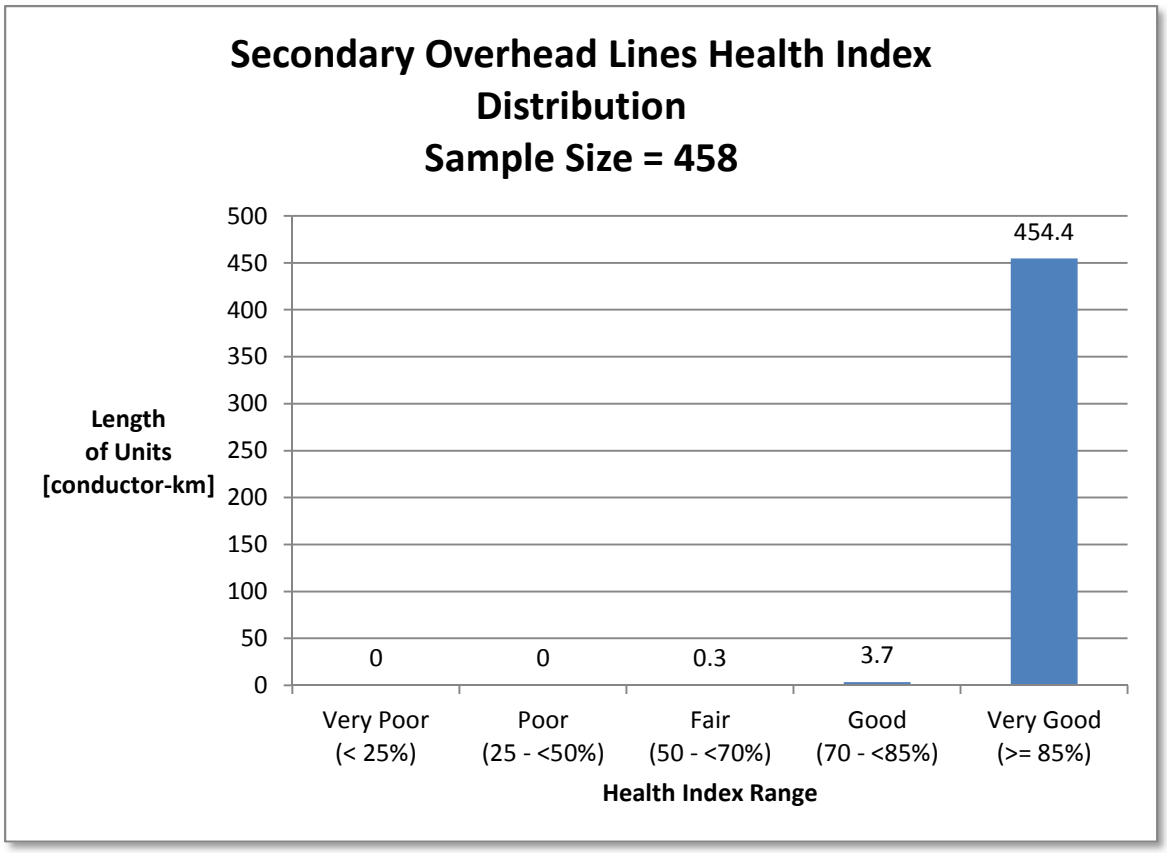


Figure 16-3 Secondary Lines Health Index Distribution (Number of Units)

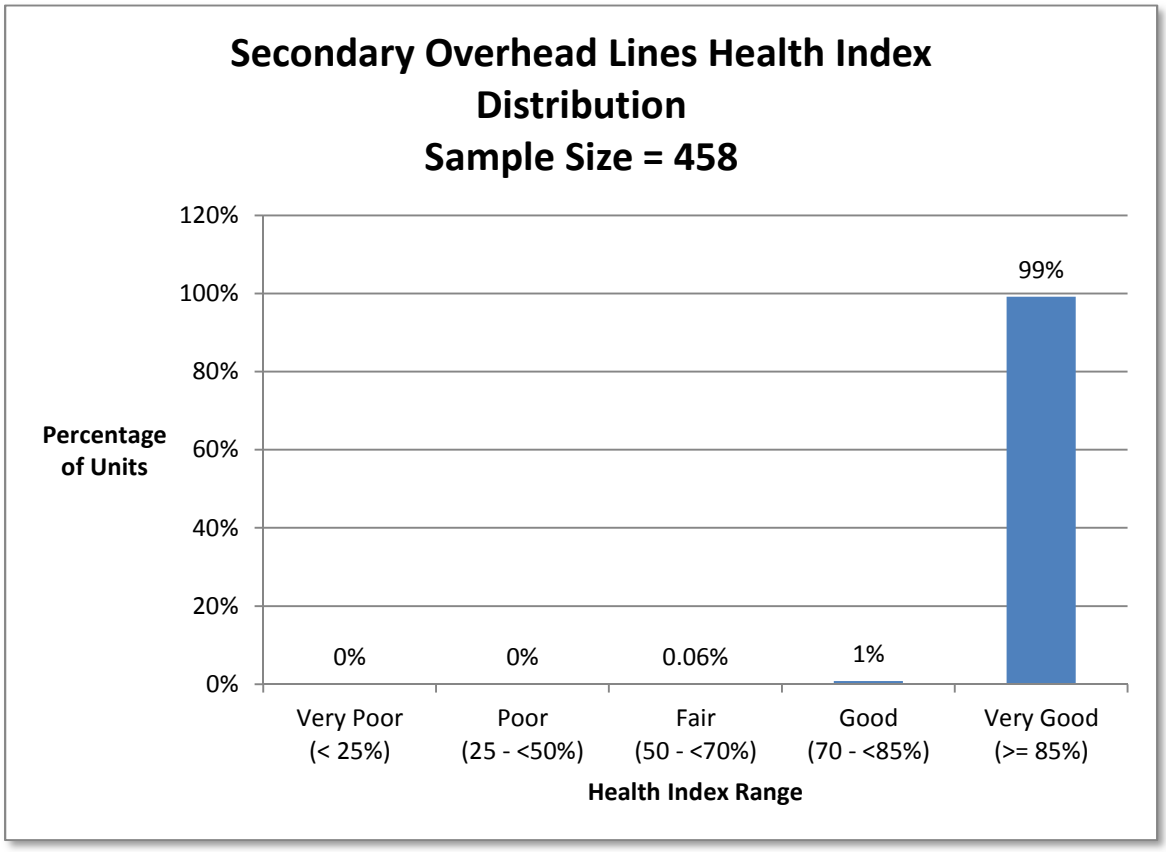


Figure 16-4 Secondary Lines Health Index Distribution (Percentage of Units)

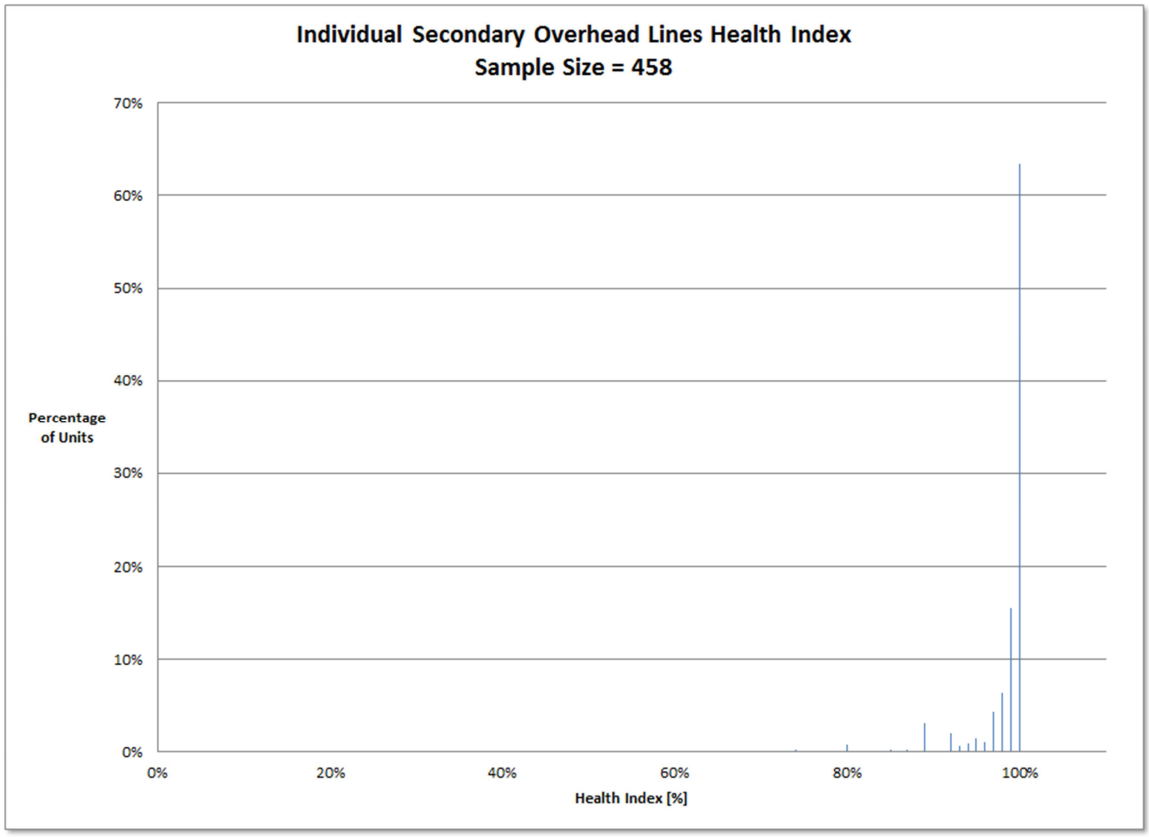


Figure 16-5 Secondary Lines Health Index Distribution by Value (Percentage of Units)

16.4 Condition-Based Flagged for Action Plan

As it is assumed that Secondary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

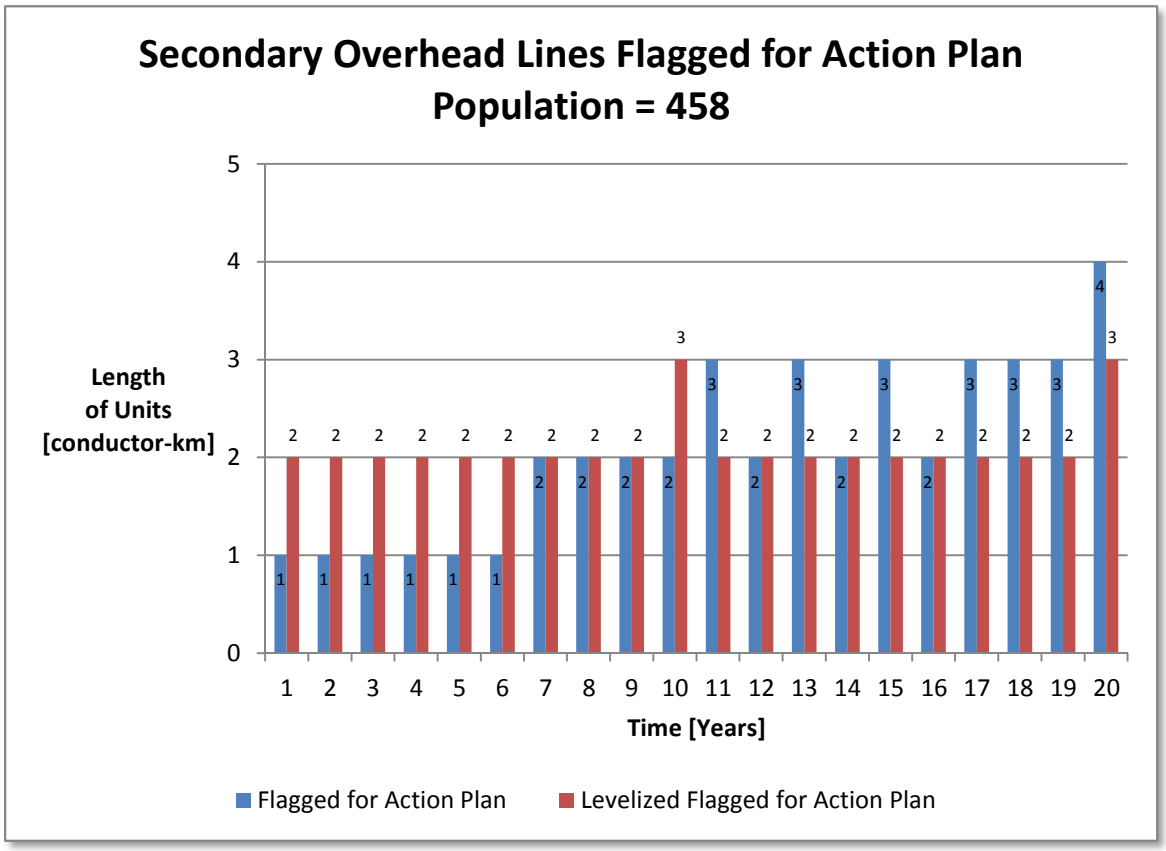


Figure 16-6 Secondary Lines Condition-Based Flagged for Action Plan

16.5 Data Analysis

16.5.1 Data Gap

The data available for Secondary Lines age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	☆☆	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		☆☆	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

16.5.2 Data Availability Distribution

The average DAI for Secondary Lines is 21%.

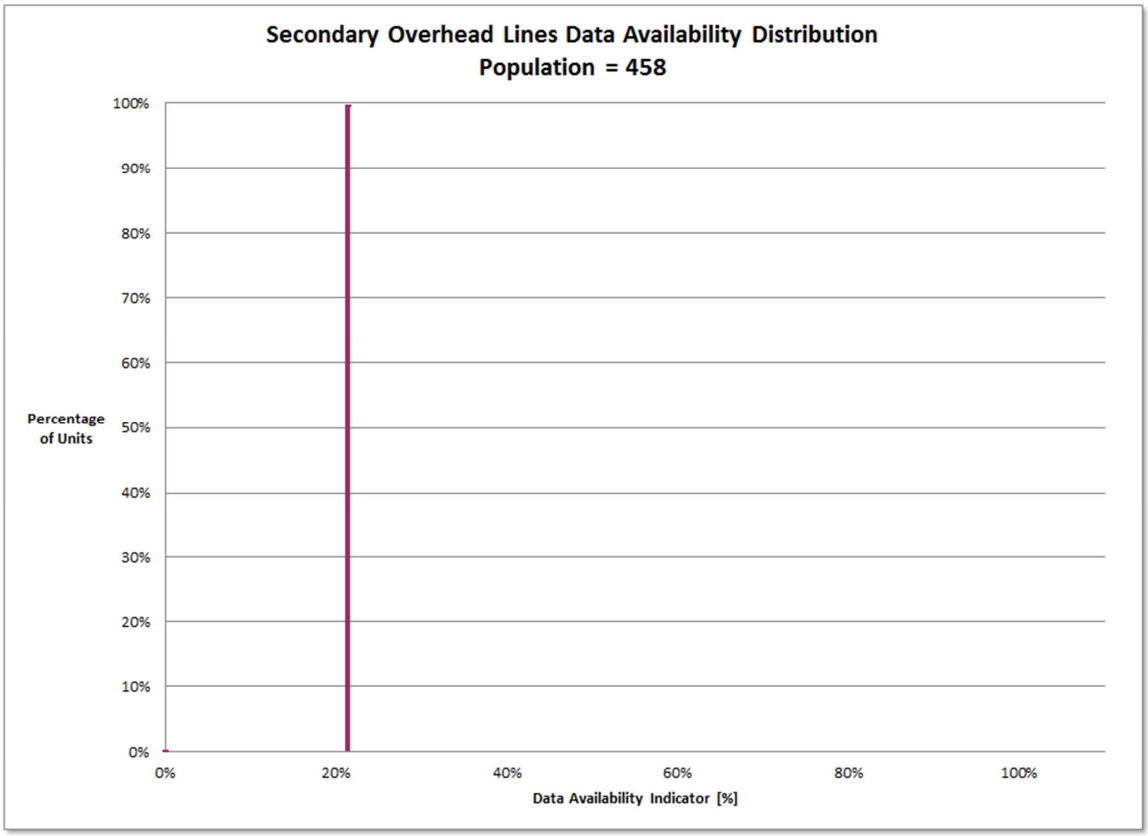


Figure 16-7 Secondary Lines Data Availability Distribution

17 Wood Poles

17.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Wood Poles. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

17.1.1 Condition and Sub-Condition Parameters

Table 17-1 Wood Poles Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Pole Strength	5	Pole Strength	1	Table 17-2
Physical Condition	5	Lean	1	Table 17-3
		Damage	2	Table 17-4
		Animal Damage	2	Table 17-4 Table 17-5
		Surface Rot/Decay	2	Table 17-4 Table 17-5
		Below Ground Rot/Decay	3	Table 17-4
		Internal Rot/Decay	3	Table 17-4
		Holes	2	Table 17-4 Table 17-5
		Pole Top Feathering	3	Table 17-4
Accessories	1	Ground	1	Table 17-5
		Cross Arm	1*	Table 17-4
Service Record	4	Overall Condition	2	Table 17-6
		Probable Remaining Life	1	Table 17-7
		Age	1	Figure 17-1
De-Rating Factor		Reject Poles, Pole Type	Table 17-8	

*Weight of this parameter is 0 if there are no cross arms

17.1.2 Condition Parameter Criteria

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 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

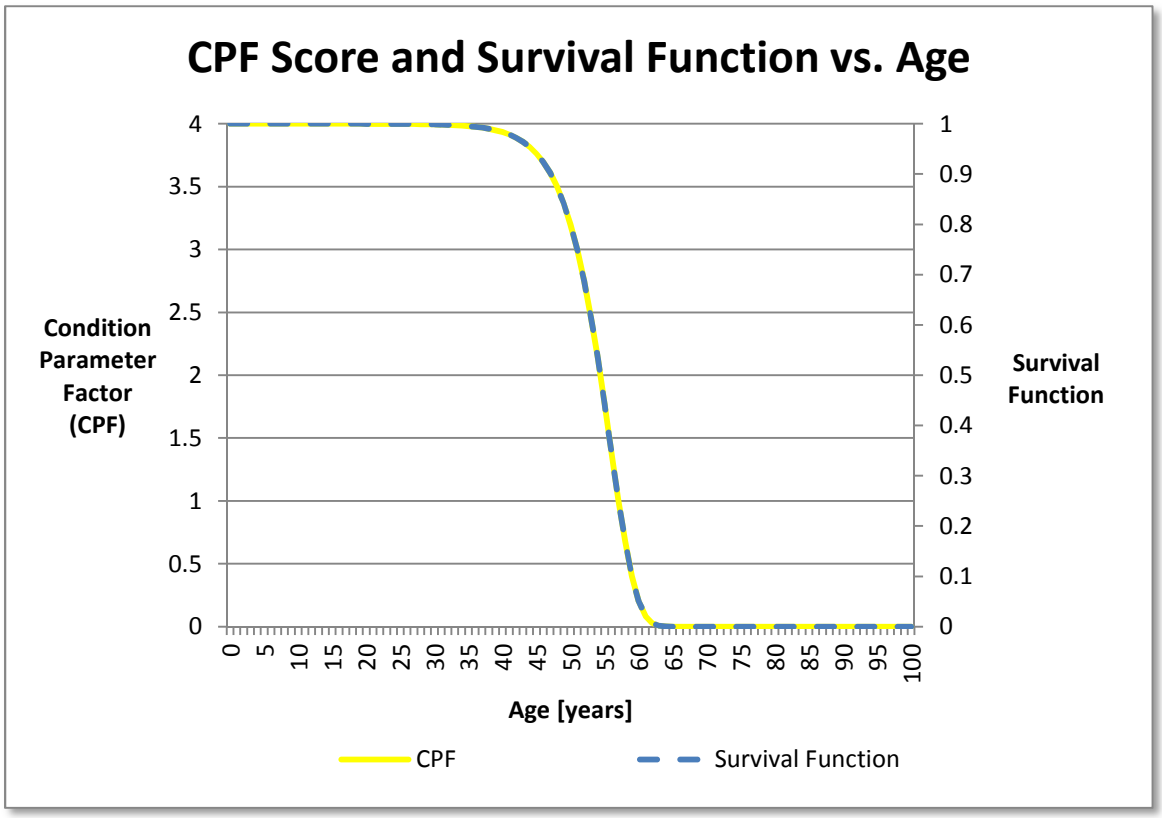


Figure 17-1 Wood Poles Age Condition Criteria

Pole Strength

Table 17-2 Wood Poles Strength Description and Score

Percentage of Maximum Strength (Measured PSI/Maximum PSI)	Score
< 50%	0
50 - 66%	1
67 - 79%	2
80 - 89%	3
90%	4

Where Maximum PSI is:

Type	Maximum Strength (PSI)
Douglas Fir	8000
Jack Pine	6600
Lodge Pine	6600
Pine	6600
Red Pine	6600
Southern Pine	6600
Western Red Cedar	6000

Lean

Table 17-3 Wood Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 17-4 Wood Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 17-5 Wood Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 17-6 Wood Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

Probable Remaining Life

Table 17-7 Wood Poles Remaining Life Description and Score

Estimated Remaining Life (Years)	Score
< 0	0
0 - 10	1
10 - 20	3
20 +	4

De-Rating Factor

The final De-Rating factor (DRF) is calculated as follows:

$$DRF = \min(DRF1, DRF2)$$

where

Table 17-8 Wood Poles De-Rating Factor Description and Value

De-Rating Factor	Description	De-Rating Value
DRF1	Reject Pole	25%
DRF2	Pole Type Douglas Fir	80%

17.2 Age Distribution

The age distribution is shown in the figure below. Age was available for nearly 100% of the population. The average age was found to be 27 years.

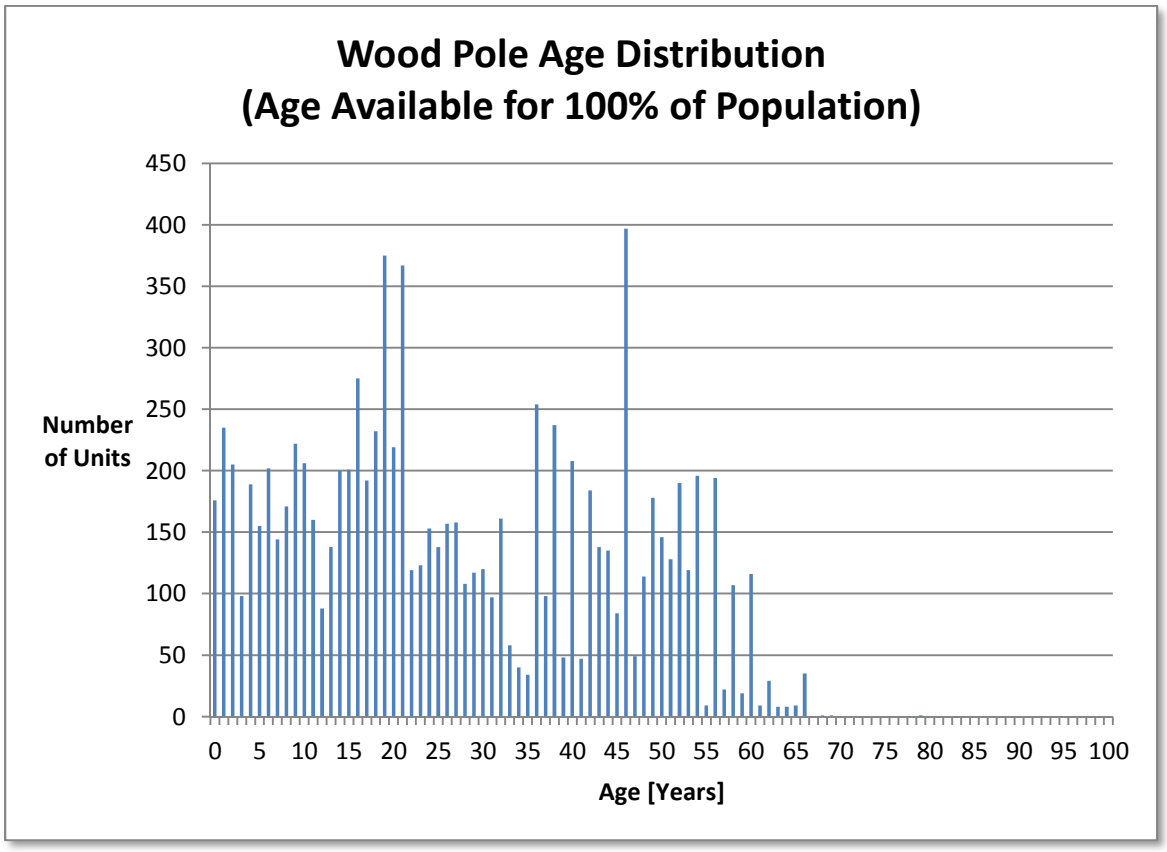


Figure 17-2 Wood Poles Age Distribution

17.3 Health Index Results

There are 10105 in-service Wood Poles at GHESI. There were 9564 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 86%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

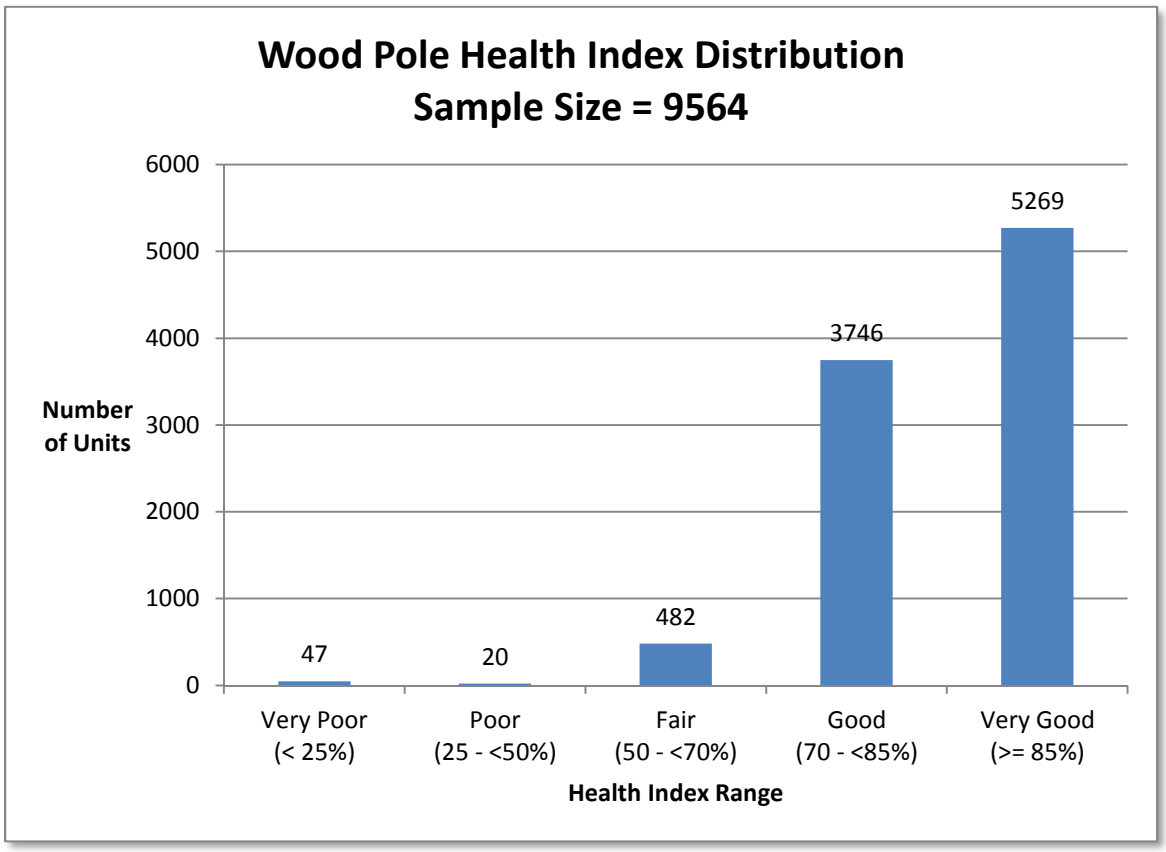


Figure 17-3 Wood Poles Health Index Distribution (Number of Units)

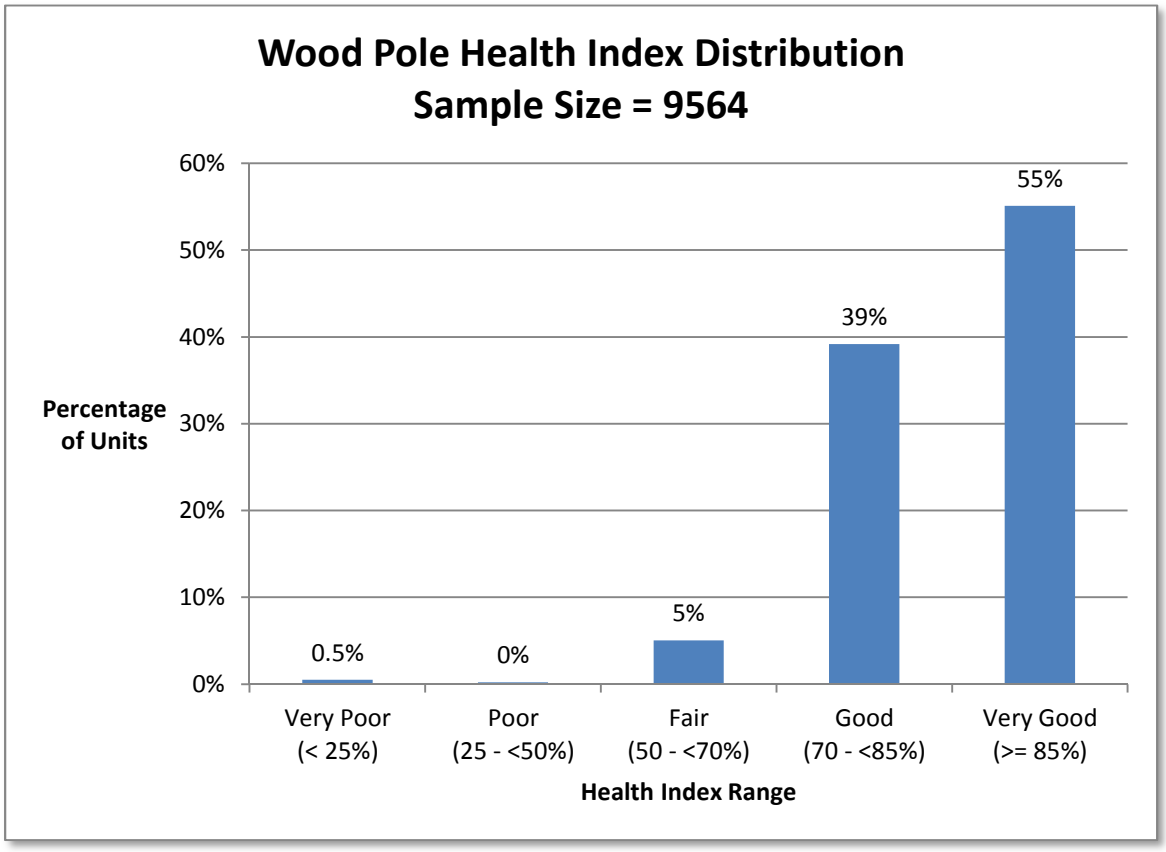


Figure 17-4 Wood Poles Health Index Distribution (Percentage of Units)

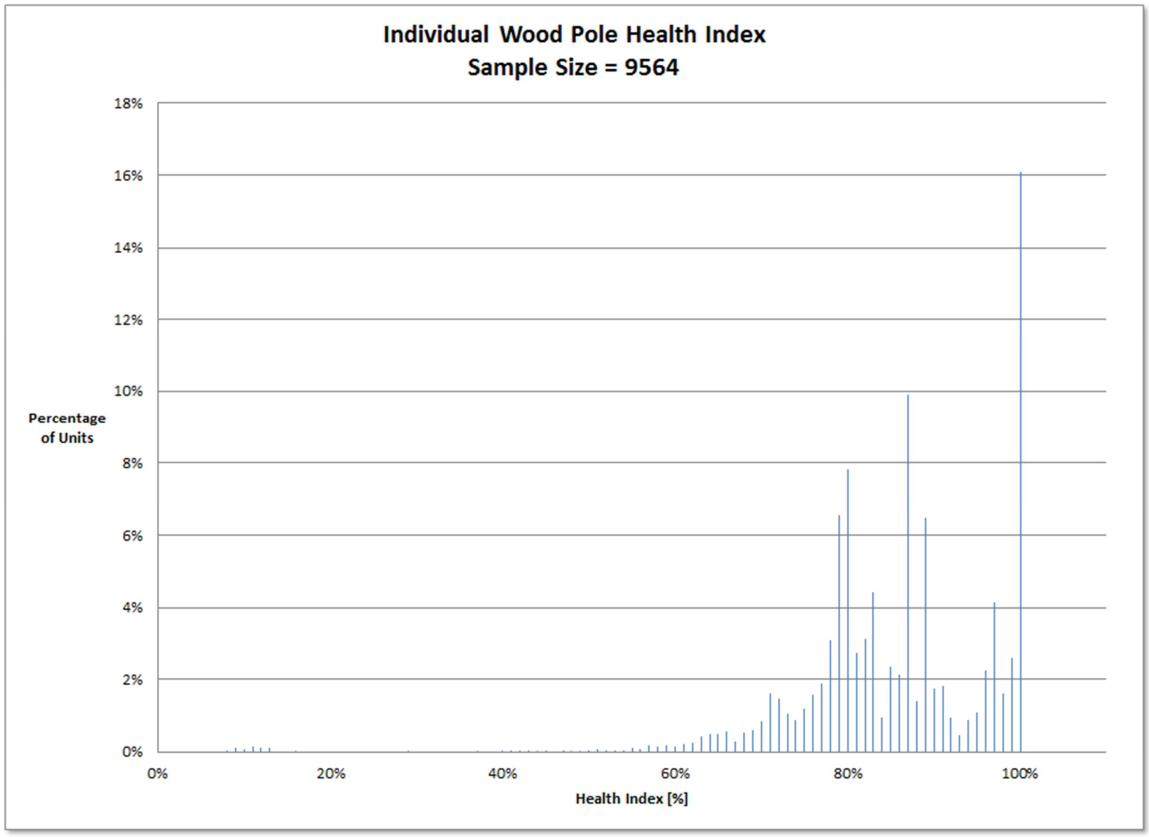


Figure 17-5 Wood Poles Health Index Distribution by Value (Percentage of Units)

17.4 Condition-Based Flagged for Action Plan

Although Wood Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

The flagged for action plan extrapolates the Health Index distribution of the sample size to the entire population of Wood Poles.

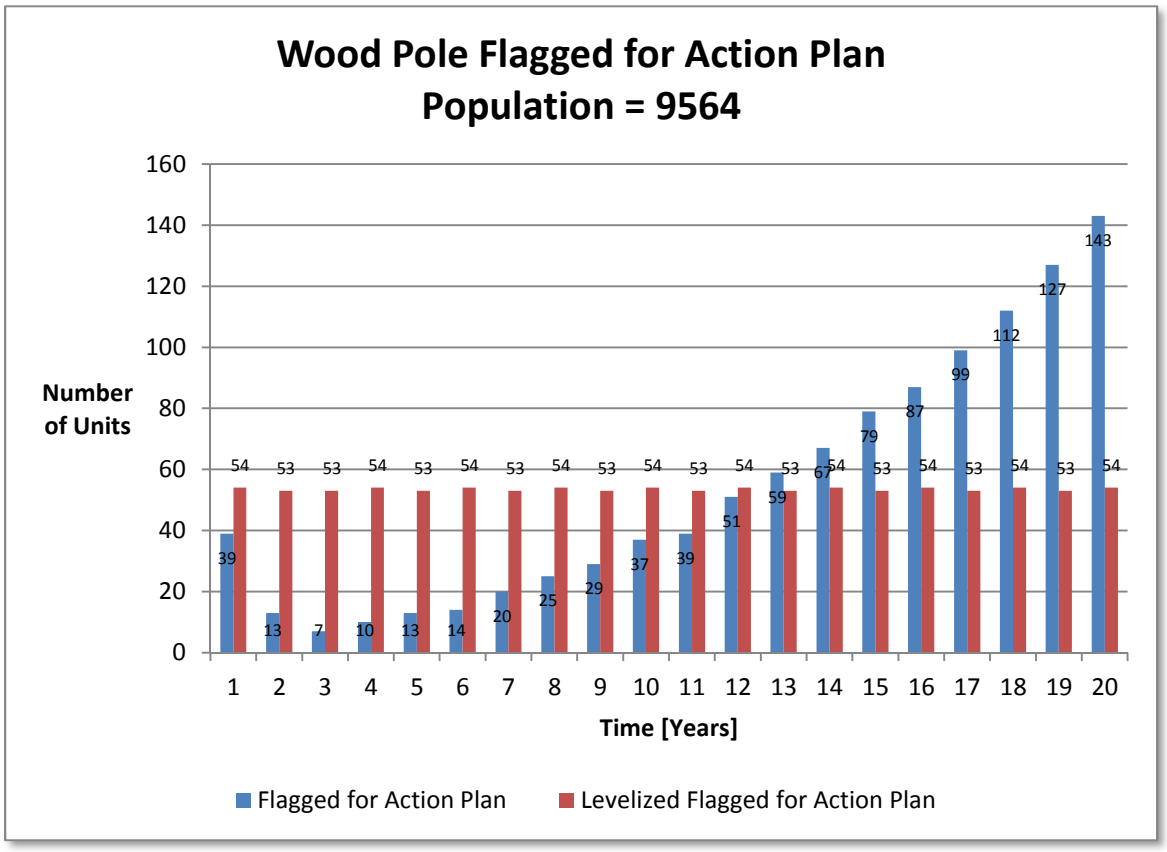


Figure 17-6 Wood Poles Condition-Based Flagged for Action Plan

17.5 Data Analysis

17.5.1 Data Gap

The data available for Wood Poles are age, pole strength, and inspection records. There are no data gaps identified.

17.5.2 Data Availability Distribution

The average DAI for Wood Poles is 78%.

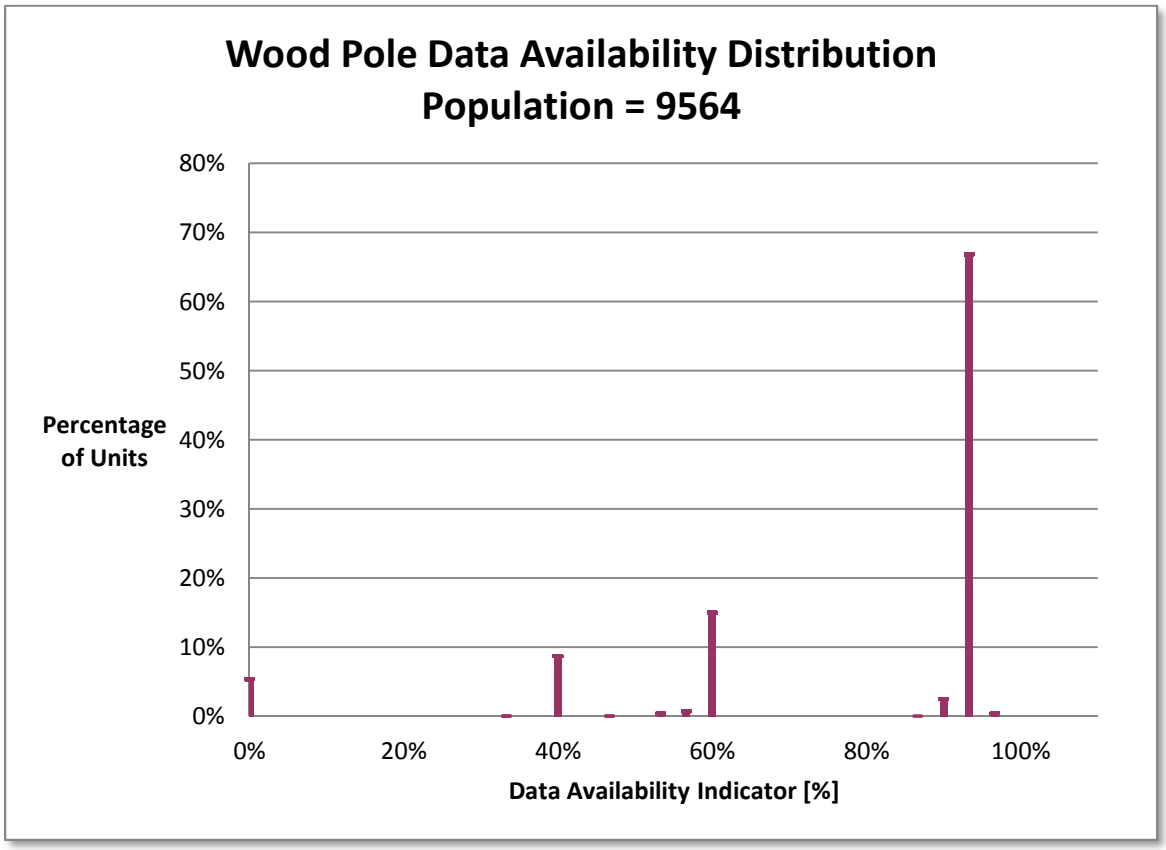


Figure 17-7 Wood Poles Data Availability Distribution

18 Concrete Poles

18.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Concrete Poles. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

18.1.1 Condition and Sub-Condition Parameters

Table 18-1 Concrete Poles Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	5	Lean	2	Table 18-2
		Damage	3	Table 18-3
		Surface Damage	3	Table 18-3
		Below Ground Damage	4	Table 18-3
Accessories	1	Ground	1	Table 18-4
		Cross Arm	1*	Table 18-4
Service Record	4	Overall Condition	2	Table 18-5
		Age	1	Figure 19-1
De-Rating Factor		Reject Pole, Arterial Pole	Table 18-6	

*Weight of this parameter is 0 if there are no cross arms

18.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Concrete 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 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

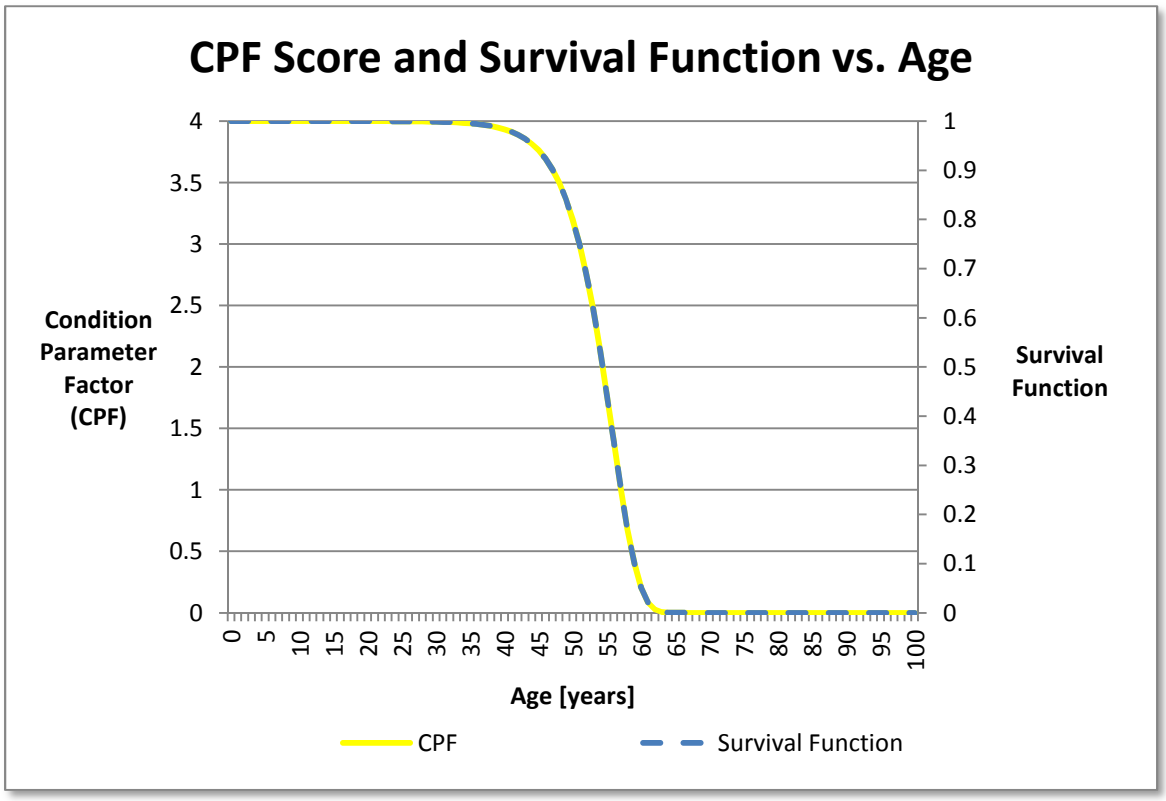


Figure 18-1 Concrete Poles Age Condition Criteria

Lean

Table 18-2 Concrete Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 18-3 Concrete Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 18-4 Concrete Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 18-5 Concrete Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

De-Rating Factor

The final De-Rating factor (DRF) is calculated as follows:

$$DRF = \min(DRF1, DRF2)$$

where

Table 18-6 Concrete Poles De-Rating Factor Description and Value

De-Rating Factor	Description	De-Rating Value
DRF1	Reject Pole	25%
DRF2	Arterial Pole	85%

18.2 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 18 years.

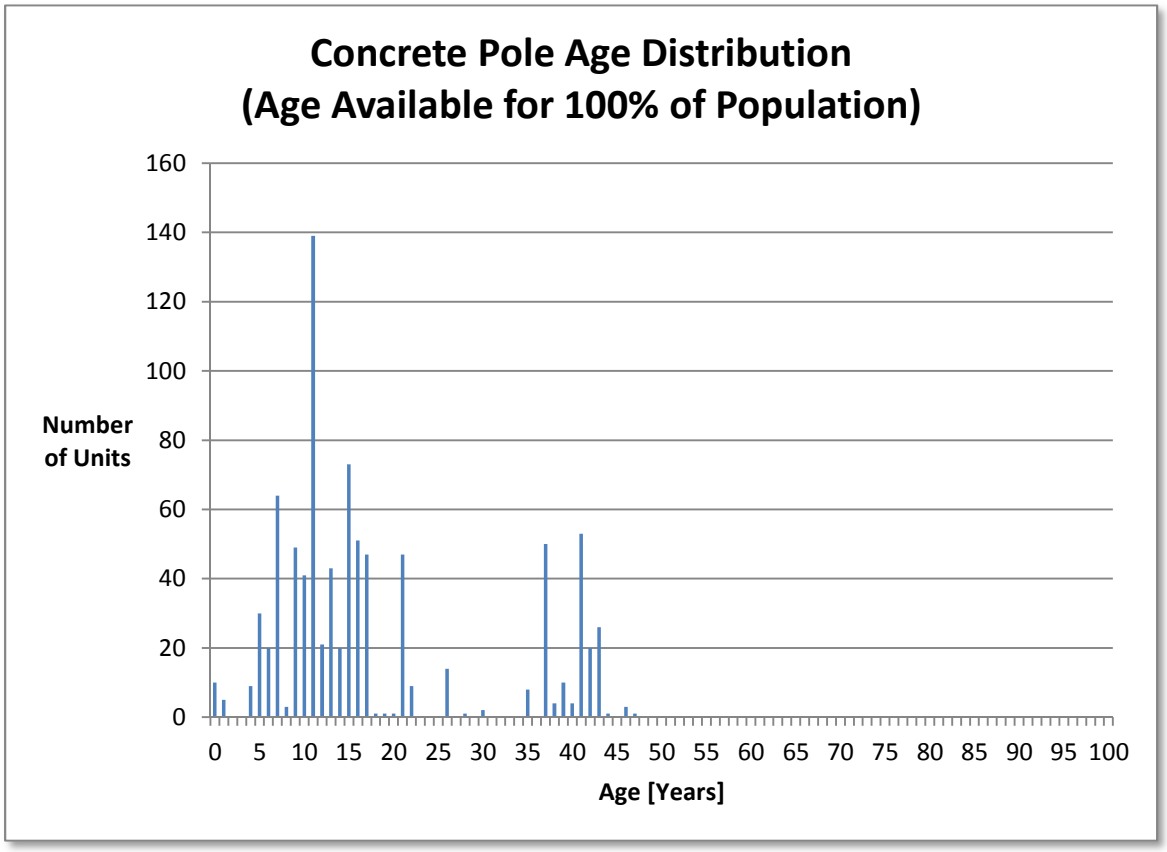


Figure 18-2 Concrete Poles Age Distribution

18.3 Health Index Results

There are 881 in-service Concrete Poles at GHESI. There were 881 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 83%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

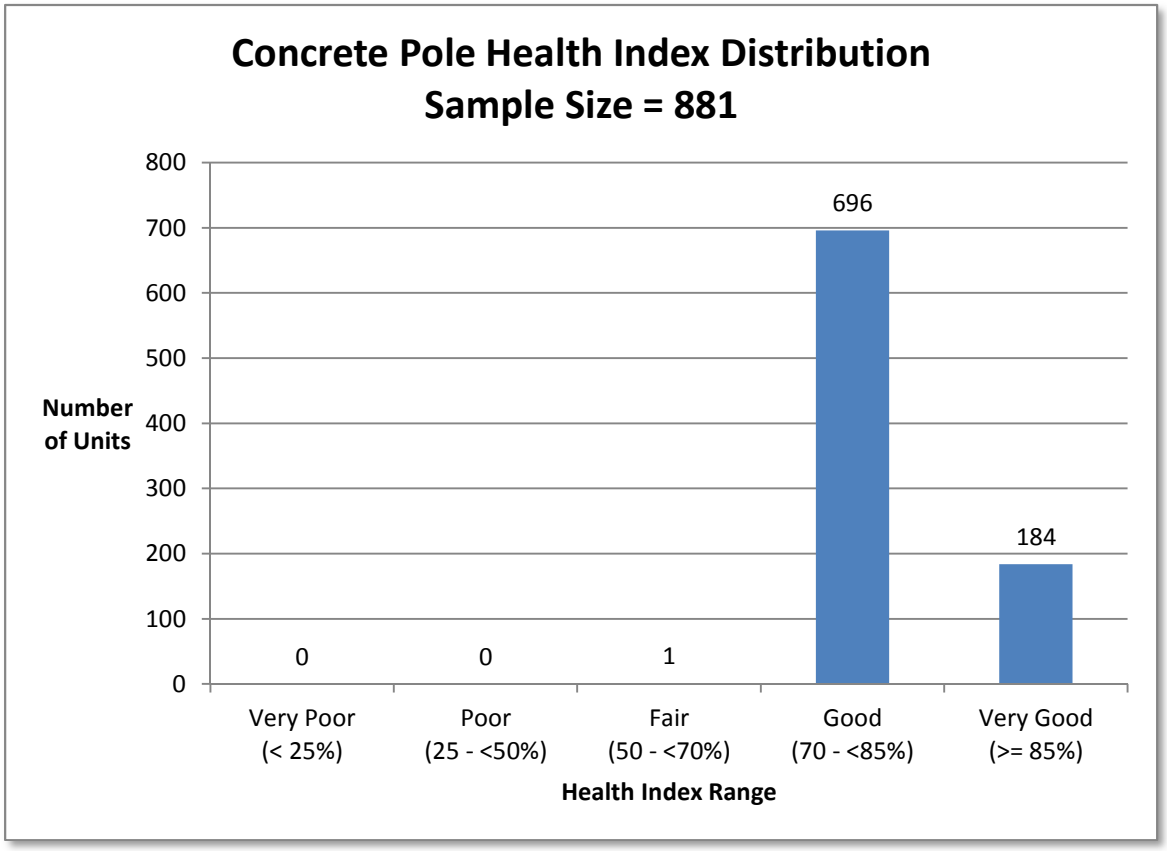


Figure 18-3 Concrete Poles Health Index Distribution (Number of Units)

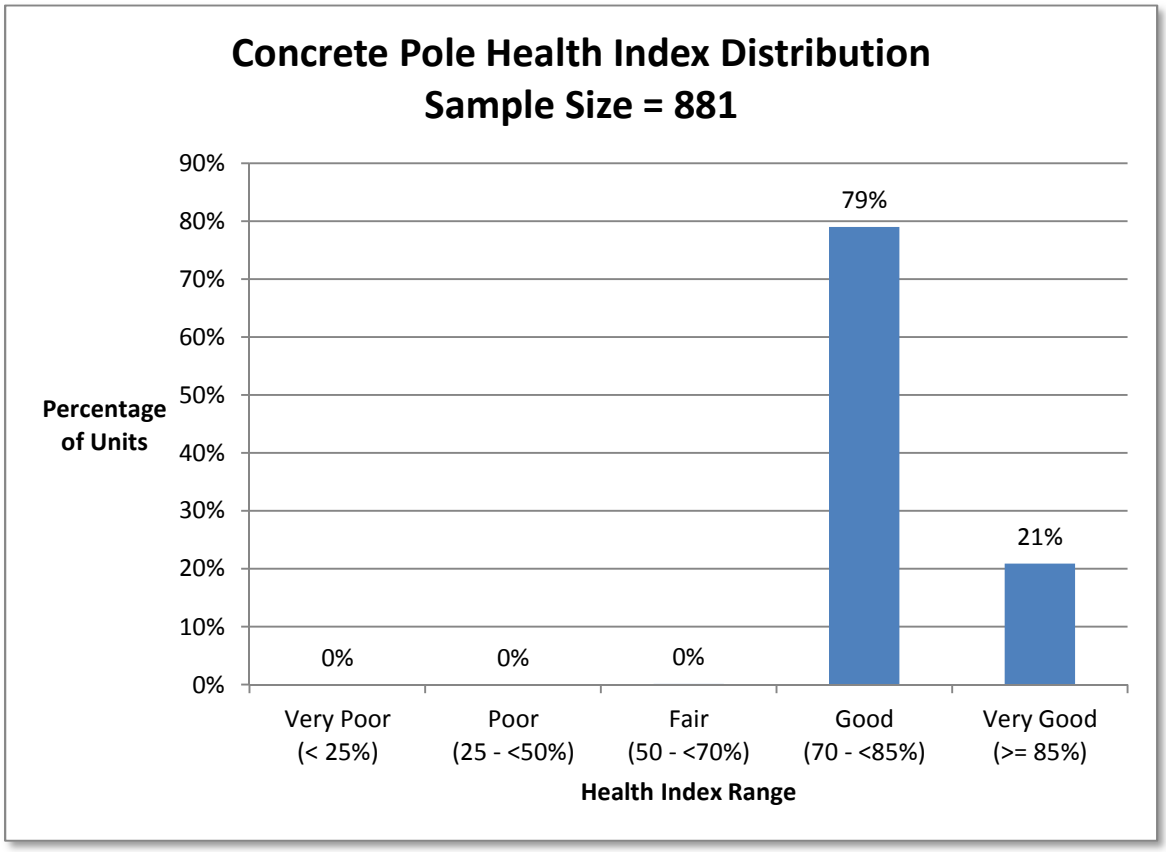


Figure 18-4 Concrete Poles Health Index Distribution (Percentage of Units)

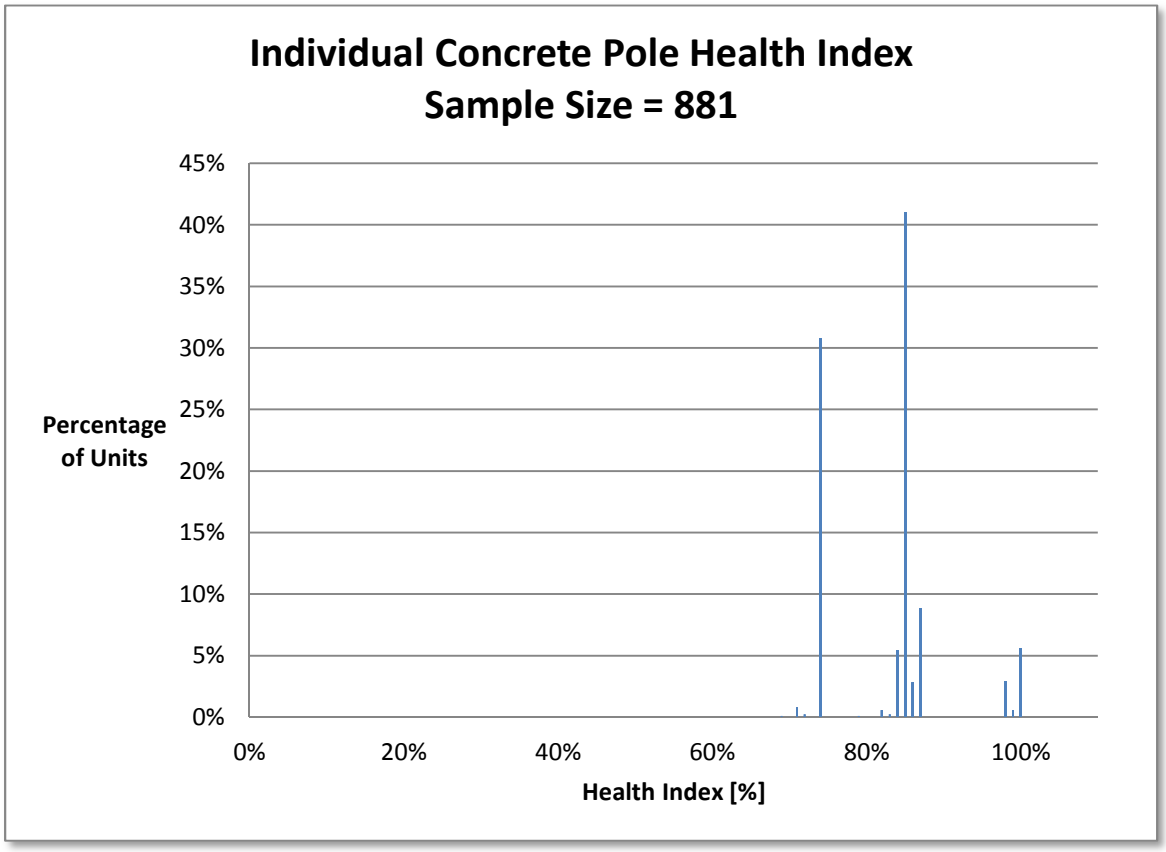


Figure 18-5 Concrete Poles Health Index Distribution by Value (Percentage of Units)

18.4 Condition-Based Flagged for Action Plan

Although Concrete Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

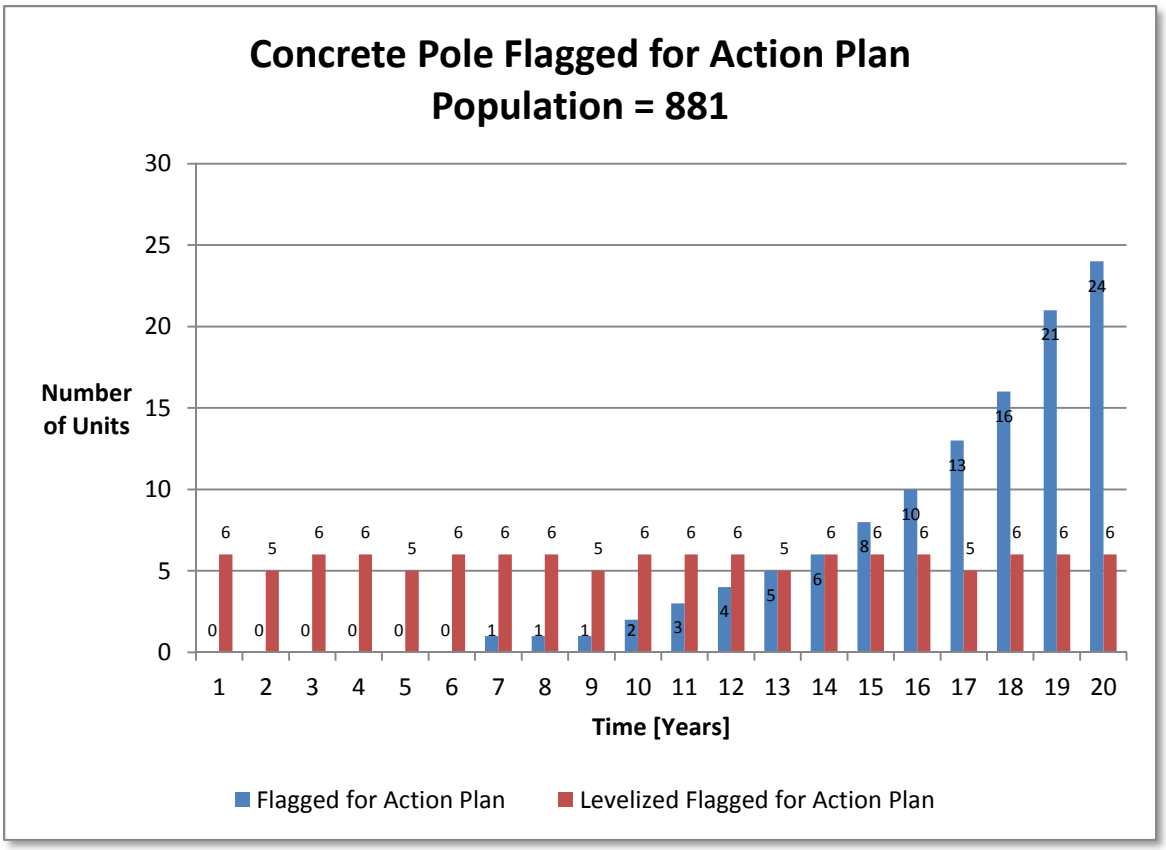


Figure 18-6 Concrete Poles Condition-Based Flagged for Action Plan

18.5 Data Analysis

18.5.1 Data Gap

The data available for Concrete Poles are age and inspection records. No data gaps are identified.

18.5.2 Data Availability Distribution

The average DAI for Concrete Poles is 84%.

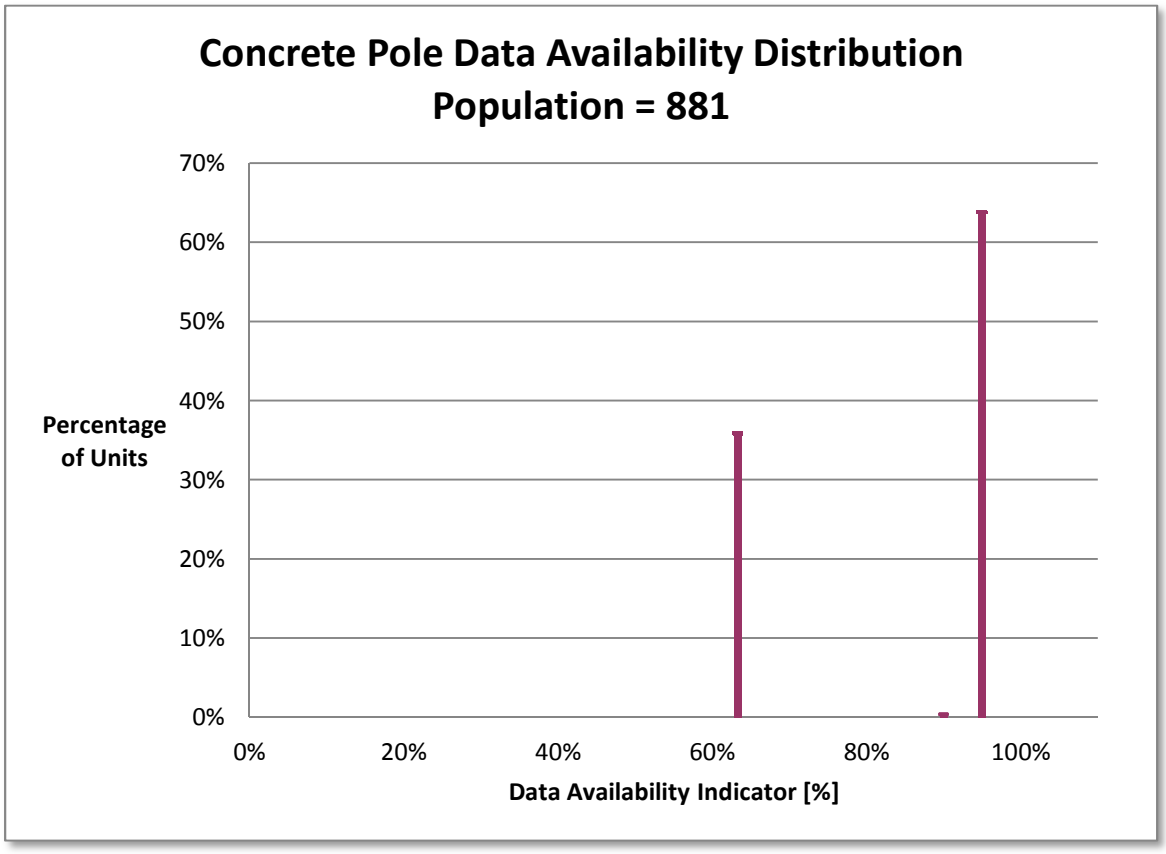


Figure 18-7 Concrete Poles Data Availability Distribution

19 Composite Poles

19.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Composite Poles. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

19.1.1 Condition and Sub-Condition Parameters

Table 19-1 Composite Poles Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	5	Lean	2	Table 19-2
		Damage	3	Table 19-3
		Surface Damage	3	Table 19-3
		Below Ground Damage	4	Table 19-3
Accessories	1	Ground	1	Table 19-4
		Cross Arm	1	Table 19-4
Service Record	4	Overall Condition	2	Table 19-5
		Age	1	Figure 19-1
De-Rating Factor		Reject Pole	25%	

19.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Composite 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 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

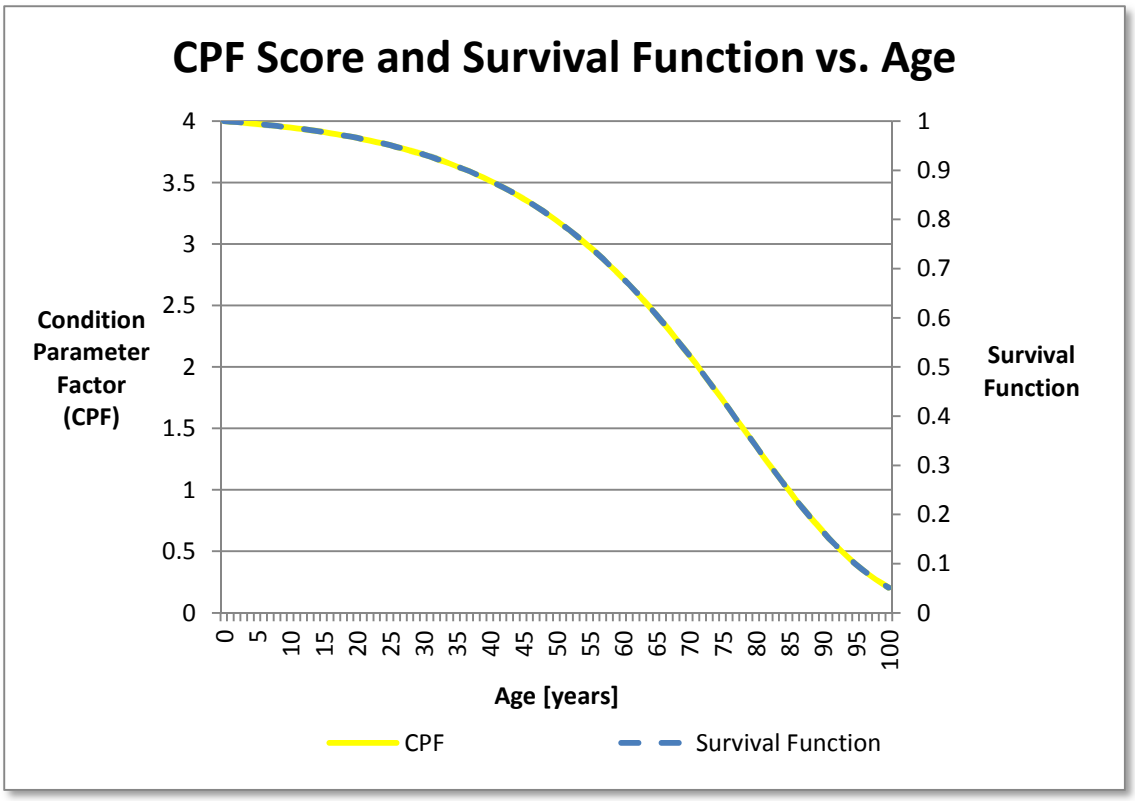


Figure 19-1 Composite Poles Age Condition Criteria

Lean

Table 19-2 Composite Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 19-3 Composite Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 19-4 Composite Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 19-5 Composite Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

19.2 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 2 years.

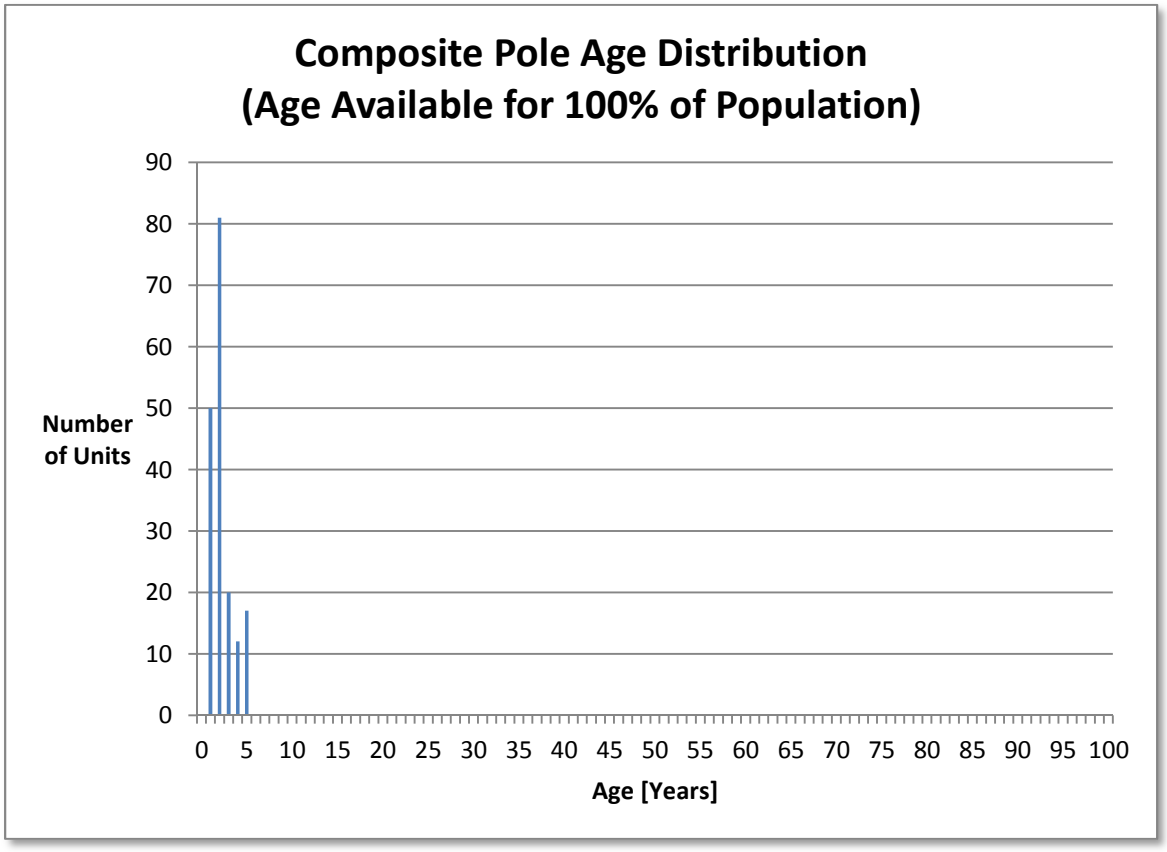


Figure 19-2 Composite Poles Age Distribution

19.3 Health Index Results

There are 180 in-service Composite Poles at GHESI. There were 180 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 88%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

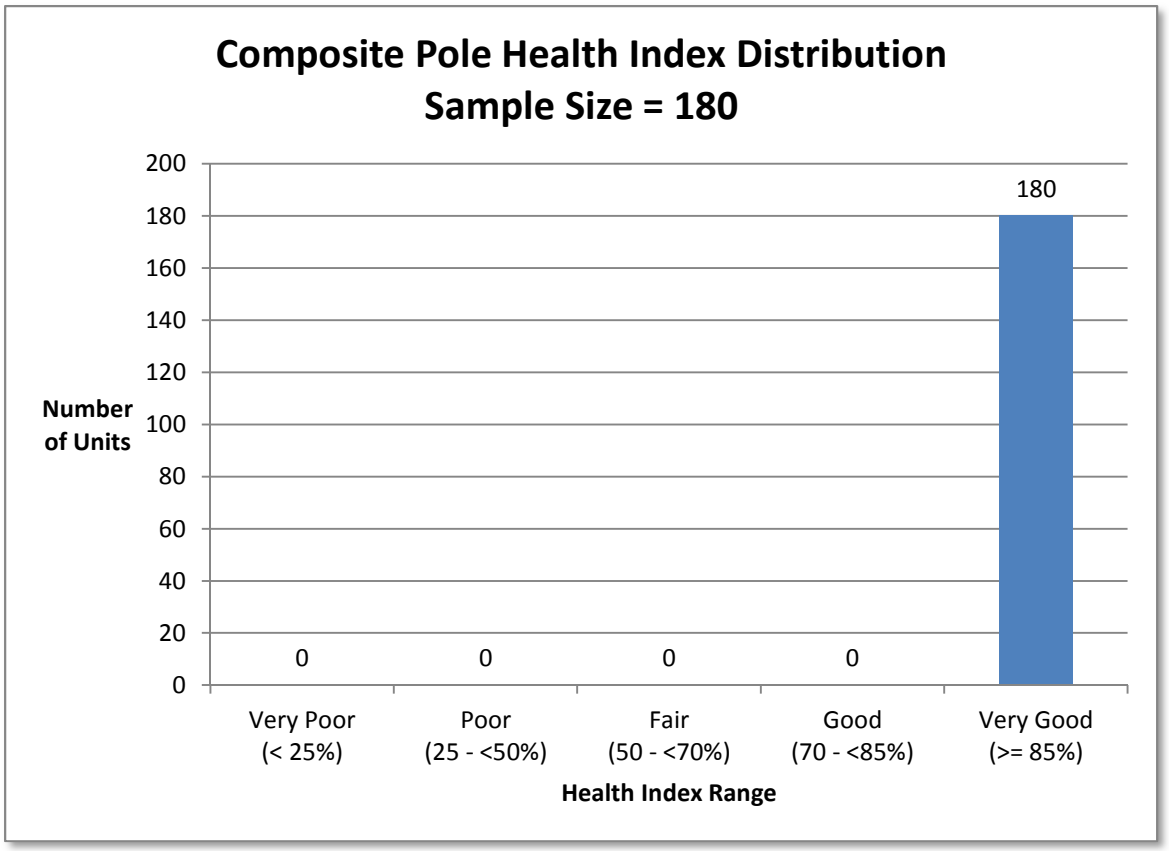


Figure 19-3 Composite Poles Health Index Distribution (Number of Units)

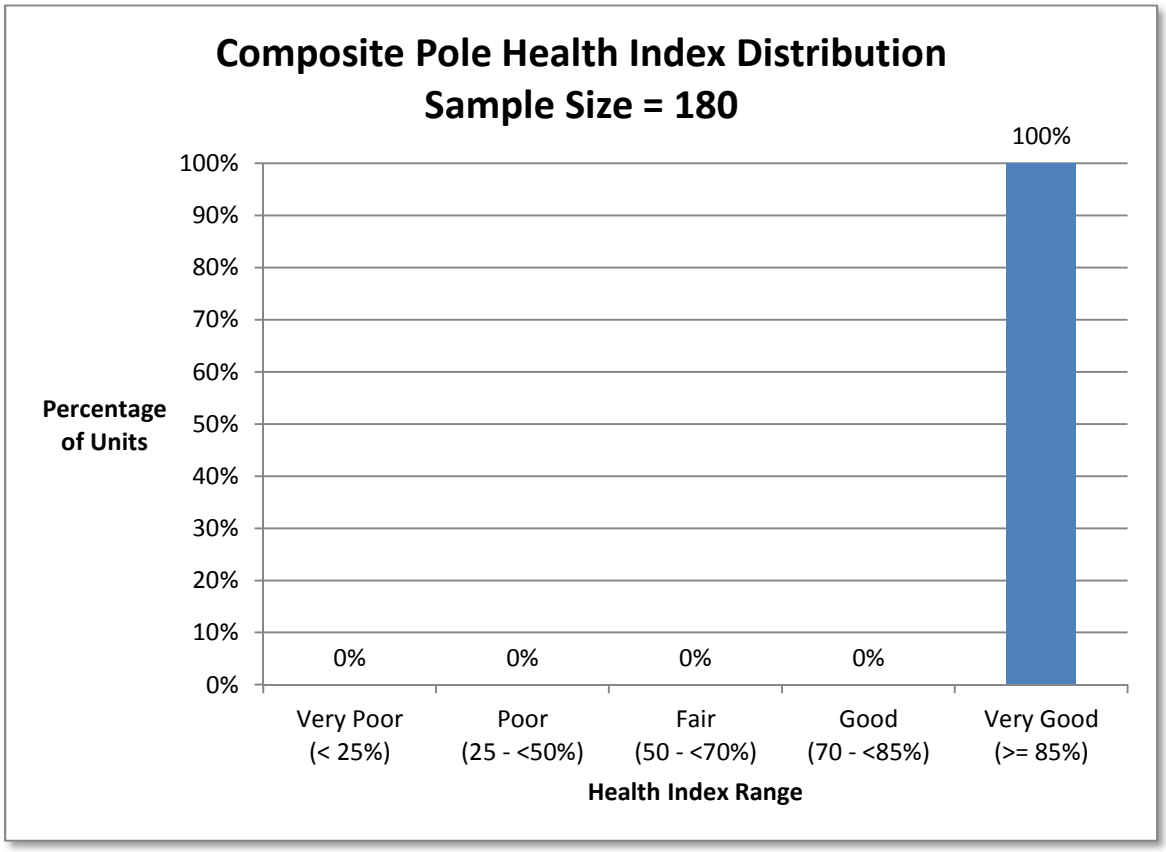


Figure 19-4 Composite Poles Health Index Distribution (Percentage of Units)

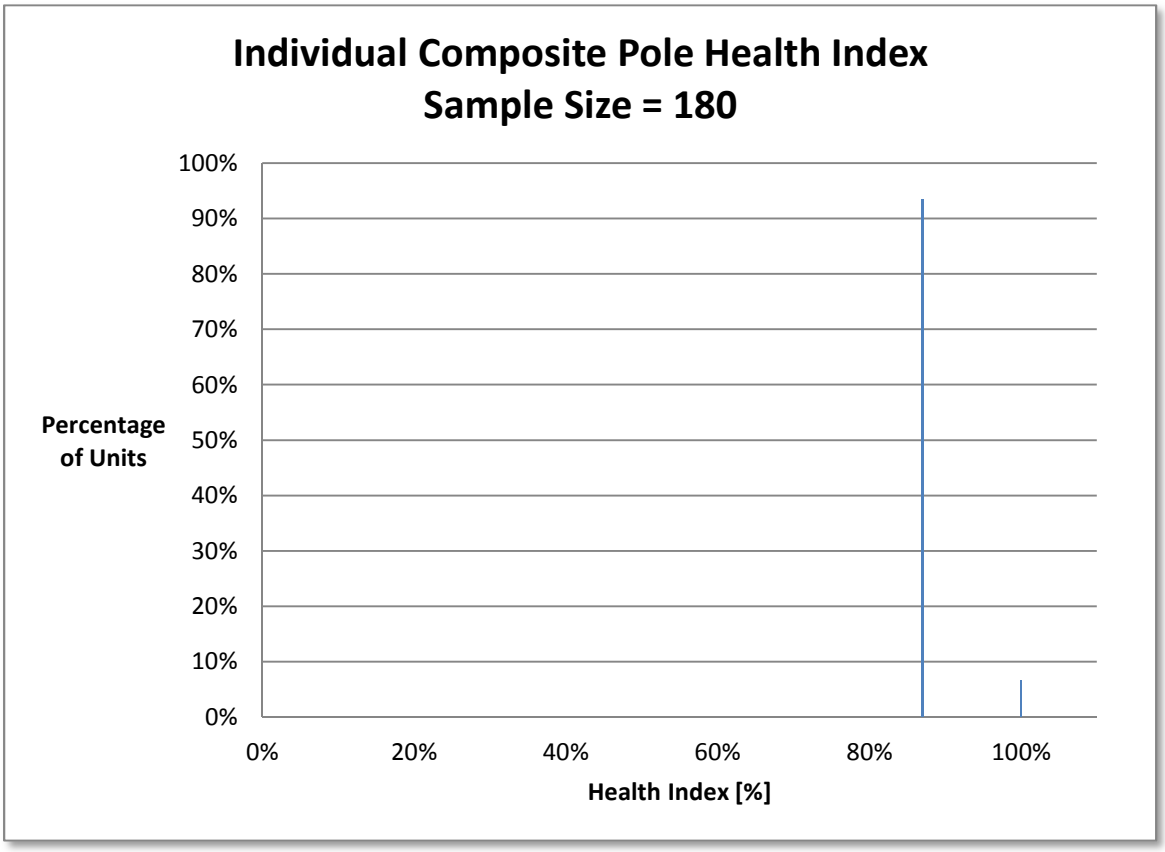


Figure 19-5 Composite Poles Health Index Distribution by Value (Percentage of Units)

19.4 Condition-Based Flagged for Action Plan

Although Composite Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t).

In the next 20 years no units are expected to be flagged for action.

19.5 Data Analysis

19.5.1 Data Gap

The data available for Composite Poles are age and inspection records.

19.5.2 Data Availability Distribution

The average DAI for Composite Poles is 95%.

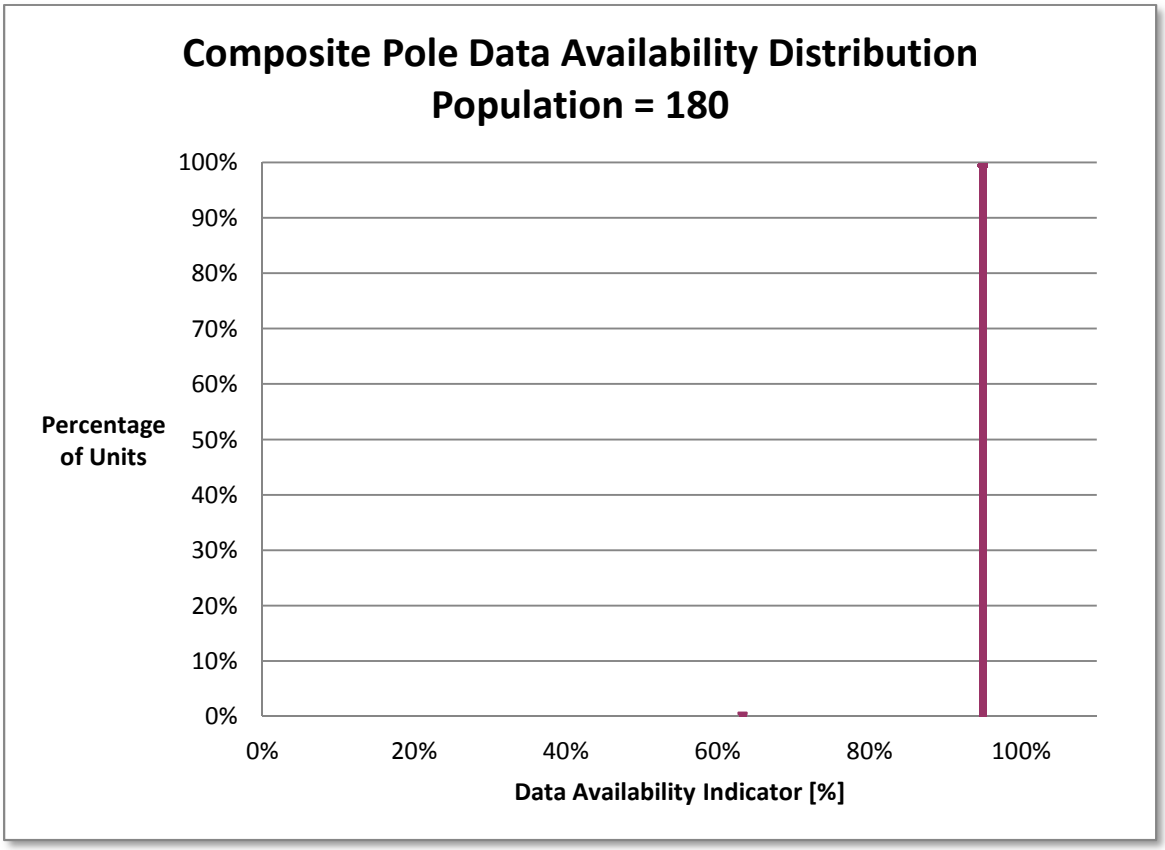


Figure 19-6 Composite Poles Data Availability Distribution

20 Vaults

20.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Vaults. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

20.1.1 Condition and Sub-Condition Parameters

Table 20-1 Vaults Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter N = North, S = South, E = East, W = West	Sub-Condition Parameter Weights	Criteria Lookup Table
Walls	5	N Wall Cracks	6	Table 21-2
		N Wall Corrosion	4	
		N Wall Erosion/ Scaling	4	
		N Wall Spalling	3	
		S Wall Cracks	6	
		S Wall Corrosion	4	
		S Wall Erosion/ Scaling	4	
		S Wall Spalling	3	
		E Wall Cracks	6	
		E Wall Corrosion	4	
		E Wall Erosion/ Scaling	4	
		E Wall Spalling	3	
		W Wall Cracks	6	
		W Wall Corrosion	4	
		W Wall Erosion/ Scaling	4	
		W Wall Spalling	3	
Ceiling	8	Cracks	6	
		Corrosion	4	
		Erosion/ Scaling	4	
		Spalling	3	
De-Rating Applied to Sub-Condition	*Wall*	*If Min (Score_N_Wall, Score_S_Wall, Score_E_Wall, Score_W_Wall) = 0, Score_Wall = Score_Wall*50%* *If 1 ≤ (Score_N_Wall, Score_S_Wall, Score_E_Wall, Score_W_Wall) ≤ 2, Score_Wall = Score_Wall*80%*		

Parameters *Assumes a Scoring System of 0 (worst condition) through 4 (as-new) CR = Cracks, CO = Corrosion, E/S = Erosion/ Scaling , SP = Spalling,*	*Ceiling*	*If Min ($Score_{CR}$, $Score_{CO,}$ $Score_{E/S}$, $Score_{SP}$) = 0, Score_Ceiling = Ceiling*70%* *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2, Score_Ceiling = Score_Ceiling*85%*

*Note: A vault typically does not have a ceiling and the Health Index is based only on walls. i.e. Of the 107 vaults inspected in 2013, 1 vault was found with a ceiling.

20.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Vaults 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 and 50 years the probability of failure (P_f) for this asset are 20% and 95% 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:

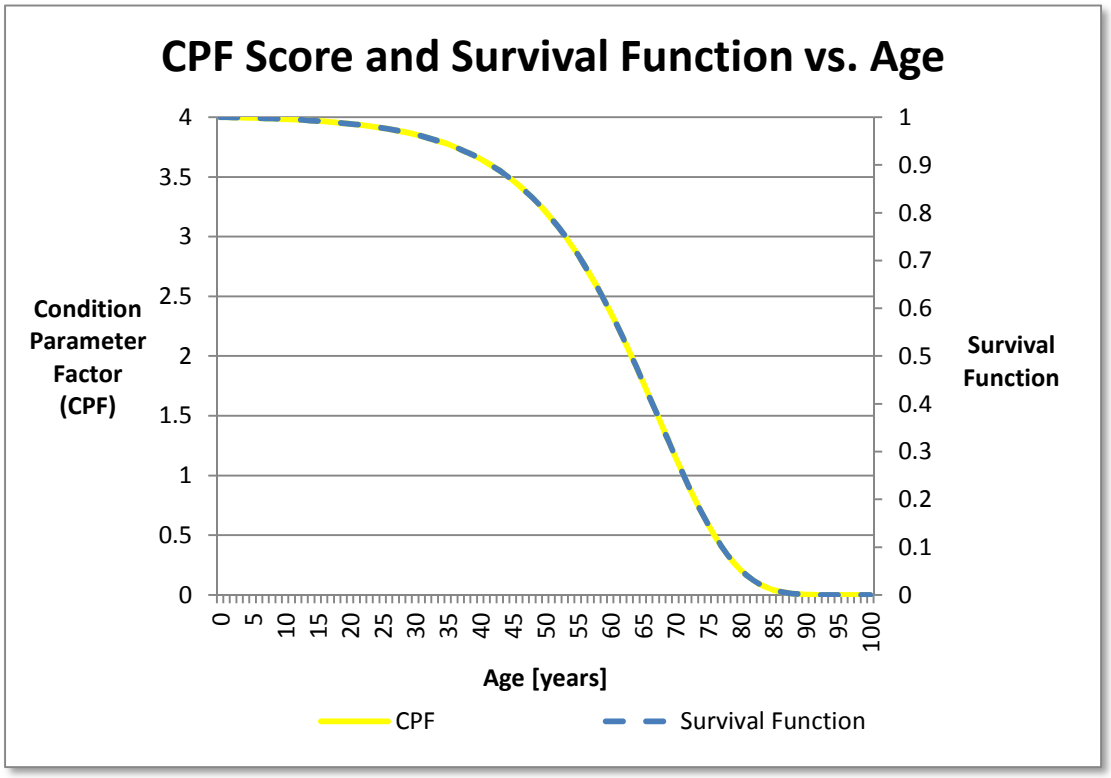


Figure 20-1 Vaults Age Condition Criteria

Inspection Results

Table 20-2 Vaults Inspection Condition Description and Score

Status	Score
Very Poor	0
Poor	1
Fair	2
Good	3
Very Good	4

20.2 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 26 years.

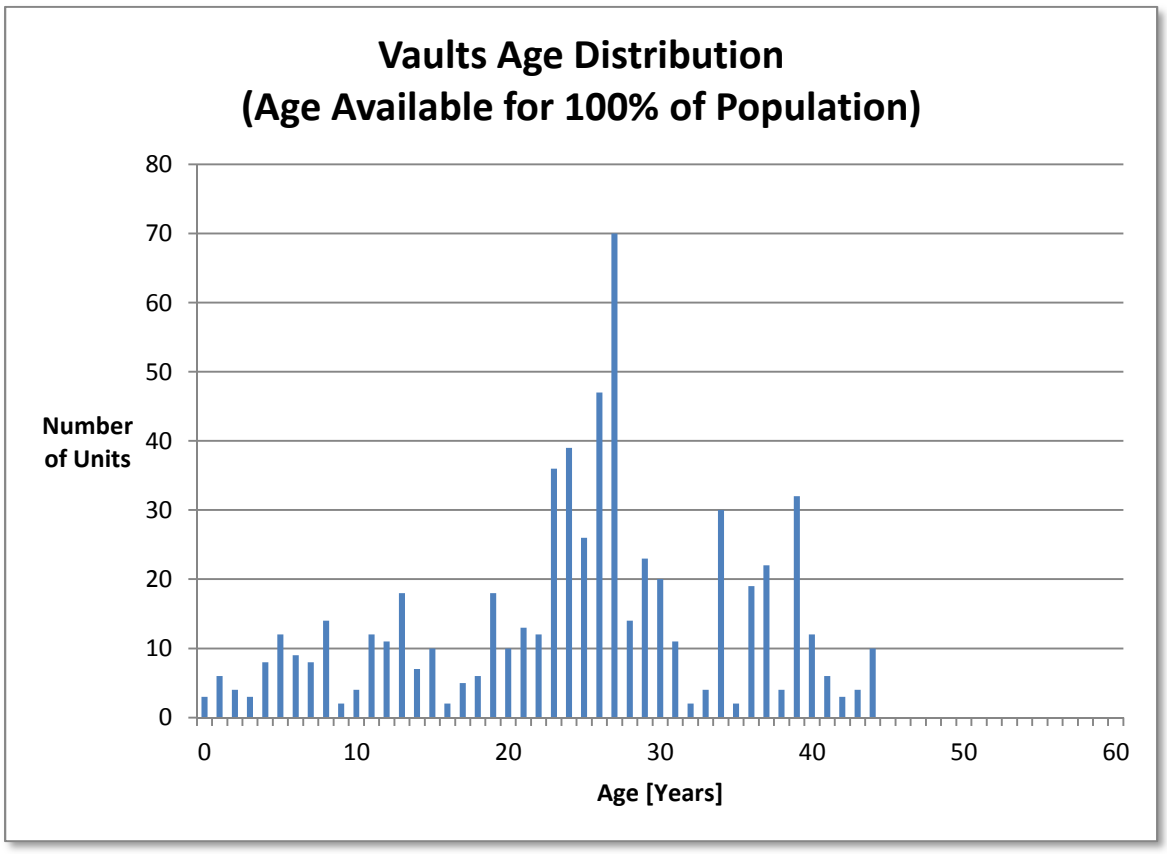


Figure 20-2 Vaults Age Distribution

20.3 Health Index Results

There are 469 in-service Vaults at GHESI. There were 105 units that were inspected and thus considered to have sufficient data for Health Indexing. It should be noted 66 inspected locations in 2013 were specifically selected for various reasons (e.g. known issues, critical locations, locations where vaults would be more prone to degradation, etc.). As such, the samples may not be representative of the entire population and therefore the results cannot be extrapolated.

The average Health Index for this asset group is 89%. Approximately 10% of the units were found to be in poor condition.

The Health Index Results are as follows:

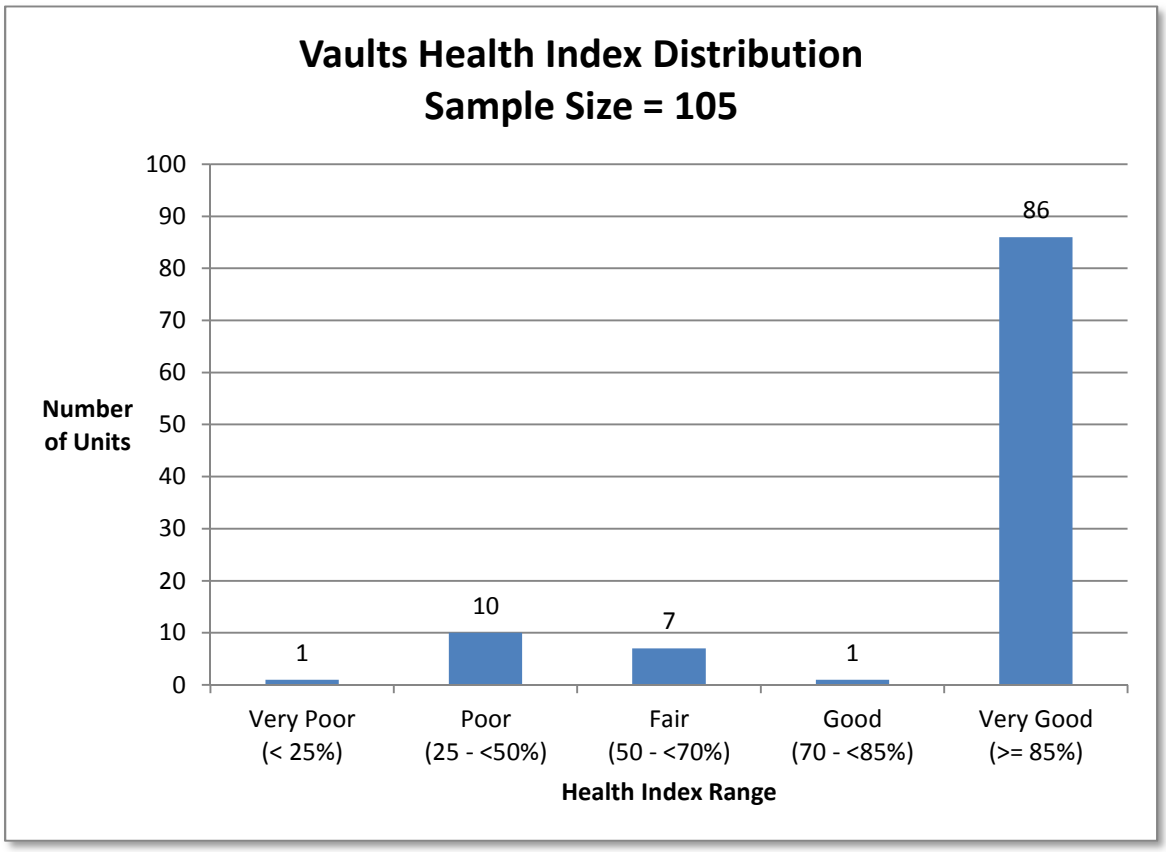


Figure 20-3 Vaults Health Index Distribution (Number of Units)

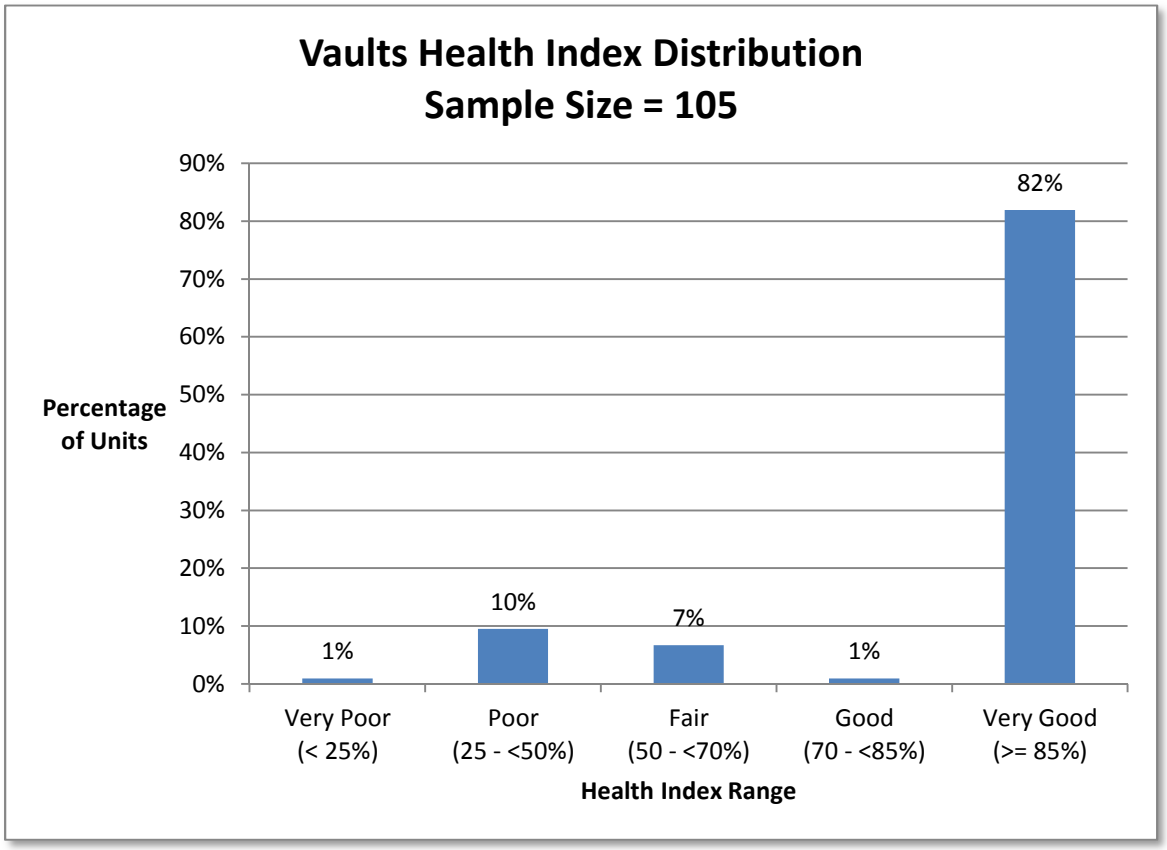


Figure 20-4 Vaults Health Index Distribution (Percentage of Units)

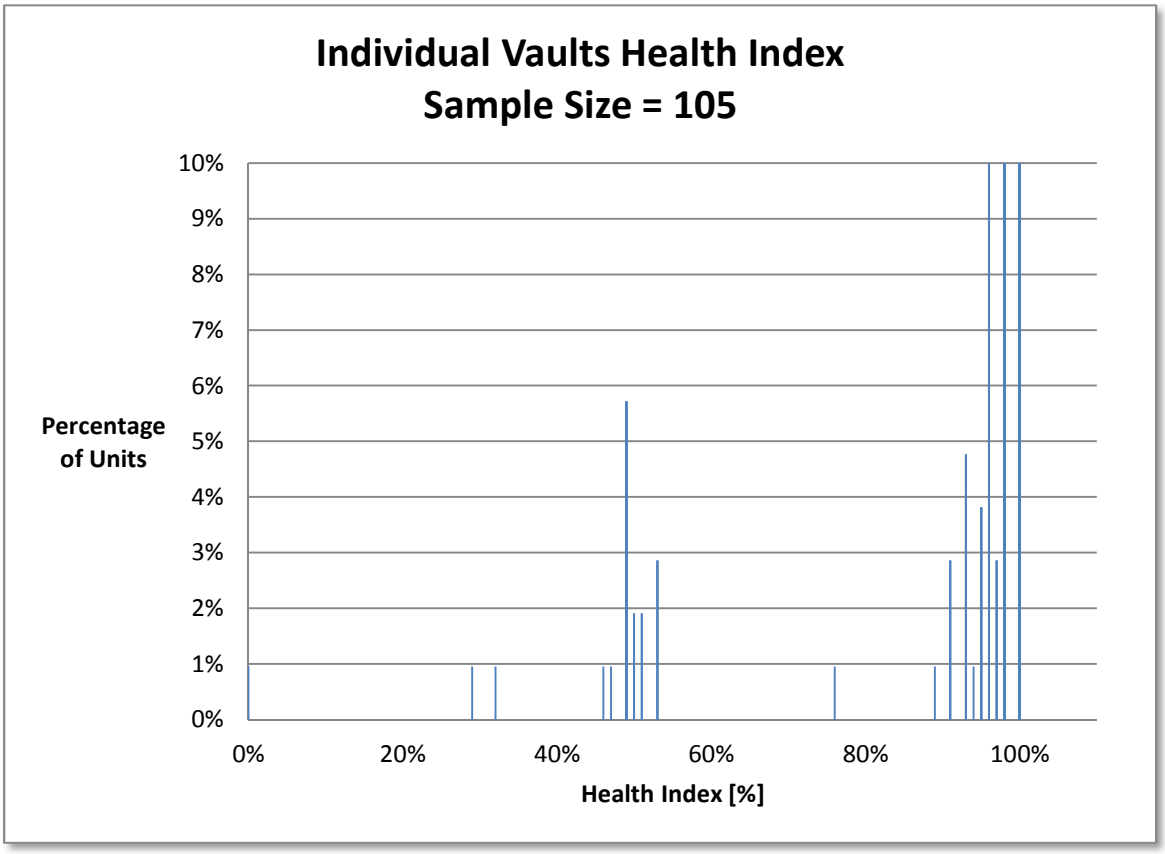


Figure 20-5 Vaults Health Index Distribution by Value (Percentage of Units)

20.4 Condition-Based Flagged for Action Plan

Although Vaults are proactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

Note that the flagged for action plan is based only on the sample size and not extrapolated to the entire population.

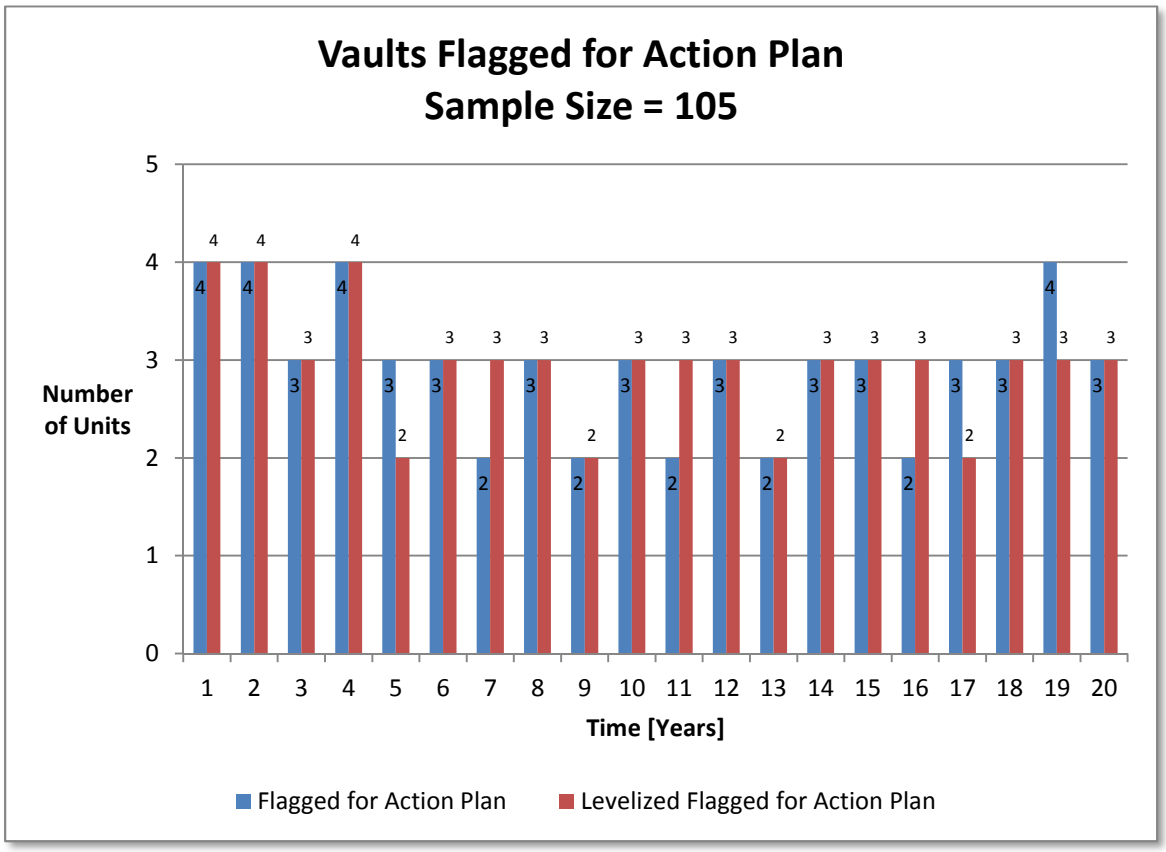


Figure 20-6 Vaults Condition-Based Flagged for Action Plan

20.5 Data Analysis

20.5.1 Data Gap

The data available for Vaults age and inspection records. No data gaps are identified. It should be noted, however that inspections were only conducted for approximately 22% of the population. The remainder of the population are assumed to have no data.

20.5.2 Data Availability Distribution

The average DAI for Vaults is 22%.

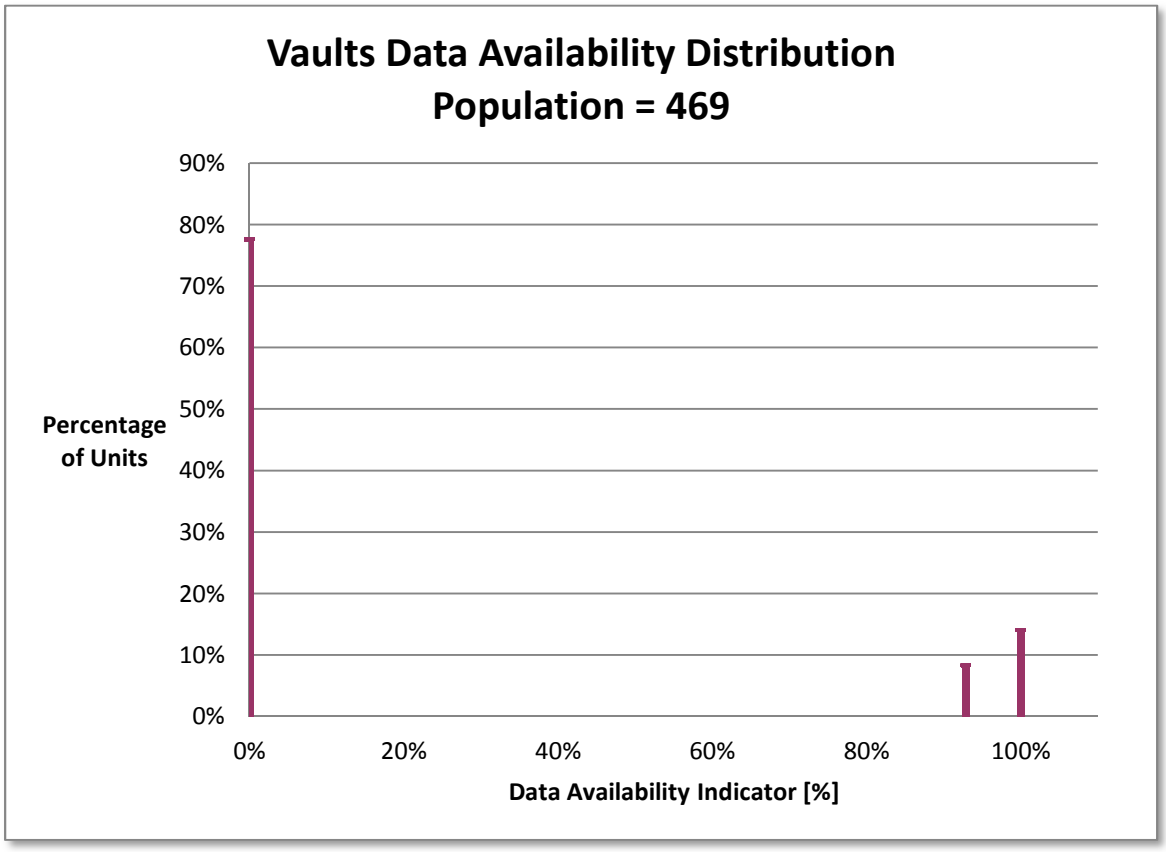


Figure 20-7 Vaults Data Availability Distribution

21 Manholes

21.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Manholes. The Health Index equation is shown in "Guelph Hydro Electric Systems Inc. 2012 Asset Condition Assessment"; 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".

21.1.1 Condition and Sub-Condition Parameters

Table 21-1 Manholes Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter N = North, S = South, E = East, W = West	Sub-Condition Parameter Weights	Criteria Lookup Table
Walls	5	N Wall Cracks	6	Table 21-2
		N Wall Corrosion	4	
		N Wall Erosion/ Scaling	4	
		N Wall Spalling	3	
		S Wall Cracks	6	
		S Wall Corrosion	4	
		S Wall Erosion/ Scaling	4	
		S Wall Spalling	3	
		E Wall Cracks	6	
		E Wall Corrosion	4	
		E Wall Erosion/ Scaling	4	
		E Wall Spalling	3	
		W Wall Cracks	6	
		W Wall Corrosion	4	
		W Wall Erosion/ Scaling	4	
		W Wall Spalling	3	
Ceiling	8	Cracks	6	
		Corrosion	4	
		Erosion/ Scaling	4	
		Spalling	3	
De-Rating Applied to Sub-Condition	*Wall*	*If Min ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) = 0, Score_N_Wall = 0* *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2 Score_N_Wall = Score_N_Wall*80%*		*If Min (Score_N_Wall, Score_S_Wall, Score_E_Wall, Score_W_Wall) = 0, Score_Wall = 0*

Parameters *Assumes a Scoring System of 0 (worst condition) through 4 (as-new) CR = Cracks, CO = Corrosion, E/S = Erosion/ Scaling , SP = Spalling,*		*If Min ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) = 0, Score_S_Wall = 0* *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2, Score_S_Wall = Score_S_Wall*80%*
		If Min ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) = 0, Score_E_Wall = 0 *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2, Score_E_Wall = Score_E_Wall*80%*
		If Min ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) = 0, Score_W_Wall = 0 *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2, Score_W_Wall = Score_W_Wall*80%*
	Ceiling	*If Min ($Score_{CR}$, $Score_{CO,}$ $Score_{E/S}$, $Score_{SP}$) = 0, Score_Ceiling = 0* *If 1 ≤ ($Score_{CR}$, $Score_{CO}$, $Score_{E/S}$, $Score_{SP}$) ≤ 2, Score_Ceiling = Score_Ceiling*80%*

21.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Manholes 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 and 60 years the probability of failure (P_f) for this asset are 20% and 95% 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:

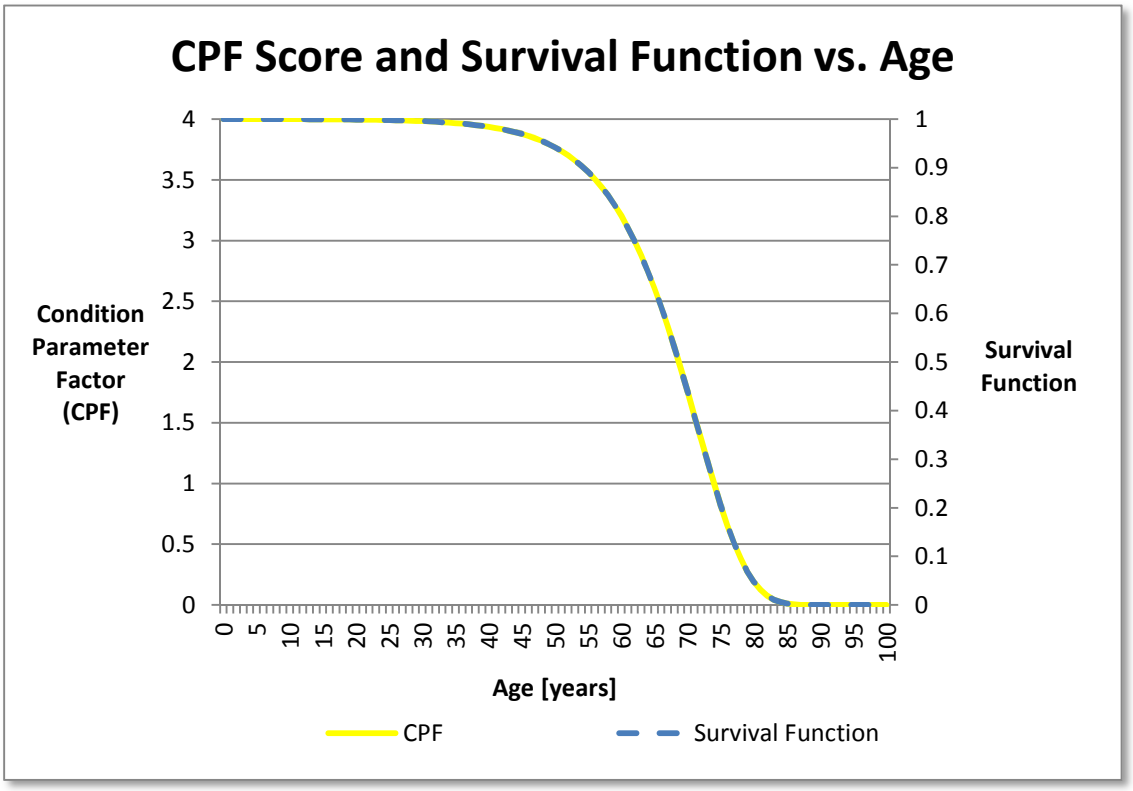


Figure 21-1 Manholes Age Condition Criteria

Inspection Results

Table 21-2 Manholes Inspection Condition Description and Score

Status	Score
Very Poor	0
Poor	1
Fair	2
Good	3
Very Good	4

21.2 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 18 years.

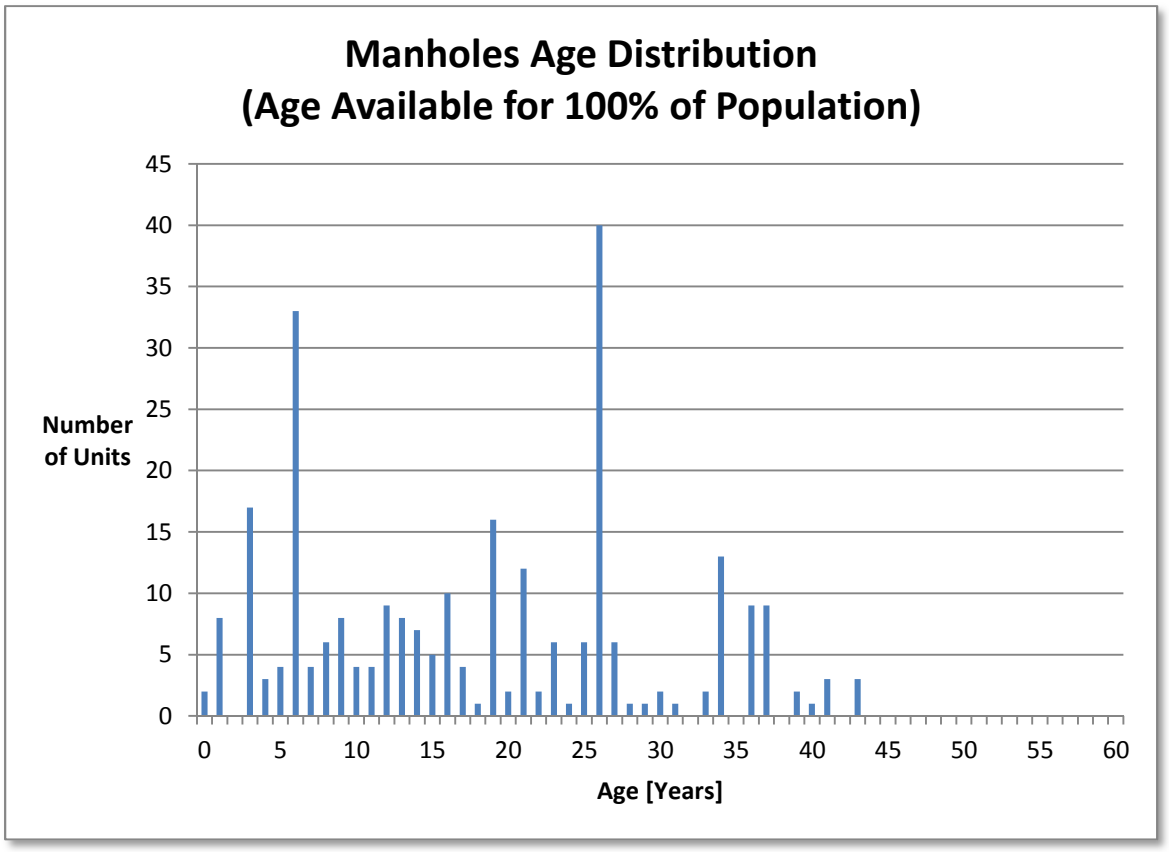


Figure 21-2 Manholes Age Distribution

21.3 Health Index Results

There are 275 in-service Manholes at GHESI. There were 62 units inspected and therefore had sufficient data for Health Indexing. It should be noted 33 of the locations inspected in 2013 were specifically selected for various reasons (e.g. known issues, critical locations, locations where manholes may be more prone to degradation, etc.). As such, the samples may not be representative of the entire population and therefore the results cannot be extrapolated.

The average Health Index for this asset group is 87%. Approximately 10% of the units were found to be in poor condition.

The Health Index Results are as follows:

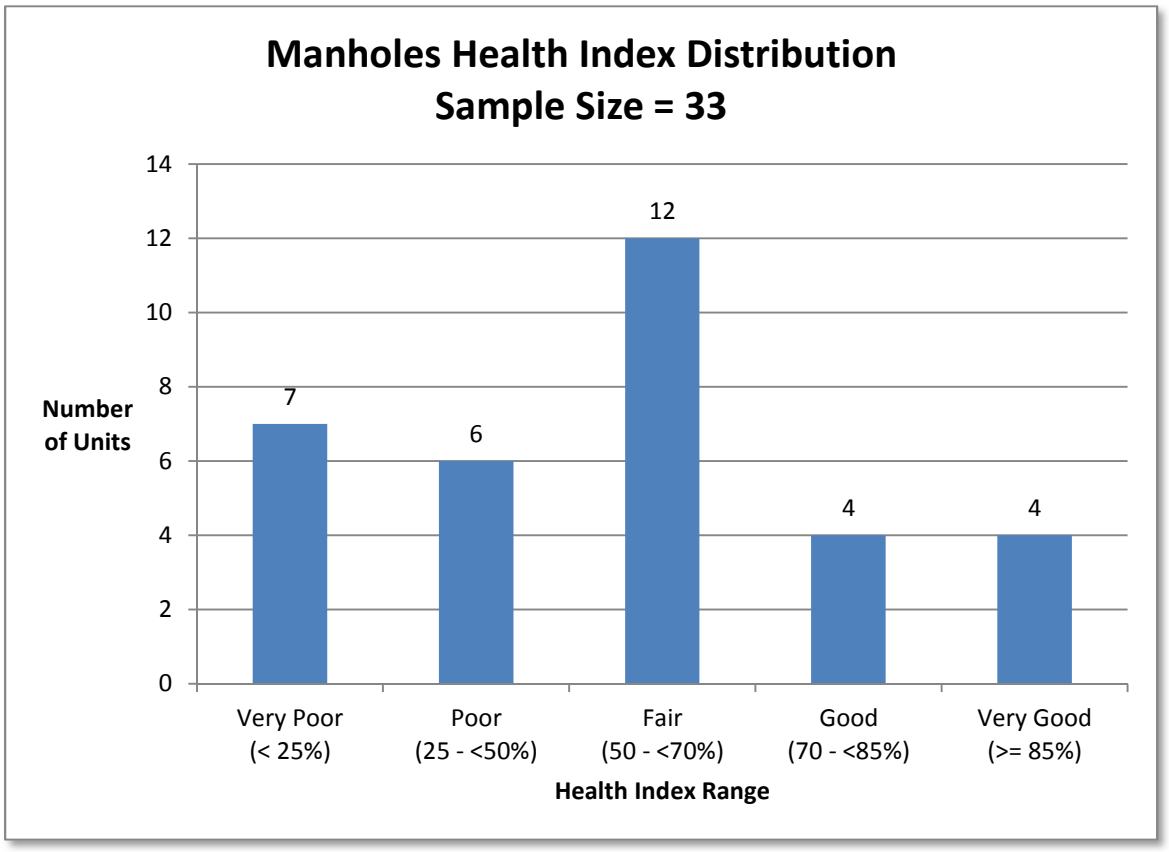


Figure 21-3 Manholes Health Index Distribution (Number of Units)

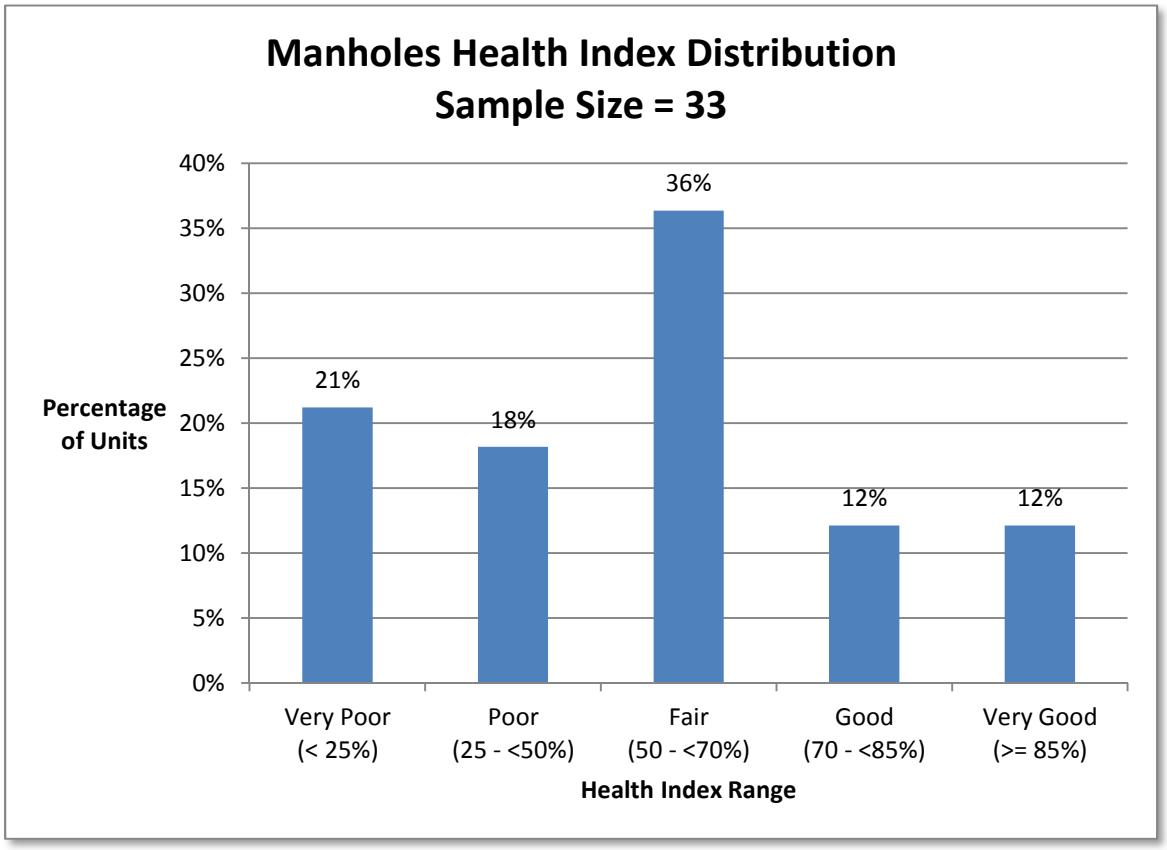


Figure 21-4 Manholes Health Index Distribution (Percentage of Units)

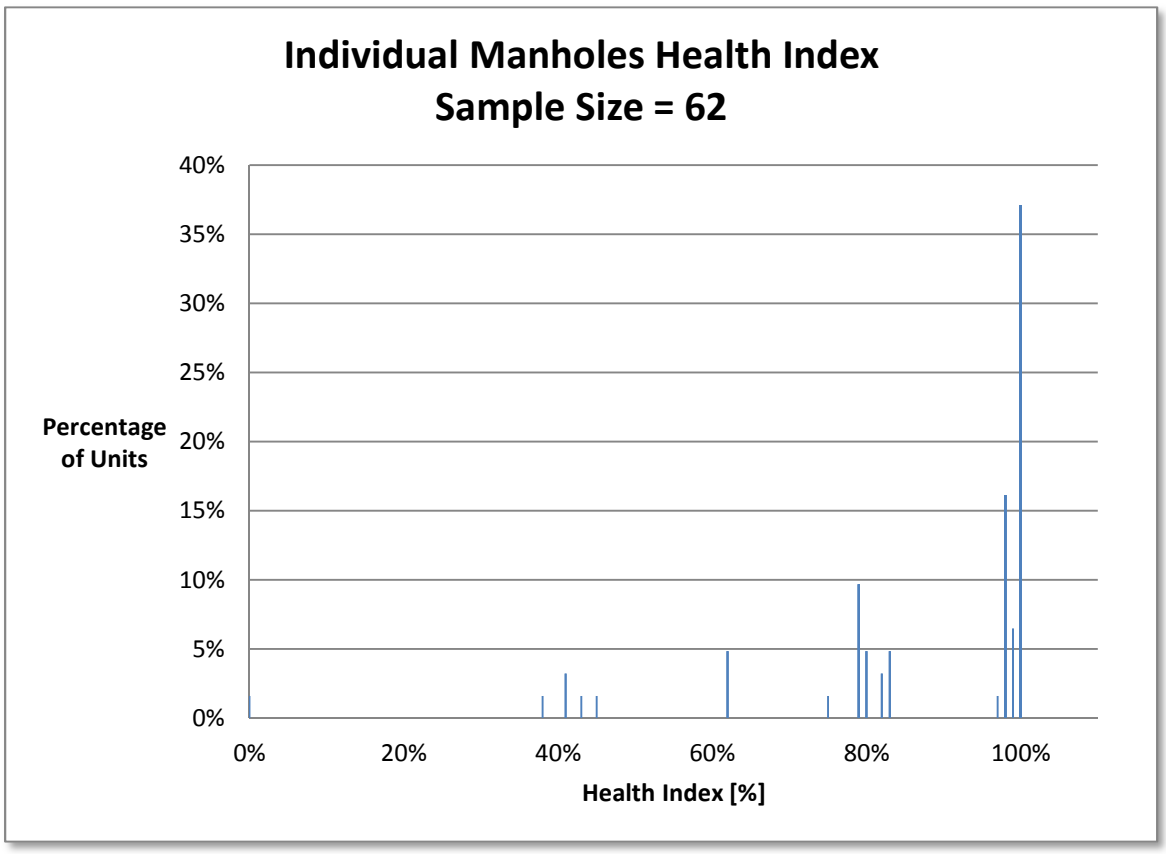


Figure 21-5 Manholes Health Index Distribution by Value (Percentage of Units)

21.4 Condition-Based Flagged for Action Plan

Although Manholes are proactively addressed, the flagged for action plan is based on asset failure rate f(t).

The flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

Note that the flagged for action plan is based only on the sample size (62 units) and not extrapolated to the entire population (275 Manholes).

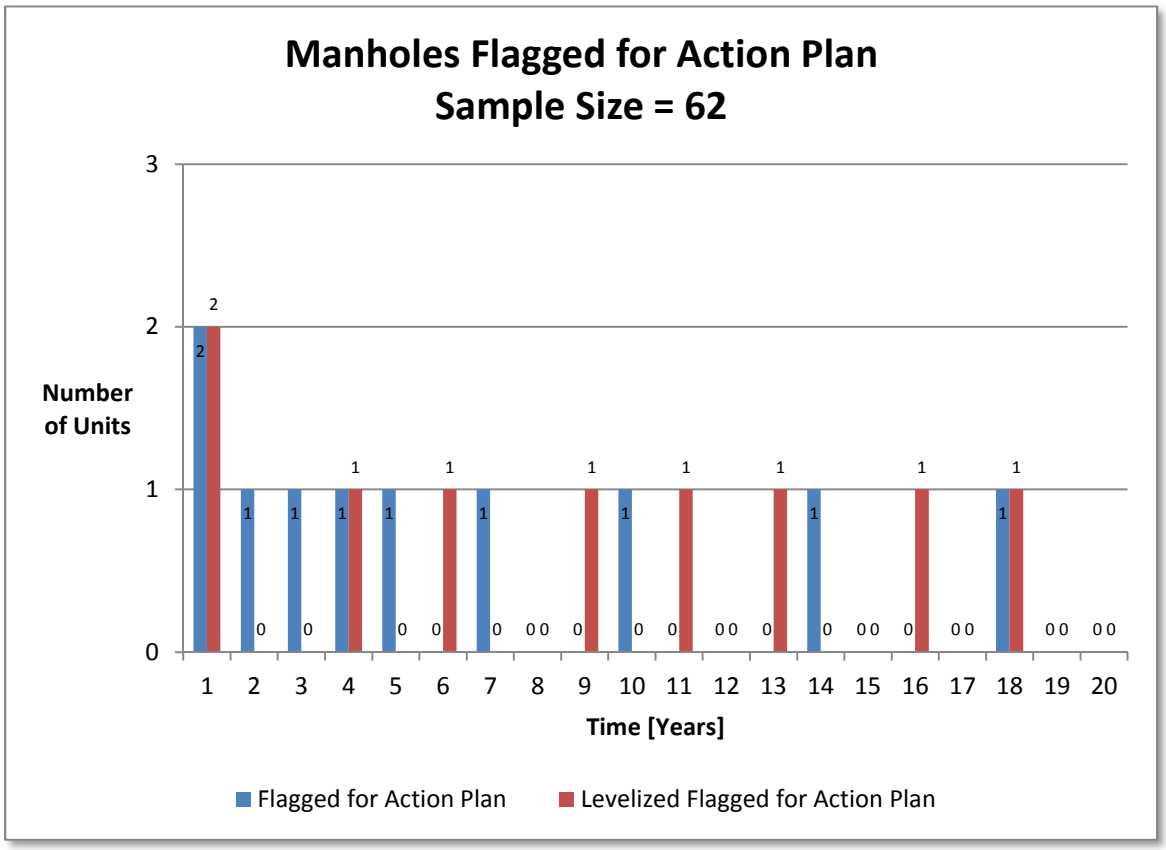


Figure 21-6 Manholes Condition-Based Flagged for Action Plan

21.5 Data Analysis

21.5.1 Data Gap

The data available for Manholes age and inspection records. No data gaps were identified for this asset category. It should be noted, however that inspections were only conducted for 22% of the population.

21.5.2 Data Availability Distribution

The average DAI for Manholes is 22%.

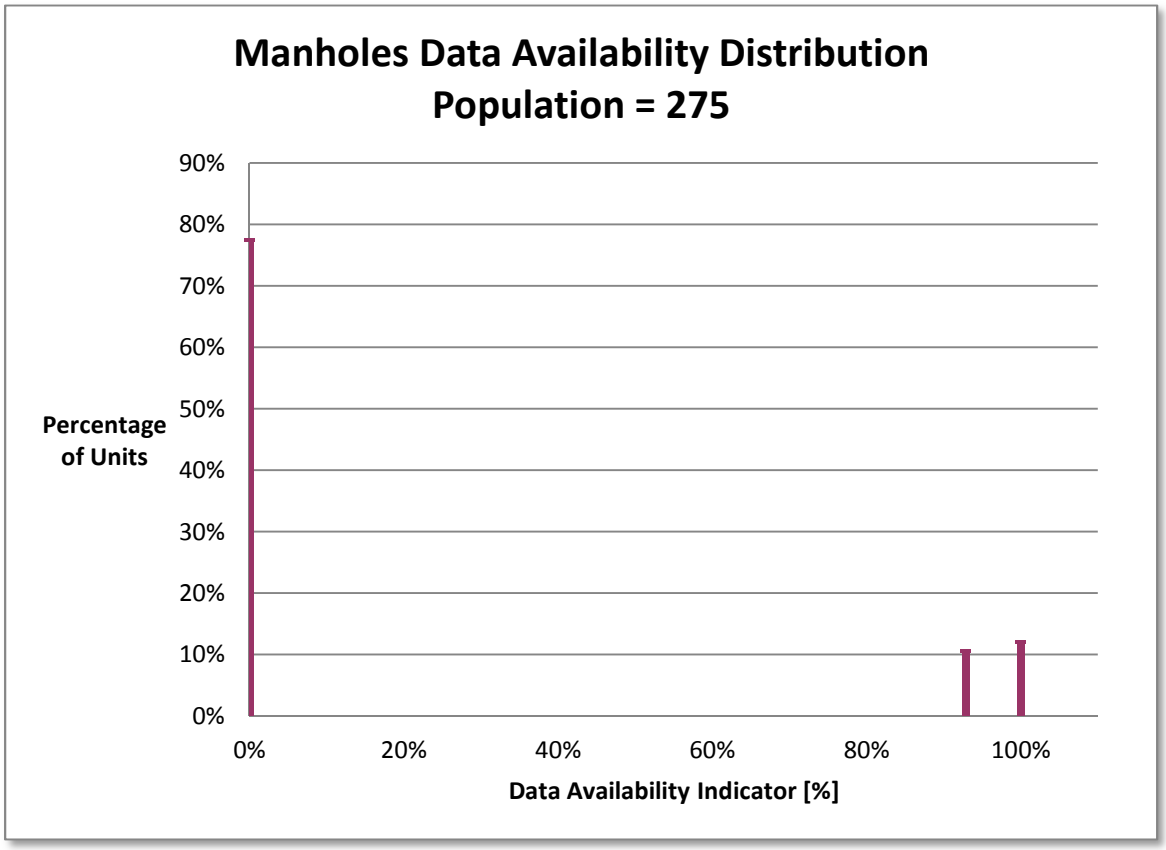


Figure 21-7 Manholes Data Availability Distribution

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APPENDIX E: GHESI Regional Planning Status Letter to Hydro One

Guelph Hydro
Electric Systems Inc.

December 1, 2014

Hydro One Networks Inc.– Transmission System Development
483 Bay Street - NT-15
Toronto, Ontario, M5G 2P5

Attention: Mr. Ajay Garg
Manager - Regional Planning Co-ordination

Dear Mr. Ajay Garg

Re: Regional Planning Status

Please be advised that Guelph Hydro Electric Systems Inc. ("Guelph Hydro") is in the process of preparing its 2016 Cost of Service Application for filing in April 2015, and as part of the Application will be filing a Distribution System Plan.

On March 28, 2014, the Ontario Energy Board revised the *"Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5"* which includes under subsection 5.1.4.1 Regional Planning and Consultation, the Distributor's obligation to participate in the regional planning process, including integrated regional resource planning (IRRP) lead by the OPA.

Guelph Hydro is interested in participating in your planning process and asks if you could please provide an update on this process in regards to the Guelph Region via a Regional Planning Status Letter at your earliest convenience.

The person to be contacted should Hydro One have questions about the content of Guelph Hydro's information during the review period is:

Michael Wittemund, P.Eng.
Director of Engineering
Guelph Hydro Electric Systems Inc
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Sincerely,

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Guelph Hydro Electric Systems Inc.
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APPENDIX F: Hydro One Planning Status Letter to GHESI

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6th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

December 2, 2014

Michael Wittemund, P.Eng.
Director of Engineering
Guelph Hydro Electric Systems Inc.
395 Southgate Drive, Guelph, ON N1G 4Y1

Dear Mr. Wittemund:

Subject: Regional Planning Status

In reference to your request for a Regional Planning Status Letter, please note that Guelph Hydro Electric Systems Inc. ("Guelph Hydro") belongs to the Kitchener-Waterloo-Cambridge-Guelph ("KWCG") Region, which is in Group 1. A map showing details with respect to the 21 Regions/Groups and a list of Local Distribution Companies in each Region is attached in Appendix A and B respectively.

Planning activity for KWCG Region was already underway prior to the new regional planning process coming into effect. This planning activity for KWCG was deemed to be in the Integrated Regional Resource Planning ("IRRP") phase of the process, led by the Ontario Power Authority ("OPA"). As part of the IRRP consultation process, a stakeholder engagement process has been initiated by the OPA in July, 2014. It is expected that this IRRP will be complete in Q2 2015.

Two transmission projects have been identified to address the near- and medium-term needs in this Region: the Guelph Area Transmission Reinforcement ("GATR") project, and the second Preston TS auto-transformer project. Work on the first project is already underway while the second project is being further reviewed.

The following stations that serve Guelph Hydro customers are affected by the GATR project: Hanlon TS, Cedar TS, Campbell TS and Arlen MTS. Currently, each of these stations is supplied radially: Hanlon TS, Arlen MTS and Cedar TS (JQ DESN) by 115 kV 2-circuit B5G/B6G from Burlington TS; Cedar TS (BY, EZ DESN) by 115 kV 2-circuit F11C/F12C through 115 kV 2-circuit D7F/D9F from Detweiler TS and Preston TS; and Campbell TS by 230 kV 2-circuit D6V/D7V from Detweiler TS and Orangeville TS. The loading levels on B5G/B6G exceed the capability of the circuit to meet demand following the loss of the companion circuit. Similarly, the required loading levels on F11C/F12C exceed the circuit capability.

The GATR project will involve extension of the 230 kV supply to Cedar TS and installation of 2-230/115 kV autotransformers at the station. The 115 kV circuits B5G/B6G and F11C/F12C will be networked at Cedar TS thus eliminating the radial nature of supply to the stations supplying Guelph Hydro customers, and improving supply reliability for these customers.

The GATR project will also involve the installation of two load interrupter switches on 230 kV circuits D6V/D7V at Guelph North Junction. The switches will minimize the impact of interruptions to Guelph Hydro customers in the event of the loss of both circuits D6V and D7V.

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The investments associated with the GATR project are proposed as a network pool cost, and there is no cost implication for Guelph Hydro.

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 Guelph Hydro 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

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
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. • Niagara West Transformation Corporation* *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 G: Arlen MTS Fault Current Reduction Feasibility Study

Arlen MTS Fault Current Reduction Feasibility Study

#1488380200-CAL-E0001-04
February 10, 2015

REPORT TO

Guelph Hydro Electric Systems Inc.
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EXECUTIVE SUMMARY

Guelph Hydro (GHESI) owns and operates 115kV – 13.8 kV Arlen Municipal Transformer Station (MTS) that provides power to the city of Guelph, Ontario. Arlen MTS is currently operating within the short-circuit ratings defined in the Ontario Transmission System Code (TSC). However, based on future changes to the transmission system in the region of Guelph due to the GATR project acceptable short-circuit ratings will be exceeded. The report also considers the impact of future DGs on the fault levels at Arlen MTS.

The present report investigates various mitigating solutions to this issue, namely installation of current-limiting reactors, upgrading station equipment and changing the station operating configuration. Solutions are evaluated against a set of criteria including impact on power quality, reduction in fault current, reliability issues, approximate cost, and technical complexity.

Based on this evaluation method of the technical options, installation of current-limiting reactors demonstrated the best overall performance.

All findings are presented to GHESI, who will make the final decision regarding the solution to be implemented.

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
CIA	Connection Impact Assessment
CLR	Current-Limiting (Series-Connected) Reactor
COMS	Constructability, Operability, Maintainability, Safety
DG	Distributed Generator
FCL	Fault Current Limiter
GATR	Guelph Area Transmission Refurbishment Project
GHESI	Guelph Hydro Electric Systems Inc.
HONI	Hydro One Networks Inc.
LDC	Local Distribution Company
LG	Phase-to-Ground Short Circuit Fault
LLL	Three-Phase Short Circuit Fault
Main Bus	The 13.8 kV Switchgear Bus at Arlen MTS (B and/or Y bus)
MTS	Municipal Transformer Station
NGR	Neutral Grounding Reactor
N.C.	Normally Closed (Breaker or Disconnect Switch)
N.O.	Normally Open
P&C	Protection & Control Equipment
PCC	Point of Common Coupling
TIR	Distributed Generation Technical Interconnection Requirements (HONI document)
TSC	Ontario Transmission System Code
Tt	Tetra Tech Inc.
ULTC	Under-Load Tap Changer

1.0 INTRODUCTION

GHESI owns and operates Arlen MTS, which provides power (13.8kV/8kV distribution loads) to customers in the municipality of Guelph, Ontario.

Arlen MTS is currently operating within the short-circuit ratings defined in the Ontario TSC (21kA LLL, 10kA LG). However, based on future changes to the transmission system in the region of Guelph due to the GATR project acceptable short-circuit ratings will be exceeded. The report also considers the impact of future DGs on the fault levels at Arlen MTS.

Tt has been retained by GHESI as the Engineering service provider and is required to conduct a system study and subsequent detailed engineering for a means to reduce fault levels at Arlen MTS, and anywhere on the distribution system to address current and future conditions. A two-phase approach has been adopted for the work:

1. ***Study Phase*** – Tt proposes and analyzes various options for addressing the cause of the increase in available short-circuit current at Arlen MTS. The options are compared in terms of capital costs, impact on power quality, impact on system reliability, the % reduction in station fault current and operation and maintenance requirements. Selected options are simulated using ETAP Power System Analysis Software. This report presents the conclusions of the Feasibility Study, and recommendations relating to items of concern identified during the software simulation. GHESI is responsible for selecting the desired option which shall be implemented during the detailed design phase. Tt will conduct a second study to determine the key parameters of the selected solution as required. After its approval by the station owner, the Study Phase is considered complete.

2. ***Detailed Design Phase*** – Subject to change based on the option preferred by the station owner, Tt will provide studies, design, and drawings necessary for its implementation. A separate proposal will be submitted for the phase two upon request from GHESI.

Table 1 presents a summary of the options analyzed during the Study Phase. Only the solutions that have a potential impact on power quality or station loading limit have been analyzed using software. Details of the methodology used for performing load flow and short circuit calculations can be found in the indicated section.

Table 1 Potential Solutions for Lowering Fault Level at Arlen MTS

Solution	Report Section	Notes
1. CLR at main transformer primary side	4.1.3	Simulated with ETAP
2. CLR at main transformer secondary side	4.1.4	Simulated with ETAP
3. CLR in series with the main bus	4.1.5	Simulated with ETAP
4. Upgrade Station Equipment	4.2	
5. Change tie-breaker from N.C. to N.O.	4.3	

All options are evaluated independently with regard to the following criteria:

- Impact on power quality
- Reduction in fault current
- Impact on P&C

- Capital cost
- Impact on Arlen MTS reliability
- Operating and Maintenance (includes estimated power losses, if any)

2.0 STUDY INPUTS & ASSUMPTIONS

1. The following inputs were used for performing software calculations:

    - Short-circuit levels at Arlen MTS per Hydro One report "Customer Impact Assessment: Guelph Area Transmission Refurbishment Project"; ultimate values in *Table 4: Fault Levels with CEDAR bus closed* were assumed for maximum available short-circuit; present / minimum values have been used as specified in *Table 2: Present Fault Levels* (refer to Appendix B). *Table 3 Fault Levels with CEDAR bus split* was not considered because the impact at Arlen MTS was negligible compared with Table 4.
    - Ratings of DGs which might be connected to the system supplied from Arlen MTS in the future, according to Table 2 (provided by GHESI)

Table 2 Details for Proposed Distributed Generators

EG	Status	Power Capacity (MVA)	Feeder Connection	Distance from Arlen MTS (km)	Comments
CHP Project	Proposed	4 x 6.25	Connected to bus B	1.6	New feeder cells assumed
Energy Storage	Proposed	4	Connected directly to bus Y	0	New feeder cells assumed
Solar	Proposed	10	Connected to bus Y	5	Future FIT projects; new feeder cell assumed for modelling purposes; average distance from station assumed: 5 km

- Major equipment data per single line diagram 2009-015-TS55-ELE-002 Rev D
- Minimum/maximum station loading (see Table 3)
- Feeder physical parameters (see Table 3)

Table 3 Station Feeder Input Data

Data	Station	Feeder F11	Feeder F12	Feeder F13	Feeder F14	Feeder 21	Feeder 22	Feeder 23	Feeder 24
Maximum Load (MVA)**	57.2	8.9	8.9	12.3	7.0	1.5	7.5	6.9	4.2
Minimum Load (MVA)**	17.9	1.6	1.6	5.0	2.7	0	1.6	2.7	2.7
Power Factor (without EGs)	N/A	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Main Circuit Length (km)*	N/A	5.6+3.8	8.3+3.9	8.3+3.9	5.6+3.8	1.9	5.6+3.8	8.3+3.9	8.3+3.9

* NOTE for Table 3: lengths are indicated as (556 ASC overhead conductor) + (1C 1000kcmil AL cable)

** NOTE for Table 3: Estimated future minimum and maximum feeder loading

2. Typical vendor data for the proposed equipment (series reactors and current-limiting devices)

3. Regulatory Documents and Standards:

    - "*Distributed Generation Technical Interconnection Requirements Interconnections at Voltages 50kV and Below*", Rev. 03, Hydro One Networks
    - "*Transmission System Code*", 2010 Edition, Ontario Energy Board
    - CSA CAN3-235, 2010 Edition, "*Preferred Voltage Levels for AC Systems, 0 to 50 000 V*"

4. Assumptions:

    a) For short-circuit calculations, pre-fault voltage is 105% when maximum fault is calculated, and 95% for minimum fault calculations
    b) Only the case when both station transformers are in service was considered for determining load flow and short-circuit results when inserting a reactor into the circuit; the reactor is taken out of the circuit when one transformer is off-line to maintain adequate voltage levels in the network
    c) Power quality issues have been investigated on the 13.8kV system only; no values are reported for lower distribution voltages
    d) Fluctuations of the power factor at the PCC with HONI are not investigated as part of this study
    e) Reactor X/R for studies: 60
    f) Short-circuit limit considered at the station: 95% of TSC limits (21kA LLL, 10kA LG)
    g) HONI source X/R ratio remains the same as modeled for previous projects: 4.978 (Z_1) and 3.663 (Z_0)
    h) Load is distributed evenly on feeders which have been modeled in detail (see Table 3)
    i) Feeders F12, F22 and F23 have been modeled as lumped loads connected directly to the station bus
    j) Station bus voltage is regulated at 1.0pu
    k) For future DGs, the interface transformer neutral reactor impedance is calculated according to HONI TIR
    l) Future DG parameters are reasonably assumed, such as: subtransient reactance (19% for turbine generators, 70% for solar/energy storage); interface transformer MVA ratings match the respective DG

5. Requirements:

    - Allowable voltage range anywhere on the 13.8 kV system: between 94% and 106% of nominal
    - Minimum fault level at 13.8 kV feeder end: L-G 1,800 A (tentative value provided by GHESI)
    - Minimum fault level at 13.8 kV feeder end: L-L-L 3,000 A (tentative value provided by GHESI)

6. References:

    - Tt Report 1388380100-REP-E0001-01, Arlen MTS F21 Feeder Study
    - Tt Report 1288380200-REP-E0001-01, Arlen MTS Generation Capacity Availability Study

3.0 BASE MODE STUDIES

Base mode studies are intended to define existing system conditions before any modifications (addition of equipment, configuration changes, equipment upgrades, etc.) are implemented and evaluated. Their main purpose is to:

- Determine existing maximum and minimum fault levels at station and at feeder ends under different operating configurations based on current & future upstream conditions and with or without future DGs. The difference between the calculated and the required values (1.8kA LG, 3kA LLL) represents the available margin for the impedance to be inserted into the circuit
- Determine the voltage performance on the 13.8kV system under different operating configurations based on current & future upstream conditions and with or without future DGs; under-voltages will determine the maximum loading limit for the station. The potential solutions can subsequently be evaluated to determine percentage reductions in the maximum loading limit

This report examines the distribution system supplied by Arlen MTS with two different supply source configurations that form the basis of the power system study:

- Utility Supply only
- Utility Supply in parallel with future Distributed Generators

The following base cases are investigated:

- Base Case 1: Load Flow Study (investigates minimum system voltage)
- Base Case 2: Short Circuit Study (current system conditions, no DGs connected)
- Base Case 3: Short Circuit Study (future system conditions – after GATR – no DGs connected)
- Base Case 4: Short Circuit Study (future system conditions – after GATR – DGs connected)

In all studies both station transformers are in service and the tie breaker is closed; only proposed DGs in Table 2 are considered.

3.1 BASE CASE 1 (LOAD FLOW ANALYSIS)

The purpose of the load flow analysis is to determine the suitability of the existing distribution system to supply power at steady-state voltage levels within tolerances (± 6%). The basis for the load flow study consists of feeder data as specified in Table 3. Since transformers T1 and T2 can regulate the voltage on buses Y and B via the ULTCs, over-voltage situations are not expected to happen as a result of any solution intended to mitigate fault levels. Therefore, this study considers only configurations which are likely to result in minimum voltage on the feeders, since this situation can be worsened by addition of extra impedance such as CLR.
The study considered is detailed in Table 4, with the following expected results (see also Appendix A):

- Base Case 1: Minimum System Voltage with 2 Transformers in Service at Present (no DGs connected)

Table 4 Load Flow Base Case 1 Parameters

Base Case #	Loading at Main Station Bus: Minimum (18MVA) or Maximum (57MVA)	# of Main Transformers in Service: 1 or 2	Distributed Generators in Service or Out of Service	Tie-breaker position: Open or Closed
1	MAX	2	OUT	CLOSED

3.1.1 Load Flow Study Results

Only the feeders modeled in detail (see assumption "i") are considered in this analysis.

Under-voltage situations discovered during the load flow study are highlighted in Table 5. Results are shown in % of nominal voltage (13.8kV). Since voltage will further deteriorate after the addition of a current-limiting reactor (if selected as the final solution), it is recommended that the specified maximum load (12.3 MVA) on feeder F13 be re-considered by GHESI. Some measures for mitigation of the situation could include transferring loads from a heavily-loaded feeder to a lightly-loaded feeder or installation of voltage regulators if load transfer is not possible. In addition, station bus voltage is assumed to be regulated at 1.0pu. The set point could be increased to compensate the under-voltage issues that may arise in the distribution system.

Table 5 Load Flow Base Case 1 Results

Base Case #	Voltage @ Arlen MTS 13.8kV Main Bus (%)	Lowest Voltage On F11 Feeder (%)	Lowest Voltage On F13 Feeder (%)	Lowest Voltage On F14 Feeder (%)	Lowest Voltage On F21 Feeder (%)	Lowest Voltage On F24 Feeder (%)
1	100.603	95.006	90.333	95.574	100.452	97.074

3.2 BASE CASE 2 (EXISTING SHORT CIRCUIT LEVELS)

The base case 2 study is intended to determine the maximum expected fault levels at the 13.8kV switchgear and at the feeder ends under present conditions. In this study, feeder end refers to the 13.8kV system, not lower voltages. Present conditions are defined as:

- Short-circuit level at Arlen MTS per Hydro One report "Customer Impact Assessment: Guelph Area Transmission Refurbishment Project" *Table 2: Present Fault Levels* (refer to Appendix B)
- No proposed DGs are connected to the feeders

The methodology considered for the short-circuit study is summarized in Table 6 (see also Appendix A for comparison with Base Case 3 and Base Case 4).

Table 6 Short-Circuit Base Case 2 Parameters

Base Case #	# of Main Transformers in Service: 1 or 2	Distributed Generators in Service or Out of Service (see Table 2)	Tie-breaker position: Open or Closed	Fault Level At 115kV Line: Min. Or Max.	Pre-fault Voltage (% of nominal)
2	2	OUT	CLOSED	MIN	105%

3.2.1 Short-Circuit Study Results

The study results are shown in Table 7. By comparing the calculated fault levels (19.6kA LLL, 10.2kA LG) with the TSC limits (21kA LLL, 10kA LG) it can be concluded that the present LG fault current at the station is large. However, this situation can be very easily mitigated by slightly increasing the impedance of the NGR installed on the station power transformer secondary winding from the existing 1.25Ω. This solution can be implemented with

a very small capital cost for the station owner. As an example, increasing the NGR size to 1.5Ω results in a line-to-ground fault level of 9.475 kA which is acceptable from the perspective of TSC requirements.

A second conclusion is that the feeder end fault levels specified by GHESI (3kA LLL, 1.8kA LG) are not attainable under existing system conditions. However, the calculated fault levels are sufficiently large compared to the maximum load current to allow proper action by the protection equipment (fuses or relays).

Table 7 Short-Circuit Base Case 2 Results

Base Case #	Fault Type	Fault Level @ Arlen 13.8kV Bus (kA)	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
2	L-L-L	19.587	2.499	1.851	2.499	1.851
	L-L	16.963	2.164	1.603	2.164	1.603
	L-G	10.181	1.724	1.366	1.711	1.183

3.3 BASE CASE 3 (SHORT CIRCUIT AFTER GATR IMPLEMENTATION)

The base case 3 study is intended to determine the maximum expected fault levels at the 13.8kV switchgear and at the feeder ends after implementation of future changes to the transmission system in the region of Guelph due to the GATR project. In this study, feeder end refers to the 13.8kV system, not lower voltages. Future conditions for base case 3 are defined as:

- Short-circuit level at Arlen MTS per Hydro One report "Customer Impact Assessment: Guelph Area Transmission Refurbishment Project" *Table 4: Fault Levels with CEDAR bus closed* (refer to Appendix B)
- No proposed DGs are connected to the feeders

The methodology considered for the short-circuit study is summarized in Table 8 (see also Appendix A for comparison with Base Case 2 and Base Case 4).

Table 8. Short-Circuit Base Case 3 Parameters

Base Case #	# of Main Transformers in Service: 1 or 2	Distributed Generators in Service or Out of Service (see Table 2)	Tie-breaker position: Open or Closed	Fault Level At 115kV Line: Min. Or Max.	Pre-fault Voltage (% of nominal)
3	2	OUT	CLOSED	MAX	105%

3.3.1 Short-Circuit Study Results

The study results are shown in Table 9. After implementation of GATR project, both LLL and LG fault levels at the station exceed TSC limits. Comparing the results in Table 9 with Table 7 (Base Case 2), an increase from 93% of the TSC limit (19.587 kA) to 112% of the TSC limit (23.651 kA) is observed for LLL fault current. In conclusion, due to changes in the HONI system the fault level at Arlen MTS has become unacceptably large and must be decreased to conform to TSC requirements. The LLL fault level can be limited by applying one of the solutions

presented in Section 4.0: for example, installing CLRs or installing new power transformers with higher internal impedance. Any solution used for limiting LLL will also lower LG fault current.

Table 9. Short-Circuit Base Case 3 Results

Base Case #	Fault Type	Fault Level @ Arlen 13.8kV Bus (kA)	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
3	L-L-L	23.651	2.556	1.882	2.556	1.882
	L-L	20.483	2.213	1.629	2.213	1.629
	L-G	10.833	1.742	1.377	1.729	1.191

3.4 BASE CASE 4 (SHORT CIRCUIT AFTER GATR IMPLEMENTATION + FUTURE DG)

The base case 4 study is intended to determine the maximum expected fault levels at the 13.8kV switchgear and at the feeder ends after implementation of future changes to the transmission system in the region of Guelph due to the GATR project and connection of future DGs to the system supplied from Arlen MTS. In this study, feeder end refers to the 13.8kV system, not lower voltages. Future conditions for base case 4 are defined as:

- Short-circuit level at Arlen MTS per Hydro One report "Customer Impact Assessment: Guelph Area Transmission Refurbishment Project" *Table 4: Fault Levels with CEDAR bus closed* (refer to Appendix B)
- DGs connected (**Case 4a**): 10MW inverter-based generation (solar) + 4MW energy storage installed at Arlen MTS
- DGs connected (**Case 4b**): 10MW inverter-based generation (e.g. solar) + 4MW energy storage installed at Arlen MTS + 25MW CHP

Details of the DGs mentioned above can be found in Section 2, Table 2. The methodology considered for the short-circuit study is summarized in Table 10 (see also Appendix A for comparison with Base Case 2 and Base Case 3).

Table 10. Short-Circuit Base Case 4 Parameters

Base Case #	# of Main Transformers in Service: 1 or 2	Distributed Generators in Service or Out of Service (see Table 2)	Tie-breaker position: Open or Closed	Fault Level At 115kV Line: Min. Or Max.	Pre-fault Voltage (% of nominal)
4	2	IN	CLOSED	MAX	105%

3.4.1 Short-Circuit Study Results

The study results are shown in Table 11 (Case 4a) and Table 12 (Case 4b). As expected, fault levels at the station increase due to addition of future DGs. To limit the fault level one of the solutions presented in Section 4.0 must be implemented.

Contributions from each DG source are summarized in Table 13.

Table 11. Short-Circuit Base Case 4a Results

Base Case #	Fault Type	Fault Level @ Arlen 13.8kV Bus (kA)	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
4a	L-L-L	24.367	2.564	1.886	2.564	1.886
	L-L	21.625	2.226	1.636	2.226	1.636
	L-G	12.109	1.764	1.387	1.752	1.205

Table 12. Short-Circuit Base Case 4b Results

Base Case #	Fault Type	Fault Level @ Arlen 13.8kV Bus (kA)	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
4b	L-L-L	28.326	2.601	1.906	2.601	1.906
	L-L	25.111	2.257	1.653	2.257	1.653
	L-G	14.842	1.802	1.405	1.790	1.228

Table 13 Fault Contribution from Individual DG Sources (Base Case 4)

Fault Type	DG Contribution		
	DG - CHP Project (4 x 6.25 MVA)	DG - Energy Storage (4 MVA)	DG - Solar FIT Projects (10 MVA)
L-L-L	3.960 kA	0.228 kA	0.492 kA
L-G	3.132 kA	0.581 kA	0.976 kA

Table 13 provides the detailed fault contribution at the station bus from each DG. The information can be useful for planning purposes; for example, the LLL contribution (per MVA connected) of solar – and broadly inverter-based generation – is much less than the contribution of co-generation (combined heat and power). Therefore, more solar FIT projects can be accommodated in the system supplied from Arlen MTS if the margin allowed by the short-circuit levels at the station is limited.

4.0 TECHNICAL SOLUTIONS FOR LIMITING FAULT CURRENT

The possible solutions for reducing available fault current at the Arlen MTS main bus are analyzed in more detail in the following subsections. Where software simulations have been performed, the impact on power quality and fault current level is compared against the existing system parameters determined in Section 3.0 – Base Mode Studies.

4.1 INSTALLATION OF CURRENT-LIMITING REACTORS

4.1.1 Overview

Current-limiting reactors are a mature and popular solution for reducing short-circuit currents. Reactors can be installed anywhere in the distribution circuit in order to limit the fault current. Since they are essentially a linear inductive reactance, their impedance will add arithmetically to the system impedance and result in a reduction of the fault currents. Series reactors allow the use of existing equipment without costly modifications or replacements, which is their main advantage. However, reactors increase the voltage drop in the system and add power loss. The voltage regulation range of the existing tap changer will be effectively reduced, since it must also compensate for the voltage drop over the reactor. Another advantage of CLRs is they can be installed in pre-planned stages based on HONI system fault level changes and/or expected DG connections.

4.1.2 Reactor Sizing

The reactor size has been calculated for each possible location (transformer primary, transformer secondary and bus tie) using the LLL current calculated in Section 3.2, Table 7 (19.587 kA) as the base line. As discussed in the same section, other methods exist for reducing LG currents, which are less costly. Results are shown in Tables 14, 15 and 16 for each location (only the reactive impedance X is shown; the resistive impedance R for the reactor is estimated for the purposes of this study by assuming X/R=60). See also Figure 1 for a simplified single-line diagram of the circuit showing proposed locations.

Table 14 Reactor Sizes Short-Circuit Current Reduction (Transformer Primary)

Reactor Located @ Transformer Primary	
Initial System Condition	**Reactor Impedance Value (X) Required to Reduce LLL to ~19.587 kA (per Base Case 2)**
LLL = 23.651 kA (Base Case 3)	9 Ω
LLL = 24.367 kA (Base Case 4a)	11 Ω
LLL = 28.326 kA (Base Case 4b)	25 Ω

Table 15. Reactor Sizes Short-Circuit Current Reduction (Transformer Secondary)

Reactor Located @ Transformer Secondary	
Initial System Condition	**Reactor Impedance Value (X) Required to Reduce LLL to ~19.587 kA (per Base Case 2)**
LLL = 23.651 kA (Base Case 3)	0.15 Ω
LLL = 24.367 kA (Base Case 4a)	0.2 Ω
LLL = 28.326 kA (Base Case 4b)	0.45 Ω

For reactor located at bus tie, the base line (19.587 kA) is compared to the bus with the higher fault current between bus B and bus Y.

Table 16. Reactor Sizes Short-Circuit Current Reduction (Bus Tie)

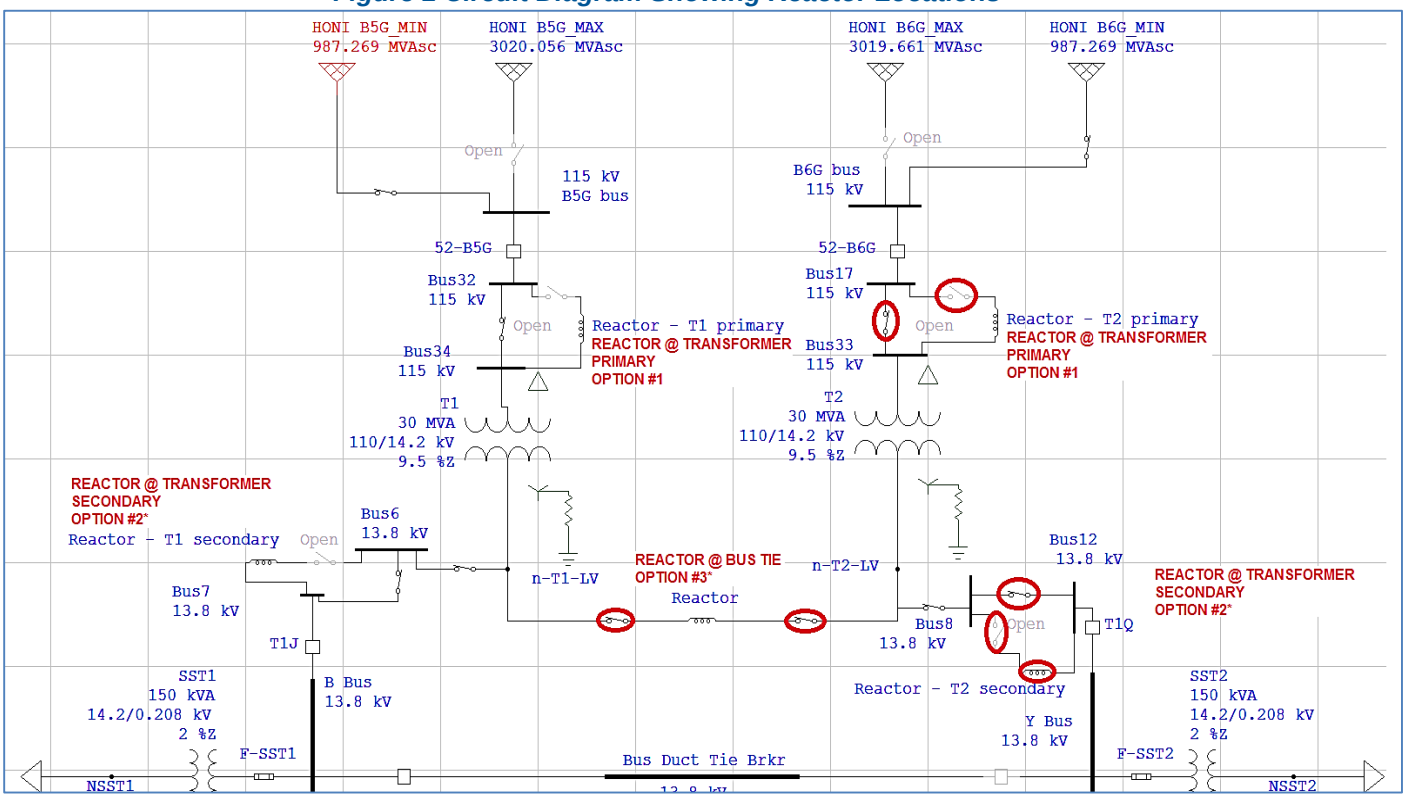
Reactor Located @ Bus Tie	
Initial System Condition	**Reactor Impedance Value (X) Required to Reduce LLL to ~19.587 kA (per Base Case 2)**
LLL = 23.651 kA (Base Case 3)	0.4 Ω
LLL = 24.367 kA (Base Case 4a)	0.5 Ω
LLL = 28.326 kA (Base Case 4b)	1.5 Ω

If CLRs are the solution preferred by GHESI, it is recommended they are installed in stages; assuming that maximum 3 stages are practical due to structural limitations, the initial stage could be sized to limit Base Case 4a fault current, second stage could be added when Base Case 4b fault level is reached, and a third stage maintained for future spare should more DGs be connected to the network supplied from Arlen MTS.

The methodology for evaluating changes in the system due to insertion of the reactor is presented below:

- To evaluate the maximum impact on the system, only the largest reactor value (computed for Base Case 4b fault levels) is considered in the following analysis
- Minimum system voltage (Base Case 1 Load Flow) is re-calculated with the reactor inserted in the circuit
- The expected feeder end fault currents are re-calculated with the reactor inserted in the circuit
- The LG fault current at the main bus is also calculated

*Figure 1 Circuit Diagram Showing Reactor Locations**



* NOTE for Figure 1: Shown for modelling purposes only, actual implementation will vary in terms of equipment used and the location/placement of the reactor. Circuit breakers will be used instead of disconnect switches for secondary application.

Note in the above figure the reactor locations; bypass switches/circuit breakers are necessary to isolate the reactor from the rest of the circuit when the station is operating with a single transformer in service.

4.1.3 CLR at Main Transformer Primary Side (Option #1)

As calculated in Section 4.1.2, a 25Ω reactor is inserted in series with the primary winding of both power transformers at Arlen MTS.

4.1.3.1 Impact on Power Quality

Continuity of service:
No impact.

Variation in voltage magnitude:
The impact on system voltage is evaluated by comparing the lowest feeder voltage obtained in Base Case 1, to the values obtained in Case 5, as summarized in the table below; Case 5 setup is similar to Base Case 1 with the reactor added in the circuit::

Table 17 System Voltage with Reactors at Transformer Primary Side

Case #	Voltage @ Arlen MTS 13.8kV Main Bus (%)	Lowest Voltage On F11 Feeder (%)	Lowest Voltage On F13 Feeder (%)	Lowest Voltage On F14 Feeder (%)	Lowest Voltage On F21 Feeder (%)	Lowest Voltage On F24 Feeder (%)
Base Case 1	100.603	95.006	90.333	95.574	100.452	97.074
5 (25 ohm reactor @ primary)	99.936	94.376	89.734	94.941	99.786	96.430

There is a negligible impact on system voltage due to the reactors at maximum loading condition. However, the voltage drop across the reactor adversely impacts the ULTC regulation capability for larger loads. Since the ULTC must compensate for this voltage drop, fewer steps are practically available for maintaining a constant voltage on the station main 13.8kV bus. At the full load condition analyzed in Case 5, the voltage drop across the reactor is 2.93% of nominal 115kV.

An in-depth analysis of voltage drop for different MVA loads, as well as the reduction in tap changer capability, will be performed in the second study if this is the option preferred by the Owner.

4.1.3.2 Reduction in LG Fault Current

The reduction in fault current at the station main bus is evaluated by comparing the maximum fault level obtained in Base Case 4b to the values obtained after reactor insertion:

Table 18 SC Level with Reactors at Transformer Primary Side

Case #	Fault Type	Fault Level @ Arlen Main Bus (kA)
Base Case 4b	L-L-L	28.326
	L-G	14.842
6 (25 ohm reactor @ primary)	L-L-L	19.624
	L-G	12.949

Note that the LLL current is reduced to the value calculated in Base Case 2 as required (present value). However, the LG current is still larger than 10kA. Increasing the reactor size beyond 25Ω is not a feasible option to addresses this issue. An in-depth analysis of LG reduction will be performed in the second study if this is the option preferred by the Owner. Increasing the transformer neutral impedance from 1.25Ω currently to a larger value shall be the solution investigated.

4.1.3.3 Impact on P&C

Station Protection:
The reactor can be included in the transformer protection zone. To avoid the requirement of two new sets of CTs, which would replace the breaker bushing CTs currently used, the reactor must be connected between the breaker

and the transformer. The overcurrent settings of the relays will have to be recalculated. Any changes in metering requirements should be further discussed with IESO if necessary.

The new motorized bypass switches must close automatically when 1 transformer is out of service, and open when service is restored. Implementation of this control might require new relays.

An in-depth review of protection & control requirements shall be done in Phase II (Detailed Design) if this solution is selected by the station Owner.

Feeder Protection:
After reactor insertion, the feeder end short-circuit values must remain large enough to allow proper operation of protection devices; these are calculated assuming current HONI system conditions and 95% pre-fault voltage:

Table 19. Feeder-End SC Level with Reactors at Transformer Primary Side

Case #	Fault Type	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
Base Case 2	L-L-L	2.499	1.851	2.499	1.851
	L-L	2.164	1.603	2.164	1.603
	L-G	1.724	1.366	1.711	1.183
7	L-L-L	2.132	1.603	2.132	1.603
	L-L	1.847	1.388	1.847	1.388
	L-G	1.519	1.210	1.508	1.050

The maximum (base case 2-no reactor, 105% pre-fault voltage) and minimum (case 7-reactor inserted, 95% pre-fault voltage) short-circuit values can be compared using the table above. Although the current values have decreased, it can be concluded that there is no impact on feeder protection due to the reactors. The protection devices will be able to discriminate between load and fault currents.

4.1.3.4 Impact on Arlen MTS Reliability

No impact.

4.1.3.5 Capital and Operation Costs (includes power losses)

Capital Cost for Equipment:
The pricing is given for estimative purposes only:

Reactors:	~ $30,000 / unit	Qty: 6
Bypass Switch:	~ $75,000 / unit	Qty: minimum 2

Engineering Cost:
±25% estimate: ~$200,000

Construction Cost:
±25% estimate: ~$450,000

Total Capital Cost (±25%): **~$980,000**

Operating Cost:
Reactor copper losses at full station load assuming X/R = 60: 29.1 kW / coil

4.1.3.6 COMS

- Significant space is required in the station yard to install the reactor bays, the bypass switches and the additional buswork to connect into the circuit. Each reactor bay can occupy approximately 14m x 7m area
- Reactor design assures maintenance-free operation
- No adverse impact on station safety
- The reactor is a passive device; there is no impact from an operability point of view
- Revenue metering will be impacted by the modification
- For installation, a complete station outage is not required. The reactors can be inserted in turn on each transformer circuit. However, customer supply would be dependent on a single transformer until work completion

4.1.4 CLR at Main Transformer Secondary Side (Option #2)

As calculated in Section 4.1.2, a 0.45Ω reactor is inserted in series with the secondary winding of both power transformers at Arlen MTS.

4.1.4.1 Impact on Power Quality

Continuity of service:
No impact.

Variation in voltage magnitude:
The impact on system voltage is evaluated by comparing the lowest feeder voltage obtained in Base Case 1 to the values obtained in Case 8, as summarized in the table below:

Table 20 System Voltage with Reactors at Transformer Secondary Side

Case #	Voltage @ Arlen MTS 13.8kV Main Bus (%)	Lowest Voltage On F11 Feeder (%)	Lowest Voltage On F13 Feeder (%)	Lowest Voltage On F14 Feeder (%)	Lowest Voltage On F21 Feeder (%)	Lowest Voltage On F24 Feeder (%)
Base Case 1	100.603	95.006	90.333	95.574	100.452	97.074
8 (0.45 ohm reactor @ secondary)	99.908	94.350	89.709	94.915	99.758	96.404

At the full load condition analyzed in Case 8, the voltage drop across the reactor is 3.11% of nominal 13.8kV. However, the ULTC compensates for this voltage drop and maintains acceptable voltages on the downstream feeders. An in-depth analysis of voltage drop for different MVA loads, as well as the reduction in tap changer capability, will be performed in the second study if this is the option preferred by the Owner.

4.1.4.2 Reduction in LG Fault Current

The reduction in fault current at the station main bus is evaluated by comparing the maximum fault level obtained in Base Case 4b to the values obtained after reactor insertion:

Table 21 Main Bus Maximum SC Level with Reactors at Transformer Secondary Side

Case #	Fault Type	Fault Level @ Arlen Main Bus (kA)
Base Case 4b	L-L-L	28.326
	L-G	14.842
9 (0.45 ohm reactor @ secondary)	L-L-L	19.197
	L-G	12.489

Note that the LLL current is reduced to the value calculated in Base Case 2 as required (present value). However, the LG current is still larger than 10kA. Increasing the reactor size beyond 0.45Ω is not a feasible option to addresses this issue. An in-depth analysis of LG reduction will be performed in the second study if this is the option preferred by the Owner. Increasing the transformer neutral impedance from 1.25Ω currently to a larger value shall be the solution investigated.

4.1.4.3 Impact on P&C

Station Protection:
The most economical solution (no new equipment required) is to include the reactor in the protection zone of the main bus. The overcurrent settings of the relays will have to be recalculated. Any changes in metering requirements should be further discussed with IESO if necessary.

The new motorized bypass switches must close automatically when 1 transformer is out of service, and open when service is restored. Implementation of this control might require new relays.

An in-depth review of protection & control requirements shall be done in Phase II (Detailed Design) if this solution is selected by the station Owner.

Feeder Protection:
After reactor insertion, the feeder end short-circuit values must remain large enough to allow proper operation of protection devices; these are calculated assuming current HONI system conditions and 95% pre-fault voltage:

Table 22 Feeder-End SC Level with Reactors at Transformer Secondary Side

Case #	Fault Type	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
Base Case 2	L-L-L	2.499	1.851	2.499	1.851
	L-L	2.164	1.603	2.164	1.603
	L-G	1.724	1.366	1.711	1.183
10 (0.45 ohm reactor @ secondary)	L-L-L	2.123	1.597	2.123	1.597
	L-L	1.838	1.383	1.838	1.383
	L-G	1.508	1.205	1.497	1.043

The maximum (base case 2-no reactor, 105% pre-fault voltage) and minimum (case 10-reactor inserted, 95% pre-fault voltage) short-circuit values can be compared using the table above. Although the current values have decreased, it can be concluded that there is no impact on feeder protection due to the reactors. The protection devices will be able to discriminate between load and fault currents.

4.1.4.4 Impact on Arlen MTS Reliability

No impact.

4.1.4.5 Capital and Operation Costs (includes power losses)

Capital Cost for Equipment:
The pricing is given for estimative purposes only, assuming outdoor installation:

Switchgear Modification (Cable Termination Box):	~ $100,000	
Reactors:	~ $30,000 / unit	Qty: 6
Switches (3000A):	~ $25,000 / unit	Qty: 4

Engineering Cost:
±25% estimate: ~$200,000

Construction Cost:
±25% estimate: ~$450,000

Total Capital Cost (±25%): ~$1,030,000

Operating Cost:
Reactor copper losses at full station load assuming X/R = 60: 9.9 kW / coil

4.1.4.6 COMS

- Significant space is required in the station yard to install the reactor bays, the bypass circuit breakers and the additional buswork to connect into the circuit. Each reactor bay can occupy approximately 10m x 6m area
- Reactor design assures maintenance-free operation
- No adverse impact on station safety
- The reactor is a passive device; there is no impact from an operability point of view
- Revenue metering will not be impacted by the modification
- For installation, a complete station outage is not required. The reactors can be inserted in turn on each transformer circuit. However, customer supply would be dependent on a single transformer until work completion

4.1.5 CLR in Series with the Main Bus - Bus Tie (Option #3)

As calculated in Section 4.1.2, a 1.5Ω reactor is inserted at the bus tie of B and Y buses at Arlen MTS.

4.1.5.1 Impact on Power Quality

Continuity of service:
No impact.

Variation in voltage magnitude:
The impact on system voltage is evaluated by comparing the lowest feeder voltage obtained in Base Case 1 to the values obtained in Case 11, as summarized in the table below:

Table 23 System Voltage with Reactors at Bus Tie

Case #	Voltage @ Arlen MTS 13.8kV B Bus (%)	Voltage @ Arlen MTS 13.8kV Y Bus (%)	Lowest Voltage On F11 Feeder (%)	Lowest Voltage On F13 Feeder (%)	Lowest Voltage On F14 Feeder (%)	Lowest Voltage On F21 Feeder (%)	Lowest Voltage On F24 Feeder (%)
Base Case 1	100.603	100.603	95.006	90.333	95.574	100.452	97.074
11 (1.5 ohm reactor @ bus tie)	99.647	100.309	94.104	89.475	94.667	100.159	96.790

In this configuration, the transformers are operating at different tap changer settings due to insertion of the reactor impedance at the bus tie; the load is no longer shared equally between the two transformers. Therefore, the voltage on buses B and Y might not necessarily be equal. At full load, the voltage drop across the reactor is only 0.64% of nominal 13.8kV; this small voltage drop, versus the large voltage drop of the previous two cases, is due to the fact that only a small percentage of load current must pass through the bus tie. This percentage is dependent on the instantaneous load imbalance between buses B and Y. An in-depth analysis of voltage drop for different MVA loads, as well as the reduction in tap changer capability, will be performed in the second study if this is the option preferred by the Owner.

4.1.5.2 Reduction in LG Fault Current

The reduction in fault current at the station main bus is evaluated by comparing the maximum fault level obtained in Base Case 4b to the values obtained after reactor insertion:

Table 24 Main Bus Maximum SC Level with Reactors at Bus Tie

Base Case #	Fault Type	Fault Level @ B Bus (kA)	Fault Level @ Y Bus (kA)
Base Case 4b	L-L-L	28.326	28.326
	L-G	14.842	14.842
12 (1.5 ohm reactor @ bus tie)	L-L-L	19.601	16.712
	L-G	11.481	10.364

When the reactor is installed at the bus tie, the fault currents on the two main buses are different due to the arrangement of the DGs on the feeders. Therefore, the results of this study are only valid in the context of assumptions specified in Section 2.0. The LLL current on bus B is reduced to the value calculated in Base Case 2 as required (present value); however, the LG current is still larger than 10kA. An in-depth analysis of further LG reduction will be performed in the second study if this is the option preferred by the Owner. Increasing the transformer neutral impedance from 1.25Ω currently to a larger value shall be the solution investigated.

4.1.5.3 Impact on P&C

Station Protection:
A new bus protection relay will be required, with two new 3000A bus tie breaker cells.

Operation of the new circuit breakers must be coordinated with existing circuit breakers 52B and 52Y such that the reactor is not in service when the station is experiencing a transformer outage. Implementation of this control will require some relay upgrades.

Feeder Protection:
After reactor insertion, the feeder end short-circuit values must remain large enough to allow proper operation of protection devices; these are calculated assuming current HONI system conditions and 95% pre-fault voltage:

Table 25 Feeder-End SC Level with Reactors at Bus Tie

Base Case #	Fault Type	Fault Level @ F11 Feeder End (kA)	Fault Level @ F13 Feeder End (kA)	Fault Level @ F14 Feeder End (kA)	Fault Level @ F24 Feeder End (kA)
Base Case 2	L-L-L	2.499	1.851	2.499	1.851
	L-L	2.164	1.603	2.164	1.603
	L-G	1.724	1.366	1.711	1.183
13 (1.5 ohm reactor @ secondary)	L-L-L	2.136	1.605	2.136	1.605
	L-L	1.850	1.390	1.850	1.390
	L-G	1.498	1.201	1.487	1.037

The maximum (base case 2-no reactor, 105% pre-fault voltage) and minimum (case 13-reactor inserted, 95% pre-fault voltage) short-circuit values can be compared using the table above. Although the current values have decreased, it can be concluded that there is no impact on feeder protection due to the reactors. The protection devices will be able to discriminate between load and fault currents.

4.1.5.4 Impact on Arlen MTS Reliability

No impact.

4.1.5.5 Capital and Operation Costs (includes power losses)

Capital Cost for Equipment:
The pricing is given for estimative purposes only, assuming outdoor installation:

Reactors:	~ $30,000 / unit	Qty: 3
Breakers (3000A) with protection upgrades:	~ $200,000 / unit	Qty: 2

Engineering Cost:
±25% estimate: ~$160,000

Construction Cost:
±25% estimate: ~$300,000

Total Capital Cost (±25%): ~$950,000

Operating Cost:
Reactor copper losses at full station load assuming X/R = 60: 0.5 kW / coil

4.1.5.6 COMS

- Compared to previous options (reactor at transformer primary/secondary), about half the space is required for this modification because only one reactor bay is required. One reactor bay can occupy approximately 10m x 6m area
- Existing underground wiring will not be affected. However, new cables will be required for reactor connection
- Reactor design assures maintenance-free operation
- No adverse impact on station safety
- The reactor is a passive device; there is no impact from an operability point of view
- Revenue metering will not be impacted by the modification
- For installation, a complete station outage will be required to add two additional reactor breaker cells to existing switchgear

4.2 UPGRADE STATION EQUIPMENT (OPTION #4)

Replacing the power transformers with higher impedance units can be an effective technical solution for accommodating larger fault currents at the station.

New transformers with higher internal impedance will act similar to the series reactors to limit the fault current at the switchgear. However, compared to the reactor solution, transformer replacement is much less cost effective. The cost of one power transformer can be estimated at $1.5-$2 million. Construction costs and outage times would also be much higher. Other unforeseen modifications to station arrangement may be required.

Due to very low cost-effectiveness, this solution is not considered feasible for implementation.

4.3 CHANGE TIE-BREAKER FROM N.C. TO N.O. (OPTION #5)

Arlen MTS operates under normal circumstances with the tie breakers closed (ie N.C.). Station operating philosophy can be modified to effectively reduce the fault current on the individual B and Y buses to half. The buses would be operated as two independent systems, with tie-breakers 52J, 52Q, or either one of them normally open. The breaker is closed only when one of the source circuits (power transformer or HONI line) is experiencing an outage. Since a manual load transfer scheme implies long customer blackouts, an automatic scheme should be used.

The main advantages of this solution are:

- No upgraded, new or replacement major equipment is required
- Cost-effective
- Available short-circuit current is reduced to approximately half of existing value

Disadvantages:

- Transformers cannot be paralleled due to possibility of fault occurring during load transfer; the number of temporary customer blackouts would increase (whenever one of the 115kV circuits or one of power transformers is out of service); these momentary interruptions could last up to a few seconds until the load is transferred to the remaining transformer
- System reliability decreases significantly
- Fault clearing times will increase due to the smaller available fault current
- Voltage sag during faults will become more severe and longer in duration
- Studies must be performed to determine power quality and loading limits for each bus, as well as connection capability of future DGs. The complete scope of these studies shall be determined if the Owner decides to pursue this option

P&C Implementation:
A new interlock between breakers 52-T1, 52-T2, 52J and 52Q can be programmed such that 52J and 52Q cannot be closed at the same time when both 52-T1 and 52-T2 are closed (except by manual override).

If load transfer is required due to a fault or scheduled maintenance, the minimum outage duration will be equal to the period between opening of 52-T1 or 52-T2 and closing of the tie breaker(s). A large number of customers will experience a temporary outage.

Capital Cost:
Engineering + P&C Field Configuration (±25% estimate): ~$60,000

5.0 CONCLUSIONS AND RECOMMENDATIONS

To facilitate evaluation of each option analyzed, a scoring system is developed based on the criteria outlined in Section 1.0. Options are assigned a score between 0-100 for each criteria, added finally for a total score; for an option to be considered feasible, the minimum total score should be 420 (average of 70 for each criteria), and no scores under 20 for any of the criteria.
The scoring system for each criteria is explained below:

Criteria #1: Impact on Power Quality
100 – No impact
0 – Unacceptable distortion, causes large voltage drop in the 13.8kV system, likely to cause service interruption under normal operating conditions

Criteria #2: Reduction in Fault Current
100 – Built-in capability to withstand short-circuit current increase due to future system expansion (new EGs, stronger HONI system); SC current reduction ability customizable per Owner's requirements
0 – Very limited short-circuit current reduction ability

Criteria #3: Impact on P&C
100 – No impact
0 – Station protection philosophy must be updated

Criteria #4: Capital Cost (Equipment + Engineering + Construction)
100 – Cost limited in the range $0 - $200,000
0 – Cost >$4 million

Criteria #5: Impact on Arlen MTS Reliability
100 – No impact
0 – Greatly reduced reliability; undependable operation (i.e. nuisance trips possible, etc.)

Criteria #6: Operating and Maintenance
100 – Correct operation with minimal human input, no power losses, no specialized maintenance required
0 – Costly or specialized maintenance required often, difficult to operate, large losses

Table 26 Final Evaluation of Technical Solutions

Option	Criteria Score						Total Score
	1	2	3	4	5	6	
1. CLR @ Xformer Primary	85	80	70	80	100	70	485
2. CLR @ Xformer Secondary	80	80	70	75	100	70	475
3. CLR @ Bus Tie	90	80	60	80	100	90	500
4. Upgrade Station Transformers	100	80	90	0	100	20	390
5. Tie-Breaker Change from N.C. to N.O.	50	95	80	100	0	100	425

The total scores should be used as a guideline only for selecting the option that is best suitable to GHESI. Based on the evaluation method presented above, a current-limiting reactor installed at the bus tie is the optimal solution for addressing the short-circuit problem at Arlen MTS.

1) The reactors are considered the best overall option, despite power losses and the fact that they offer a fixed value of fault current reduction. They are a cost-effective solution which does not involve changes in the reliability or the operation procedures of the station.
2) Changing tie-breaker(s) to N.O. operation is the preferred option from a cost perspective; however, the number of momentary customer outages/year may increase. Any voltage or frequency disturbances will have a much stronger impact on each individual system, compared to parallel operation of the source circuits.
3) Upgrading station transformers offers the optimal technical solution. However, due to very low cost-effectiveness, this solution is not considered feasible for implementation.

As shown in Appendix C, the ultimate plan for the substation includes the addition of another DESN (transformers T3 and T4) which are supplied in parallel with T1 and T2 from lines B5G/B6G. To avoid high short-circuit levels on the tied secondary buses of T3 and T4, these transformers can be procured from the start with a larger internal impedance to limit LLL currents at some desired level (similar to applying option 4 to transformers T1 and T2). An in-depth study before the expansion, and discussions with manufacturers, should confirm the feasibility of this option. This solution is preferable in terms of layout and space availability; however, losses for T3 and T4 should be analyzed in particular. It is likely that an alternative solution such as providing a bus tie reactor between the secondary buses of T3 and T4 could result in significant power loss reduction at the station.

APPENDIX A – SYSTEM STUDY CASE PARAMETERS

Table 1. Study case details

Case #/Name	Parameters								Comments	Criteria Met (Y/N) Minimum Fault Level at Feeder End: L-G 1800A L-L-L 3000A Min. Voltage at Any Point on the Feeders: 94% of nominal 13.8kV (12.97 kV)
	Case Type: Load Flow (LF) or Short-Circuit (SC)	Loading at Main Station Bus: Minimum (17.9MVA) or Maximum (57.2MVA)[1]	# of Main Transformers in Service: 1 or 2	Generators in Service or Out of Service	Fault Level at 115kV Lines: Minimum (LLL 5kA, LG 2.6kA) or Maximum (LLL 15.29kA, LG 10.4kA) [1]	Transformer Tap Position	Tie-breaker position: Open or Closed	Pre-fault Voltage (% of nominal)		
1 Base Case	LF	MAX	2	OUT	N/A	AUTO	CLOSED	N/A	MINIMUM SYSTEM VOLTAGE	
2 Base Case	SC	N/A	2	OUT	MIN	AUTO	CLOSED	105%	*CURRENT SC LEVEL AT ARLEN MTS*	
3 Base Case	SC	N/A	2	OUT	MAX	AUTO	CLOSED	105%	SC LEVEL AFTER GATR	
4 Base Case	SC	N/A	2	IN	MAX	AUTO	CLOSED	105%	*SC LEVEL AFTER GATR INCLUDING DGs*	
5	LF	MAX	2	OUT	N/A	AUTO	CLOSED	N/A	SYSTEM VOLTAGE - 25Ω REACTOR ON PRIMARY	
6	SC	N/A	2	IN	MAX	AUTO	CLOSED	105%	*MAX SC - 25Ω REACTOR ON PRIMARY*	
7	SC	N/A	2	OUT	MIN	AUTO	CLOSED	95%	FEEDER END VOLTAGE WITH 25Ω REACTOR ON PRIMARY	
8	LF	MAX	2	OUT	N/A	AUTO	CLOSED	N/A	*SYSTEM VOLTAGE – 0.45Ω REACTOR ON SECONDARY*	
9	SC	N/A	2	IN	MAX	AUTO	CLOSED	105%	MAX SC – 0.45Ω REACTOR ON SECONDARY	
10	SC	N/A	2	OUT	MIN	AUTO	CLOSED	95%	*FEEDER END VOLTAGE WITH 0.45Ω REACTOR ON SECONDARY*	
11	LF	MAX	2	OUT	N/A	AUTO	CLOSED	N/A	SYSTEM VOLTAGE – 1.5Ω REACTOR AT BUS TIE	
12	SC	N/A	2	IN	MAX	AUTO	CLOSED	105%	*MAX SC – 1.5Ω REACTOR AT BUS TIE*	
13	SC	N/A	2	OUT	MIN	AUTO	CLOSED	95%	FEEDER END VOLTAGE WITH 1.5Ω REACTOR AT BUS TIE	

[1] For load flow studies, the voltage at the transformer primary should be selected as 108.1 kV for maximum load cases and 121.9 kV for minimum load cases, to determine voltage regulator performance when the reactor is in service.

APPENDIX B – HONI SYSTEM SHORT-CIRCUIT LEVEL

BY COURIER

April 8, 2013

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2013-0053 – Hydro One Networks' Section 92 – Guelph Area Transmission Refurbishment Project – Additional Evidence

I am attaching two (2) paper copies of additional evidence with respect to Hydro One Networks' Application and Prefiled Evidence that was filed with the Board on March 8, 2013.

Exhibit B, Tab 6, Schedule 4, pages 1–21 has been filed electronically using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. Intervenors (electronic)

CUSTOMER IMPACT ASSESSMENT

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

Guelph Area Transmission Refurbishment Project

AR:17389

Revision: **Draft**

Date: March 25, 2013

Issued by**:** Transmission Planning Department
System Development Division
Hydro One Networks Inc.

Prepared by:

Eva Tarasiewicz
Senior Network Management Officer
Transmission Projects Development
Hydro One Networks Inc.

Approved by:

John Sabiston, P. Eng
Manager, Transmission Planning
Transmission Projects Development
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on information available about the Guelph Area Transmission Project. It is intended to highlight significant impacts to affected transmission customers listed in Table 1 of this document early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have. Subsequent changes and the required modifications or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. Hydro One shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise

CUSTOMER IMPACT ASSESSMENT

GUELPH AREA TRANSMISSION REFURBISHMENT

1.0 INTRODUCTION

1.1 Scope of the Study

This Customer Impact Assessment (CIA) study assesses the potential impacts of the proposed Guelph Area Transmission Project on the load customers and generators in the local vicinity.
This study is intended to supplement the Draft System Impact Assessment "CAA ID 2012- 478" issued by the IESO on February 28, 2013.
This study covers the impact of the Guelph Area Transmission (GATR) Project on the Hydro One Networks Inc. (Hydro One) system in the Kitchener-Waterloo-Cambridge-Guelph Area (KWCG). The primary focus of this study is to identify the fault levels and capacity changes on the transmission customer connected facilities.

This study does not evaluate the overall impact of the GATR project on the bulk system. The impact of the GATR project on the bulk system is the subject of the System Impact Assessment (SIA) which is issued by the Independent Electricity System Operator (IESO).

1.2. 0 Background

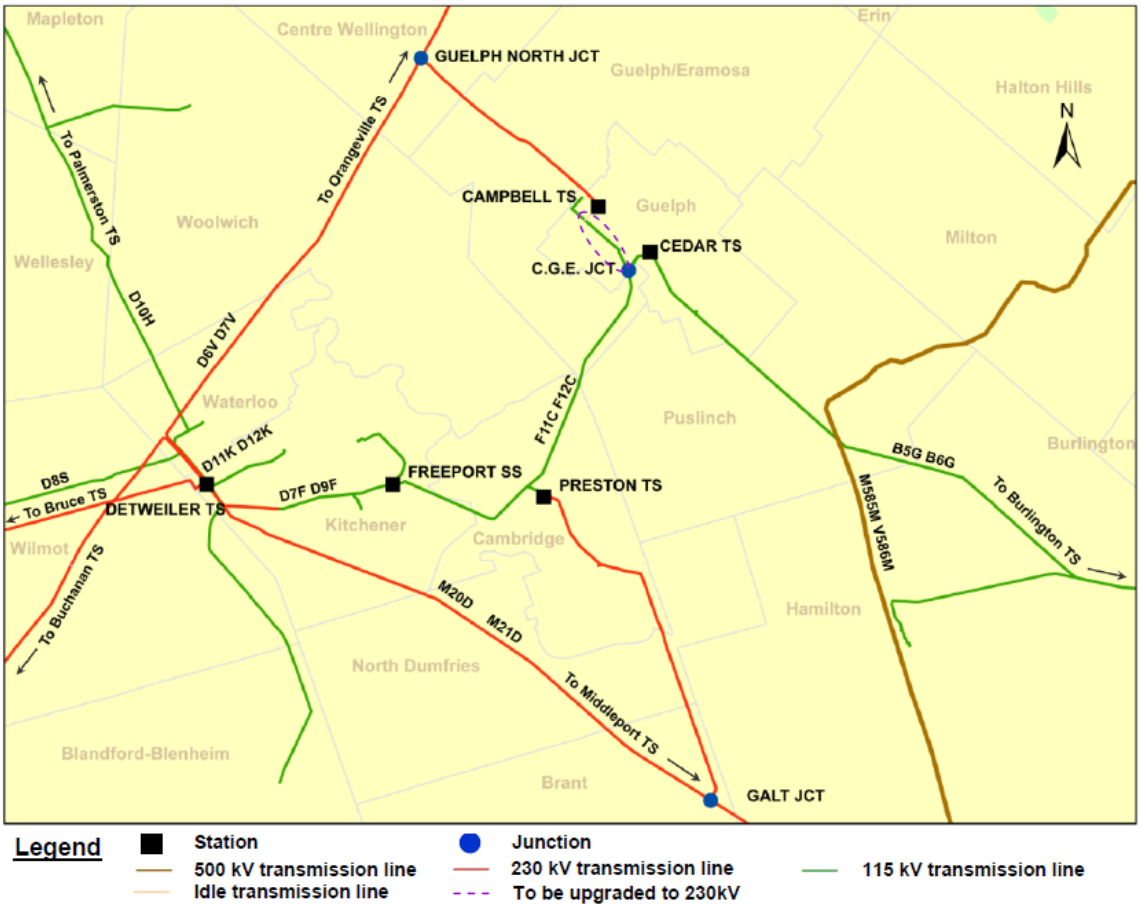
The Guelph Area Transmission Refurbishment project will contribute to meeting the supply needs of the South-Central Guelph, Kitchener-Guelph and the Cambridge area as well as improve the adequacy and reliability of electricity supply in the KWCG area.
The GATR project proposes the following transmission facilities:

- Upgrade approximately 5 km of the existing 115 kV double-circuit transmission line B5G and B6G between CGE Junction and Campbell TS to a 230 kV double-circuit transmission line that is capable of a higher thermal capacity.

- Install two new 230 / 115 kilovolt (kV) autotransformers at the existing Cedar Transformer Station (TS) in the City of Guelph;
- Install 115 kV switchgear facilities at Cedar TS to ensure security of the IESO-controlled grid for a variety of fault and operating scenarios, and
- Upgrade the existing Guelph North Junction in the Township of Centre Wellington to a switching station, Inverhaugh SS, by installing two 230 kV breakers and associated equipment.

This work will address the near- and medium-term needs in the KWCG area. Additional solutions to address longer-term reliability in the area will be identified as part of the continuing KWCG regional planning process.

The Guelph Area Transmission Project is located in southwestern Ontario. The transmission elements of this project extend from Guelph Cedar TS located in city of Guelph to Guelph North Jct. located in County of Centre Wellington. The 115 kV transmission corridor, comprises B5G/B6G, F11C/F12C and D9F/D7F lines that connect Burlington TS (in Burlington) to Detweiler TS (in Kitchener) (see Figure 1 below). Approximately five kilometers of 115 kV line B5G/B6G in this corridor, between Guelph Central (C.G.E. Jct) and Guelph North (Campbell TS), will be upgraded to 230 kV.



Source: Hydro One TLGIS

Figure 1 – The KWCG area

1.2.1 Existing Transmission Facilities in Southwestern Ontario

The generation capacity in southwestern Ontario is mainly a mix of nuclear, gas-fired, coal-fired and renewable sources. Some of the larger generating stations in the region are Bruce GS, Nanticoke GS, Lambton GS and Beck GS. The area also includes major load centers such as Hamilton, London, Windsor and Kitchener-Waterloo-Cambridge-Guelph ("**KWCG**").

The transmission assets in southwestern Ontario connect the major generation and load centers in the region to the interconnected grid. Almost half of the generating capacity in the region supplies the energy needs of other parts of the Province. The transmission system in this area is designed and placed to support this concentration of generation

capacity, respecting physical constraints such as voltage stability and thermal limits. This is a tightly interconnected system, where the availability and performance of each major element (especially the 230 kV facilities) can affect the integrity of the entire network and neighboring jurisdictions.

1.2.2. Transmission Resources in the KWCG Area

KWCG area is located in southwestern Ontario and consists of cities of Kitchener, Waterloo, Cambridge, and Guelph, townships of Wellesley, Woolwich, Wilmot, and North Dumfries, as well as County of Centre Wellington. Much of this area is within the Regional Municipality of Waterloo. Population growth in the four KWCG cities is among the highest in the province, and in the summer of 2005 the demand for electricity in the area peaked at roughly 1,400 MW. While the recent economic recession has impacted growth in the region, the demand for electricity had almost recovered to pre-recession levels in the summer of 2010, and is expected to grow at roughly 2% between 2010 and 2030; more than four times the forecast growth in peak demand for province over the same period. Within the KWCG area, the strongest growth in demand is expected in the Cambridge and North Dumfries and South-Central Guelph areas. As mentioned above, the KWCG area is one of the major load centers in Ontario. With the lack of local generation, the area relies entirely on the transmission system to deliver electricity from external generation sources to the area.

The transmission system supplying the KWCG area is highly integrated and interactive. It includes the 230 kV circuits between Detweiler TS (in Kitchener), Orangeville TS (in Orangeville) and Middleport TS (in Hamilton), as well as eight 115 kV circuits emanating from Detweiler TS and Burlington TS (in Burlington). High voltage autotransformers tie the 115 kV and 230 kV systems together at Detweiler TS, Burlington TS and Preston TS (in Cambridge). The 230 kV and 115 kV transmission lines in the KWCG area are as follows:

- The 230 kV Detweiler TS x Orangeville TS double-circuit tower line, D6V and D7V;

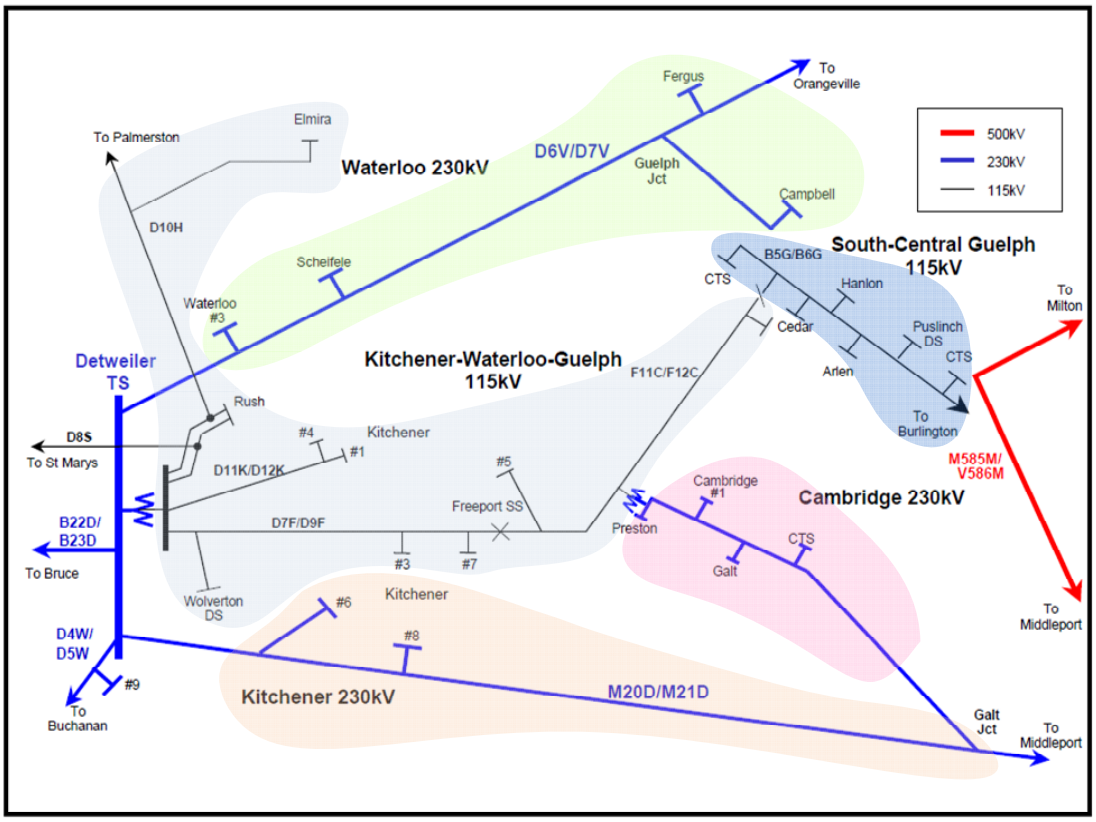
- The 230 kV Middleport TS x Detweiler TS and Preston TS double-circuit tower line, M20D and M21D;
- The 115 kV Burlington TS x Cedar TS double-circuit tower line, B5G and B6G;
- The 115 kV Detweiler TS x Freeport SS double-circuit tower line, D7F and D9F;
- The 115 kV Detweiler TS x St. Mary's TS single-circuit tower line, D8S;
- The 115 kV Detweiler TS x Palmerston TS single-circuit pole line, D10H;
- The 115 kV Detweiler TS x Kitchener TS double-circuit tower line, D11K and D12K;
- The 115 kV Freeport SS x Cedar TS double-circuit tower line, F11C and F12C.

Other major 230 kV facilities connected the KWCG area include transformer and switching stations at Detweiler TS, Burlington TS, Orangeville TS, Middleport TS, Freeport SS and Preston TS.

For the purpose of this submission, the transmission system in the KWCG area can be separated into five subsystems as follows:

- The South-Central Guelph 115 kV Subsystem: customers supplied from Burlington TS via B5G/B6G;
- The Kitchener-Waterloo-Guelph 115 kV Subsystem: customers supplied from Detweiler TS via D7F/D9F, F11C/F12C, D11K/D12K and D8S/D10H;
- The Cambridge 230 kV Subsystem - customers supplied from M20D/M21D via the "Preston Tap";
- The Kitchener 230 kV Subsystem - customers supplied directly from Detweiler TS via M20D/M21D;
- The Waterloo 230 kV Subsystem - customers supplied directly from Detweiler TS via D6V/D7V.

Figure 2 provides a graphical representation of these subsystems.



Source: Hydro One

Figure 2 – Five Existing Subsystems of the KWCG Area Network

The Hydro One proposed Guelph Area Transmission Refurbishment project will contribute to meeting the supply needs of the South-Central Guelph, Kitchener-Guelph and the Cambridge area as well as improve the adequacy and reliability of electricity supply in the KWCG area.

2.0 DETAILS OF THE PROPOSED FACILITIES

Line Work

Approximately 5 km of an existing 115 kV transmission line (B5G/B6G) between CGE Junction and Campbell TS will have to be replaced with a double circuit 230 kV line to address the supply needs in the KWCG area. The transmission line passes through the city of Guelph. An existing customer owned station directly connected to the 115 kV B5G/B6G circuits will need to be disconnected from Hydro One's Transmission system

and reconnected to Guelph Hydro Electric System's distribution system at Campbell TS in order to maintain supply to the customer.

Cedar TS to CGE Jct

The line section from Cedar TS to CGE Jct can currently operate at 230 kV (with existing 230 kV towers and conductors), therefore, only the grounding conductor (skywire) in this section needs to be replaced with Optic Ground Wire (OPGW) conductor which will allow for grounding and communication.

CGE Jct to ABB Jct

The line section from CGE Jct to ABB Jct is designed for 115 kV operation and needs to be rebuilt to 230 kV voltage level. This section was built in 1953. The 3.8 km existing double circuit 115 kV line on double wood pole structures from CGE Jct to ABB Jct consists of 35 wood poles and 1 steel tower. 26 out of 35 wood poles are 59 years old, exceeding the expected life of 50 years for wood poles. The other 9 wood poles were replaced in 2002. The wood poles in this section will be removed and replaced with double circuit 230 kV steel structures, conductors and accessories.

As per Hydro One's policy on the use of steel pole structures in residential areas it is recommended to install steel *pole* structures (instead of the standard steel *lattice* structures) in residential areas, where it is technically feasible and where such a preference has been indicated. Therefore, as requested by residents in the Deerpath Drive Community and by staff from the City of Guelph's Planning, Building, Engineering and Environment group, steel poles are recommended for use in current residential areas on this line section, where possible. This includes approximately 1.9 km of line from the railway just north of the Speed River, to just south of Willow Road. Steel lattice structures are recommended for use on the remainder of the line section to be refurbished and in locations where steel poles are not technically feasible (i.e. locations where there is an angle in the line, such as structures on either side of the line crossing over the Hanlon Parkway).

ABB Jct to Campbell TS

The line section from ABB Jct to Campbell TS is designed for 115 kV operation and needs to be rebuilt to 230 kV voltage level. This section was built in 1964 and is presently idle. The line section from ABB Jct to Campbell TS consists of 4 steel towers. This section will also be removed and replaced with double circuit 230 kV steel structures, conductors and accessories. One OPGW will be installed from CGE Jct. to Campbell TS.

Station Work

The GATR project requires work to be completed at Cedar TS and the planned Guelph North Junction Switching Station.

Cedar TS

Cedar TS in the City of Guelph is currently supplied from Burlington TS via the double circuit 115 kV line B5G/B6G (T7 and T6 step-down transformers) and from Detweiler TS (T1 and T2 step-down transformers) via the double circuit 115 kV line F11C/F12C. At Cedar TS, Hydro One plans to:

- Install two new 230/115 kV autotransformers and associated electrical equipment allowing for supply at 230 kV from circuits D6V/D7V via the Campbell tap
- Install new 115 kV switchgear facilities to connect the existing 115 kV circuits: F11C, F12C, B5G and B6G, existing step-down transformers: T1, T2, T7 and T8 , and two new 230/115 kV autotransformers: T3 and T4, and ensure that adequate transmission supply capability is maintained following the loss of any one of the existing transmission lines without interrupting customers.
- The installation of the facilities listed above at Cedar TS would close the normally open point between the 115 kV circuits: B5G/B6G and F11C/F12C, and thus the D6V/D7V 230 kV system would be connected to the B5G/B6G 115 kV and F11C/F12C 115 kV systems, reinforcing the supply to both South-Central Guelph and Kitchener- Guelph.

Upon completion, Cedar TS will become a strong source of supply within KWCG area. By augmenting the existing Burlington TS 115 kV supply to Cedar TS, Hanlon TS and Arlen MTS through the installation of autotransformers connecting the existing 115 kV circuits B5G/B6G to the 230 kV D6V/D7V circuit from Orangeville TS and Detweiler TS, the GATR project will provide sufficient incremental supply capacity to meet the needs of South-Central Guelph.

Inverhaugh Switching Station at Guelph North Junction

The existing Guelph North Jct. is located in the County of Wellington, in the Township of Centre Wellington, just north of Sideroad 10 and west of 2nd Line East. The double circuit 230 kV transmission line (D6V/D7V) between Detweiler TS in Kitchener and Orangeville TS is tapped to Campbell TS. With the proposed 230 kV line upgrade and autotransformers at Cedar TS the B5G/B6G 115 kV and F11C/F12C 115 kV systems will be connected to D6V/D7V, hence reinforcing the supply to both South-Central Guelph and Kitchener-Waterloo-Guelph.

In order to improve the reliability of electrical supply to South Central Guelph stations on B5G/B6G, Guelph North Jct is proposed to be upgraded by building a Switching Station (SS) and installing two 230 kV circuit breakers and associated station facilities. The existing tap to Campbell TS will connect to the upgraded transmission line section from Campbell TS to Cedar TS to provide supply to Cedar TS, Hanlon TS and Arlen MTS from D6V/D7V. Adding the current and future load on D6V/D7V requires upgrading the junction to a switching station to meet customer supply reliability requirements. Access to the new SS would be from Sideroad 10.

2.1 Single Line Diagrams

Cedar TS

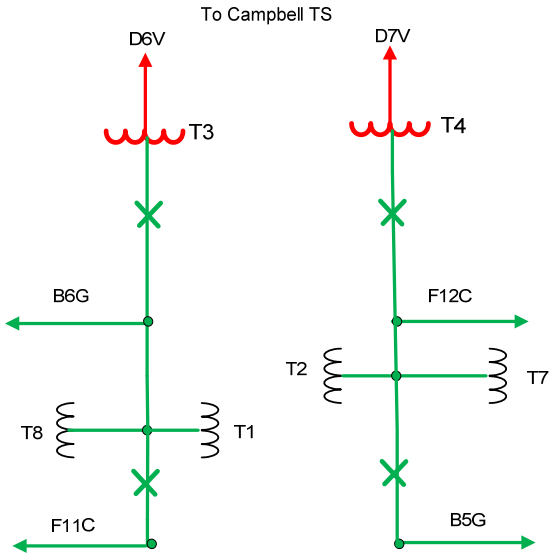


Figure 3: STAGE 1 - Schematic Single Line Diagram of CEDAR TS with Implementation of GATR

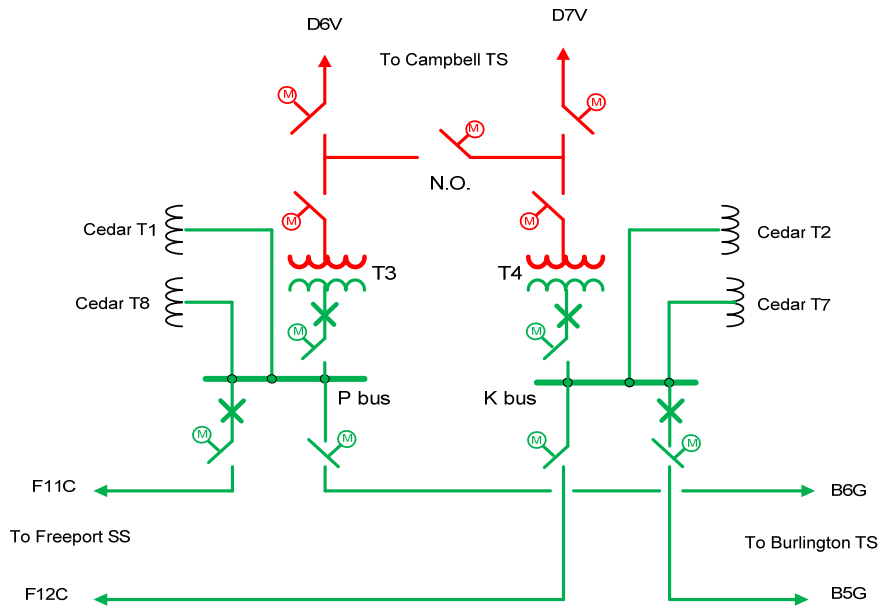


Figure 4: STAGE 1 - Detailed Single Line Diagram of CEDAR TS with Implementation of GATR
(CEDAR bus split – 4 in-line breakers)

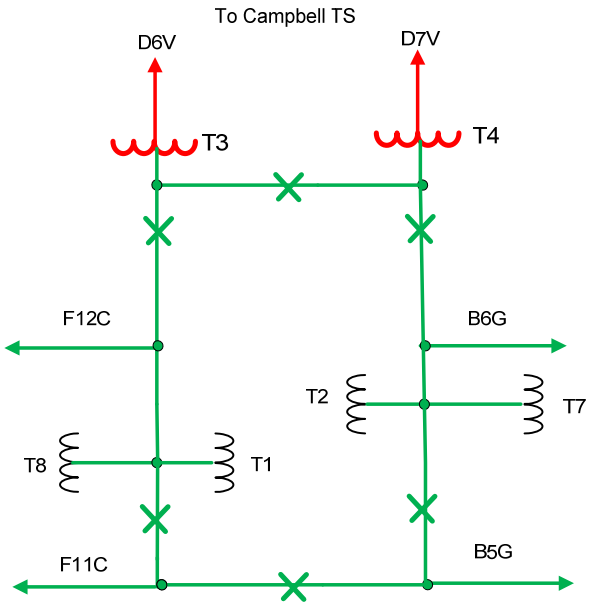


Figure 5: STAGE 2 - Schematic Single Line Diagram CEDAR TS ring bus configuration with six 115 kV breakers (future configuration - ultimate design)

Inverhaugh SS

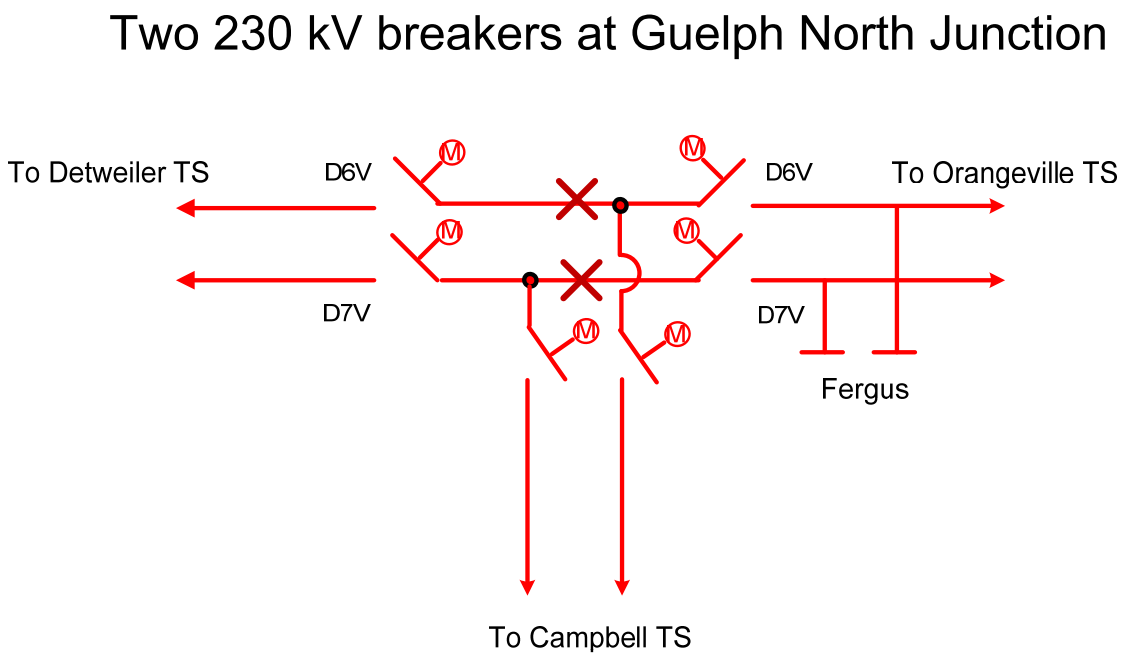


Figure 6 : Two 230 kV circuit breakers at Guelph North Junction

3.0 CUSTOMER IMPACT ASSESSMENT

This Customer Impact Assessment (CIA) is a requirement of the Transmission System Code (TSC) to assess the potential impacts on the existing transmission connected customer(s). The primary focus of this study is to communicate the Guelph Area Transmission Project to customers supplied directly in the KWCG area and in the vicinity of the mentioned geographical area (Figure 2). Table 1 summarizes the customers connected at each station:

Table 1: Transmission Customers in the KWCG Area

Customers	Station
Ameri Steel Cambridge	Gerdau-Courtice Steel CTS
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1
	Galt TS
	Preston TS
	Wolverton DS
Centre Wellington Hydro Ltd.	Fergus TS
Guelph Hydro Electric System - Rockwood Division	Fergus TS
Guelph Hydro Electric Systems Inc.	Arlen MTS
	Campbell TS
	Cedar TS
	Hanlon TS
Halton Hills Hydro Inc.	Fergus TS
Hydro One Networks Inc.	Fergus TS
	Puslinch DS
	Wolverton DS
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1
	Kitchener MTS#3
	Kitchener MTS#4
	Kitchener MTS#5
	Kitchener MTS#6
	Kitchener MTS#7
	Kitchener MTS#8
	Kitchener MTS#9
Milton Hydro Distribution Inc.	Fergus TS
Waterloo North Hydro Inc.	Elmira TS
	Fergus TS
	Rush MTS
	Scheifele MTS
	Waterloo North MTS 3
Wellington North Power Inc	Fergus TS
Westover	Enbridge Westover CTS

3.1 Study Assumptions

The short circuit study was carried out with the following primary system assumptions:

(1) Generation Facilities In-service

East

Lennox G1-G4 Chenaux G1-G8
Kingston Cogen G1-G2 Mountain Chute G1-G2
Wolf Island 300 MW Stewartville G1-G5
Arnprior G1-G2 Brockville G1
Barrett Chute G1-G4 Havelock G1
Chats Falls G2-G9 Saunders G1-G16
Cardinal Power G1, G2

Toronto

Pickering units G1, G4-G8 Sithe Goreway G11-13, G15
Darlington G1-G4 TransAlta Douglas G1-G3
Portlands GS G1-G3 GTAA G1-G3
Algonquin Power G1, G2 Brock west G1
Whitby Cogen G1

Niagara

Thorold GS GTG1, STG2 Beck 2 G11-G26
Beck 1 G3-G10 Beck 2 PGS G1-G6
Decew G1, G2, ND1

South West

Nanticoke G5-G8 Kingsbridge WGS 39.6 MW
Halton Hills GS G1-G3 Amaranth WGS 199.5 MW

Bruce

Bruce A G1-G4 Ripley WGS 76 MW
Bruce B G5-G8 Underwood WGS 198 MW
Bruce A Standby SG1

West

Lambton units G3-G4 Imperial Oil G1
Brighton Beach G1, G1A, G1B Kruger Port Alma WGS 101.2 MW
Greenfield Energy Centre G1-G4 Gosfield Wind Project 50.6 MW
St. Clair Energy Centre CTG3, STG3, CTG4, STG4 Kruger Energy Chatham WF 101 MW
East Windsor Cogen G1-G2 Raleigh Wind Energy Centre 78 MW
TransAlta Sarnia G861, G871, G881, G891 Talbot Wind Farm 98.9 MW

Ford Windsor CTS STG5 Dow Chemicals G1, G2, G5
TransAlta Windsor G1, G2 Port Burwell WGS 99 MW
West Windsor Power G1, G2 Fort Chicago London Cogen 23 MVA
Great Northern Tri-Gen Cogen 15 MVA

(2) Previously Committed Generation Facilities

- Port Dover and Nanticoke
- Big Eddy GS and Half Mile Rapids GS • Grand Renewable Energy Park
- White Pines Wind Farm • Green Electron
- Amherst Island • Comber East C24Z
- York Energy Centre • Comber West C23Z

• Conestogo Wind Energy Centre 1 • Pointe-Aux-Roches Wind
• Dufferin Wind Farm • South Kent Wind Farm
• Summerhaven Wind Farm • Wolfe Island Shoals
• Bluewater Wind Energy Centre • East Lake St. Clair Wind
• Jericho Wind Energy Centre • Adelaide Wind Power Project
• Bornish Wind Energy Centre • Gunn's Hill Wind Farm
• Goshen Wind Energy Centre • Silvercreek Solar Park
• Cedar Point Wind Power Project Phase II • K2 wind
• Adelaide Wind Energy Centre • Armow
• Grand Bend Wind Farms • 300 MW wind at Orangeville
• Grand Valley Wind Farms (Phase 3) • 100 MW wind at S2S
• Erieau Wind

(3) Existing and Committed Embedded Generation

• Essa area: 264 MW • Niagara area: 52 MW
• Ottawa area: 90 MW • Southwest area: 348 MW
• East area: 580 MW • Bruce area: 26 MW
• Toronto area: 168 MW • West area: 585 MW

(4) Transmission System Upgrades

• Woodstock Area transmission reinforcement (CAA2006-253);
o Karn TS in-service and connected to M31W & M32W at Ingersol TS
o W7W/W12W terminated at LFarge CTS
o Woodstock TS connected to Karn TS
• Rodney (Duart) TS DESN connected to W44LC and W45LS 230 kV circuits (CAA2007-260)

(5) System Operation Conditions

• Lambton TS 230 kV operated *open*
• Claireville TS 230 kV operated *open*
• Leaside TS 230 kV operated *open*
• Leaside TS 115 kV operated *open*
• Middleport TS 230 kV bus operated *open*
• Hearn SS 115 kV bus operated *open*
• Preston T2 connected to M21D
• Cherrywood TS north & south 230kV buses operated ***open***
• Richview TS 230 kV bus operated ***open***
• All tie-lines in-service and phase shifters on neutral taps
• Maximum voltages on the buses

4.0 Results of Assessment

4.1 Short-Circuit Analysis

The GATR project will have no material impact on fault levels after completion of the Project, therefore, existing levels at each bus are shown in Table 2 and 3. Two cases were included to simulate scenarios whether the Cedar 115 kV bus is split and closed (ring bus). 2016 system conditions have the Cedar 115 kV bus split.

Table 2: Present Fault Levels

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	11.449	13.388	9.715	11.662
Burlington TS 230kV	51.410	61.691	43.592	55.718
Cambridge MTS #1 230kV M20D	8.916	10.422	6.349	6.814
Cambridge MTS #2 230kV M21D	10.344	12.080	8.901	11.004
Detweiler TS 230kV	23.608	27.687	23.116	29.508
Kitchener MTS #6 230kV M20D	17.938	20.908	16.092	18.554
Kitchener MTS #6 230kV M21D	17.897	20.865	16.110	18.575
Kitchener MTS #8 230kV M20D	17.584	20.830	14.409	16.560
Kitchener MTS #8 230kV M21D	17.424	20.661	14.443	16.656
Kitchener MTS #9 230kV D4W	14.738	17.106	11.452	12.839
Kitchener MTS #9 230kV D5W	14.738	17.106	11.463	12.849
Middleport TS 230kV DK1	47.130	59.276	44.120	57.728
Middleport TS 230kV DK2	42.868	55.035	40.126	54.459
Orangeville TS 230kV	19.411	22.207	20.916	24.991
Scheifele CTS 230kV D6V	16.211	18.489	13.637	15.311
Scheifele CTS 230kV D7V	16.180	18.454	13.610	15.280
Waterloo North CTS 230kV D6V	18.752	21.494	16.825	19.338
Waterloo North CTS 230kV D7V	18.667	21.390	16.735	19.225
Arlen MTS 115kV B5G	5.017	5.097	2.606	2.624
Arlen MTS 115kV B6G	5.017	5.097	2.605	2.623
Burlington TS 115kV	34.996	43.549	39.214	50.887
Detweiler TS 115kV	24.602	28.487	28.510	35.151
Enbridge Westover CTS 115kV North	5.222	5.223	3.315	3.315
Enbridge Westover CTS 115kV South	5.024	5.025	3.196	3.196
Kitchener MTS #1 115kV D11K	14.219	14.944	11.382	11.873
Kitchener MTS #1 115kV D12K	14.220	14.944	11.383	11.873
Kitchener MTS #3 115kV D7F	13.875	14.928	11.292	11.903
Kitchener MTS #3 115kV D9F	11.322	12.251	8.587	8.916
Kitchener MTS #4 115kV D11K	14.286	15.020	11.455	11.952
Kitchener MTS #4 115kV D12K	14.287	15.021	11.455	11.953
Kitchener MTS #5 115kV F12C	10.207	10.707	7.540	7.850
Kitchener MTS #5 115kV F11C	8.298	8.769	5.727	5.888
Kitchener MTS #7 115kV D7F	14.374	15.586	12.426	13.299
Kitchener MTS #7 115kV D9F	10.690	11.575	8.143	8.416
Puslinch DS 115kV B5G	5.382	5.458	2.894	2.914
Puslinch DS 115kV B6G	5.382	5.458	2.893	2.914
Rush MTS 115kV D10	14.005	14.562	11.360	11.784
Rush MTS 115kV D8S	13.812	14.331	11.297	11.703
Wolverton DS 115kV	5.899	5.899	3.941	3.941
Fergus TS 44kV	14.514	14.707	6.911	8.097
Elmira TS 27.6kV	7.062	7.062	7.188	7.188
Galt TS 27.6kV J	12.293	12.657	9.845	11.315
Galt TS 27.6kV Y	12.227	12.587	9.816	11.278
Preston TS 27.6kV J	12.359	12.960	9.771	11.287
Preston TS 27.6kV Q	12.712	13.293	9.919	11.436
Campbell TS 13.8kV BY	16.940	17.221	8.328	9.760
Campbell TS 13.8kV EZ	17.367	17.729	8.397	9.885
Campbell TS 13.8kV JQ	16.924	17.183	8.324	9.744
Cedar TS 13.8kV JQ	13.109	13.109	7.691	7.691
Cedar TS 13.8kV BY	14.061	14.061	6.819	7.435
Cedar TS 13.8kV EZ	13.998	13.998	6.805	7.410
Hanlon TS 13.8kV BY	13.939	13.939	7.858	7.858

Table 3: Fault Levels with Implementation of GATR (CEDAR bus split – 4 in-line breakers)

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	11.970	13.982	10.068	12.052
Burlington TS 230kV	52.661	63.061	44.375	56.591
Cambridge MTS #1 230kV M20D	8.969	10.499	6.387	6.852
Cambridge MTS #2 230kV M21D	10.932	12.771	9.329	11.517
Detweiler TS 230kV	24.726	28.857	24.030	30.483
Kitchener MTS #6 230kV M20D	18.545	21.541	16.548	19.005
Kitchener MTS #6 230kV M21D	18.515	21.509	16.561	19.023
Kitchener MTS #8 230kV M20D	18.030	21.305	14.668	16.818
Kitchener MTS #8 230kV M21D	17.942	21.210	14.744	16.956
Kitchener MTS #9 230kV D4W	15.064	17.445	11.623	13.007
Kitchener MTS #9 230kV D5W	15.064	17.445	11.634	13.017
Middleport TS 230kV DK1	47.212	59.369	44.175	57.792
Middleport TS 230kV DK2	42.953	55.137	40.185	54.535
Orangeville TS 230kV	20.169	23.062	21.555	25.744
Scheifele CTS 230kV D6V	16.957	19.281	14.297	15.989
Scheifele CTS 230kV D7V	16.955	19.279	14.298	15.986
Waterloo North CTS 230kV D6V	19.551	22.328	17.489	20.013
Waterloo North CTS 230kV D7V	19.479	22.239	17.408	19.908
Arlen MTS 115kV B5G	13.071	13.509	9.656	9.899
Arlen MTS 115kV B6G	12.597	13.048	6.414	6.449
Burlington TS 115kV	39.372	48.028	43.055	55.019
Detweiler TS 115kV	27.474	31.332	31.142	37.811
Enbridge Westover CTS 115kV North	5.976	5.976	3.811	3.812
Enbridge Westover CTS 115kV South	5.716	5.717	3.654	3.655
Kitchener MTS #1 115kV D11K	15.129	15.821	11.776	12.248
Kitchener MTS #1 115kV D12K	15.129	15.822	11.776	12.249
Kitchener MTS #3 115kV D7F	16.247	17.272	12.521	13.094
Kitchener MTS #3 115kV D9F	14.255	15.160	10.073	10.388
Kitchener MTS #4 115kV D11K	15.205	15.907	11.854	12.333
Kitchener MTS #4 115kV D12K	15.205	15.907	11.854	12.333
Kitchener MTS #5 115kV F12C	11.763	12.231	8.236	8.523
Kitchener MTS #5 115kV F11C	10.331	10.767	6.626	6.777
Kitchener MTS #7 115kV D7F	17.634	18.821	14.420	15.247
Kitchener MTS #7 115kV D9F	14.434	15.319	10.111	10.373
Puslinch DS 115kV B5G	11.524	11.740	7.999	8.113
Puslinch DS 115kV B6G	11.231	11.457	6.033	6.060
Rush MTS 115kV D10	14.858	15.384	11.747	12.152
Rush MTS 115kV D8S	14.656	15.144	11.687	12.074
Wolverton DS 115kV	6.062	6.063	3.992	3.993
Fergus TS 44kV	14.745	14.986	6.948	8.167
Elmira TS 27.6kV	7.111	7.111	7.222	7.222
Galt TS 27.6kV J	12.335	12.712	9.863	11.347
Galt TS 27.6kV Y	12.270	12.641	9.834	11.311
Preston TS 27.6kV J	12.409	13.036	9.791	11.329
Preston TS 27.6kV Q	12.764	13.371	9.940	11.478
Campbell TS 13.8kV BY	17.254	17.617	8.378	9.864
Campbell TS 13.8kV EZ	17.680	18.124	8.445	9.984
Campbell TS 13.8kV JQ	17.238	17.576	8.374	9.846
Cedar TS 13.8kV JQ	16.653	16.653	8.387	8.649
Cedar TS 13.8kV BY	16.498	16.981	7.160	8.269
Cedar TS 13.8kV EZ	16.410	16.856	7.145	8.227
Hanlon TS 13.8kV BY	17.226	17.226	8.461	8.715

Table 4: Fault Levels with CEDAR bus closed
(Future arrangement – 6 breaker ring bus – ultimate design)

Table 4: Fault Levels with Implementation of GATR (Cedar Solid Buses)

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	12.008	14.021	10.086	12.071
Burlington TS 230kV	52.661	63.061	44.389	56.608
Cambridge MTS #1 230kV M20D	8.970	10.501	6.387	6.853
Cambridge MTS #2 230kV M21D	10.980	12.821	9.352	11.542
Detweiler TS 230kV	24.729	28.861	24.038	30.493
Kitchener MTS #6 230kV M20	18.547	21.543	16.580	19.036
Kitchener MTS #6 230kV M21	18.516	21.511	16.576	19.037
Kitchener MTS #8 230kV M20	18.031	21.306	14.672	16.821
Kitchener MTS #8 230kV M21	17.942	21.210	14.747	16.959
Kitchener MTS #9 230kV D4W	15.064	17.446	11.625	13.008
Kitchener MTS #9 230kV D5W	15.064	17.446	11.636	13.018
Middleport TS 230kV DK1	47.212	59.370	44.176	57.793
Middleport TS 230kV DK2	42.958	55.142	40.188	54.539
Orangeville TS 230kV	20.170	23.064	21.557	25.746
Scheifele CTS 230kV D6V	17.005	19.336	14.320	16.015
Scheifele CTS 230kV D7V	16.972	19.299	14.306	15.995
Waterloo North CTS 230kV D6V	19.575	22.355	17.503	20.029
Waterloo North CTS 230kV D7V	19.482	22.243	17.410	19.911
Arlen MTS 115kV B5G	15.295	15.666	10.451	10.661
Arlen MTS 115kV B6G	15.293	15.665	10.439	10.648
Burlington TS 115kV	39.374	48.029	43.077	55.044
Detweiler TS 115kV	27.499	31.357	31.192	37.863
Enbridge Westover CTS 115kV North	6.023	6.023	3.824	3.825
Enbridge Westover CTS 115kV South	5.759	5.760	3.666	3.667
Kitchener MTS #1 115kV D11	15.136	15.829	11.783	12.255
Kitchener MTS #1 115kV D12	15.137	15.830	11.783	12.255
Kitchener MTS #3 115kV D7F	16.334	17.355	12.555	13.126
Kitchener MTS #3 115kV D9F	14.573	15.468	10.827	11.207
Kitchener MTS #4 115kV D11	15.212	15.914	11.861	12.340
Kitchener MTS #4 115kV D12	15.213	15.915	11.861	12.340
Kitchener MTS #5 115kV F12	11.846	12.311	8.264	8.549
Kitchener MTS #5 115kV F11	10.582	11.010	7.141	7.325
Kitchener MTS #7 115kV D7F	17.861	19.038	14.521	15.342
Kitchener MTS #7 115kV D9F	14.980	15.849	11.356	11.717
Puslinch DS 115kV B5G	12.789	12.962	8.406	8.501
Puslinch DS 115kV B6G	12.788	12.961	8.400	8.495
Rush MTS 115kV D10	14.865	15.391	11.753	12.158
Rush MTS 115kV D8S	14.663	15.151	11.693	12.080
Wolverton DS 115kV	6.063	6.064	3.993	3.993
Fergus TS 44kV	14.746	14.987	6.948	8.167
Elmira TS 27.6kV	7.111	7.111	7.222	7.222
Galt TS 27.6kV J	12.338	12.714	9.864	11.349
Galt TS 27.6kV Y	12.272	12.644	9.835	11.312
Preston TS 27.6kV J	12.412	13.039	9.793	11.330
Preston TS 27.6kV Q	12.768	13.375	9.942	11.480
Campbell TS 13.8kV BY	17.254	17.618	8.378	9.864
Campbell TS 13.8kV EZ	17.681	18.125	8.445	9.984
Campbell TS 13.8kV JQ	17.238	17.577	8.374	9.847
Cedar TS 13.8kV JQ	16.654	16.654	8.387	8.649
Cedar TS 13.8kV BY	16.501	16.994	7.160	8.273
Cedar TS 13.8kV EZ	16.412	16.867	7.145	8.230
Hanlon TS 13.8kV BY	17.228	17.228	8.462	8.716

Notes

1. Pre-fault voltages of 250 kV at 230 kV stations and 29 kV at 27.6 kV stations are assumed.
2. A breaker contact parting time of 25ms was assumed for asymmetrical current calculation for 230kV breakers and a contact parting time of 30ms was assumed for asymmetrical current calculation for 27.6kV breakers.
3. 2 units at Lambton GS, 6 units at Nanticoke, latest FIT project additions and all 5 phases of Samsung projects were considered.

4.2 Observations

Results show that fault levels are within maximum symmetrical three-phase and single line-to-ground faults (kA) of 230 kV, 115kV, 27.6 kV and 13.8 kV systems for all equipment connected to Hydro One transmission system as set out in Appendix 2 of the TSC when the Cedar 115kV bus is split or closed.

The largest changes observed were found to be at Arlen MTS, 8.4 kA, Cedar TS, 3.5 kA and Hanlon TS 3.3 kA. As noted above, the magnitude of these changes are acceptable.

The maximum symmetrical three-phase and single line-to-ground faults given for those voltages in the TSC may be summarized as follows:

Nominal Voltage (kV)	***Max. 3-Phase Fault (kA)***	***Max. SLG Fault (kA)***
230	63	80 (usually limited to 63 kA)
115	50	50
44	20	19 (usually limited to 8 kA)
27.6	17	12 (4 wire)/ 0.45 (3 wire)
13.8	21	10

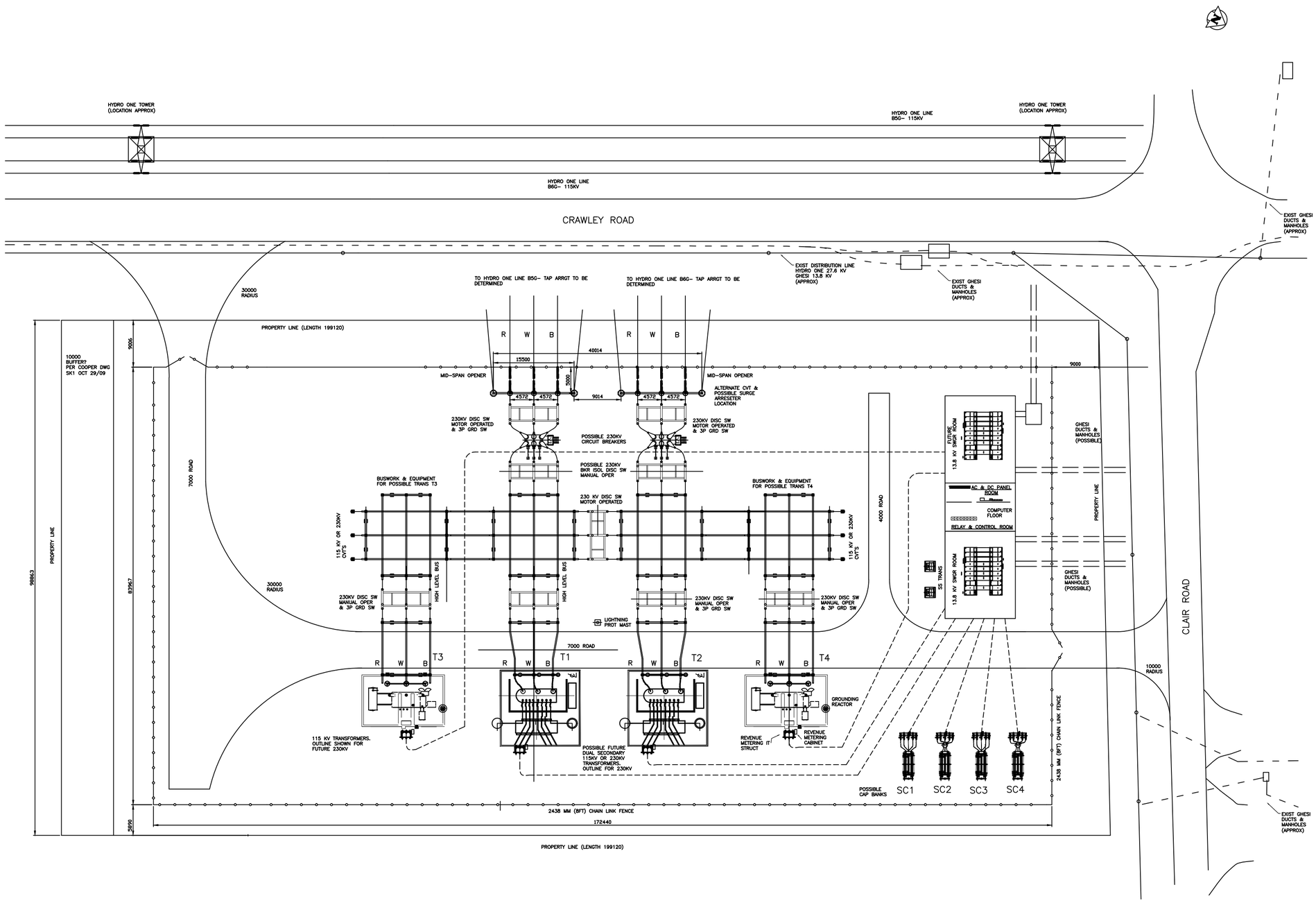
5.0 Conclusions and Recommendations

This CIA report presents results of incorporating the transmission facilities planned for meeting the reliability needs of the Kitchener-Waterloo-Cambridge-Guelph Area in the near- and medium-terms. In particular, the results of short-circuit analyses have been presented.

Short-circuit studies were carried out to determine the new projected fault levels at customer transmission connection points. The short-circuit levels observed at connection points are within the requirements of the Transmission System Code.

It is recommended that the customers review the impact of the short-circuit change on their facilities and take appropriate and timely action to address any safety/technical issues arising out of these changes which will result following incorporation of the transmission facilities in the Fall of 2015.

APPENDIX C – FUTURE STATION ELECTRICAL ARRANGEMENT



REFERENCE DRAWINGS

NO.	DESCRIPTION

NOTES:

1) TRANSFORMERS T1 & T2 PADS & CONTAINMENT SHALL BE BUILT TO ACCOMMODATE DOUBLE SECONDARY 230KV TRANSFORMERS WITH 30/40/50 MVA ON EACH SECONDARY WINDING.

2) SWITCHGEAR & CONTROL BUILDING SHALL BE BUILT TO ACCOMMODATE EXTENSIION FOR FUTURE SWITCHGEAR.

3) HIGH VOLTAGE SIDE IS DESIGNED FOR 230 KV EXCEPT CVT'S AND SURGE ARRESTERS.

WARDROP Engineering Inc.

REFERENCE No. 0988380100–DWG–E0010B

THE CONTENT OF THIS DOCUMENT IS NOT INTENDED FOR THE USE OF, NOR IS IT INTENDED TO BE RELIED UPON BY ANY PERSON, FIRM OR CORPORATION, OTHER THAN THE CLIENT AND WARDROP ENGINEERING INC. WARDROP ENGINEERING DENIES ANY LIABILITY WHATSOEVER TO OTHER PARTIES FOR DAMAGES OR INJURY SUFFERED BY SUCH THIRD PARTY ARISING FROM USE OF THIS DOCUMENT BY SUCH. WITHOUT THE EXPRESS PRIOR WRITTEN AUTHORITY OF WARDROP ENGINEERING AND OUR CLIENT. THIS DOCUMENT IS SUBJECT TO FURTHER RESTRICTIONS IMPOSED BY THE CONTRACT BETWEEN THE CLIENT AND WARDROP ENGINEERING INC. AND THESE PARTIES' PERMISSION MUST BE SOUGHT REGARDING THIS DOCUMENT IN ALL OTHER CIRCUMSTANCES.

NO.	DATE	DESCRIPTION	PREPARED	REVIEW	DESIGN	AUTHORIZE
01	MAR 5/10	REVISED FOR MAIN STATION RD OFF CRAWLEY & ADDED EXIST GHESI DUCTS	MG	HF	MG	MB

REVISIONS/ISSUE | DRAFTING | ENGINEERING

SEAL:

PERMIT STAMP

PRELIMINARY DRAWING

NOT TO BE USED FOR CONSTRUCTION

DESIGNED BY:	PREPARED BY:	REVIEWED BY:
M. GERMANI	M.G.	H. FAYAZ
AUTHORIZED BY:	3D MODEL REF No:	SCALE:
M. BOLOORCHI		NTS

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SUB-CONSULTANT(S):

CLIENT:

Guelph Hydro Electric Systems Inc.

395 SOUTHGATE DRIVE
GUELPH, ON N1G 4Y1

WARDROP A TETRA TECH COMPANY

PEOPLE, PASSION, PERFORMANCE.
TRUSTED GLOBALLY

PROJECT NAME:

Guelph Hydro 115/13.8 kV MTS #1

DRAWING DESCRIPTION:

GUELPH HYDRO ELECTRIC SYSTEMS MTS #1 POSSIBLE ULTIMATE CONCEPTUAL LAYOUT SITE 3

DRAWING NO:	REV:	DATE:
GUELPH HYDRO-06	01	5-Mar-10

A1 (841 x 594)

APPENDIX H: Hydro One Guelph Area Transmission Refurbishment Customer Impact Assessment

Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

April 8, 2013

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2013-0053 – Hydro One Networks' Section 92 – Guelph Area Transmission Refurbishment Project – Additional Evidence

I am attaching two (2) paper copies of additional evidence with respect to Hydro One Networks' Application and Prefiled Evidence that was filed with the Board on March 8, 2013.

Exhibit B, Tab 6, Schedule 4, pages 1–21 has been filed electronically using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. Intervenors (electronic)

CUSTOMER IMPACT ASSESSMENT

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

Guelph Area Transmission Refurbishment Project

AR:17389

Revision: **Draft**

Date: March 25, 2013

Issued by**:** Transmission Planning Department
System Development Division
Hydro One Networks Inc.

Prepared by:

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Hydro One Networks Inc.

Approved by:

John Sabiston, P. Eng
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Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on information available about the Guelph Area Transmission Project. It is intended to highlight significant impacts to affected transmission customers listed in Table 1 of this document early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have. Subsequent changes and the required modifications or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. Hydro One shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise

CUSTOMER IMPACT ASSESSMENT

GUELPH AREA TRANSMISSION REFURBISHMENT

1.0 INTRODUCTION

1.1 Scope of the Study

This Customer Impact Assessment (CIA) study assesses the potential impacts of the proposed Guelph Area Transmission Project on the load customers and generators in the local vicinity.
This study is intended to supplement the Draft System Impact Assessment "CAA ID 2012- 478" issued by the IESO on February 28, 2013.
This study covers the impact of the Guelph Area Transmission (GATR) Project on the Hydro One Networks Inc. (Hydro One) system in the Kitchener-Waterloo-Cambridge-Guelph Area (KWCG). The primary focus of this study is to identify the fault levels and capacity changes on the transmission customer connected facilities.

This study does not evaluate the overall impact of the GATR project on the bulk system. The impact of the GATR project on the bulk system is the subject of the System Impact Assessment (SIA) which is issued by the Independent Electricity System Operator (IESO).

1.2. 0 Background

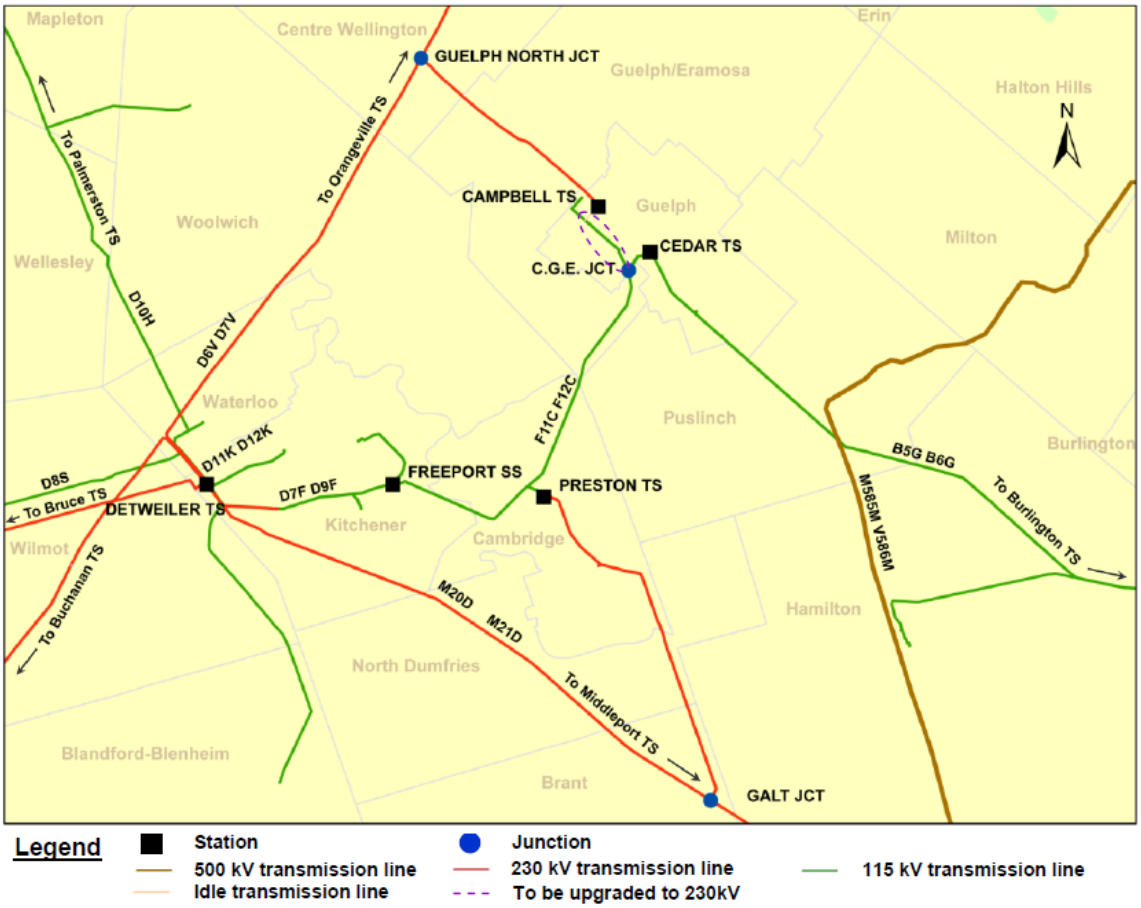
The Guelph Area Transmission Refurbishment project will contribute to meeting the supply needs of the South-Central Guelph, Kitchener-Guelph and the Cambridge area as well as improve the adequacy and reliability of electricity supply in the KWCG area.
The GATR project proposes the following transmission facilities:

- Upgrade approximately 5 km of the existing 115 kV double-circuit transmission line B5G and B6G between CGE Junction and Campbell TS to a 230 kV double-circuit transmission line that is capable of a higher thermal capacity.

- Install two new 230 / 115 kilovolt (kV) autotransformers at the existing Cedar Transformer Station (TS) in the City of Guelph;
- Install 115 kV switchgear facilities at Cedar TS to ensure security of the IESO-controlled grid for a variety of fault and operating scenarios, and
- Upgrade the existing Guelph North Junction in the Township of Centre Wellington to a switching station, Inverhaugh SS, by installing two 230 kV breakers and associated equipment.

This work will address the near- and medium-term needs in the KWCG area. Additional solutions to address longer-term reliability in the area will be identified as part of the continuing KWCG regional planning process.

The Guelph Area Transmission Project is located in southwestern Ontario. The transmission elements of this project extend from Guelph Cedar TS located in city of Guelph to Guelph North Jct. located in County of Centre Wellington. The 115 kV transmission corridor, comprises B5G/B6G, F11C/F12C and D9F/D7F lines that connect Burlington TS (in Burlington) to Detweiler TS (in Kitchener) (see Figure 1 below). Approximately five kilometers of 115 kV line B5G/B6G in this corridor, between Guelph Central (C.G.E. Jct) and Guelph North (Campbell TS), will be upgraded to 230 kV.



Source: Hydro One TLGIS

Figure 1 – The KWCG area

1.2.1 Existing Transmission Facilities in Southwestern Ontario

The generation capacity in southwestern Ontario is mainly a mix of nuclear, gas-fired, coal-fired and renewable sources. Some of the larger generating stations in the region are Bruce GS, Nanticoke GS, Lambton GS and Beck GS. The area also includes major load centers such as Hamilton, London, Windsor and Kitchener-Waterloo-Cambridge-Guelph ("**KWCG**").

The transmission assets in southwestern Ontario connect the major generation and load centers in the region to the interconnected grid. Almost half of the generating capacity in the region supplies the energy needs of other parts of the Province. The transmission system in this area is designed and placed to support this concentration of generation

capacity, respecting physical constraints such as voltage stability and thermal limits. This is a tightly interconnected system, where the availability and performance of each major element (especially the 230 kV facilities) can affect the integrity of the entire network and neighboring jurisdictions.

1.2.2. Transmission Resources in the KWCG Area

KWCG area is located in southwestern Ontario and consists of cities of Kitchener, Waterloo, Cambridge, and Guelph, townships of Wellesley, Woolwich, Wilmot, and North Dumfries, as well as County of Centre Wellington. Much of this area is within the Regional Municipality of Waterloo. Population growth in the four KWCG cities is among the highest in the province, and in the summer of 2005 the demand for electricity in the area peaked at roughly 1,400 MW. While the recent economic recession has impacted growth in the region, the demand for electricity had almost recovered to pre-recession levels in the summer of 2010, and is expected to grow at roughly 2% between 2010 and 2030; more than four times the forecast growth in peak demand for province over the same period. Within the KWCG area, the strongest growth in demand is expected in the Cambridge and North Dumfries and South-Central Guelph areas. As mentioned above, the KWCG area is one of the major load centers in Ontario. With the lack of local generation, the area relies entirely on the transmission system to deliver electricity from external generation sources to the area.

The transmission system supplying the KWCG area is highly integrated and interactive. It includes the 230 kV circuits between Detweiler TS (in Kitchener), Orangeville TS (in Orangeville) and Middleport TS (in Hamilton), as well as eight 115 kV circuits emanating from Detweiler TS and Burlington TS (in Burlington). High voltage autotransformers tie the 115 kV and 230 kV systems together at Detweiler TS, Burlington TS and Preston TS (in Cambridge). The 230 kV and 115 kV transmission lines in the KWCG area are as follows:

- The 230 kV Detweiler TS x Orangeville TS double-circuit tower line, D6V and D7V;

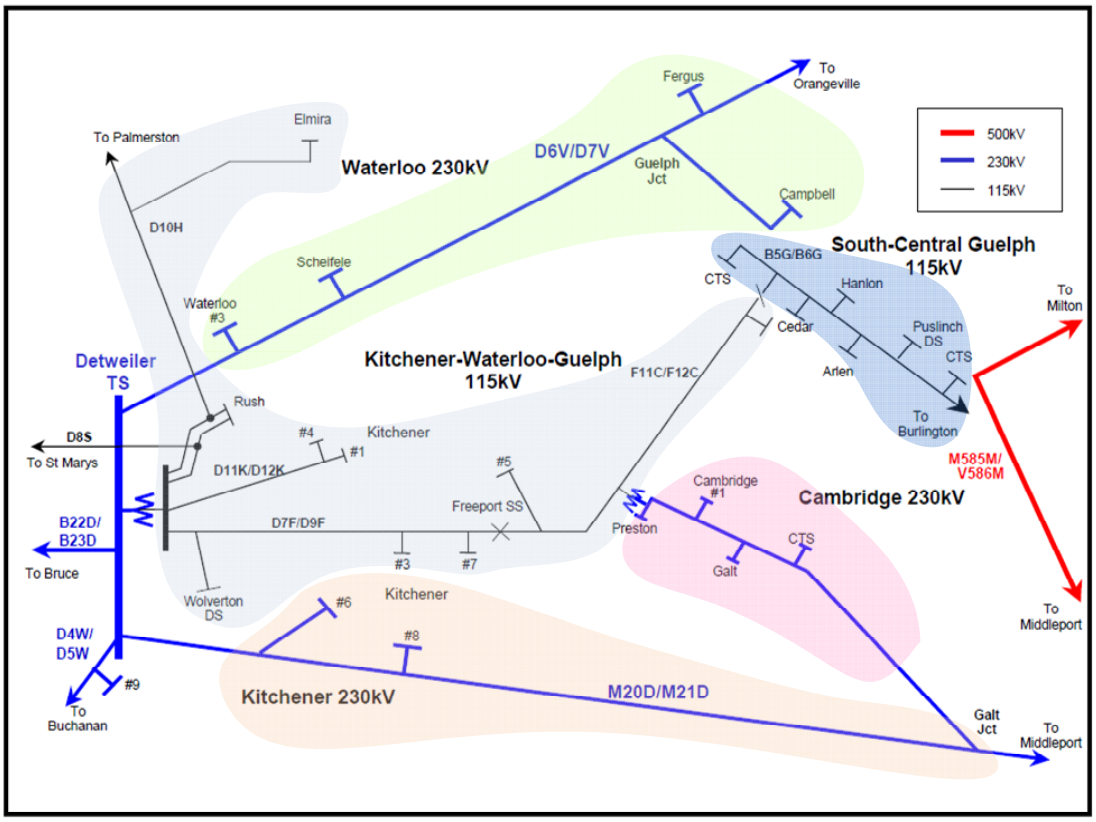
- The 230 kV Middleport TS x Detweiler TS and Preston TS double-circuit tower line, M20D and M21D;
- The 115 kV Burlington TS x Cedar TS double-circuit tower line, B5G and B6G;
- The 115 kV Detweiler TS x Freeport SS double-circuit tower line, D7F and D9F;
- The 115 kV Detweiler TS x St. Mary's TS single-circuit tower line, D8S;
- The 115 kV Detweiler TS x Palmerston TS single-circuit pole line, D10H;
- The 115 kV Detweiler TS x Kitchener TS double-circuit tower line, D11K and D12K;
- The 115 kV Freeport SS x Cedar TS double-circuit tower line, F11C and F12C.

Other major 230 kV facilities connected the KWCG area include transformer and switching stations at Detweiler TS, Burlington TS, Orangeville TS, Middleport TS, Freeport SS and Preston TS.

For the purpose of this submission, the transmission system in the KWCG area can be separated into five subsystems as follows:

- The South-Central Guelph 115 kV Subsystem: customers supplied from Burlington TS via B5G/B6G;
- The Kitchener-Waterloo-Guelph 115 kV Subsystem: customers supplied from Detweiler TS via D7F/D9F, F11C/F12C, D11K/D12K and D8S/D10H;
- The Cambridge 230 kV Subsystem - customers supplied from M20D/M21D via the "Preston Tap";
- The Kitchener 230 kV Subsystem - customers supplied directly from Detweiler TS via M20D/M21D;
- The Waterloo 230 kV Subsystem - customers supplied directly from Detweiler TS via D6V/D7V.

Figure 2 provides a graphical representation of these subsystems.



Source: Hydro One

Figure 2 – Five Existing Subsystems of the KWCG Area Network

The Hydro One proposed Guelph Area Transmission Refurbishment project will contribute to meeting the supply needs of the South-Central Guelph, Kitchener-Guelph and the Cambridge area as well as improve the adequacy and reliability of electricity supply in the KWCG area.

2.0 DETAILS OF THE PROPOSED FACILITIES

Line Work

Approximately 5 km of an existing 115 kV transmission line (B5G/B6G) between CGE Junction and Campbell TS will have to be replaced with a double circuit 230 kV line to address the supply needs in the KWCG area. The transmission line passes through the city of Guelph. An existing customer owned station directly connected to the 115 kV B5G/B6G circuits will need to be disconnected from Hydro One's Transmission system

and reconnected to Guelph Hydro Electric System's distribution system at Campbell TS in order to maintain supply to the customer.

Cedar TS to CGE Jct

The line section from Cedar TS to CGE Jct can currently operate at 230 kV (with existing 230 kV towers and conductors), therefore, only the grounding conductor (skywire) in this section needs to be replaced with Optic Ground Wire (OPGW) conductor which will allow for grounding and communication.

CGE Jct to ABB Jct

The line section from CGE Jct to ABB Jct is designed for 115 kV operation and needs to be rebuilt to 230 kV voltage level. This section was built in 1953. The 3.8 km existing double circuit 115 kV line on double wood pole structures from CGE Jct to ABB Jct consists of 35 wood poles and 1 steel tower. 26 out of 35 wood poles are 59 years old, exceeding the expected life of 50 years for wood poles. The other 9 wood poles were replaced in 2002. The wood poles in this section will be removed and replaced with double circuit 230 kV steel structures, conductors and accessories.

As per Hydro One's policy on the use of steel pole structures in residential areas it is recommended to install steel *pole* structures (instead of the standard steel *lattice* structures) in residential areas, where it is technically feasible and where such a preference has been indicated. Therefore, as requested by residents in the Deerpath Drive Community and by staff from the City of Guelph's Planning, Building, Engineering and Environment group, steel poles are recommended for use in current residential areas on this line section, where possible. This includes approximately 1.9 km of line from the railway just north of the Speed River, to just south of Willow Road. Steel lattice structures are recommended for use on the remainder of the line section to be refurbished and in locations where steel poles are not technically feasible (i.e. locations where there is an angle in the line, such as structures on either side of the line crossing over the Hanlon Parkway).

ABB Jct to Campbell TS

The line section from ABB Jct to Campbell TS is designed for 115 kV operation and needs to be rebuilt to 230 kV voltage level. This section was built in 1964 and is presently idle. The line section from ABB Jct to Campbell TS consists of 4 steel towers. This section will also be removed and replaced with double circuit 230 kV steel structures, conductors and accessories. One OPGW will be installed from CGE Jct. to Campbell TS.

Station Work

The GATR project requires work to be completed at Cedar TS and the planned Guelph North Junction Switching Station.

Cedar TS

Cedar TS in the City of Guelph is currently supplied from Burlington TS via the double circuit 115 kV line B5G/B6G (T7 and T6 step-down transformers) and from Detweiler TS (T1 and T2 step-down transformers) via the double circuit 115 kV line F11C/F12C. At Cedar TS, Hydro One plans to:

- Install two new 230/115 kV autotransformers and associated electrical equipment allowing for supply at 230 kV from circuits D6V/D7V via the Campbell tap
- Install new 115 kV switchgear facilities to connect the existing 115 kV circuits: F11C, F12C, B5G and B6G, existing step-down transformers: T1, T2, T7 and T8 , and two new 230/115 kV autotransformers: T3 and T4, and ensure that adequate transmission supply capability is maintained following the loss of any one of the existing transmission lines without interrupting customers.
- The installation of the facilities listed above at Cedar TS would close the normally open point between the 115 kV circuits: B5G/B6G and F11C/F12C, and thus the D6V/D7V 230 kV system would be connected to the B5G/B6G 115 kV and F11C/F12C 115 kV systems, reinforcing the supply to both South-Central Guelph and Kitchener- Guelph.

Upon completion, Cedar TS will become a strong source of supply within KWCG area. By augmenting the existing Burlington TS 115 kV supply to Cedar TS, Hanlon TS and Arlen MTS through the installation of autotransformers connecting the existing 115 kV circuits B5G/B6G to the 230 kV D6V/D7V circuit from Orangeville TS and Detweiler TS, the GATR project will provide sufficient incremental supply capacity to meet the needs of South-Central Guelph.

Inverhaugh Switching Station at Guelph North Junction

The existing Guelph North Jct. is located in the County of Wellington, in the Township of Centre Wellington, just north of Sideroad 10 and west of 2nd Line East. The double circuit 230 kV transmission line (D6V/D7V) between Detweiler TS in Kitchener and Orangeville TS is tapped to Campbell TS. With the proposed 230 kV line upgrade and autotransformers at Cedar TS the B5G/B6G 115 kV and F11C/F12C 115 kV systems will be connected to D6V/D7V, hence reinforcing the supply to both South-Central Guelph and Kitchener-Waterloo-Guelph.

In order to improve the reliability of electrical supply to South Central Guelph stations on B5G/B6G, Guelph North Jct is proposed to be upgraded by building a Switching Station (SS) and installing two 230 kV circuit breakers and associated station facilities. The existing tap to Campbell TS will connect to the upgraded transmission line section from Campbell TS to Cedar TS to provide supply to Cedar TS, Hanlon TS and Arlen MTS from D6V/D7V. Adding the current and future load on D6V/D7V requires upgrading the junction to a switching station to meet customer supply reliability requirements. Access to the new SS would be from Sideroad 10.

2.1 Single Line Diagrams

Cedar TS

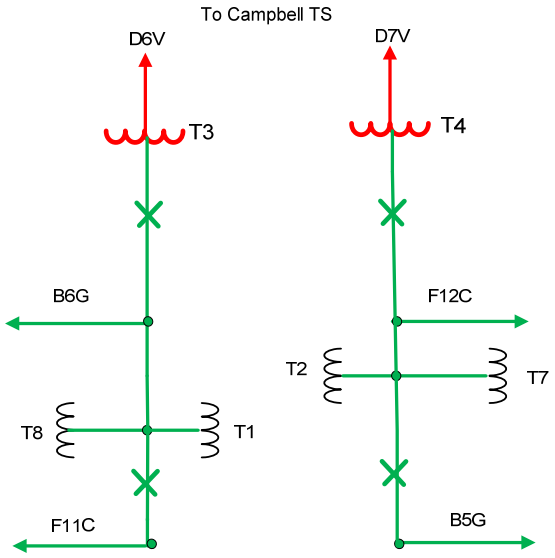


Figure 3: STAGE 1 - Schematic Single Line Diagram of CEDAR TS with Implementation of GATR

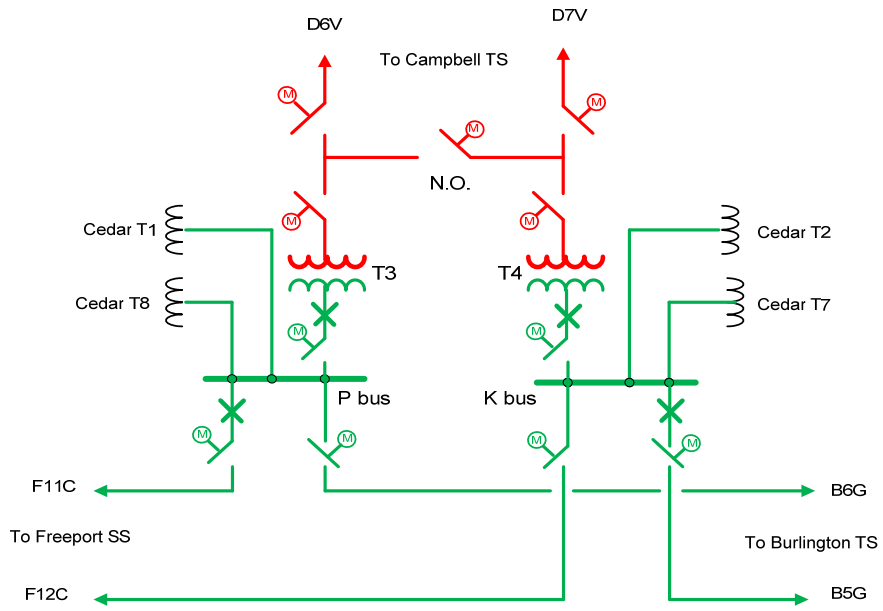


Figure 4: STAGE 1 - Detailed Single Line Diagram of CEDAR TS with Implementation of GATR
(CEDAR bus split – 4 in-line breakers)

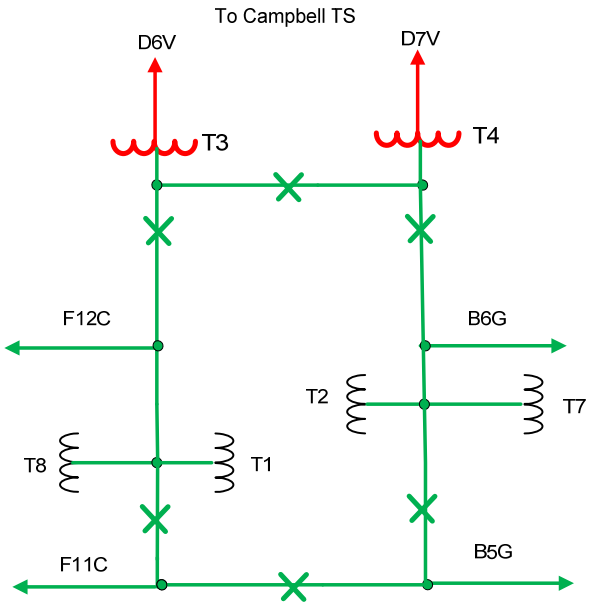


Figure 5: STAGE 2 - Schematic Single Line Diagram CEDAR TS ring bus configuration with six 115 kV breakers (future configuration - ultimate design)

Inverhaugh SS

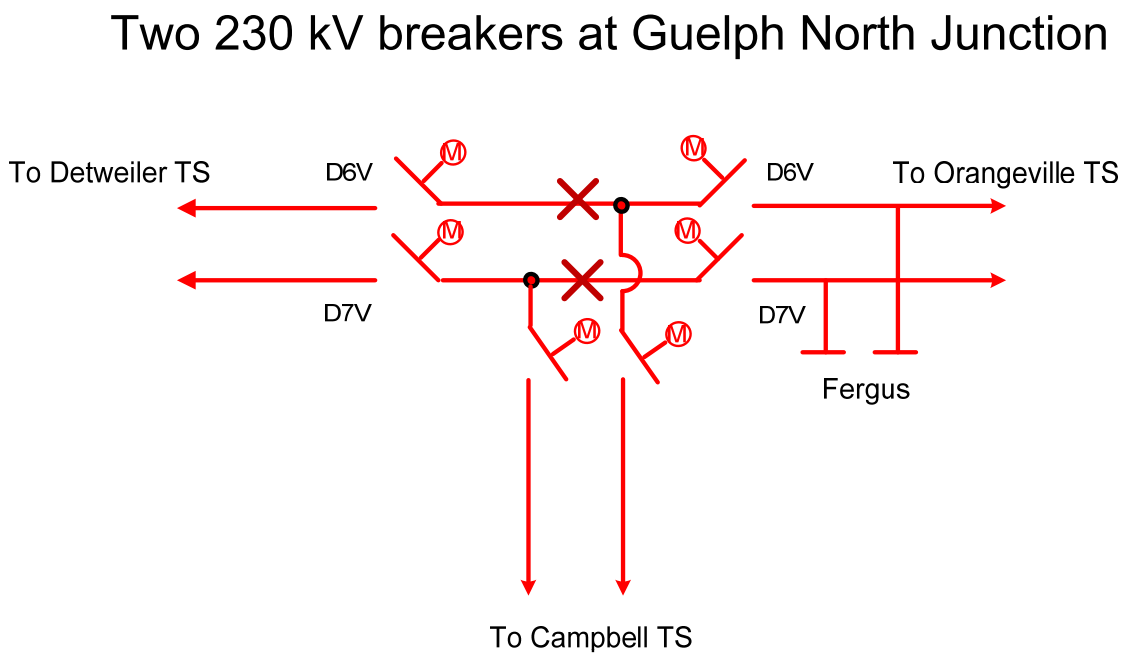


Figure 6 : Two 230 kV circuit breakers at Guelph North Junction

3.0 CUSTOMER IMPACT ASSESSMENT

This Customer Impact Assessment (CIA) is a requirement of the Transmission System Code (TSC) to assess the potential impacts on the existing transmission connected customer(s). The primary focus of this study is to communicate the Guelph Area Transmission Project to customers supplied directly in the KWCG area and in the vicinity of the mentioned geographical area (Figure 2). Table 1 summarizes the customers connected at each station:

Table 1: Transmission Customers in the KWCG Area

Customers	Station
Ameri Steel Cambridge	Gerdau-Courtice Steel CTS
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1
	Galt TS
	Preston TS
	Wolverton DS
Centre Wellington Hydro Ltd.	Fergus TS
Guelph Hydro Electric System - Rockwood Division	Fergus TS
Guelph Hydro Electric Systems Inc.	Arlen MTS
	Campbell TS
	Cedar TS
	Hanlon TS
Halton Hills Hydro Inc.	Fergus TS
Hydro One Networks Inc.	Fergus TS
	Puslinch DS
	Wolverton DS
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1
	Kitchener MTS#3
	Kitchener MTS#4
	Kitchener MTS#5
	Kitchener MTS#6
	Kitchener MTS#7
	Kitchener MTS#8
	Kitchener MTS#9
Milton Hydro Distribution Inc.	Fergus TS
Waterloo North Hydro Inc.	Elmira TS
	Fergus TS
	Rush MTS
	Scheifele MTS
	Waterloo North MTS 3
Wellington North Power Inc	Fergus TS
Westover	Enbridge Westover CTS

3.1 Study Assumptions

The short circuit study was carried out with the following primary system assumptions:

(1) Generation Facilities In-service

East

Lennox G1-G4 Chenaux G1-G8
Kingston Cogen G1-G2 Mountain Chute G1-G2
Wolf Island 300 MW Stewartville G1-G5
Arnprior G1-G2 Brockville G1
Barrett Chute G1-G4 Havelock G1
Chats Falls G2-G9 Saunders G1-G16
Cardinal Power G1, G2

Toronto

Pickering units G1, G4-G8 Sithe Goreway G11-13, G15
Darlington G1-G4 TransAlta Douglas G1-G3
Portlands GS G1-G3 GTAA G1-G3
Algonquin Power G1, G2 Brock west G1
Whitby Cogen G1

Niagara

Thorold GS GTG1, STG2 Beck 2 G11-G26
Beck 1 G3-G10 Beck 2 PGS G1-G6
Decew G1, G2, ND1

South West

Nanticoke G5-G8 Kingsbridge WGS 39.6 MW
Halton Hills GS G1-G3 Amaranth WGS 199.5 MW

Bruce

Bruce A G1-G4 Ripley WGS 76 MW
Bruce B G5-G8 Underwood WGS 198 MW
Bruce A Standby SG1

West

Lambton units G3-G4 Imperial Oil G1
Brighton Beach G1, G1A, G1B Kruger Port Alma WGS 101.2 MW
Greenfield Energy Centre G1-G4 Gosfield Wind Project 50.6 MW
St. Clair Energy Centre CTG3, STG3, CTG4, STG4 Kruger Energy Chatham WF 101 MW
East Windsor Cogen G1-G2 Raleigh Wind Energy Centre 78 MW
TransAlta Sarnia G861, G871, G881, G891 Talbot Wind Farm 98.9 MW

Ford Windsor CTS STG5 Dow Chemicals G1, G2, G5
TransAlta Windsor G1, G2 Port Burwell WGS 99 MW
West Windsor Power G1, G2 Fort Chicago London Cogen 23 MVA
Great Northern Tri-Gen Cogen 15 MVA

(2) Previously Committed Generation Facilities

- Port Dover and Nanticoke
- Big Eddy GS and Half Mile Rapids GS • Grand Renewable Energy Park
- White Pines Wind Farm • Green Electron
- Amherst Island • Comber East C24Z
- York Energy Centre • Comber West C23Z

• Conestogo Wind Energy Centre 1 • Pointe-Aux-Roches Wind
• Dufferin Wind Farm • South Kent Wind Farm
• Summerhaven Wind Farm • Wolfe Island Shoals
• Bluewater Wind Energy Centre • East Lake St. Clair Wind
• Jericho Wind Energy Centre • Adelaide Wind Power Project
• Bornish Wind Energy Centre • Gunn's Hill Wind Farm
• Goshen Wind Energy Centre • Silvercreek Solar Park
• Cedar Point Wind Power Project Phase II • K2 wind
• Adelaide Wind Energy Centre • Armow
• Grand Bend Wind Farms • 300 MW wind at Orangeville
• Grand Valley Wind Farms (Phase 3) • 100 MW wind at S2S
• Erieau Wind

(3) Existing and Committed Embedded Generation

• Essa area: 264 MW • Niagara area: 52 MW
• Ottawa area: 90 MW • Southwest area: 348 MW
• East area: 580 MW • Bruce area: 26 MW
• Toronto area: 168 MW • West area: 585 MW

(4) Transmission System Upgrades

• Woodstock Area transmission reinforcement (CAA2006-253);
o Karn TS in-service and connected to M31W & M32W at Ingersol TS
o W7W/W12W terminated at LFarge CTS
o Woodstock TS connected to Karn TS
• Rodney (Duart) TS DESN connected to W44LC and W45LS 230 kV circuits (CAA2007-260)

(5) System Operation Conditions

• Lambton TS 230 kV operated *open*
• Claireville TS 230 kV operated *open*
• Leaside TS 230 kV operated *open*
• Leaside TS 115 kV operated *open*
• Middleport TS 230 kV bus operated *open*
• Hearn SS 115 kV bus operated *open*
• Preston T2 connected to M21D
• Cherrywood TS north & south 230kV buses operated ***open***
• Richview TS 230 kV bus operated ***open***
• All tie-lines in-service and phase shifters on neutral taps
• Maximum voltages on the buses

4.0 Results of Assessment

4.1 Short-Circuit Analysis

The GATR project will have no material impact on fault levels after completion of the Project, therefore, existing levels at each bus are shown in Table 2 and 3. Two cases were included to simulate scenarios whether the Cedar 115 kV bus is split and closed (ring bus). 2016 system conditions have the Cedar 115 kV bus split.

Table 2: Present Fault Levels

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	11.449	13.388	9.715	11.662
Burlington TS 230kV	51.410	61.691	43.592	55.718
Cambridge MTS #1 230kV M20D	8.916	10.422	6.349	6.814
Cambridge MTS #2 230kV M21D	10.344	12.080	8.901	11.004
Detweiler TS 230kV	23.608	27.687	23.116	29.508
Kitchener MTS #6 230kV M20D	17.938	20.908	16.092	18.554
Kitchener MTS #6 230kV M21D	17.897	20.865	16.110	18.575
Kitchener MTS #8 230kV M20D	17.584	20.830	14.409	16.560
Kitchener MTS #8 230kV M21D	17.424	20.661	14.443	16.656
Kitchener MTS #9 230kV D4W	14.738	17.106	11.452	12.839
Kitchener MTS #9 230kV D5W	14.738	17.106	11.463	12.849
Middleport TS 230kV DK1	47.130	59.276	44.120	57.728
Middleport TS 230kV DK2	42.868	55.035	40.126	54.459
Orangeville TS 230kV	19.411	22.207	20.916	24.991
Scheifele CTS 230kV D6V	16.211	18.489	13.637	15.311
Scheifele CTS 230kV D7V	16.180	18.454	13.610	15.280
Waterloo North CTS 230kV D6V	18.752	21.494	16.825	19.338
Waterloo North CTS 230kV D7V	18.667	21.390	16.735	19.225
Arlen MTS 115kV B5G	5.017	5.097	2.606	2.624
Arlen MTS 115kV B6G	5.017	5.097	2.605	2.623
Burlington TS 115kV	34.996	43.549	39.214	50.887
Detweiler TS 115kV	24.602	28.487	28.510	35.151
Enbridge Westover CTS 115kV North	5.222	5.223	3.315	3.315
Enbridge Westover CTS 115kV South	5.024	5.025	3.196	3.196
Kitchener MTS #1 115kV D11K	14.219	14.944	11.382	11.873
Kitchener MTS #1 115kV D12K	14.220	14.944	11.383	11.873
Kitchener MTS #3 115kV D7F	13.875	14.928	11.292	11.903
Kitchener MTS #3 115kV D9F	11.322	12.251	8.587	8.916
Kitchener MTS #4 115kV D11K	14.286	15.020	11.455	11.952
Kitchener MTS #4 115kV D12K	14.287	15.021	11.455	11.953
Kitchener MTS #5 115kV F12C	10.207	10.707	7.540	7.850
Kitchener MTS #5 115kV F11C	8.298	8.769	5.727	5.888
Kitchener MTS #7 115kV D7F	14.374	15.586	12.426	13.299
Kitchener MTS #7 115kV D9F	10.690	11.575	8.143	8.416
Puslinch DS 115kV B5G	5.382	5.458	2.894	2.914
Puslinch DS 115kV B6G	5.382	5.458	2.893	2.914
Rush MTS 115kV D10	14.005	14.562	11.360	11.784
Rush MTS 115kV D8S	13.812	14.331	11.297	11.703
Wolverton DS 115kV	5.899	5.899	3.941	3.941
Fergus TS 44kV	14.514	14.707	6.911	8.097
Elmira TS 27.6kV	7.062	7.062	7.188	7.188
Galt TS 27.6kV J	12.293	12.657	9.845	11.315
Galt TS 27.6kV Y	12.227	12.587	9.816	11.278
Preston TS 27.6kV J	12.359	12.960	9.771	11.287
Preston TS 27.6kV Q	12.712	13.293	9.919	11.436
Campbell TS 13.8kV BY	16.940	17.221	8.328	9.760
Campbell TS 13.8kV EZ	17.367	17.729	8.397	9.885
Campbell TS 13.8kV JQ	16.924	17.183	8.324	9.744
Cedar TS 13.8kV JQ	13.109	13.109	7.691	7.691
Cedar TS 13.8kV BY	14.061	14.061	6.819	7.435
Cedar TS 13.8kV EZ	13.998	13.998	6.805	7.410
Hanlon TS 13.8kV BY	13.939	13.939	7.858	7.858

Table 3: Fault Levels with Implementation of GATR (CEDAR bus split – 4 in-line breakers)

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	11.970	13.982	10.068	12.052
Burlington TS 230kV	52.661	63.061	44.375	56.591
Cambridge MTS #1 230kV M20D	8.969	10.499	6.387	6.852
Cambridge MTS #2 230kV M21D	10.932	12.771	9.329	11.517
Detweiler TS 230kV	24.726	28.857	24.030	30.483
Kitchener MTS #6 230kV M20D	18.545	21.541	16.548	19.005
Kitchener MTS #6 230kV M21D	18.515	21.509	16.561	19.023
Kitchener MTS #8 230kV M20D	18.030	21.305	14.668	16.818
Kitchener MTS #8 230kV M21D	17.942	21.210	14.744	16.956
Kitchener MTS #9 230kV D4W	15.064	17.445	11.623	13.007
Kitchener MTS #9 230kV D5W	15.064	17.445	11.634	13.017
Middleport TS 230kV DK1	47.212	59.369	44.175	57.792
Middleport TS 230kV DK2	42.953	55.137	40.185	54.535
Orangeville TS 230kV	20.169	23.062	21.555	25.744
Scheifele CTS 230kV D6V	16.957	19.281	14.297	15.989
Scheifele CTS 230kV D7V	16.955	19.279	14.298	15.986
Waterloo North CTS 230kV D6V	19.551	22.328	17.489	20.013
Waterloo North CTS 230kV D7V	19.479	22.239	17.408	19.908
Arlen MTS 115kV B5G	13.071	13.509	9.656	9.899
Arlen MTS 115kV B6G	12.597	13.048	6.414	6.449
Burlington TS 115kV	39.372	48.028	43.055	55.019
Detweiler TS 115kV	27.474	31.332	31.142	37.811
Enbridge Westover CTS 115kV North	5.976	5.976	3.811	3.812
Enbridge Westover CTS 115kV South	5.716	5.717	3.654	3.655
Kitchener MTS #1 115kV D11K	15.129	15.821	11.776	12.248
Kitchener MTS #1 115kV D12K	15.129	15.822	11.776	12.249
Kitchener MTS #3 115kV D7F	16.247	17.272	12.521	13.094
Kitchener MTS #3 115kV D9F	14.255	15.160	10.073	10.388
Kitchener MTS #4 115kV D11K	15.205	15.907	11.854	12.333
Kitchener MTS #4 115kV D12K	15.205	15.907	11.854	12.333
Kitchener MTS #5 115kV F12C	11.763	12.231	8.236	8.523
Kitchener MTS #5 115kV F11C	10.331	10.767	6.626	6.777
Kitchener MTS #7 115kV D7F	17.634	18.821	14.420	15.247
Kitchener MTS #7 115kV D9F	14.434	15.319	10.111	10.373
Puslinch DS 115kV B5G	11.524	11.740	7.999	8.113
Puslinch DS 115kV B6G	11.231	11.457	6.033	6.060
Rush MTS 115kV D10	14.858	15.384	11.747	12.152
Rush MTS 115kV D8S	14.656	15.144	11.687	12.074
Wolverton DS 115kV	6.062	6.063	3.992	3.993
Fergus TS 44kV	14.745	14.986	6.948	8.167
Elmira TS 27.6kV	7.111	7.111	7.222	7.222
Galt TS 27.6kV J	12.335	12.712	9.863	11.347
Galt TS 27.6kV Y	12.270	12.641	9.834	11.311
Preston TS 27.6kV J	12.409	13.036	9.791	11.329
Preston TS 27.6kV Q	12.764	13.371	9.940	11.478
Campbell TS 13.8kV BY	17.254	17.617	8.378	9.864
Campbell TS 13.8kV EZ	17.680	18.124	8.445	9.984
Campbell TS 13.8kV JQ	17.238	17.576	8.374	9.846
Cedar TS 13.8kV JQ	16.653	16.653	8.387	8.649
Cedar TS 13.8kV BY	16.498	16.981	7.160	8.269
Cedar TS 13.8kV EZ	16.410	16.856	7.145	8.227
Hanlon TS 13.8kV BY	17.226	17.226	8.461	8.715

Table 4: Fault Levels with CEDAR bus closed
(Future arrangement – 6 breaker ring bus – ultimate design)

Table 4: Fault Levels with Implementation of GATR (Cedar Solid Buses)

Area Customers	Fault Levels (kA)			
	3-phase		Line-to-ground	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Ameri Steel CTS 230kV	12.008	14.021	10.086	12.071
Burlington TS 230kV	52.661	63.061	44.389	56.608
Cambridge MTS #1 230kV M20D	8.970	10.501	6.387	6.853
Cambridge MTS #2 230kV M21D	10.980	12.821	9.352	11.542
Detweiler TS 230kV	24.729	28.861	24.038	30.493
Kitchener MTS #6 230kV M20	18.547	21.543	16.580	19.036
Kitchener MTS #6 230kV M21	18.516	21.511	16.576	19.037
Kitchener MTS #8 230kV M20	18.031	21.306	14.672	16.821
Kitchener MTS #8 230kV M21	17.942	21.210	14.747	16.959
Kitchener MTS #9 230kV D4W	15.064	17.446	11.625	13.008
Kitchener MTS #9 230kV D5W	15.064	17.446	11.636	13.018
Middleport TS 230kV DK1	47.212	59.370	44.176	57.793
Middleport TS 230kV DK2	42.958	55.142	40.188	54.539
Orangeville TS 230kV	20.170	23.064	21.557	25.746
Scheifele CTS 230kV D6V	17.005	19.336	14.320	16.015
Scheifele CTS 230kV D7V	16.972	19.299	14.306	15.995
Waterloo North CTS 230kV D6V	19.575	22.355	17.503	20.029
Waterloo North CTS 230kV D7V	19.482	22.243	17.410	19.911
Arlen MTS 115kV B5G	15.295	15.666	10.451	10.661
Arlen MTS 115kV B6G	15.293	15.665	10.439	10.648
Burlington TS 115kV	39.374	48.029	43.077	55.044
Detweiler TS 115kV	27.499	31.357	31.192	37.863
Enbridge Westover CTS 115kV North	6.023	6.023	3.824	3.825
Enbridge Westover CTS 115kV South	5.759	5.760	3.666	3.667
Kitchener MTS #1 115kV D11	15.136	15.829	11.783	12.255
Kitchener MTS #1 115kV D12	15.137	15.830	11.783	12.255
Kitchener MTS #3 115kV D7F	16.334	17.355	12.555	13.126
Kitchener MTS #3 115kV D9F	14.573	15.468	10.827	11.207
Kitchener MTS #4 115kV D11	15.212	15.914	11.861	12.340
Kitchener MTS #4 115kV D12	15.213	15.915	11.861	12.340
Kitchener MTS #5 115kV F12	11.846	12.311	8.264	8.549
Kitchener MTS #5 115kV F11	10.582	11.010	7.141	7.325
Kitchener MTS #7 115kV D7F	17.861	19.038	14.521	15.342
Kitchener MTS #7 115kV D9F	14.980	15.849	11.356	11.717
Puslinch DS 115kV B5G	12.789	12.962	8.406	8.501
Puslinch DS 115kV B6G	12.788	12.961	8.400	8.495
Rush MTS 115kV D10	14.865	15.391	11.753	12.158
Rush MTS 115kV D8S	14.663	15.151	11.693	12.080
Wolverton DS 115kV	6.063	6.064	3.993	3.993
Fergus TS 44kV	14.746	14.987	6.948	8.167
Elmira TS 27.6kV	7.111	7.111	7.222	7.222
Galt TS 27.6kV J	12.338	12.714	9.864	11.349
Galt TS 27.6kV Y	12.272	12.644	9.835	11.312
Preston TS 27.6kV J	12.412	13.039	9.793	11.330
Preston TS 27.6kV Q	12.768	13.375	9.942	11.480
Campbell TS 13.8kV BY	17.254	17.618	8.378	9.864
Campbell TS 13.8kV EZ	17.681	18.125	8.445	9.984
Campbell TS 13.8kV JQ	17.238	17.577	8.374	9.847
Cedar TS 13.8kV JQ	16.654	16.654	8.387	8.649
Cedar TS 13.8kV BY	16.501	16.994	7.160	8.273
Cedar TS 13.8kV EZ	16.412	16.867	7.145	8.230
Hanlon TS 13.8kV BY	17.228	17.228	8.462	8.716

Notes

1. Pre-fault voltages of 250 kV at 230 kV stations and 29 kV at 27.6 kV stations are assumed.
2. A breaker contact parting time of 25ms was assumed for asymmetrical current calculation for 230kV breakers and a contact parting time of 30ms was assumed for asymmetrical current calculation for 27.6kV breakers.
3. 2 units at Lambton GS, 6 units at Nanticoke, latest FIT project additions and all 5 phases of Samsung projects were considered.

4.2 Observations

Results show that fault levels are within maximum symmetrical three-phase and single line-to-ground faults (kA) of 230 kV, 115kV, 27.6 kV and 13.8 kV systems for all equipment connected to Hydro One transmission system as set out in Appendix 2 of the TSC when the Cedar 115kV bus is split or closed.

The largest changes observed were found to be at Arlen MTS, 8.4 kA, Cedar TS, 3.5 kA and Hanlon TS 3.3 kA. As noted above, the magnitude of these changes are acceptable.

The maximum symmetrical three-phase and single line-to-ground faults given for those voltages in the TSC may be summarized as follows:

Nominal Voltage (kV)	***Max. 3-Phase Fault (kA)***	***Max. SLG Fault (kA)***
230	63	80 (usually limited to 63 kA)
115	50	50
44	20	19 (usually limited to 8 kA)
27.6	17	12 (4 wire)/ 0.45 (3 wire)
13.8	21	10

5.0 Conclusions and Recommendations

This CIA report presents results of incorporating the transmission facilities planned for meeting the reliability needs of the Kitchener-Waterloo-Cambridge-Guelph Area in the near- and medium-terms. In particular, the results of short-circuit analyses have been presented.

Short-circuit studies were carried out to determine the new projected fault levels at customer transmission connection points. The short-circuit levels observed at connection points are within the requirements of the Transmission System Code.

It is recommended that the customers review the impact of the short-circuit change on their facilities and take appropriate and timely action to address any safety/technical issues arising out of these changes which will result following incorporation of the transmission facilities in the Fall of 2015.

APPENDIX I: OPA Letter to Hydro One

Integrated Regional Resource Planning (IRRP)

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May 29, 2013

Mr. Bing Young
Director, Transmission System Development
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Initiating Near-Term Transmission Components of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Area Integrated Regional Resources Plan (IRRP)

Dear Bing:

The purpose of this letter is to:

- Hand-off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the near-term transmission component of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area Integrated Regional Resource Planning (IRRP) process to Hydro One.

- Request that Hydro One develop wires solutions and implement the near-term transmission component of the integrated plan to meet the near- and medium-term reliability needs in the KWCG area.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity.

The KWCG Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and local distribution companies in the KWCG area, has been conducting an IRRP process for the KWCG area. In combination with conservation and local generation options, the Working Group has identified two transmission projects for meeting the reliability needs of the area in the near- and medium- term. These projects are:

- the Guelph Area Transmission Refurbishment (GATR) project – Hydro One is currently proceeding with this project, including seeking the necessary OEB Leave-to-Construct approval; and
- the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive facilities (Preston Autotransformer Project) – the OPA has completed a preliminary assessment of this option as part of the IRRP process.

While the GATR project has advanced to the approval phase, more detailed study and development work is required for planning the Preston Autotransformer Project. This is best accomplished by the lead transmitter, Hydro One, leading these efforts as part of the Working Group, guided by the information and requirements provided below from the IRRP process.

Objectives:

The objectives of the Preston Autotransformer Project are:

- To provide adequate load meeting capability to connect a future Cambridge & North Dumfries Hydro transformer station on the Kitchener-Guelph 115 kV system by about 2018

- To substantially improve the ability to restore electricity supply and minimize the potential impact of service interruptions to customers following a major transmission outage in the Cambridge area consistent with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)

- To provide sufficient voltage support for the Kitchener-Guelph 115 kV system and Cambridge 230 kV system to comply with IESO requirements

- To facilitate the necessary measures to manage multiple outages conditions on the Kitchener-Guelph 115 kV system and Cambridge 230 kV system

Scope:

The Working Group has discussed various options for meeting the above objectives and recommends proceeding with the following measures:

- Installation of a second 230/115 kV autotransformer at Preston TS and associated 115 kV switching facilities

- Installation of low-voltage capacitor banks on the Kitchener-Guelph 115 kV and/or the Cambridge 230 kV system

- Design and implementation of a Load Rejection (L/R) scheme for the Kitchener-Guelph 115 kV system, or have available operational measures adequate to provide similar relief.

In addition to the scope outlined above, other options for meeting the above objectives may also be considered as part of the development work. Hydro One will confirm the scope and costs of the above facilities to meet the identified reliability needs and to optimize their specifications and configuration. At this time, based on preliminary cost estimates provided by Hydro One, the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support are expected to be between $20 million and $35 million. However, further refinements to the cost will be provided as part of the development work. The costs may also

vary due to any significant scope changes arising from new information that is substantively different to that used in the IRRP process to date.

Consistent with the support letter that was submitted to Hydro One on August 7, 2012, these measures will further leverage the system improvements gained through the GATR project to address the near- and medium-term needs of the KWCG area. The ability of the Preston Autotransformer Project to meet the above objectives is subject to the availability of the GATR facilities.

In coordination with and subject to the OEB approval of the GATR project, the second 230/115kV autotransformer at Preston TS and associated switching and reactive support should be in-service by the end of 2015.

Supporting Information:

To facilitate the development of these wires solutions, the OPA may provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to information, results and deliverables from the Preston Autotransformer project as part of the KWCG Working Group activities and to continuing to work with and support Hydro One on the implementation of this project.

Regards,

R. F. Chow

Bob Chow
Director, Transmission Integration
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APPENDIX J: CDM Analysis

Historical Results and LTEP Peak Demand Reduction Associated with Energy Savings Targets (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EE (historical and future programs)	1,248	1,435	1,528	1,662	1,575	1,752	2,022	2,321	2,357	2,470

Historical Results and LTEP Annual Energy Savings Targets (TWh)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecasted savings from future programs	1.0	2.5	3.3	4.8	5.9	7.2	8.7	10.4	10.9	12.0
Historical program persistence (2006-2012)	5.9	5.8	5.5	4.1	3.0	2.3	2.2	1.8	1.6	1.4
Codes and Standards (forecasted savings)	0.2	0.2	0.5	0.9	1.0	1.9	2.6	3.0	3.7	4.0
Codes and Standards (existing savings)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
LTEP 2013 total energy savings	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0
EE (historical and future programs) TWh	6.9	8.3	8.8	8.9	8.9	9.5	10.9	12.2	12.5	13.4
EE (historical and future programs) MWh	6,900,000	8,300,000	8,800,000	8,900,000	8,900,000	9,500,000	10,900,000	12,200,000	12,500,000	13,400,000

Energy to Peak Ratio (MW/MWh)	**0.000181**	**0.000173**	**0.000174**	**0.000187**	**0.000177**	**0.000184**	**0.000186**	**0.000190**	**0.000189**	**0.000184**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Calculated kW/GWh:	***181***	***173***	***174***	***187***	***177***	***184***	***186***	***190***	***189***	***184***
GHESI 2015-2020 Total Energy Reduction Target:		***99.04***	***GWh***							
GHESI 2015-2020 Annual Energy Reduction Target:		***[GWh]***	***16.51***	***16.51***	***16.51***	***16.51***	***16.51***	***16.51***	***99.04***	***Total GWh***
Annual Demand Reduction Estimate:		***[MW]***	***2.87***	***3.08***	***2.92***	***3.04***	***3.06***	***3.14***	***18.12***	***Total MW***

GHESI 2015-2020 Total Energy Reduction Target:	**99.035**	**GWh**
GHESI 2015-2020 Annual Energy Reduction Target:	**16.51**	**GWh / year**

APPENDIX K: 2014 Useful Life of Assets Study

Kinectrics Inc.

Guelph Hydro Electric System Inc.

Asset Useful Life Review

Kinectrics Inc. Report No: K-418636-RA-001-R01

April 23, 2015

Confidential & Proprietary Information
Contents of this report shall not be disclosed
without authority of client.
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Guelph Hydro Electric System Inc.

@Kinectrics Inc., 2015.

Guelph Hydro Electric System Inc.
Asset Useful Life Review

Kinectrics Inc. Report No: K-418636-RA-001-R01

April 23, 2015

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Revision History

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R00	December 19, 2014	Initial Draft	N/A
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R01	April 22, 2015	Final	Yury Tsimberg

EXECUTIVE SUMMARY

This study provides a review of Guelph Hydro Electric System Inc (GHESI)'s revised asset useful lives with reference to the useful life values in OEB depreciation study report. For the asset groups that were not covered by OEB study, the revised useful lives are compared against the 2010 useful life study report for GHESI.

The review on all the asset groups at GHESI finds that for majority of these asset groups, the useful lives in GHESI financial asset system are identical or better than the typical useful life values listed in OEB study.

For the asset groups that show shorter useful lives than in OEB study, rationales are provided highlighting the major contributing factors. In most cases, these were related to specific operation and replacement strategies at GHESI. A small portion of such cases were due to asset manufacturing or operation environments.

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A INTRODUCTION

Guelph Hydro Electric System Inc (GHESI) determined the need to update the useful life values in their financial asset system, so as to better reflect the practical asset status at GHESI. The useful life values in such a database directly affect the asset book values, and are used for the purpose of financial accounting, asset consolidation and amortization assessment.

In 2010, Kinectrics conducted a useful life study of all the asset groups for a consortium of local distribution utilities, including GHESI. The useful life values were compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience.

Since then, GHESI kept track on their asset condition status by recording information and issues that might affect the useful lives of their asset groups, such as:

- Issues related to asset manufacturing
- Issues related to specific operation environment
- Inventory statistics on asset replacement
- Replacement strategies

Based on collection of the above information, GHESI proposed revisions on part of their asset useful lives.

The purpose of this study is to review the updated asset useful lives in GHESI financial system, with reference to the asset useful life ranges listed in OEB depreciation study report. Given the diversity in asset fleet, maintenance philosophies and geographic restraints among local distribution utilities, OEB depreciation study report functions only as a guideline rather than a requirement. Nevertheless, such a lateral comparison can help highlight the aspects that remain to be improved.

A.1 Project Scope

This report provides, for the assets that are owned and operated by the GHESI, a comparison of their useful lives in GHESI financial asset system against the useful life values listed in OEB asset depreciation study report. The typical parent system(s) to which the asset belongs is provided and these “parent” systems are: *Overhead Lines* (OH), *Distribution Transformers* (DT), *Stations (TS & DS), Underground Systems* (UG) and *Monitoring and Control System* (S). For each asset or component, the following information is presented:

- OEB useful life range
- Typical useful life in GHESI financial asset system
- Rational for GHESI’s typical useful life if shorter than OEB value

Section A.2 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

A.2 Definition of Terms

A.2.1 Typical Distribution System Asset

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

A.2.2 Component

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its replacement value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

A.2.3 Useful Life

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report for each type of asset, the OEB useful life range, in years, is presented in terms of a minimum, maximum, and typical value, while the GHESI financial asset system lists only a typical useful life value.

An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. The majority of the units within this class will perform as required for at least 20 years and likewise the majority of the units will not operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in various utilization factors including mechanical stress, electrical loading, and environmental conditions and operating practices.

A.2.4 Typical Life

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

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B RESULTS AND FINDINGS

Table 1-1 summarizes OEB useful and typical lives, as well as typical useful lives in GHESI asset system. The highlighted cells refer to GHESI's useful life values that are shorter than the typical useful life value in OEB study. Rationales are provided in later sections addressing these highlighted useful life values.

Table 1 Summary of Componentized Assets

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
OH	1	Fully Dressed Poles		Wood	35	45	75	50
				Composite	NA	NA	NA	70
				Concrete	50	60	80	40
				Framing	NA	NA	NA	50
	3	Fused Cutouts			25	30	40	50
	4	Manual Overhead Switches		Solid Blade Disconnects	30	45	55	50
				Gang-Operated LIS	30	45	55	50
	7	Integral Switch	Switch	SCADAMate	35	45	60	45
			RTU		NA	NA	NA	10
	8	Conductors	Primary	Single-Phase	50	60	75	50
				Three-Phase	50	60	75	50
			Neutral		50	60	75	50
			Secondary	Insulated Wire	50	60	75	50
			Services	Insulated Wire	50	60	75	60

* OH = Overhead Lines UG = Underground System
DT = Distribution Transformers S = Monitoring and Control System

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
OH	9	Capacitor Banks		Frame and Tanks	25	30	40	30
				Switch	25	30	40	30
				RTU	NA	NA	NA	10
DT	12	Pole Top Transformer		Single-Phase	30	40	60	40
				Three-Phase	30	40	60	40
	14	Pad-Mounted Transformer	Transformer	Single-Phase	25	40	45	40
				Three-Phase	25	40	45	40
			Foundation	Single-Phase	35	55	70	60
				Three-Phase	35	55	70	60
	16	Submersible Transformer	Transformer		25	35	45	35
			Vault		40	60	80	60
			Roof		20	30	45	30
	17	Indoor Vault Transformer	Transformer	Single-Phase	25	35	45	35
				Three-Phase	25	35	45	40
UG	18	UG Switchgear	Riser Switch	Gang-Operated LIS	20	30	45	30
				Solid-Blade	20	30	45	30
				Fused	20	30	45	30
			Air Insulated	Live-Front	20	30	45	25
				Dead-Front	20	30	45	25

* OH = Overhead Lines UG = Underground
DT = Distribution Transformers S = Substation

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
UG	18	UG Switchgear	Solid Dielectric		20	30	45	30
			Switch Base		NA	NA	NA	55
			Motor		NA	NA	NA	20
			RTU		NA	NA	NA	10
	19	Primary Cables	Solid Dielectric in Duct	Single-Phase Lateral	35	40	55	40
				Three-Phase Lateral	35	40	55	40
				Three-Phase Feeder	35	40	55	40
	20	Secondary Cables	Solid Dielectric in Duct		35	40	60	40
			Solid Dielectric Direct Buried		25	35	40	40
			Solid Dielectric in Duct / DB - Service		NA	NA	NA	30
	21	Ducts	Concrete Encased		35	55	80	50
			PVC (Direct Buried)		30	50	85	50
			HDPE (Direct Buried)		30	50	85	50
			FRE (Direct Buried)		30	50	85	50
	22	Cable Chambers	Large - Manhole		50	60	80	60
			Sidewalk / Field Vault		NA	NA	NA	60
			Sidewalk / Field Vault Roof		NA	NA	NA	30

* OH = Overhead Lines UG = Underground
DT = Distribution Transformers S = Substation

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
UG	23	Junction Cubicle / Service Box	Pads/bases		NA	NA	NA	60
			Junction/switching cabinets		NA	NA	NA	30
S	24	Station Grounding Transformer		TS	30	40	40	40
	25	Station Service Transformer		TS	30	45	55	40
				MS	30	45	55	40
	26	TS Power Transformer	Overall		30	45	60	45
			Bushing		10	20	30	30
			Tap Changer		20	30	60	30
	27	MS Power Transformer	Overall		30	45	60	45
			Bushing		10	20	30	30
			Tap Changer		20	30	60	30
	28	MV Switchgear - TS	Assembly	Air Insulated	30	40	60	50
				Vacuum	25	40	60	40
		MV Switchgear - MS	Assembly	Air Insulated	30	40	60	50
	29	Independent Breakers - TS		Gas (SF6)	35	45	65	45
	30	Protection & Control Devices - TS	Panels		NA	NA	NA	40
			Control Cable		NA	NA	NA	40
			Relays	Digital	15	20	20	15

* OH = Overhead Lines UG = Underground
DT = Distribution Transformers S = Substation

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
S	30	Protection & Control Devices - MS	Panels		NA	NA	NA	40
			Control Cable		NA	NA	NA	40
			Relays	Digital	15	20	20	15
	31	Station Disconnect Switch - TS	Manual Switch		30	50	60	45
			Remote Operated Switch		30	50	60	45
			Switch Motor		NA	NA	NA	45
		Station Disconnect Switch - MS			30	50	60	45
	32	DC System - TS	Batteries		10	15	15	15
			Chargers		20	20	30	20
			DC Distribution Equipment		10	20	30	20
		DC System - MS	Batteries		10	10	15	15
			Chargers		20	20	30	20
			DC Distribution Equipment		10	20	30	20
	33	Station Grounding System - TS		Ground Grid	NA	NA	NA	40
				Neutral Reactors	NA	NA	NA	40
				Arresters	NA	NA	NA	20
		Station Grounding System - MS		Ground Grid	NA	NA	NA	40
				Arresters	NA	NA	NA	20

* OH = Overhead Lines UG = Underground

PARENT*	#	Asset Group			OEB Useful Life			GHESI Financial Asset System Useful Life
		Category	Component	Type	Min	Typical	Max	
DT = Distribution Transformers S = Substation								
S	34	Bus Work & Steel Structures		TS	35	50	90	50
				MS	35	50	90	50
	35	Station Building	Structure		50		75	50
			Roof		20		30	20
			Fence		25		60	35
	36	Metering	Meter	Smart	5		15	15
				Industrial/Commercial	25		35	20
				Wholesale	15		30	20
			Transformers (CTs, PT's)		35		50	45
	37	SCADA System	Master		NA	NA	NA	5
			RTU		15	20	30	10
			Battery		NA	NA	NA	5
	38	Remote Fault Indicators	Indicator		NA	NA	NA	10
			RTU		NA	NA	NA	10
	39	Communication System		Towers	60		70	65
				Circuits	NA	NA	NA	15
				Electronics	NA	NA	NA	10
* OH = Overhead Lines UG = Underground DT = Distribution Transformers S = Substation								

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1. Fully Dressed Poles

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself. For the purposes of this report we are discussing the useful life of five types:

- Wood
- Composite
- Concrete
- Framing

1.1. Wood Poles

According to OEB asset depreciation study report, the useful life of wood poles is in the range of 35 to 75 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study range, and better than OEB study typical useful life.

1.2. Composite Poles

OEB asset depreciation study report does not address the useful life of composite poles.

In GHESI financial asset system, a typical useful life value of 70 years is set up. This is the typical useful life as per GHESI 2010 useful life study.

1.3. Concrete Poles

According to OEB asset depreciation study report, the useful life of concrete poles is in the range of 50 to 80 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is due to the manufacturing issue that caused defects during practical operation. GHESI has contacted the manufacturer multiple times regarding the issue. The issues started since 1990's with the concrete poles of a specific manufacturer, and spanned over late 2000's. Both manufacture flaws and installation defects contributed to the issues [3][1]. As a consequence, some concrete poles had to be replaced earlier than their expected life cycle.

In 1992, GHESI noticed some problems of incorrect bolt holes, concrete slumping and rusting rebars, mainly related to manufacturing process. What the manufacturer proposed was case-by-case remedial actions, i.e. drilling new holes for incorrectly placed holes, using patch to cover the exposed bars.

Since then till 1999, some other issues such as outer concrete cracking, concrete patching and varying wall thickness at pole butt end arose. Although the manufacturer admitted some issues such as concrete patching as flawed, they re-assured GHESI that there was no long term issue so far.

In 2001 to 2003, GHESI observed constant longitudinal cracking and rusting mold seams issues, along with the known bolt holes and concrete patching issues. Also an increased frequency of defects was noticed in the poles provided by the manufacturer.

In 2007, the manufacturer admitted that some of GHESI's deteriorated poles were beyond repair and needed to be replaced, though their expected useful life should have been much longer than GHESI had

experienced. Even though the poles warranty periods expired, the manufacturer offered free replacement and assured GHESI that a better quality control team had been set up to ensure lifetime warranty. This indirectly indicates a shorter useful life for the poles provided to GHESI in the past years.

1.4. Framings

OEB asset depreciation study report does not address the useful life of framings.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is the typical useful life as per GHESI 2010 useful life study.

2. Fuse Cutouts

The asset referred to in this category is the Fuse Cutouts. They are applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions. For the purposes of this report, fuse cutouts refers to the completed mounted fuse rather than the fuse itself.

According to OEB asset depreciation study report, the useful life of fuse cutouts is in the range of 25 to 40 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is better than OEB study range.

3. Manual Overhead Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

For the purposes of this report we are discussing the useful life of two types:

- Solid blade disconnect
- Gang operated LIS

3.1. Solid Blade Disconnects

According to OEB asset depreciation study report, the useful life of solid blade disconnects is in the range of 30 to 55 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study range, and better than OEB study typical useful life.

3.2. Gang Operated LISs

According to OEB asset depreciation study report, the useful life of gang operated LISs is in the range of 30 to 55 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study range, and better than OEB study typical useful life.

4. Integral Switch

Integral switches are a type of overhead line switches that are can receive signals from and be monitored by the SCADA system. These units include the switch, communications, and RTU. As with other line switches, this asset allows for the isolation of overhead line sections or equipment for maintenance, safety, or other operating requirement.

For the purposes of this report we are discussing the useful life of two major components:

- SCADA Mate switch
- RTU

4.1. SCADA Mate Switches

According to OEB asset depreciation study report, the useful life of SCADA mate switches is in the range of 35 to 60 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is identical to OEB study typical useful life.

4.2. RTUs

OEB asset depreciation study report does not address the useful life of RTUs for integral switches.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per operation experience at GHESI inventory records. Another factor affecting the useful life of RTUs is the fast-paced obsolescence process of IT devices in today's time. Because RTUs are essentially computer devices, they are prone to obsolescence. Obsolescence could result from technology or spare part supply that is no longer supported by the vendor, or incompatibility with new technology. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow the quantity, resolution, and accuracy of modern data acquisition.

5. Conductors

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the GHESI are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, weather protected wire and insulated wire.

For the purposes of this report we are discussing the useful life of four types:

- Primary
- Neutral
- Secondary
- Services

5.1. Primary Conductors

According to OEB asset depreciation study report, the useful life of primary conductors (both single-phase and three-phase) is in the range of 50 to 75 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study range, but shorter than OEB study typical useful life. The reason is that as per GHESI replacement strategy, when replacing poles the associated conductors need to be replaced as well.

GHESI's practice when replacing poles that have reached end-of-life is to replace conductors and hardware as well. In order to more efficiently replace pole lines, new poles are set at a distance from the existing poles. Due to the migration to current standards of equipment spacing and configuration, the new poles are, in almost all cases, taller than the old poles. During construction, GHESI aims to keep power supplied to customers to avoid inconvenient interruptions and to maintain customer satisfaction, which limits the size of isolated work zone that can be created during construction. Due to the energized conductor, limited sag and the extreme height difference between poles, it is typically not possible or practical to transfer the existing conductor to the new poles at the new height. Additionally, due to the new location of the poles, the secondary bus work must be repaired at the old pole location due to sections of removed jacket to facilitate customer connections. The repair work involves taping and splicing conductor and results in a reduction to the health of the conductor and an increased probability of faults. Additionally, the secondary mounting height must change to meet new standards and faces similar constraints to the primary conductor discussed above. This necessitates installing a new secondary bus and GHESI's experience has determined that it stringing in new primary at the same time is more efficient, cost effective and promotes better asset condition and future reliability than cutting and splicing the primary conductor multiple times in order to transfer it to the new pole and also minimizes the number of customer interruptions required to complete construction.

Since most of GHESI’s poles are of wood type, which has a typical life of 50 years, the typical useful life for conductors is therefore set to be 50 years.

5.2. Neutral Conductors

According to OEB asset depreciation study report, the useful life of neutral conductors is in the range of 50 to 75 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. The rational is the same as for primary conductors.

5.3. Secondary Conductors

According to OEB asset depreciation study report, the useful life of secondary conductors is in the range of 50 to 75 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. The rational is the same as for primary conductors.

5.4. Service Conductors

According to OEB asset depreciation study report, the useful life of service conductors is in the range of 50 to 75 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 60 years is set up. This is identical to OEB study typical useful life.

6. Capacitor Banks

This asset category refers to a group of capacitors arranged in rows, equipped with inter-rack insulators, interconnecting bus work, and support frame installed on pole top. The capacitor bank also includes capacitor unit fuses, break switch, instrumental transformers, protection and control devices, and in some cases, current-limiting fuse cutout or surge arrester. They regulate voltage in distribution systems, provide reactive compensation and voltage support.

For the purposes of this report we are discussing the useful life of three major components in capacitor banks:

- Frame and tanks
- Switch
- RTU

6.1. Frame and Tanks

According to OEB asset depreciation study report, the useful life of the frame and tanks in capacitor banks is in the range of 25 to 40 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

6.2. Switches

According to OEB asset depreciation study report, the useful life of the switches for capacitor banks is in the range of 25 to 40 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

6.3. RTU

OEB asset depreciation study report does not address the useful life of RTUs for capacitor banks.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per operation experience at GHESI inventory records. Another factor affecting the useful life of RTUs is the fast-paced obsolescence process of IT devices in today's time. Because RTUs are essentially computer devices, they are prone to obsolescence. Obsolescence could result from technology or spare part supply that is no longer supported by the vendor, or incompatibility with new technology. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow the quantity, resolution, and accuracy of modern data acquisition.

7. Pole Top Transformers

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

According to OEB asset depreciation study report, the useful life of pole top transformers (both single-phase and three-phase) is in the range of 30 to 60 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

8. Pad-Mounted Transformers

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

For the purposes of this report we are discussing the useful life of two major components in pad mounted transformers:

- Transformers
- Foundations

8.1. Transformers

According to OEB asset depreciation study report, the useful life of pad mounted transformers (both single-phase and three-phase) is in the range of 25 to 45 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

8.2. Foundations

According to OEB asset depreciation study report, the useful life of foundations for pad mounted transformers (both single-phase and three-phase) is in the range of 35 to 70 years, with typical useful life being 55 years.

In GHESI financial asset system, a typical useful life value of 60 years is set up. This is within OEB study range, and better than OEB study typical useful life.

9. Submersible Transformers

Submersible transformers typically employ sealed tank construction with corrosion resistance hardware and are liquid filled with mineral insulating oil.

For the purposes of this report we are discussing the useful life of three major components in submersible transformers:

- Transformers
- Vaults
- Roofs

9.1. Transformers

According to OEB asset depreciation study report, the useful life of submersible transformers is in the range of 25 to 45 years, with typical useful life being 35 years.

In GHESI financial asset system, a typical useful life value of 35 years is set up. This is identical to OEB study typical useful life.

9.2. Vaults

According to OEB asset depreciation study report, the useful life of vaults for submersible transformers is in the range of 40 to 80 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 60 years is set up. This is identical to OEB study typical useful life.

9.3. Roofs

According to OEB asset depreciation study report, the useful life of roofs for submersible transformers is in the range of 20 to 45 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

10. Indoor Vault Transformers

Similar to submersible transformers, indoor vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

For the purposes of this report we are discussing the useful life of two types:

- Single-phase
- Three-phase

10.1. Single-phase

According to OEB asset depreciation study report, the useful life of single-phase indoor vault transformers is in the range of 25 to 45 years, with typical useful life being 35 years.

In GHESI financial asset system, a typical useful life value of 35 years is set up. This is identical to OEB study typical useful life.

10.2. Three-phase

According to OEB asset depreciation study report, the useful life of three-phase indoor vault transformers is in the range of 25 to 45 years, with typical useful life being 35 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is within OEB study range, and better than OEB study typical useful life.

11. Underground Switchgear

Underground Switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, solid dielectric and gas insulated.

For the purposes of this report we are discussing the useful life of the following major components:

- Riser switches
- Air insulated switchgear
- Solid dielectric switchgear
- Switch bases
- Motors
- RTUs

11.1. Riser Switches

According to OEB asset depreciation study report, the useful life of riser switches for underground switchgear (Gang operated, solid blade or fused) is in the range of 20 to 45 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

11.2. Air Insulated Switchgear

According to OEB asset depreciation study report, the useful life of air insulated switchgear (live-front, dead-front) is in the range of 20 to 45 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 25 years is set up. This is due to the rust and moisture issues at GHESI underground switchgear sites.

There are many factors that could affect the useful life of pad mounted switchgear. Excluding the issues related to mechanical installation, electrical operation and animal aggression, the major contributing factors are environmental corrosion caused by chemical rusting, as well as contamination due to dust, dirt and other contaminants. In practice, the most likely encountered problem is field failure due to moisture in the top of pad mounted switchgear, and a third-party engineering company has offered service to exclusively fix the issues [6].

A typical sequence of such failure happens when moisture together with other dust and dirt deteriorate the insulation within pad mounted switchgear. This provides a path for leakage current to pass through insulators and barriers to cause a flashover, shortening the useful life of pad mounted switchgear.

To mitigate the above issue, normally an energized cleaning using dry-ice pellets is adopted.

Since 2002, GHESI kept track on their inspection records on air insulated switchgear. Out of GHESI's 173 inspections for 95 units, only 9 (or 10%) of the units had paint or rusty cabinet issue. As for the water ingress, there were 13 units (or 14%) had water flooding issue [5].

However, the inspection record also showed that among the 95 units inspected, 52 of them (or 55%) did not have any dry-ice cleaning since 2002. The number could be even higher if extrapolated to the entire population of about 190 units. This could contribute to shorter useful life for PMH switchgear at GHESI.

11.3. Solid Dielectric Switchgear

According to OEB asset depreciation study report, the useful life of solid dielectric switchgear is in the range of 20 to 45 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

11.4. Switch Base

OEB asset depreciation study report does not address the useful life of switch base for underground switchgear.

In GHESI financial asset system, a typical useful life value of 55 years is set up. This is identical to OEB study typical useful life for foundations in other asset groups (e.g. pad mounted transformers).

11.5. Motors

OEB asset depreciation study report does not address the useful life of motors for underground switchgear.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is the typical useful life as per GHESI 2010 useful life study for overhead switch motors.

11.6. RTUs

OEB asset depreciation study report does not address the useful life of RTUs for underground switchgear.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per operation experience at GHESI inventory records. Another factor affecting the useful life of RTUs is the fast-paced obsolescence process of IT devices in today's time. Because RTUs are essentially computer devices, they are prone to obsolescence. Obsolescence could result from technology or spare part supply that is no longer supported by the vendor, or incompatibility with new technology. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow the quantity, resolution, and accuracy of modern data acquisition.

12. Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The GHESI uses two cable types: paper insulated lead covered (PILC), and solid dielectric both in duct and direct buried. For the purposes of this report, solid dielectric cable refers to cross linked polyethylene (XLPE) cable and ethylene-propylene rubber (EPR).

According to OEB asset depreciation study report, the useful life of primary cables (single-phase lateral, three-phase lateral, three-phase feeder) is in the range of 35 to 55 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

13. Secondary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. Secondary underground cables are used to supply customer premises. The GHESI uses solid dielectric both in duct and direct buried. For the purposes of this report, solid dielectric cable refers to cross linked polyethylene (XLPE) cable and ethylene-propylene rubber (EPR).

For the purposes of this report, the useful life of three types is discussed:

- Solid dielectric in duct
- Solid dielectric direct buried
- Solid dielectric in Duct/DB - Service

13.1. Solid Dielectric in Duct

According to OEB asset depreciation study report, the useful life of solid dielectric in duct secondary cables is in the range of 35 to 60 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

13.2. Solid Dielectric Direct Buried

According to OEB asset depreciation study report, the useful life of solid dielectric direct buried secondary cables is in the range of 25 to 40 years, with typical useful life being 35 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is within OEB study range, and better than OEB study typical useful life.

13.3. Solid Dielectric in Duct/DB - Service

OEB asset depreciation study report does not address the useful life of solid dielectric in duct/DB – service cables.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is the typical useful life as per GHESI 2010 useful life study.

14. Ducts

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter. This report discusses both concrete encased duct banks and directly buried pipes. The GHESI has three direct buried pipe types: Polyvinyl Chloride (PVC), High Density Polyethylene (HDPE) and Fiber Reinforced Epoxy (FRE).

For the purposes of this report, the useful life of following types is discussed:

- Concrete encased
- PVC (direct buried)
- HDPE (direct buried)
- FRE (direct buried)

14.1. Concrete Encased

According to OEB asset depreciation study report, the useful life of concrete encased ducts is in the range of 35 to 80 years, with typical useful life being 55 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study useful life range, but shorter than OEB typical useful life. This is based on GHESI 2010 useful life study for concrete encased ducts.

14.2. PVC (Direct Buried)/HDPE (Direct Buried)/FRE (Direct Buried)

According to OEB asset depreciation study report, the useful life of PVC (direct buried) / HDPE (direct buried) / FRE (direct buried) ducts is in the range of 30 to 85 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is identical to OEB study typical useful life.

15. Cable Chambers

Cable Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

For the purposes of this report, the useful life of following components in cable chambers is discussed:

- Large manhole
- Sidewalk / field vault
- Sidewalk / field vault roof

15.1. Large Manholes

According to OEB asset depreciation study report, the useful life of large manholes is in the range of 50 to 80 years, with typical useful life being 60 years.

In GHESI financial asset system, a typical useful life value of 60 years is set up. This is identical to OEB study typical useful life.

15.2. Sidewalk / Field Vaults

OEB asset depreciation study report does not address the useful life of sidewalk / field vaults for cable chambers.

In GHESI financial asset system, a typical useful life value of 60 years is set up. This is the typical useful life as per GHESI 2010 useful life study for vaults.

15.3. Sidewalk / Field Vault Roofs

OEB asset depreciation study report does not address the useful life of sidewalk / field vault roofs for cable chambers.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is within useful life range as per GHESI 2010 useful life study for roofs, and better than the typical useful life value.

16. Junction Cubicle & Service Box

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is reference to the junction cubicle and service boxes pads and bases, and junction/switching cabinets. However as a distinction from pad mount switchgear, some of the units are directly buried.

For the purposes of this report, the useful life of following components in junction cubicle & service box is discussed:

- Junction/switching cabinets
- Pads/bases

16.1. Junction/Switching Cabinets

OEB asset depreciation study report does not address the useful life of junction/switching cabinets.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is within useful life range as per GHESI 2010 useful life study, but shorter than the typical useful life value. The reason is that the junction/switching cabinets are older generation products and are on planned phase-out.

16.2. Pads/Bases

OEB asset depreciation study report does not address the useful life of pads/bases for junction cubicle & service boxes.

In GHESI financial asset system, a typical useful life value of 60 years is set up. GHESI uses modified distribution vaults as junction cubicle and service box bases. In GHESI financial asset system, a typical useful life value of 60 years is set up for field vaults. This is the typical useful life as per GHESI 2010 useful life study for field vaults.

17. Station Grounding Transformer

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Grounding transformers, smaller transformers similar in construction to power transformers, are used in this application.

According to OEB asset depreciation study report, the useful life of station grounding transformers is in the range of 30 to 40 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

18. Station Service Transformer

The station service transformer is the supply system that provides power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are configured to provide this requirement.

According to OEB asset depreciation study report, the useful life of station service transformers (TS, MS) is in the range of 30 to 55 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. The reason is that at GHESI, the station service transformers are of pad mounted type, which has a typical useful life of 40 years.

19. TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA.

For the purposes of this report, the useful life of following components in TS Power Transformers is discussed:

- Overall (transformers)
- Bushing
- Tap changers

19.1. Overall (Transformers)

According to OEB asset depreciation study report, the useful life of TS power transformers is in the range of 30 to 60 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

19.2. Bushings

According to OEB asset depreciation study report, the useful life of bushings for TS power transformers is in the range of 10 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, and better than OEB typical useful life value.

19.3. Tap Changers

According to OEB asset depreciation study report, the useful life of tap changers for TS power transformers is in the range of 20 to 60 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

20. MS Power Transformers

Substation power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA.

For the purposes of this report, the useful life of following components in MS Power Transformers is discussed:

- Overall (transformers)
- Bushing
- Tap changers

20.1. Overall (Transformers)

According to OEB asset depreciation study report, the useful life of MS power transformers is in the range of 30 to 60 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

20.2. Bushings

According to OEB asset depreciation study report, the useful life of bushings for MS power transformers is in the range of 10 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, and better than OEB typical useful life value.

20.3. Tap Changers

According to OEB asset depreciation study report, the useful life of tap changers for MS power transformers is in the range of 20 to 60 years, with typical useful life being 30 years.

In GHESI financial asset system, a typical useful life value of 30 years is set up. This is identical to OEB study typical useful life.

21. Medium Voltage Switchgear

The medium voltage (MV) switchgear asset category can be classified in two types: gas insulated and air insulated switchgear. The gear also is compartmentalized with separate compartments for removable breakers which have three types of interrupting mediums: air magnetic, vacuum and gas (SF6).

For the purposes of this report, the useful life of following types in Medium Voltage Switchgear is discussed:

- Air insulated type
- Vacuum type

21.1. Air Insulated MV Switchgear

According to OEB asset depreciation study report, the useful life of air insulated MV switchgear is in the range of 30 to 60 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study useful life range, and better than OEB typical useful life value.

21.2. Vacuum MV Switchgear

According to OEB asset depreciation study report, the useful life of vacuum MV switchgear is in the range of 25 to 60 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is identical to OEB study typical useful life.

22. Independent Breakers in MV Switchgear

Circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage.

For the purposes of this report, the useful life of the following types of breakers in Independent Breakers in MV Switchgear is discussed:

- Air insulated type
- Gas (SF6) type

In air magnetic circuit breakers, magnetic blowout coils are used to create a strong magnetic field that draws the arc into specially designed arc chutes. The breaker current flows through the blowout coils and produces a magnetic flux. This magnetic field drives the arc against barriers built perpendicular to the length of the arc. The cross sectional area of the arc is thereby reduced, and its resistance is considerably increased. The surface of the barriers cool and de-ionize the arc, thus collaborating to extinguish the arc.

Gas, sulfur hexafluoride (SF6) insulated equipment is a relatively young technology. The first SF6 equipment was developed in the late 1960s. After some initial design and manufacturing problems equipment was increasingly used to replace oil filled equipment with widespread adoption and utilization since the mid-1980s. One of the more remarkable features of SF6 is its performance when subjected to an arc, or during a fault operation. SF6 is extremely stable and even at the high temperatures associated with an arc, limited breakdown occurs. Furthermore, most of the products of the breakdown recombine to form SF6. Consequently, SF6 circuit breakers can operate under fault conditions many more times than oil breakers before requiring maintenance.

22.1. Air Insulated Breakers

According to OEB asset depreciation study report, the useful life of air insulated breakers in MV switchgear is in the range of 30 to 60 years, with typical useful life being 40 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB study useful life range, and better than OEB typical useful life value.

22.2. Gas (SF6) Breakers

According to OEB asset depreciation study report, the useful life of gas (SF6) breakers in MV switchgear is in the range of 35 to 65 years, with typical useful life being 45 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is identical to OEB study typical useful life.

23. Protective and Control Devices

This asset of protective and control devices are classified into panels, control cables and relays.

Relays are classified into of three types, electromechanical, solid state and digital. The function of these relays is to increase long term reliability. The protection relays work to detect and isolate faults on the system by opening and closing the circuit breakers.

For the purposes of this report, the useful life of the following components in Protective and Control Devices is discussed:

- Panels
- Control cables
- Digital relays

23.1. Panels

OEB asset depreciation study report does not address the useful life of panels for protective and control devices.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is the typical useful life as per GHESI 2010 useful life study for panels of protective and control devices.

23.2. Control Cables

OEB asset depreciation study report does not address the useful life of control cables for protective and control devices.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is the typical useful life as per GHESI 2010 useful life study for control cables of protective and control devices.

23.3. Digital Relays

According to OEB asset depreciation study report, the useful life of digital relays is in the range of 15 to 20 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is within OEB study useful life range, but shorter than OEB typical useful life. This is based on GHESI 2010 useful life study for digital relays.

24. Station Disconnect Switches - TS

This asset class consists of the disconnect switches used to physically and electrically isolate sections of the power system for the purposes of maintenance, safety, and other operational requirements. Switches typically consist of manual or motor operated isolating devices mounted on support insulators and metal support structures. Many high voltage disconnect switches (e.g. line and transformer isolating switches) have motor-operators and the capability of remote-controlled operation. These switches are normally operated when there is no current through the switch, unless specifically designed to be capable of operating under load.

For the purposes of this report, the useful life of the following types and component of Station Disconnect Switches - TS is discussed:

- Manual switches
- Remote operated switches
- Switch motors

24.1. Manual Switches

According to OEB asset depreciation study report, the useful life of manual switches is in the range of 30 to 60 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, but shorter than OEB typical useful life. This is based on GHESI 2010 useful life study for manual switches.

24.2. Remote Operated Switches

According to OEB asset depreciation study report, the useful life of remote operated switches is in the range of 30 to 60 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, but shorter than OEB typical useful life. This is based on GHESI 2010 useful life study for manual switches.

24.3. Switch Motors

OEB asset depreciation study report does not address the useful life of switch motors for station disconnect switches.

In GHESI financial asset system, a typical useful life value of 45 years is set up. The reason is that based on manufacturer specifications in practice, a switch motor itself is a maintenance free component in disconnect switch throughout the life cycle of the switch. For many utilities, when replacing switches the associated switch motors need to be replaced as well.

25. Station Disconnect Switches - MS

This asset class is the same as station disconnect switches – TS, except that the switches are located at municipal stations.

According to OEB asset depreciation study report, the useful life of station disconnect switches - MS is in the range of 30 to 60 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, but shorter than OEB typical useful life. This is based on GHESI 2010 useful life study for station disconnect switches.

26. Direct Current System -TS

Direct current (DC) systems are critical to the safe and efficient operation of transformer cooling, switchgear and protection & control. This asset category has been componentized into batteries, chargers and other DC distribution equipment. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Batteries consist of multiple individual cells. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the battery banks.

For the purposes of this report, the useful life of the following types and component of Direct Current System -TS is discussed:

- Batteries
- Chargers
- DC distribution equipment

26.1. Batteries

According to OEB asset depreciation study report, the useful life of batteries is in the range of 10 to 15 years, with typical useful life being 15 years.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is identical to OEB typical useful life.

26.2. Chargers

According to OEB asset depreciation study report, the useful life of chargers is in the range of 20 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is identical to OEB typical useful life.

26.3. DC Distribution Equipment

According to OEB asset depreciation study report, the useful life of DC distribution equipment is in the range of 10 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is identical to OEB typical useful life.

27. Direct Current System - MS

This asset class is the same as Direct Current System – TS, except that the system is located at municipal stations.

For the purposes of this report, the useful life of the following types and component of Direct Current System - MS is discussed:

- Batteries
- Chargers
- DC distribution equipment

27.1. Batteries

According to OEB asset depreciation study report, the useful life of batteries is in the range of 10 to 15 years, with typical useful life being 15 years.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is identical to OEB typical useful life.

27.2. Chargers

According to OEB asset depreciation study report, the useful life of chargers is in the range of 20 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is identical to OEB typical useful life.

27.3. DC Distribution Equipment

According to OEB asset depreciation study report, the useful life of DC distribution equipment is in the range of 10 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is identical to OEB typical useful life.

28. Station Grounding System - TS

Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

For the purposes of this report, the useful life of the following types and component of Station Grounding System - TS is discussed:

- Ground grid
- Neutral reactors
- Arrestors

28.1. Ground Grid

OEB asset depreciation study report does not address the useful life of ground grid for station grounding system.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is the typical useful life as per GHESI 2010 useful life study for ground grid.

28.2. Neutral Reactors

OEB asset depreciation study report does not address the useful life of neutral reactors for station grounding system.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is the typical useful life as per GHESI 2010 useful life study for neutral reactors in station grounding system.

28.3. Arrestors

OEB asset depreciation study report does not address the useful life of arrestors for station grounding system.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is the typical useful life as per GHESI 2010 useful life study for arrestors in station grounding system.

29. Station Grounding System - MS

This asset class is the same as Station Grounding System – TS, except that the system is located at municipal stations.

For the purposes of this report, the useful life of the following types and component of Station Grounding System - MS is discussed:

- Ground grid
- Arrestors

29.1. Ground Grid

OEB asset depreciation study report does not address the useful life of ground grid for station grounding system.

In GHESI financial asset system, a typical useful life value of 40 years is set up. This is the typical useful life as per GHESI 2010 useful life study for ground grid.

29.2. Arrestors

OEB asset depreciation study report does not address the useful life of arrestors for station grounding system.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is the typical useful life as per GHESI 2010 useful life study for arrestors in station grounding system.

30. Bus Work and Steel Structures

There are a number of different types of structures at distribution stations for supporting buses and equipment. The predominant types are galvanized steel, either lattice or hollow sections.

For the purposes of this report, the useful life of the following types of Bus Work and Steel Structures is discussed:

- Structures at TS
- Structures at MS

30.1. Structures at TS

According to OEB asset depreciation study report, the useful life of structures at TS is in the range of 35 to 90 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is identical to OEB typical useful life.

30.2. Structures at MS

According to OEB asset depreciation study report, the useful life of structures at MS is in the range of 35 to 90 years, with typical useful life being 50 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is identical to OEB typical useful life.

31. Station Buildings

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building structure itself, the roof and fence.

For the purposes of this report, the useful life of the following components of Station Buildings is discussed:

- Structures
- Roofs
- Fences

31.1. Structures

According to OEB asset depreciation study report, the useful life of structures at stations is in the range of 50 to 75 years.

In GHESI financial asset system, a typical useful life value of 50 years is set up. This is within OEB useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for structures.

31.2. Roofs

According to OEB asset depreciation study report, the useful life of roofs at TS is in the range of 20 to 30 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is within OEB useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for roofs.

31.3. Fences

According to OEB asset depreciation study report, the useful life of fences at stations is in the range of 25 to 60 years.

In GHESI financial asset system, a typical useful life value of 35 years is set up. This is within OEB useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for fences.

32. Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on smart meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT). A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

For the purposes of this report, the useful life of the following types and components of Metering is discussed:

- Smart meters
- Industrial/commercial meters
- Wholesale meters
- Transformers (CTs, PTs)

32.1. Smart Meters

According to OEB asset depreciation study report, the useful life of smart meters is in the range of 5 to 15 years.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is within OEB study useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for smart meters.

32.2. Industrial/Commercial Meters

According to OEB asset depreciation study report, the useful life of industrial/commercial meters is in the range of 25 to 35 years.

In GHESI financial asset system, a typical useful life value of 20 years is set up. This is beyond OEB study useful life range. The reason is that in recent years, revenue metering technology has evolved into electronic metering, with the current generation of electronic revenue meters essentially a metrology computer. These meters are more prone to obsolescence, similar to the obsolescence experienced with other computer and electronics based technology, which will shorten their practical useful life.

In addition, these revenue meters are subject to Industry Canada - Measurement Canada testing, sealing and recertification processes, which typically has resulted in more stringent recertification requirements for electronic meters than for the previous generation of mechanical and electro-mechanical meters. Measurement Canada's initial seal period for these meters has typically been less than that of other traditional revenue meters, ultimately reducing the effective useful life of the revenue meter, following Measurement Canada's declining scale recertification protocols [7].

32.3. Wholesale Meters

According to OEB asset depreciation study report, the useful life of wholesale meters is in the range of 15 to 30 years.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is within OEB study useful life range, and is as per operation experience at GHESI inventory records. GHESI's current wholesale revenue meters are electronic devices subject to Industry Canada - Measurement Canada testing, sealing and recertification processes. Based on Measurement Canada requirements, the initial

seal period for these meters is typically less than that of other electronic revenue meters. In addition, the meter recertification extension period follows a declining scale, thereby reducing the meters remaining certification life at every seal period recertification. This results in a 15 year effective life for a wholesale revenue meter, as after 15 years the wholesale meter change, testing and market registration costs do not justify the installation of a replacement meter with less than a 4 year seal period [7].

Another factor affecting the useful life of wholesale meters is the fast-paced obsolescence process of IT devices in today's time. Obsolescence could result from technology or spare part supply that is no longer supported by the vendor, or requirement of technology upgrading from some regulating organizations such as IESO. In both cases, the existing wholesale meters have to be removed out of service, even though they are functionally in good performance status.

32.4. Transformers (CTs, PTs)

According to OEB asset depreciation study report, the useful life of transformers (CTs, PTs) is in the range of 35 to 50 years.

In GHESI financial asset system, a typical useful life value of 45 years is set up. This is within OEB study useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for CTs and PTs.

33. SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

For the purposes of this report, the useful life of the following components of SCADA is discussed:

- Master
- RTU
- Batteries

33.1. Master

OEB asset depreciation study report does not address the useful life of master for SCADA system.

In GHESI financial asset system, a typical useful life value of 5 years is set up. This is as per GHESI operation experience on SCADA/NMS equipment.

GHESI's SCADA/NMS system has followed a pattern of minor and major upgrades as outlined above. A brief synopsis of major upgrade events is as follows [8]:

- 2001 – SCADA system purchased and put into service to replace aging Data Acquisition System. This provided GHESI the ability to monitor and control remotely operable distribution switches;
- 2003 – introduction of single non-redundant ICCP connection to Hydro-One control center, as well as introduction of secure web-browser for improved operations visibility
- 2006 – full upgrade due to hardware end-of-life, major NMS software upgrade, and introduction of dual-redundant ICCP servers
- 2011 – full NMS hardware and software upgrade due to workstation and server end-of-life as well as major NMS software upgrade; also worked towards integrating real-time Smart Meter outage information for improved system operations
- 2014-2015 – major operating system upgrade and addition of Advanced Fault Location, Isolation, and Service Restoration (FLISR) software

From the above history records, it can be observed that within a 15 year period, there are in total 3 major upgrading. This justifies the 5 year useful life for this asset group.

33.2. RTU

According to OEB asset depreciation study report, the useful life of RTUs for SCADA system is in the range of 15 to 30 years, with typical useful life being 20 years.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per operation experience at GHESI inventory records. Another factor affecting the useful life of RTUs is the fast-paced obsolescence process of IT devices in today's time. Because RTUs are essentially computer devices, they are prone to obsolescence. Obsolescence could result from technology or spare part supply that is

no longer supported by the vendor, or incompatibility with new technology. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow the quantity, resolution, and accuracy of modern data acquisition.

33.3. Batteries

OEB asset depreciation study report does not address the useful life of batteries for SCADA system.

The manufacturer's application manual suggests that in laboratory conditions, at 25 deg. C and in a float charge mode, the battery life cycle can reach 10 years.

However, battery life-cycles vary widely depending on operating conditions. In the case of GHESI, the SCAD batteries are in an outdoor environment which is not humidity or temperature controlled (no heaters are installed in the SCADA control cabinet). In such a situation, there are some factors that can impact the life cycle of SCADA batteries: many fluctuations in battery usage and charging cycles (whenever the primary line voltage dips or is interrupted); temperature variation throughout the year; batteries exposed to environmental hazards such as humidity and airborne salt spray for units near roadways. As a consequence the batteries cannot be expected to last as long as 10 years.

GHESI’s experience indicates a 5 year typical life cycle (on average) for SCADA batteries. The absolute range of life recorded by GHESI has been between 2 and 7 years, with most of the SCADA batteries failing after 5 years.

Therefore, in GHESI financial asset system, a typical useful life value of 5 years is set up.

34. Remote Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers. For the purposes of this report, only smart fault indicators will be discussed.

For the purposes of this report, the useful life of the following components of Remote Fault Indicators is discussed:

- Indicators
- RTUs

34.1. Indicators

OEB asset depreciation study report does not address the useful life of indicators.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per GHESI operation experience on several generations of fault indicators, and within useful life range as per GHESI 2010 useful life study for remote fault indicators.

In GHESI's early experience with fault indicators, less than 5 years of useful life was expected for such devices of field use. However, the current generation of remote fault indicators shows significant advantage over earlier generations, in terms of installation, replacement program requirement and communication features. The improvement in communication and monitoring process allow GHESI to locate issues remotely rather than relying on physically patrolling, making maintenance and troubleshooting more effective and punctual, thus benefiting the system reliability.

Since GHESI has new generation of fault indicators for only a few years, its life cycle is predicted based on up-to-date operation experience, which shows longer than before useful life. This useful life value might get adjusted after more years of operation at GHESI.

34.2. RTUs

OEB asset depreciation study report does not address the useful life of RTUs for fault indicators.

In GHESI financial asset system, a typical useful life value of 10 years is set up. The reason is that as per GHESI replacement strategy, when replacing fault indicators the associated RTUs need to be replaced as well, as RTUs are built inside fault indicators.

35. Communication System

A communication system is used to communicate via some network back to the local utility for monitoring and billing purposes.

For the purposes of this report, the useful life of the following components of Communication SystemCommunication SystemCommunication System is discussed:

- Communication towers
- Communication circuits
- Communication electronics

35.1. Communication Towers

According to OEB asset depreciation study report, the useful life of communication towers is in the range of 60 to 70 years.

In GHESI financial asset system, a typical useful life value of 65 years is set up. This is within OEB study useful life range, and is identical to typical useful life as per GHESI 2010 useful life study for communication towers.

35.2. Communication Circuits

OEB asset depreciation study report does not address the useful life of communication circuits, which mainly consist of fibre optic cables.

In GHESI financial asset system, a typical useful life value of 15 years is set up. This is as per generic industrial experience, based on both the tax depreciation rate and projected depreciation life among different countries [9][10][11].

35.3. Communication Electronics

OEB asset depreciation study report does not address the useful life of communication electronics.

In GHESI financial asset system, a typical useful life value of 10 years is set up. This is as per generic industrial experience [12].

C REFERENCES

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APPENDIX L: Operations Guideline: Fleet Replacement

1.0 Background

Guelph Hydro manages a fleet of vehicles that are essential to the efficient and effective day-to-day operation of the utility. This fleet includes large bucket trucks, radial boom derricks (RBDs), underground step vans, various trailers, small pickup trucks, small vans, and pool vehicles. It is crucial that all fleet vehicles are maintained properly and replaced in a timely manner - keeping overall costs in mind. This requires balancing new vehicle purchase costs against excessive repair bills and operational downtime that occur when vehicles are kept for too long.

2.0 Applicability

The Operations division is responsible for managing the operating and capital replacement of the Guelph Hydro fleet. Requests for replacement vehicles are made via the appropriate Operations management staff, including the Director of Operations, the Manager of Operations, and the Operations Supervisor.

This guideline establishes a philosophy specific to the Guelph Hydro fleet that ensures continued safety, minimized down time, and maximum overall efficiency. This helps to preserve the core functionality for the utility and maximize the overall efficiency at which the fleet is operated.

3.0 Asset Detail

The total value of the Guelph Hydro fleet, based on original purchase costs, is approximately $5.1M. Assuming the annual capital replacement budget is $520k, it would take roughly 10 years to replace the entire fleet. This, on average, is in line with previously established and recognized vehicle replacement timelines.

For the purposes of this document, large trucks are defined as those costing more than $50k. Small vehicles are those that are purchased for under $50k.

Guelph Hydro's fleet information is summarized here (as of June, 2014):

Vehicle Type	***#***	***Average Age (years)***	***Max. Age (years)***	***Average km***	***Max km***
Large bucket truck	8	6.6	11	64,000	120,000
Large RBD	3	8.0	14	41,000	63,000
Large step van	3	4.7	6	51,000	69,000
Pickup truck	12	4.3	7	52,000	145,000
Trailers/misc. equipment	16	12.7	20	-	-
Small vehicles/pool	15	3.9	5	55,000	136,000
Total all vehicles	***57***	***7.1***			

4.0 Responsibility

All fleet vehicle purchases are made in compliance with Guelph Hydro's latest Purchasing Policy – FIN-04. Fleet purchases are budgeted for on an annual basis with the annual capital and operating budgets for the department approved as part of the corporate budgeting process.

Large vehicles are typically budgeted for and ordered one year in advance of delivery due to the long lead times required by the manufacturers.

Statistics such as maintenance costs, fuel consumption, mileage are tracked per vehicle on a monthly basis with detailed reports distributed to the Director of Operations.

5.0 Procedure

Replacement Criteria:

Guelph Hydro's fleet vehicle replacement determination considers the following factors:

a) Age of the vehicle,
b) Odometer reading,

c) Engine/power take-off (PTO) hours,
d) Maintenance costs,
e) Annual vehicle test results, including stress/electrical testing,
f) Practicality of existing vehicle including new technology available,
g) Changing emissions, weight, and road safety regulations obsoleting some existing units, and
h) Crew/other department needs.

When the age of the vehicle approaches its life expectancy, a case by case evaluation is done to determine whether or not replacement is an option ahead of or later than the vehicles normal life expectancy - with factors noted above as additional considerations. Normal life expectancy for small vehicles is 6 to 10 years and 10 to 12 years is the expected life for large trucks.

Odometer readings and engine hours are also factors considered when contemplating vehicle replacement. Generally, when a vehicle reaches 100,000 km, a vehicle's residual value drops significantly and maintenance costs will begin to increase.

Vehicle testing includes large bucket trucks that are tested annually for insulation resistance – the main electrical property of the boom assembly. If significant work is required to maintain the unit within specifications, this could drastically impact planned vehicle replacement timelines. In addition, changes to provincial vehicle regulations can impact residual values through changes in planned or existing use limitations for large fleet vehicles.

Needs Evaluation:

Finally, with every vehicle replacement, department needs are reviewed to determine the best option:

- Replacement like for like,
- Replace with an alternative vehicle,
- Replace and keep the existing (addition to the fleet), or
- Don't replace (removal from the fleet).

Smaller vehicles and pool vehicles may be moved between departments, before their end of life, to balance the age of the vehicle with the accumulated km to fully optimize overall vehicle use.

Vehicle end of life:

In general, when a vehicle is determined to no longer be of use to the Guelph Hydro fleet, it is sold at or above the appraised value by one of the following methods:

- Sold internally or through a fleet service,
- Traded in as part of the replacement vehicle purchase, or
- Sent to a public auction.

Any useable equipment on or attached to the vehicle is removed for reuse and all company logos are removed. All vehicles are sold "as is".

Small vehicles and equipment are traded in, sold internally, or sent to a public auction. If the vehicle is sold internally it is sold to the highest bidder via a sealed bid process using the appraised value as the minimum bid.

Large vehicles and equipment are sold via a fleet service. An appraised value is determined and the fleet service is paid by commission. The service has the ability to advertise the vehicle to a wider audience with all offers and proposals provided for company consideration, prior to sale.

From an accounting perspective, vehicles are fully depreciated prior to disposal or sale. Large trucks are depreciated over 10 years and small vehicles are depreciated over a 5 year timeframe. Exceptions are possible only under extenuating circumstances and with the approval of the Director of Operations. All proceeds from used vehicle sales are treated as "miscellaneous" income and do not impact the fleet capital budgeting process.

6.0 Guideline Review

This document will be reviewed and updated with the appropriate Operations management and administration staff on a regular basis. Further information on the Guelph Hydro fleet or related procedures is available from the Guelph Hydro Operations administration area.

7.0 Five Year Expense Forecast

Item		*Purchase Year*	*$*	*Budget*
2015	Replace Double Bucket (T8)	2002	360,000	566,000
	New Single Bucket (42')	-	206,000	
2016	Replace Single Bucket (T9)	2005	300,000	573,000
	Replace Crew HD Pickup (T18)	2006	90,000	
	Replace Pickup (T19)	2008	35,000	
	Replace Pickup (T35)	2007	38,000	
	Replace Forklift	1991	110,000	
2017	Replace HIAB	2000	385,000	590,000
	Replace Van (T41)	2008	45,000	
	Replace Van (T43)	2008	45,000	
	Replace Van (T51)	2009	45,000	
	Replace Pickup (T65)	2009	35,000	
	Replace Pickup (T66)	2009	35,000	
2018	Replace Radial BD (T24)	2005	473,000	608,000
	Replace Pickup (T33)	2011	35,000	
	Replace Car (84)	2010	30,000	
	Replace Bobcat	1998	35,000	
	Replace Pickup (T61)	2007	35,000	
2019	Replace Single Bucket (T6)	2006	380,000	626,000
	Replace Step Van (25)	1994	145,000	
	Replace Pickup (T36)	2012	35,000	
	Replace Car (T64)	2011	31,000	
	Replace Pickup (T34)	2007	35,000	
2020	Replace Double Bucket (T4)	2007	470,000	645,000
	Replace Step Van (26)	2008	140,000	
	Replace Pickup (T32)	2012	35,000	

APPENDIX M: GHESI I.S. & I.T. Assessment

Guelph Hydro Electric Systems Inc.

I.S. and I.T. Assessment

Overview of Information Systems and Technology strategy and capital projects.

Content:

- Executive summary
- IS/IT Strategy
- Hardware
- Software
- Resources

Executive summary

The purpose of this document is to outline the business requirements for IS/IT resource initiatives in capital budget IS/IT expenditures. Three initiative groups will be covered in this presentation including hardware, software and resource requirements. The IS/IT capital expenditures for the upcoming years ensure that our business goals are aligned with technological solutions and business resiliency.

Planning of IS/IT capital expenditures is based on established life cycle of both hardware and software. Annual IS/IT capital projects leverage replacement and new technology requirements.

IS/IT Strategy

Information Systems and Technology expenditures ensure that the business goals are aligned with technology solutions. These expenditures include hardware network cabling infrastructure, switches, servers, PCs, cell phones, tablets, laptops, printers and plotters. Over the past several years, Guelph Hydro has been working on creating a stable, reliable and secure computer network with business continuity and sustainability.

There are three areas covered by the IS/IT capital budget:

- Hardware
- Software
- Resources

The requests within each of these groups allow for the following goals to be met:

- Effective and efficient business processes
- Integrated, reliable enterprise solutions
- Support for disaster and pandemic business continuity
- Proven best practice in network and security systems

In meeting the established goals, Guelph Hydro Electric Systems Inc. IS/IT services contribute to meeting the board established utility performance outcomes:

- Customer Focus: Self server web portal and procedures have been implemented to enable customers including Ontarians with disabilities, to access and analyse electrical consumption information, billing information and to streamline the move in and out process. Guelph Hydro has also installed an Intelligent Voice Response (IVR) system for customers wanting to bypass our call centre.
- Operational Effectiveness: In today's ever changing technology needs, Guelph Hydro needs to be able to react and plan for various technologies and must be proactive and flexible in embracing these changes. An example of such a change, is our mobile web applications with system integration applications with GPS and outage notification systems. Guelph Hydro is reaching towards a higher level of a safer working environment with these applications.
- Public Policy Responsiveness: Guelph Hydro continues to work on solutions for current and future technical requirements to ensure that our utility can deliver on its obligations mandated by government.
- Financial Performance: Guelph Hydro continues to demonstrate good financial business decisions and applies best in practice solutions with its decisions.

Hardware

The purchasing of hardware is managed with continued emphasis on business requirements such as networking infrastructure and disaster recovery. To help maximise the IS/IT investments, Guelph Hydro requires continual monitoring of the network assets and must build resiliency and redundancy on core systems.

Guelph Hydro's current hardware infrastructure consists of:

- 3- IBM I series power system boxes, AS400 for our ERP system
- 27 physical servers
- 43 virtual servers
- 105 PCs
- 35 laptops
- 76 smart phones
- 2 plotters
- 12 network printers
- 16 network switches
- 2 internal firewalls
- 2 SAN data storage systems

Costs are related to the following projects/business needs. Although most hardware replacement is based on a 5 year renewal schedule some items such as smart phones are

replaced based on hardware limitations such as battery life, damage units or items being lost or stolen.

- Personal computers and monitors: 5 year life cycle replacement
- Printers: 5 year life cycle
- Cell phones: 2-3 year life cycle
- Server replacements and upgrades: 5-6 year life cycle
- Network switches replacements: 8 year life cycle
- Air Conditioning unit for the offsite disaster recovery center. Over the next few years, some of our IT infrastructure will be moved to our disaster recovery site. To help lower the temperature of the computer room Guelph Hydro will be purchasing an air conditioning unit for the site.
- Installation of an internet connection for our disaster recovery site. To help support the business continuity requirement for high availability, a secondary internet connection point is required at our DR site
- Mobile application and hardware requirements for in home access in case of a pandemic alert. Over the past several years Guelph Hydro has been proactively working with employees to see who can work from home. Although there are many benefits to this, we've noticed that some departments are missing key infrastructure requirements to support them
- Firewall system renewal: 4 year life cycle
- Network cabling upgrade. The existing operations department was built in 1995 and is in need of an upgrade
- AS400 server upgrades: 5 year life cycle rotation. We are using the older units as stand by units for the disaster recovery site. These servers are used for our corporate ERP program and performs the daily billing functions
- SAN storage drive system: All electronic information is held on these massive storage devices. There is a need to have multiple copies of this data.

Category Hardware	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Cell Phones	5,880	6,056	6,238	6,425	6,618	31,218
PC's, Laptops, Monitors	35,000	40,000	41,200	42,436	43,709	202,345
Network Switches	32,300	35,269	36,327	37,417	38,539	179,852
Printers	25,000	35,000	36,050	37,132	38,245	171,427
Servers	100,000	100,000	100,000	100,000	50,000	450,000
3-IBM I series Servers	220,000	20,000			220,000	460,000
DR Site infrastructure	37,000	25,000	31,750	32,703	33,684	160,136
HDD SAN Storage		34,000	70,000		60,000	164,000
Firewall security systems		30,000		40,000		
Network cabling	10,000	10,300	14,000	14,420	14,853	63,573
Total	465,180	335,625	335,565	310,532	505,648	1,818,978

This past year Guelph Hydro has been working with the City of Guelph and are using their services to support and monitor a new IP based phone system. This has provided Guelph Hydro with two benefits, one is a much lower operating cost per year on hardware upgrades and the other provides Guelph Hydro with the technical expertise that is currently not in our organization.

Software

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

- ERP enhancement: Guelph Hydro has contacted our ERP vendor and requested that they work with Guelph Hydro on a joint venture to improve the functionality and ease of use of their software. Guelph Hydro has noticed that a substantial amount of time is spent navigating through screens by customer service when looking for specific information on customer accounts
- Application interface and integration: There's a need to develop other user Application Interface Program (API) to our corporate application to help speed up the input process of work orders by the Engineering department
- HRMS program: The Human Resources department has flagged key items that are not currently being supported by our ERP System. Key gaps that need to be filled or lacking are recruiting and onboarding applications, tracking of training and development, succession planning, performance appraisals, reporting and employee/manager self-service
- Web Portal upgrade: Customer self-serve internet portal is a vital key component to customer account information
- MS Office 365: Guelph Hydro has been using Lotus Notes as the email service provider for the past 20 years. With our recent changes to MS exchange and SharePoint there's a need to migrate our current email processes to Outlook and the hosted solutions from Microsoft for MS office
- Ortho-imagery of the City of Guelph and Rockwood: To help with planning and design by the Engineering Department, Guelph Hydro has in the past purchased and will be purchasing the new Ortho-imagery being provided by Ministry of Natural Resources under the SWOOP program

Category Software	2015	2016	2017	2018	2019	Total
ERP enhancement	60,000	61,800	40,000	30,000		191,800
Interface customization	20,000	20,600	21,000	21,630	22,279	105,509
HRMS Program	100,000	60,000	44,000			180,000
Web Portal upgrade		20,000				20,000
MS Office 365	35,000					35,000
Custom Application builds	40,000	41,200	42,436	43,709	45,020	212,365
Antivirus upgrade				20,000		20,000
Ortho Imagery	10,000		10,000		10,000	30,000
Network Security software				70,000		70,000
Professional services	50,000	51,500	52,140	53,704	55,315	262,660
Total	315,000	255,100	209,576	239,043	132,615	1,127,334

Resources

Technology is changing faster than ever before. IS and IT have been in the direct path for these changes which includes new electronic systems, mobility in fleet, SCADA, internet, applications development or customization, reporting requirements, billing modifications, smart metering data storage, outage notification and web site integration to name a few. Keeping abreast of these ever evolving technologies has become unattainable and in the future may require outside consulting resources to help facilitate these enterprise solutions.

Conclusion

Guelph Hydro is committed to delivering sound technical solutions and services to both our internal and external customers. These solutions continue to be aligned with our corporate business initiatives.

Year	2015	2016	2017	2018	2019
Total by year	780,180	590,725	545,141	549,575	638,263

APPENDIX N: Material Capital Project Summary 2016

A. General Information						
Project /Activity	Apartment, Commercial, and Industrial Customer Connections					
Project Number	CACI					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$600,858	$546,155	$544,823	$1,035,517	$628,053	$646,894
Capital contribution	$242,745	$257,163	$343,813	$411,549	$290,532	$299,181
Net Cost	$358,113	$288,992	$201,010	$623,968	$337,521	$347,714
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Typically, a connection in this program involves establishing a connection from GHESI's distribution system to the customer owned facilities, which can be a meter panel or transformer vault. In a typical year, GHESI will connect approximately 270 new services in this category and they can range from a few kW to 10's of MW. (In 2013, GHESI connected 72 commercial services, 174 apartment services and no industrial services. In 2014, GHESI connected 67 commercial services, 230 apartment services and 2 industrial services.)

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 17,386	$ 121,700	$ 17,386	$ 191,243

Project Summary

This program is essential in order to meet the demand of connecting new apartment, commercial and industrial customers to Guelph Hydro's distribution system. Supply is at a primary voltage level, or through a utility transformer providing secondary voltage to a single building or group of buildings. The distribution system to individual customers within the building(s) is not part of utility's assets. Projects also include ar upgrades to existing customer services. A significant portion of this cost is recovered through capital contributions. Connections within this program are initiated by customer service requests. The overall capital requirement for the program is an estimate based on information in the City of Guelph Development Priorities Plan (DPP), historical trends, and other known projects anticipated over the planning horizon. Detailed planning and project listing is not available for this program. However, it is expected that none of the individual projects within this program will exceed the materiality threshold.

Risk Identification & Mitigation (5.4.5.2 A.4)

Risks associated with projects in this program typically include:
Schedule delays that result from non-compliance of customers with GHESI standards and requirements
Lack of or incorrect information required from the customer that could result delays
GHESI's strategy to mitigate these risks is to maintain frequent communication with customers such that all requirements, both of GHESI and of the customer, are well understood and met.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Customer connection project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not applicable

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

Customers are connected in accordance with GHESI's Conditions of Service. Connection details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Projects in this program are driven by customer service requests and the mandated obligation to service new customers.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Not applicable
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to ensure proper allocation of investments to meet service obligations.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
GHESI's capital planning for apartment, commercial, and industrial customer connections incorporates information from the City of Guelph Development Priorities Plan (DPP), historical trends, and other service connections that have been identified for this planning cycle.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore cannot be deferred. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
The new facilities will be designed and constructed in compliance with current standards and practices to create more flexibility in system operations. This reduces the needs for system modifications in the future and helps GHESI achieve better system operation efficiency and cost-effectiveness in the long term.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
With this program in place new customers will be connected in a timely manner and receive consistent, reliable electricity service of GHESI.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
New connections will be installed to current standards that maintains or improves the overall reliability of GHESI's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Individual connection options are evaluated under the terms of GHESI's Conditions of Service to ensure an adequate and reliability supply of energy to the customer. Requirements for contribution, and scheduling are also described in that document.
Safety (5.4.5.2.B2)
New facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is part of every project. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Utility plant located in vaults on customer premises is designed to the latest standard for operational needs, which could include controllable primary switching devices and monitoring equipment and sensors.
Economic Development (5.4.5.2.B5) (where applicable)
This program is in place to support load growth that accompanies local development in the service region of GHESI.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Timing and pacing of these projects is largely determined by the number of customer service requests received in each year, and the time when these requests are received. GHESI will prioritize new service connection requests based on customer's expectation of when the service requirement will be fulfilled, such that these expectations can be met. In cases where the customer is responsible for constructing or installing civil infrastructure that is deemed required by GHESI to facilitate the service connection, project delays can result if the civil infrastructure does not meet current standards of GHESI.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
For all service connections, a certain amount of GHESI plant must be located on the customer's premises. This can range from a meter installation up to a pad mounted transformer or internal transformer vault. GHESI's Conditions of Service document outlines the requirements for the different types of services and has been crafted to account for customer preferences and to minimize the impacts on the customer's premises. Factors such as service location or plant location relative to customer owned equipment may be optional. GHESI strives to work with customers to agree on the optimal placement of assets.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Final cost of the program is determined by the scope and timing of the work performed. The scope is subject to changes depending on the actual number of customer service requests received in each year, which may deviate from the estimates provided in the DSP. Factors that can affect the cost are size of the service, length of services, and subsurface conditions.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all new Apartment Commercial and Industrial Connections are in accordance with the GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI makes new connections in accordance with the Conditions of Service and does not conduct life-cycle cost and cost efficiency reviews for each project. Where options exist, the Customer can select the option with the least impact on the project. GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects. Timing of projects are dealt with as they are received.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
Apartments, Commercial and Industrial Connections generally have a low impact on the system unless the developments are very large. Individual connections and small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. Where a development requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	Metering Installations					
Project Number	CMEG					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$1,342,946	$567,148	$422,899	$389,899	$1,010,000	$415,000
Capital contribution	$0	$0	$0	$0	$0	$0
Net Cost	$1,342,946	$567,148	$422,899	$389,899	$1,010,000	$415,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Specific projects are not contemplated at this time. In a typical year, GHESI will replace or install approximately 1,200 meters affecting customers from 1 or 2kW to 10's of MVA.

Start Date (5.4.5.2 A.3)	01-01-16	**In-Service Date (5.4.5.2 A.3)**		12-31-2016
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 103,750	$ 103,750	$ 103,750	$ 103,750

Project Summary

GHESI is required to maintain its retail meter inventory to ensure compliance with Measurement Canada and other applicable regulatory requirements.
Capital expenditures in this program cover all conventional general service metering for customers who require demand meters and may include the existing meters due to: customer electrical service upgrades, the need to replace obsolete or damaged meters, or conversion from 2.5 element metering to 3 element metering.

Risk Identification & Mitigation (5.4.5.2 A.4)

GHESI has limited control over these projects as they are customer driven or are requirements of the provincial authorities.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Meter project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not applicable

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

Meters are installed in accordance with GHESI's Conditions of Service. Details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
The main driver for this program is mandated obligation to service new customers.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary drivers include mandated technology upgrades, asset health renewal and enabling of CDM and Renewable programs.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to meet GHESI's service obligation to maintain its retail meter inventory.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
Meter installations are governed by Measurements Canada, and are a requirement for service connection under GHESI's Conditions of Service. Meters are tracked in the GHESI asset registry, but a specific health index is not created as meters are changed out on a regulated program. Meter upgrades such as SMART metering etc. generally originate at the Provincial level.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore cannot be deferred. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
Installation of smart meters reduces the need for manual meter reading, thus improving system operation efficiency.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
This program will ensure the timeliness and accuracy of customers' electricity bills.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
This program ensures that GHESI maintains a retail meter inventory that provides critical information about the consumption of electricity on its distribution system. GHESI can utilize this data to monitor power quality, predict supply problems and reduce service interruptions.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
GHESI is required to maintain its retail meter inventory to ensure compliance with Measurement Canada and other applicable regulatory requirements. GHESI has a very limited ability to consider project alternatives
Safety (5.4.5.2.B2)
This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Meter Installations at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is part this activity. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Not applicable.
Economic Development (5.4.5.2.B5) (where applicable)
Not applicable
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Prioritization is based on customers' expectation on when the service will be delivered. Timing will be coordinated with the requesting customer.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
Not applicable
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Final cost of this program is largely determined by the scope of work performed, which depends on the number of requests received by GHESI in each year. Factors that can affect the cost are size of the service, acces complexities or special requirements.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all new metering installations are in accordance with the GHESI Standards which; have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI makes new metering installations in accordance with the Conditions of Service and does not conduct life-cycle cost and cost efficiency reviews for each project. Where options exist, the Customer can select the option with the least impact on the program. GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
Metering Installations have a low impact on the system. If installations reach any magnitude, the program will be connected with a subdivision development of some kind. Individual connections and small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. In the case of a wholesale meter change due to technology or regulator requirements, a major or minor betterment program will be created

A. General Information						
Project /Activity	Distribution System Modifications / Expansions for Customers					
Project Number	CMOD					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$2,148,440	$75,748	$83,682	$962,910	$761,407	$784,249
Capital contribution	$1,648,249	$62,429	$83,682	$669,847	$616,511	$634,863
Net Cost	$500,191	$13,319	$0	$293,062	$144,896	$149,386
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific project within the program. A detailed listing of individual projects is not available at this time.
In a typical year, GHESI will make approximately 3 modifications to lines that can affect 1 or 100's of new customers of approximately 2-5kW in size. (GHESI completed 4 distribution system modification projects in 2014 and completed 2 distribution system modification projects in 2013.)

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 37,347	$ 37,347	$ 37,347	$ 37,347

Project Summary

This program represents capital expenditures related to line modification projects for additions or modifications to the distribution system to accommodate specific new commercial and industrial customers. A significant portion of this cost is recovered through capital contributions.

Risk Identification & Mitigation (5.4.5.2 A.4)

Relocation projects are driven by customer service requests. GHESI has very limited control over the scope and timing of these projects.
GHESI will review customer service requests on a regular basis such that expansions are identified in a timely manner to accommodate all commercial/industrial developments. GHESI will work with developers to control timing of these projects such that customer expectations are met.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Customer connection project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Customers are connected in accordance with GHESI's Conditions of Service. Connection details vary widely within that standard. Line construction activities will follow GHESI standards for distribution design and construction.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Projects in this program are driven by customer service requests.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary driver for this program is mandated obligation to service new customers.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to ensure proper allocation of investments to fulfill service obligations and meet existing and future demand levels.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
This program was planned incorporating elements of the municipal development to assist in forecasting commercial and industrial developments over the planning cycle.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore must be completed in the test year. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
The new facilities will be designed and constructed to create more flexibility in system operations. This reduces the needs for system modifications in the future and helps GHESI achieve better system operation efficiency and cost-effectiveness in the long term.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
This program provides access for commercial and industrial customers to connect and receive reliable electricity supply from GHESI's distribution system.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
Although this program is not intended for reliability improvements, it is expected to have a positive impact on GHESI's system reliability performance, reflected in improved SAIDI/SAIFI. New facilities will be constructed underground, eliminating causes of outages that typically exist with overhead facilities, such as tree contacts, lightning, and adverse weather conditions. New facilities will be designed to the most recent standards that maintains or improves the overall reliability of GHESI's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Developments are planned and funded in accordance with GHESI's Conditions of Service. Where options are available, the most effective overall alternative is selected.
Safety (5.4.5.2.B2)
This program helps to mitigate potential safety risks associated with events such as a pole falling down during severe weather event, or a vehicle hitting a pole, that can potentially result in fire, damage to surroundin houses and facilities, and serious injuries of personnel. New facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is part of every project. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Distribution Lines are designed to the latest standard for operational needs, which could include controllable primary switching devices and monitoring equipment and sensors.
Economic Development (5.4.5.2.B5) (where applicable)
Although not directly related to economic development, these projects often connect new industrial or commercial customers that contribute to the economic development of the service area.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Timing and pacing of these projects is largely determined by the number of customer service requests received in each year, and the time when these requests are received. GHESI will prioritize new service connection requests based on customer's expectation of when the service requirement will be fulfilled, such that these expectations can be met. In cases where the customer is responsible for constructing or installing civil infrastructure that is deemed required by GHESI to facilitate the service connection, project delays can result if the civil infrastructure does not meet current standards of GHESI.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
For all service connections, a certain amount of GHESI plant must be located on the customer's premises. This can range from a meter installation up to a pad mounted transformer or internal transformer vault. GHESI's Conditions of Service document outlines the requirements for the different types of services and has been crafted to account for customer preferences and to minimize the impacts on the customer's premises. For plant located in the road allowance, local preferences for improved appearance, reliability or cost management are considered in the development of the installation. Factors such as service location or plant location relative to customer owned equipment may be optional.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Final cost of the program is determined by the scope and timing of the work performed. The scope is subject to changes depending on the actual number of customer service requests received in each year, which may deviate from the estimates provided in the DSP. Factors that can affect the cost are length of lines being modified, number of new services, and subsurface conditions. A large portion of the capital cost for these activites are recovered through customer capital contributions.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all Distribution System Modifications are in accordance with the GHESI Standards which; have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI designs all installations in accordance with the GHESI standards and procedures for construction and does not conduct life-cycle cost and cost efficiency reviews for each project. GHESI manages its portion of the cost by applying GHESI Standards which; have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
Distribution System Modifications and Expansions generally have a low impact on the system unless the developments are very large. Individual connections and small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. Where a development requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	System Relocations Property Development					
Project Number	CREL					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$646,265	$1,728,042	$760,464	$1,176,556	$1,262,023	$1,299,884
Capital contribution	$191,631	$846,098	$499,021	$486,240	$607,071	$625,142
Net Cost	$454,634	$881,944	$261,442	$690,316	$654,953	$674,742
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Number of customer attachments and load is different for each individual project depending on the circuit to be relocated and the number of customers supplied from it. Without detailed listing of projects this information is not available at this time. In a typical year, GHESI will conduct 5 line relocations that can affect 1000s of customes at a time ranging in size from 2kW to 10's of MW. (GHESI completed 5 line relocations in 2013, and 4 line relocations in 2014).

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 168,686	$ 168,686	$ 168,686	$ 168,686

Project Summary

This program consists of line relocation projects which are required in order to accommodate projects related to road work by the City of Guelph, the Township of Guelph-Eramosa, as well as projects associated with the Ministry of Transportation work. Projects within this program are initiated by third party request to relocate GHESI facilities. The overall capital requirement for the program is an estimate based on historical spending on relocations and other projects that have already been identified. Detailed planning and project listing is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

Relocation projects are driven by development plans of municipal government and other third parties. GHESI has very limited control over the scope and timing of these projects. GHESI will maintain frequent communication with municipal governments and the Ministry of Transportation for timely exchange of information. This is to ensure that all road work requiring system relocations are planned for and well coordinated with other projects of GHESI.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Relocation project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Line construction activities will follow GHESI standards for distribution design and construction. Details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Third party infrastructure development requirement
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary driver for this program is mandated obligation to requesting parties.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to meet regulatory obligation to relocate facilities for municipal road work.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
GHESI's capital plan for system relocation as presented in the DSP is based on consultation with municipal officials to understand future projects requiring relocation of distribution system assets.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore must be completed in the test year. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
While relocating the facilities, GHESI can take this opportunity to upgrade / modify the system to create flexibility in operations and accommodate future needs on the system. This will reduce the need for System Service work required in the future and contribute to higher system operation efficiency and cost effectiveness in the long term.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
There are no direct benefits to customers.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
This program is not intended to improve system reliability performance. However, adoption of new design standards and installation of new and standardized equipment can contribute to lower asset failure risks resulting in less service interruptions.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Line relocations are generally executed on a like-for-like basis, however the opportunity is taken to consider project alternatives which may include: underground or overhead options, use of alternate routings, increasing conductor sizing's. The optimal solution for immediate and future system needs is selected.
Safety (5.4.5.2.B2)
Facilities will be built to current standards to maintain and potentially improve safety. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Plant Relocations at this level do not impact inter-utility coordination or regional planning activities.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Distribution Lines are designed to the latest standard for operational needs, which could include controllable primary switching devices and monitoring equipment and sensors.
Economic Development (5.4.5.2.B5) (where applicable)
Although not directly related to economic development, these projects are often done in support of municipal projects target at economic development.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Prioritization of relocation projects is based on development plans of the City. Timing of these projects is determined by that of the road work where the facilities are located. Projects can be delayed/cancelled as a result of delay/cancellation of the planned road work of the road authority.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
For plant located in the road allowance, local preferences for improved appearance, reliability or cost management are considered in the development of the installation.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Factors affecting the final cost of these projects can include : - scope changes in the road work resulting in potential scope change of GHESI's relocations, and - modifications to the road authority's capital plan resulting in projects to be dropped from or added to GHESI's list of planned capital projects.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all System Relocations are in accordance with the GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI designs all installations in accordance with the GHESI standards and procedures for construction and does not conduct life-cycle cost and cost efficiency reviews for each project. In the case of technically feasible system alternatives such as underground vs overhead design or alternate routings, the optimal solution for both the immediate and future system need is selected. GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
System Relocations generally have a low impact on the system unless the changes are very large. Individual projects are funded through customer contributions based on fixed and variable fees as well as a cost sharing agreement between GHESI and the land owner. Where a relocation requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	Expansions for New Residential Subdivisions					
Project Number	CRES					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$796,412	$1,409,933	$1,642,688	$861,802	$1,401,224	$1,443,261
Capital contribution	$601,987	$1,016,768	$1,587,642	$524,569	$992,742	$1,022,294
Net Cost	$194,425	$393,165	$55,045	$337,233	$408,482	$420,967
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific project within the program. This information is not available at this time. In a typical year, GHESI will make approximately 5 expansions to lines that can affect 100's of new customers of approximately 2-5kVA in size. (GHESI completed a total of 16 expansions to supply residential subdivisions in 2012, 2013 and 2014.)

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 63,145	$ 84,193	$ 168,387	$ 105,242

Project Summary

These investments are related to expansions of GHESI's distribution system for new residential developments. Work within this section covers the installation of new underground distribution system facilities to accommodate new residential developments. A large portion of the cost is recoverable through capital contributions by the developer based on an economic evaluation model. Expansions for new residential subdivisions are initiated by customer service requests. The overall capital requirement for this program is an estimate based on information in the City of Guelph Development Priorities Plan (DPP), historical trends, and other known projects anticipated over the planning horizon. Detailed planning is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

New Subdivision projects are driven by customer service requests. GHESI has very limited control over the scope and timing of these projects.
GHESI will review customer service requests on a regular basis such that expansions are identified in a timely manner to accommodate all residential subdivision developments. GHESI will work with developers to control timing of these projects such that customer expectations are met.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Residential Development project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investment associated with these expansions.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Developments are connected in accordance with GHESI's Conditions of Service and standards for design and construction. Connection details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Projects in this program are driven by customer service requests.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary driver for this program is mandated obligation to service new customers.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to ensure proper allocation of investments to fulfill service obligations and meet existing and future demand levels.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
This program was planned incorporating elements of the municipal development to assist in forecasting residential developments over the planning cycle.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore must be completed in the test year. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
The new facilities will be designed and constructed to create more flexibility in system operations. This reduces the needs for system modifications in the future and helps GHESI achieve better system operation efficiency and cost-effectiveness in the long term.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
This program creates access for residential customers to receive reliable electricity supply from GHESI's distribution system.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
Although this program is not intended for reliability improvements, new construction will be designed to reduce impact on GHESI's system reliability performance, reflected in improved SAIDI/SAIFI. New facilities will be constructed underground, eliminating causes of outages that typically exist with overhead facilities, such as tree contacts, lightning, and adverse weather conditions. New facilities will be designed to the most recent standards that maintains or improves the overall reliability of GHESI's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Developments are planned and funded in accordance with GHESI's Conditions of Service. Where options are available, the most effective overall alternative is selected.
Safety (5.4.5.2.B2)
This program helps to mitigate potential safety risks associated with events such as a pole falling down during severe weather event, or a vehicle hitting a pole, that can potentially result in fire, damage to surroundin houses and facilities, and serious injuries of personnel. New facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers is part of this activity. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Not applicable.
Economic Development (5.4.5.2.B5) (where applicable)
Not applicale
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Timing and pacing of these projects is largely determined by the number of new development installations received in each year, and the time when these requests are received. GHESI will prioritize new connections requests based on customer's expectation of when the service requirement will be fulfilled, such that these expectations can be met. In cases where the customer is responsible for constructing or installing civil or electrical infrastructure that is deemed required by GHESI to facilitate the service connection, project delays can result if the infrastructure does not meet current standards of GHESI.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
For new developments, a certain amount of GHESI plant must be located on the customer's premises and in customer developed right-of-ways. This can range from a meter installation up to a pad mounted transformer and primary cables or poles. GHESI's Conditions of Service document outlines the requirements for the different types of services and has been crafted to account for customer preferences and to minimize the impacts on the development. Factors such as service location or plant location relative to customer owned equipment may be optional.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Final cost of the program is determined by the scope and timing of the work performed. The scope is subject to changes depending on the actual number of customer service requests received in each year, which may deviate from the estimates provided in the DSP. Additional costs may be required to complete the work if projects are delayed. Factors that can affect the cost are number of units, length of services, and subsurface conditions.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all Expansions for New Residential Subdivisions are in accordance with the GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI makes new connections in accordance with the Conditions of Service and does not conduct life-cycle cost and cost efficiency reviews for each project. Where options exist, the Customer can select the option with the least impact on the project. GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
Expansions for new Residential Subdivisions generally have a low impact on the system unless the developments are very large. Small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. Where a development requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	New Residential Service Connections					
Project Number	CSER					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$410,079	$311,801	$348,477	$216,128	$231,994	$238,954
Capital contribution	$312,588	$231,837	$347,259	$135,640	$169,468	$174,513
Net Cost	$97,491	$79,964	$1,218	$80,488	$62,526	$64,441
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Typically, a connection in this program involves establishing a connection from GHESI's distribution system to the customer owned facilities. Each year, GHESI will connect approximately 310 services each of which is a single customer of 5kVAor less. (Based on 307 services connected in 2013 and 309 services connected in 2014).

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 9,666	$ 12,888	$ 25,776	$ 16,110

Project Summary

This programs consists projects to establish electrical service connections to residential subdivisions as well as in-fill and small commercial properties. A significant portion of the capital costs associated with these projects is recovered through capital contributions based on an economic model. Connections within this program are initiated by customer service requests. The overall capital requirement for the program is an estimate based on information in the City of Guelph Development Priorities Plan (DPP), historical trends, and other known projects anticipated over the planning horizon. Detailed planning and project listing is not available for this program. However, it is expected that none of the individual projects within this program will exceed the materiality threshold.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include variances between forecasted and actual connection requirements, and system capacity constraints that prevent GHESI from connecting customers in a timely manner. To mitigate these risks GHESI will coordinate connection service and system expansions and maintain frequent communication with customers to ensure timely exchange of information.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Customer connection project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not applicable

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

Customers are connected in accordance with GHESI's Conditions of Service. Connection details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Projects in this program are driven by customer service requests.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary driver for this program is mandated obligation to service new customers.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to ensure proper allocation of investments to meet service obligations.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
GHESI bases its budgeted service installations on information from the City of Guelph Development Priorities Plan (DPP) and historical trends.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore must be completed in the test year. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
In the long term, benefits are achieved in system operations efficiency and cost-effectiveness through integrated planning of system expansions and new connections.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
This program ensures that new customers are connected and have access to electricity services provided by GHESI.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
Before connecting a new customer, GHESI must ensure that enough supply capacity is available such that the new connection will not affect GHESI's ability to provide consistent and quality electricity service to existing customers. Therefore this program is expected to have minimum impact on system reliability performance.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
GHESI is obligated by the Distribution System Code and Condition of Service to connect new customers in its service region. No other alternatives exist for this program.
Safety (5.4.5.2.B2)
Establishment of the new connections will be carried out, from design to construction, in accordance with ESA Regulations and the latest standards, to ensure safety of the connection. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers is part of this activity. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Not applicable
Economic Development (5.4.5.2.B5) (where applicable)
Although not directly related to economic development, these projects often connect new small commercial customers that contribute to the economic development of the service area.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access
Factors Affecting Timing/Priority (5.4.5.2 SA - C1)
Timing and pacing of this program is largely determined by the number of customer service requests received in each year, and the time when these requests are received. Prioritization of individual projects is based on the customer's expectation of when the service requirement will be fulfilled, which is identified through communication between GHESI and the customer. Where the new connection requires expansion on GHESI's systems to upgrade the system's supply capacity such that connecting the new customer will not cause capacity constraints on the system, timing of the new connection can be delayed until the expansion is completed.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)
GHESI will prioritize connection services to meet expectations of customers. Factors such as service location or plant location relative to customer owned equipment may be optional.
Factors Affecting the Final Cost (5.4.5.2 SA - C3)
Capital costs for this program as presented in the DSP are based on information from the City of Guelph Development Priorities Plan (DPP) and the number of requests received in historical years. Final cost of the program might deviate from budgeted costs, resulting from variances between forecasted number of connections required and the actual number received. Factors that can affect the cost are size of service, length of services, and subsurface conditions.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)
GHESI ensures all Residential Service Connections are in accordance with the GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)
Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)
GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.
Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)
GHESI makes new connections in accordance with the Conditions of Service and does not conduct life-cycle cost and cost efficiency reviews for each project. Where options exist, the Customer can select the option with the least impact on the project. GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.
Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)
Final Economic Analysis as described in the DSC is not applicable to this program
System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)
New Residential Service Connections generally have a low impact on the system unless the developments are very large. Individual connections and small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. Where a development requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	Expansions for New Residential Townhouse Subdivisions					
Project Number	CTH					
Investment Category	System Access					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$629,739	$379,538	$433,944	$243,783	$552,236	$568,803
Capital contribution	$467,883	$266,306	$408,069	$144,378	$380,676	$392,008
Net Cost	$161,856	$113,232	$25,875	$99,405	$171,559	$176,795
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific project within the program. Without detailed listing of individual projects this information is not available at this time. In a typical year, GHESI will connect an estimated 210 units with a typical load of 2kW/unit (based on 127 townhouse units installed in 2014, 235 townhouse units installed in 2013 and 258 estimated registrations noted the City of Guelph "2014 Development Priorities Plan").

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16

Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$ 88,397	$ 17,679	$ 35,359	$ 35,359

Project Summary

This is a program consisting of individual projects and investments related to expansions of GHESI's distribution system for new townhouses developments. Work within this section covers the installation of new underground distribution system facilities to accommodate these new developments. A large portion of the cost is recoverable through capital contributions by the developer based on an economic evaluation model. Expansions for new townhouse developments are initiated by customer service requests. The overall capital requirement for this program is an estimate based on information in the City of Guelph Development Priorities Plan (DPP), historical trends, and other known projects anticipated over the planning horizon. Detailed planning is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

New Townhouse connection projects are driven by customer service requests. GHESI has very limited control over the scope and timing of these projects.
GHESI will review customer service requests on a regular basis such that expansions are identified in a timely manner to accommodate all residential subdivision developments. GHESI will work with developers to control timing of these projects such that customer expectations are met.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Townhouse Development project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investment associated with these expansions.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Developments are connected in accordance with GHESI's Conditions of Service and standards for design and construction. Connection details vary widely within that standard.

B. Evaluation criteria and information requirements for each project/activity
Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)
Projects in this program are driven by customer service requests.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)
Secondary driver for this program is mandated service obligations.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)
The objective of this program is to ensure proper allocation of investments to fulfill service obligations and meet existing and future demand levels.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
This program was planned incorporating elements of the municipal development to assist in forecasting residential developments over the planning cycle.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments
This program is of top priority relative to other material investments as it is part of GHESI's mandated service obligations and therefore must be completed in the test year. Project planning will be coordinated with other projects/programs of the same priority level.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)
The new facilities will be designed and constructed to create more flexibility in system operations. This reduces the needs for system modifications in the future and helps GHESI achieve better system operation efficiency and cost-effectiveness in the long term.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),
This program creates access for residential customers to receive reliable electricity supply from GHESI's distribution system.
Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)
Although this program is not intended for reliability improvements, it is expected to have a positive impact on GHESI's system reliability performance, reflected in improved SAIDI/SAIFI. New facilities will be constructed underground, eliminating causes of outages that typically exist with overhead facilities, such as tree contacts, lightning, and adverse weather conditions. New facilities will be designed to the most recent standards that maintains or improves the overall reliability of GHESI's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Developments are planned and funded in accordance with GHESI's Conditions of Service. Where options are available, the most effective overall alternative is selected.
Safety (5.4.5.2.B2)
This program helps to mitigate potential safety risks associated with events such as a pole falling down during severe weather event, or a vehicle hitting a pole, that can potentially result in fire, damage to surrounding houses and facilities, and serious injuries of personnel. New facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers is part of this activity. Authorization from the Electrical Safety Authority is required prior to reconnection of connection of any services which is handled through an established process.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Not applicable.
Economic Development (5.4.5.2.B5) (where applicable)
Not applicable
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable

C. Category-Specific Requirements – System Access

Factors Affecting Timing/Priority (5.4.5.2 SA - C1)

Timing is typically affected by:
Availability of resources
Approval of designs and specifications

Timing and pacing of these projects is largely determined by the number of new development installations received in each year, and the time when these requests are received. GHESI will prioritize new connections requests based on customer's expectation of when the service requirement will be fulfilled, such that these expectations can be met. In cases where the customer is responsible for constructing or installing civil or electrical infrastructure that is deemed required by GHESI to facilitate the service connection, project delays can result if the infrastructure does not meet current standards of GHESI. Factors such as service location or plant location relative to customer owned equipment may be optional.

Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA - C2)

For new developments, a certain amount of GHESI plant must be located on the customer's premises and in customer developed right-of-ways. This can range from a meter installation up to a pad mounted transformer and primary cables or poles. GHESI's Conditions of Service document outlines the requirements for the different types of services and has been crafted to account for customer preferences and to minimize the impacts on the development. Factors such as service location or plant location relative to customer owned equipment may be optional.

Factors Affecting the Final Cost (5.4.5.2 SA - C3)

Final cost of the program is determined by the scope and timing of the work performed. The scope is subject to changes depending on the actual number of customer service requests received in each year, which may deviate from the estimates provided in the DSP. Additional costs may be required to complete the work if projects are delayed. Factors that can affect the cost are number of units, length of services, and subsurface conditions.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA - C4)

GHESI ensures all new Expansions for new Townhouse Subdivisions are in accordance with the GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.

Other Planning Objectives (5.4.5.2 SA - C5) (where applicable)

Where appropriate, GHESI's other planning objectives, as detailed in Section 5.4.2 of the Distribution System Plan, are considered on a project by project basis. These objectives include: maintain assets in a safe and reliable system, meet existing and future demand requirements, and support general plant. This program will maintain or improve system reliability performance, safety performance, and operational efficiency and cost-effectiveness, based on the installation of equipment to the latest standards and in excellent condition.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA - C6)

GHESI makes all connections in accordance with the Conditions of Service document which has been designed to minimize overall costs and impact on the customer. General technically feasible options will not exist, however, if an option is requested by the customer. Specilized requests are evaluated on a case by case basis.

Summary of results analysis - "Least Cost", "Cost efficient" options (5.4.5.2 SA - C7)

GHESI makes new connections in accordance with the Conditions of Service and does not conduct life-cycle cost and cost efficiency reviews for each project. Where options exist, the Customer can select the option with the least impact on the project.
GHESI manages its portion of the cost by applying GHESI Standards which have been designed to minimize overall costs and impact on the customer, are based on establish processes, use standards materials and methods, and benefit from efficiencies established through GHESI's experience in such projects.

Results of a final Economic Evaluation (5.4.5.2 SA - C8) (where applicable)

Final Economic Analysis as described in the DSC is not applicable to this program

System impacts costs & cost recovery method (5.4.5.2 SA - C9) (where applicable)

Expansions for new Residential Townhouse Subdivisions generally have a low impact on the system unless the developments are very large. Individual connections and small developments are below the materiality threshold and are funded through customer contributions base on fixed and variable fees. Where a development requires major infrastructure upgrades, a specific minor or major betterment project will be created.

A. General Information						
Project /Activity	295 Water St					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$448,000
Capital contribution						$0
Net Cost						$448,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 98 (97 residential, 1 GS <50)
Customer load within project area: 237 kW
Customer attachments downstream of project area: 98
Customer load downstream of project area: 237 kW

Start Date (5.4.5.2 A.3)	4-Apr-16	**In-Service Date (5.4.5.2 A.3)**	24-Jun-16

Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
		$448,000		

Project Summary

This reconstruction project includes the replacement of 6 pad-mounted transformers and the replacement of the existing direct-buried distribution system with a new underground distribution system in duct. One of the existing transformers has been replaced due to failure and the remaining original transformers have an average age of 38 years. The existing underground primary cable is direct buried, was installed in 1975 and is 40 years old. The project area has suffered two primary cable faults over the past five years, contributing to 13,988 customer minutes of interruptions. One segment of primary cable is currently out of service due to an unrepaired fault. Additionally, a switching cubicle is out of service due to damage and lack of a suitable like-for-like live-front replacement unit. Cable faults in direct buried cable result in higher costs to locate and repair faults. Guelph Hydro's practice is to install all underground conductors in duct and to install switching cubicles on distribution vaults.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: This project is subject to scheduling risks with respect to external contractors and with other major projects. Specifically, this project risks not being completed in 2016 due to the amount of civil and electrical construction required to install a complete new underground distribution system and competing requirements from other civil intensive projects such as the Yewholme Drive reconstruction project. This project must also be completed before frost sets in the ground (due to the large amount of civil work required and the high costs of constructing in frost). The mitigation plan for this risk is bi-weekly internal project meetings and monthly contractor meetings to review projects underway and identify action plans to keep construction on schedule. This project is planned to begin in the second quarter of 2016, in order to allow the frost to leave the soil. By scheduling the project to begin in Q2 of 2016, the amount of available time for construction before frost returns will be maximized. If this project is not completed in 2016, the risk of asset failure will be further increased. Due to the switching equipment that is out of service due to past asset failure, any future outages will be significantly longer in duration than they would be if a switching point was available to loop the supply. Therefore, delaying this project significantly increases the risk to GHESI's system reliability performance.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

GHESI completed a similar reconstruction project of a direct-buried townhouse development in 2007 at 15 Willow Road. The 15 Willow Road project was a reconstruction project involving the replacement of a direct-buried primary and secondary distribution system and four pad-mounted transformers, serving 31 customers. The cost of construction was $130,740.82. Based on the comparable 15 Willow Road project, the proposed construction cost of the 295 Water Street project is in-line with the historic costs considering this project is approximately three times the size of the 15 Willow Road project in scope and includes the replacement of a switching cubicle and an additional three-phase transformer.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - 295 Water Rehab

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". The underground system in this townhouse site is made up of direct buried, unjacketed cable. THe unjacketed cable has an exposed concentric neutral which is prone to failure due to the exposure to moisture in the soil from being directly buried. When a fault occurs, the outages are very difficult and time-consuming to repair. Replacement of the direct-buried system with a cable in duct system will facilitate the quick replacement of faulted cables.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Operational Efficiency". The replacement of damaged cable and the damaged switching cubicle will restore the looped configuration of the primary system in this site. This will allow for quicker isolation and restoration of equipment due to the availability of a backup supply.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Operational Efficiency".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are Asset Condition Assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's direct-buried cable program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, and expert opinion based on known past issues with direct-buried cable.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to the existing damaged equipment and to reduce the risk of incurring additional significant outages. This completion of this project will result in the removal of a significant amount of direct-buried cable. This project is prioritized ahead of other direct-buried cable projects due to the existing damaged equipment, which puts the project at a higher risk of significant restoration times since no alternate supply is available. This project is ranked number 3 of the 9 material system renewal projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of transformers that have reached their end of life and direct-buried cable will greatly decrease the probability of a failure in this project area. Because the cables are not in duct, faults must be located, exposed and spliced out in order to repair the cable, which is a very time consuming process. Additionally, the installation of a new dead-front switching cubicle that meet current standards will allow for the operation of equipment in a safer and more efficient manner in the future due to improved clearance and dead-front operation.
Spot replacement of poles for this project was not considered to be a viable option due to the fact that pole-trans units are no longer manufactured, therefore replacement involves locating space for a pad-mounted transformer base, and either replacing the attached primary and secondary cables due to the change in physical location, or splicing of all cables to extend them to the new location. This option is not preferable due to the amount of work and duration required to repair each transformer location and the weakening of the remaining system due to the excessive splicing required by the repair.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers within the project area will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers will also indirectly benefit from the lower maintenance costs a new system will provide.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from a switching cubicle failure will be reduced through the use of a dead-front unit, which does not exhibit the tracking problems that are prevalent in older live-front switching cubicles. This will reduce the probability of an outage due to failure.
The replacement of the direct-buried cable system with a cable in duct system will improve the probability and duration of future outages. The new cable is fully jacketed cable, which protects the concentric neutral from damage due to exposure to moisture. Additionally, the duct system allows faulted cables to easily be pulled out and replaced. This eliminates the process of digging up faulted cable and splicing in new segments, resulting in greatly reduced duration for future outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of an overhead system is not conducive to the design and aesthetic of the existing townhouse site. Private townhouse sites are supplied by underground distribution systems and installing an overhead system would not provide the same level of aesthetics and customer value.
- Replacing the transformers only is not a practical solution due to the amount of splicing that would be required to connect the new transformers to the existing cable. This would further weaken the direct buried cable system and expose the system to lower reliability.
- Like-for-like replacement is not a practical option for this proejct. The maintenance costs and reliability impacts associated with direct-buried cable far outweigh the cost savings of installing a direct buried system, making the use of a direct-buried system inefficient in the long-term
- A "Do-Nothing" solution is not a viable solution for this project. Existing equipment in the project area is already out of service due to asset failures which have removed the ability to provide a looped system and puts system reliability at greater risk. Doing nothing will put this area at a risk of extensive outages when the remaining aged assets fail.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the construction outside of the winter season due to the amount of civil construction required and the increased cost and complexity involved with excavating in frost conditions, therefore the project cannot be completed in either the first or fourth quarters of the year.

Ownership Alternatives:
- Because this underground system supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI. Third parties will be approached to seek out opportunities for joint construction in order to reduce costs.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing live-front switching-cubicle with dead-front equipment. Dead-front equipment provides an inherently safe interface for working on the equipment.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will be contacted to coordinate construction wherever possible. This will allow for multiple utilities to be installed in a common trench, reducing capital costs and limiting the amount of space utilized in the site.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

This project supplies a fully-developed private townhouse site. No further development is possible on the site and the system does not supply any additional loads downstream. Therefore no further future operational requirements are being provided for at this time.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this underground system does not impacts economic development. This system serves a residential townhouse site which is fully developed.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the removal of live-front equipment. Additionally, the selected course of reconstruction has a lower life-cycle cost than other underground alternatives due to the reduction in ongoing maintenance requirements provided by the cable in duct system. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed equipment and direct buried cable.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The original transformers in the project area were purchased and installed in 1977 on average (one transformer has already been replaced). The units are 38 years old on average which falls in line below the typical useful life of pad-mounted transformers in GHESI's system. The transformers have performed below average from an age perspective. The direct-buried primary cable in the project area was installed in 1975 and no complete cables have been replaced. The remaining cable has reached the typical useful life for primary cable in duct. Given the fact that the cable is direct buried, which tends to reduce the useful life of the cable, this cable has performed very well compared to other underground primary cable of the same age in the GHESI system. However, the cable is now exceeding the typical useful life, dramatically increasing its probability of failure. Additionally, cable of this vintage is unjacketed and has non-tree retardant insulation which increases the probability of asset failure by means of burn-off, corroded and disconnected neutrals and insulation break-down.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

97 Residential customers and 1 General Service (less than 50 kW) are within this project area and would be affected by an asset failure in this project area. No additional customers are downstream of this project area.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Several reliability events have occurred within this project area. One transformer was replaced due to condition and one equipment failure from animal contact as well as one cable failure has occurred. The equipment failure resulted in 184 customer minutes interrupted and the cable failures have resulted in 4,840 customer minutes interrupted. These high customer minute counts illustrate the extended duration required to repair failures on direct buried cable.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this townhouse site's distribution system performs at or above reliability targets. Replacement of the switching cubicle, transformers and direct buried cable system will reduce the probability of a long duration failure occurring. Long duration failures have a negative impact on customer satisfaction, especially if the failure occurs during the winter season or during a holiday or other important event.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies a residential townhouse site of customers who will have a relatively low cost of failure and tend to not have no backup supply arrangements.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
Due to the amount of civil construction required, this project requires coordination amongst other projects in the system to ensure that sufficient contractor resources are available to complete the project before the fourth quarter of 2016. This project does not rely on any System Renewal, System Access, System Service or General Plant projects being completed first. This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources, and weather conditions (such as winter frost conditions) into account. This project has been ranked at number 3 of 9 material system renewal projects planned for completion in 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replacement of damaged equipment and live-front equipment will improve the flexibility of the system and reduce isolation, restoration and switching times.
- Replacement of the direct-buried cable system with a cable in duct system will reduce the cost of future repairs from cable faults. Cable can be removed and replaced in the duct and time intensive fault locating and costly excavating and splicing work will be avoided.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Removal of live-front equipment will improve Employee Safety by providing inherently safe interfaces on the switching cubicle.
- Replacement of a direct-buried cable system with a cable in duct system will improve reliability by greatly decreasing restoration times.

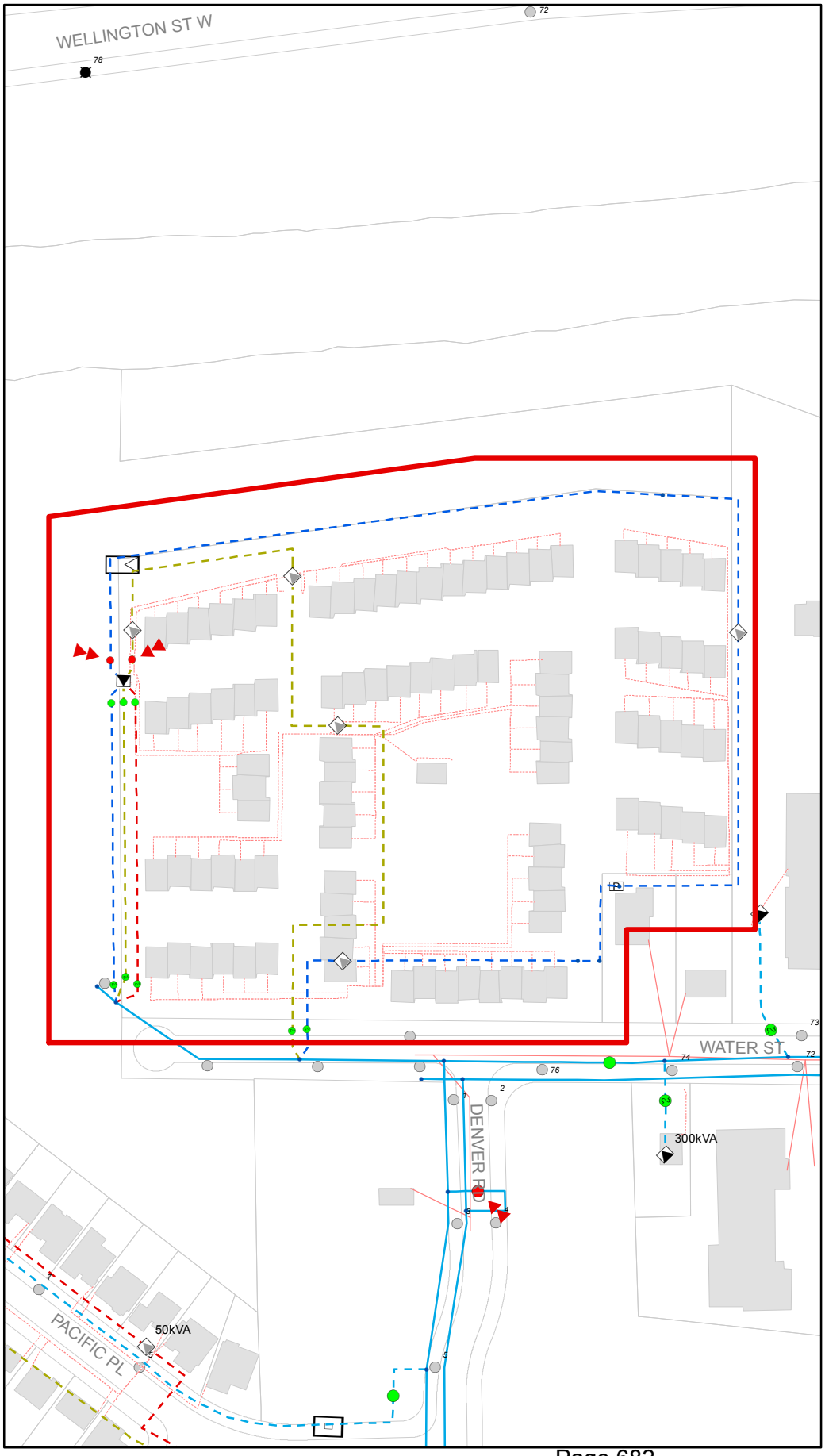
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

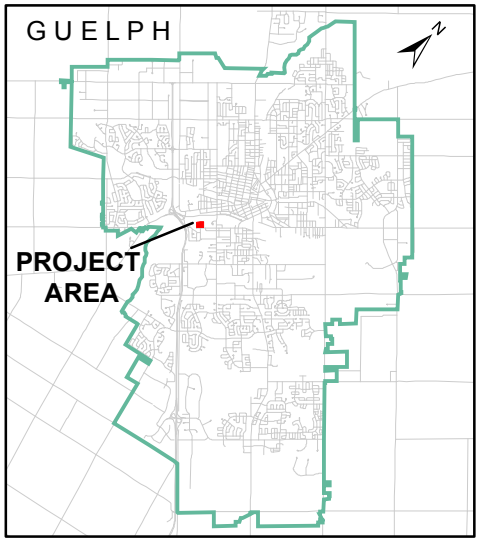
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 3 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by removing direct-buried cable. Direct-buried cable faults require time intensive fault locating and costly excavation and splicing work. The timing of this project could be affected by the ability to obtain sufficient contractor resources, poor weather and long lead times on large orders of transformers and poles.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to the current lack of a looped system due to other asset failures in the area. Failures would result in very long duration outages and restoration times.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project but because the installation of direct-buried cable is no longer supported by GHESI due to reliability impacts and decreased asset life, like for like renewal is not an option for this project. Other alternatives, such as installing an overhead system will result in negative impacts to reliability and aesthetics and are not compatible with the existing site. Construction during winter months is not feasible due to the increased costs and time involved with excavating in frost conditions and the large amount of excavation required for this project.

295 Water Street





LEGEND

Transformers

- CO — CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Alma Street North - Willow Road to Drew Street, and Plymouth Court					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$218,000
Capital contribution						$0
Net Cost						$218,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 143
Customer load within project area: 388.6 kW
Customer attachments downstream of project area: 143
Customer load downstream of project area: 388.6 kW

Start Date (5.4.5.2 A.3)	4-Apr-16	**In-Service Date (5.4.5.2 A.3)**		24-Jun-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
		$218,000		

Project Summary

This reconstruction project includes the replacement of 18 poles on Alma Street North and Plymouth Court within the project area and the replacement of 4 underground services in the project area due to conductor age and the presence of transite duct. The poles on Alma Street North and Plymouth Court are Alma Street are 53 years old on average and are in poor condition. Ongoing maintenance to replace broken or damaged connections and equipment has occurred and has extended the lives of these poles to their present age. Some poles (7, 56, 65 and 66) have been spot replaced since 1995 due to carpenter ants and internal decay and will therefore not be replaced as part of this project. The remaining poles are 35' length poles on Alma Street North and Plymouth Court and will be replaced with 45' long poles to meet current standards and improve clearances for equipment and working space. The underground cables being replaced on Alma Street North and Plymouth Court are 48 years old on average and are installed in transite duct which is an asbestos containing material. Due to the health hazards in working with transite duct, completely new services are installed upon failure which can mean very lengthy outages or the use of costly generators to provide temporary power. GHESI has a transite duct removal program that seeks to proactively replace these services in a controlled manner on a priority basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to other major projects. A preceeding project, the reconstruction of Willow Road at Alma Street North is planned for completion in mid-2015; this project risks being started late if the preceding year's work is not completed. Both projects rely on civil work and coordinated outages in order to replace the underground services to low-rise apartment buildings and risk being late if GHESI's general contractor cannot handle the large civil construction workload in 2015. The mitigation plan for these risks are bi-weekly internal project meetings and monthly meetings with the general contractor to review projects underway and identify action plans to keep construction on schedule. This project must be completed between April and August to ensure that the underground services are replaced outside of frost season and to provide sufficient time for subsequent projects. If the project goes into the frost season, the probability of failure for the underground services in transite is increased and the consequence will greatly increase due to the difficulty in digging through the frost to install a new service, and the need to supply emergency power to the customers due to cold weather. All of this results in a risk to cost, customer satisfaction and reliability. This risk is minimized by scheduling the work to begin in the spring, thereby allowing the largest window of frost-free time to construct.
If this project is not completed in 2016, the risk of an asset failure will be increased. GHESI's previous experiences with cable failures in transite duct have demonstrated a much greater cost of repair and duration of outage. The consequences of delaying this project include the possibility that a failure will occur during winter months and further complicate the restoration process, affecting system reliability and customer satisfaction.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope was completed in 2013 on Hearn Avenue between Waterloo Avenue and Inkerman Street. The total cost of construction was $146,087. Both projects were single-phase pole lines of approximately the same age, however, the Alma Street North and Plymouth Court project has four additional poles to replace and underground secondary services that must be fully replaced. Some underground services on Alma Street North and Plymouth Court supply low-rise apartment buildings and are in transite duct under asphalt driveways, which will increase the cost of installation due to the need to remove and replace asphalt, use a specialized contractor to remove cable from transite duct and to hire an electrician to perform the work inside of the customers' electrical rooms. A comparable service replacement project was completed in 2014 at 188 Waterloo Avenue, where an underground secondary service that was in transite duct was replaced under asphalt to a commercial building at a cost of $10,679. There are four services of this type to be replaced in the project area. Based on these comparable projects, the proposed construction cost of the Alma Street North and Plymouth Court project is in-line with the historic costs, considering the Alma Street North and Plymouth Crescent project has a slightly greater scope than the combined scope of the comparable projects.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Alma-Plymouth

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". The risk to reliability is evidenced by a high risk score, driven by a high composite probability of failure. This project also has a low dollar per risk point abated score which makes it a particularly prudent project. The high probability of failure score is related primarily to the age of the underground secondary cable and secondarily to the age and condition of some of the poles in the project area.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Customer Value". The underground services in transite duct have a high probability of failure and a long duration to repair due to the number of parties involved and limited options for providing an alternate supply. These services supply small apartment buildings which results in a large number of customers out of power if a failure occurs. By proactively targeting this difficult services, the majority of the replacement work can be done without customer interruptions and planned, which spares lengthy outages that would negatively affect the customers' experience, satisfaction and safety.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's transite duct removal program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with transite duct.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to a high composite probability of failure and to follow the completion of similar transite removal efforts on Willow Road that are occurring in 2015. This project ties into othe projects on Willow Road and further South on Alma Street North, including Julia Drive and Drew Street, which have been identified and have been placed in order considering risk and dollars per risk point abated, as well as to best allow for constructability of the future associated projects by building on lessons learned. This project is has a composite probability of failure of approximately 99.3% which indicates that an asset failure within this project area is imminent. This project is ranked at number 4 of 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of secondary services in transite duct in this project will greatly decrease the duration and cost of outages. Through experience with past cable failures in transite duct, the repair process is very lengthy due to the need to obtain emergency locates, organize contractors to install new duct work and to bring in an asbestos management contractor to remove the damaged cable. Typically customers have been connected to emergency generators that are contracted by GHESI during the repair process. By installing the replacement service in a planned and proactive way, the majority of this cost can be reduced and the duration of outage is reduced to a minimum. This is a more cost-effective approach. Additionally, the installation of poles that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner in the future due to easier access and safer working conditions.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide. Because the suspect services supply apartment buildings, many customers would be affected by a single cable failure, therefore the benefits of this project also reach a large number of customers per service replaced.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages on the overhead portion of the project from animal contact will be replaced due to improved framing standards, increased spacing between energized conductors and second points of contact and the use of modern insulators. The risk of failure on the underground portion of the project will be greatly reduced due to the replacement of aging cable and the duration of outages will be greatly reduced by the elimination of hazardous materials such as transite duct.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, in this case the line is single-phase and does not supply customers downstream of the project area, therefore the benefits would be very limited. Reliability issues in this area are primarily related to damaged overhead conductor due to storms. Replacement of the conductor and connectors as part of this project, combined with tree trimming, will reduce the future occurrences of these types of failures.
- Like-for-like replacement is not a practical solution for this project because of the health and safety risks associated with transite duct. Additionally, like-for-like replacement would not provide the additional reliability benefits of a taller pole line with improved conductor spacing.
- A "Do-Nothing" solution is not practical for this project. GHESI's experience with services in transite duct are that failures result in long and expensive restoration efforts. By delaying the project, there is an increased risk of a failure during winter conditions, which will futher increase the duration and cost of the restoration effort.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete replacement work on Willow Road, which supplies this project area, prior to beginning construction.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles with taller 45' long poles and replacing the existing framing to improve spacing on the pole. The replacement of transite duct with PVC duct will remove the risk of asbestos particles being carried into the environment or customers' premises by disturbances to the service or during a failure event.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line does not directly impact economic development. This pole line serves two mature, fully developed residential streets.

Environmental Benefits (5.4.5.2.B6) (where applicable)

This project will remove or decommission asbestos containing materials which will prevent the future distribution of asbestos particles from disturbing the duct or the cable within the duct. The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed services in transite duct.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles in this project area were installed (on average) in 1962 and have an average age of 53 years. From an age perspective, the poles have surpassed the typical end of useful life for fully dressed wood poles. This effective age, combined with the relatively low rate of spot replacement (due to internal decay and carpenter ants) demonstrates that the pole line has had an above-average performance record relative to other pole lines of the same age in GHESI's system, however the poles have surpassed their useful life and must be replaced to avoid impending asset failure. The secondary cable in this project is 48 years old, which is above the typical useful life for underground secondary cables and therefore the cables have performed above-average relative to other cables of the same age in GHESI's system. Because of the age and high probability of failure of the secondary cables, and their installation in transite duct, these cables must be replaced soon to avoid lengthy outages. Similarly, because of the age of the poles and multiple life-extending repairs that have been made to them, it is prudent to replace the poles within this project area which have not already had previous spot replacements completed.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

131 Residential and 12 General Service (less than 50 kW) are within this project area and would be affected by an asset failure. No additional customers outside of this project area would be affected by a failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

This project area has sustained 194 customer minutes of unplanned outages over a five year period. However, due to the number of customers living in each apartment building and the known typical duration of outages sustained during the repair of defective transite services, combined with the high probability of failure, this area is at risk for developing very poor reliability in the next few years if the project is not completed. Completing this project will renew the system in this area and provide many years of good reliability performance for the customers in the area.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this line segment performs at or above reliability targets. Changes to the configuration of the equipment in this project will result in better operational performance, which will reduce future outage and construction times. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from reducing the risk of exposure to transite duct.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies residential customers who will not have a high cost of failure, however, most residential customers have no backup supply arrangements and a failure in the underground secondary cable will result in a much longer than typical outage due to the need for multiple parties on site and the challenges of working with and around transite duct. The general service customers in this area are the common amenities and offices of the residential buildings and are not expected to have a significantly higher cost of failure than the residential customers.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
This project requires System Renewal work on Willow Road to be completed prior to commencing, but does not rely on any System Access, System Service or General Plant projects.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources weather conditions into account. This project has been ranked at number 4 of 9 material system renewal projects planned for 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- Modifications to spacing will reduce the number of animal contacts. This will reduce the costs associated patrol and repair time.
- Repair and restoration times will be reduced for future outages due to the replacement of transite duct with PVC duct.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances will reduce the number of animal contact related outages, thereby improving reliability performance.
- Tree trimming and conductor replacement will reduce the amount of storm damage sustained by this project area.
- The removal of transite duct will allow for shorter duration outages in the future, as cable can simply be pulled out of and pulled in to PVC duct.
- The removal of transite duct in a controlled manner will improve worker and public safety due to the elimination of the risk of improper handling resulting in exposure to asbestos particles.

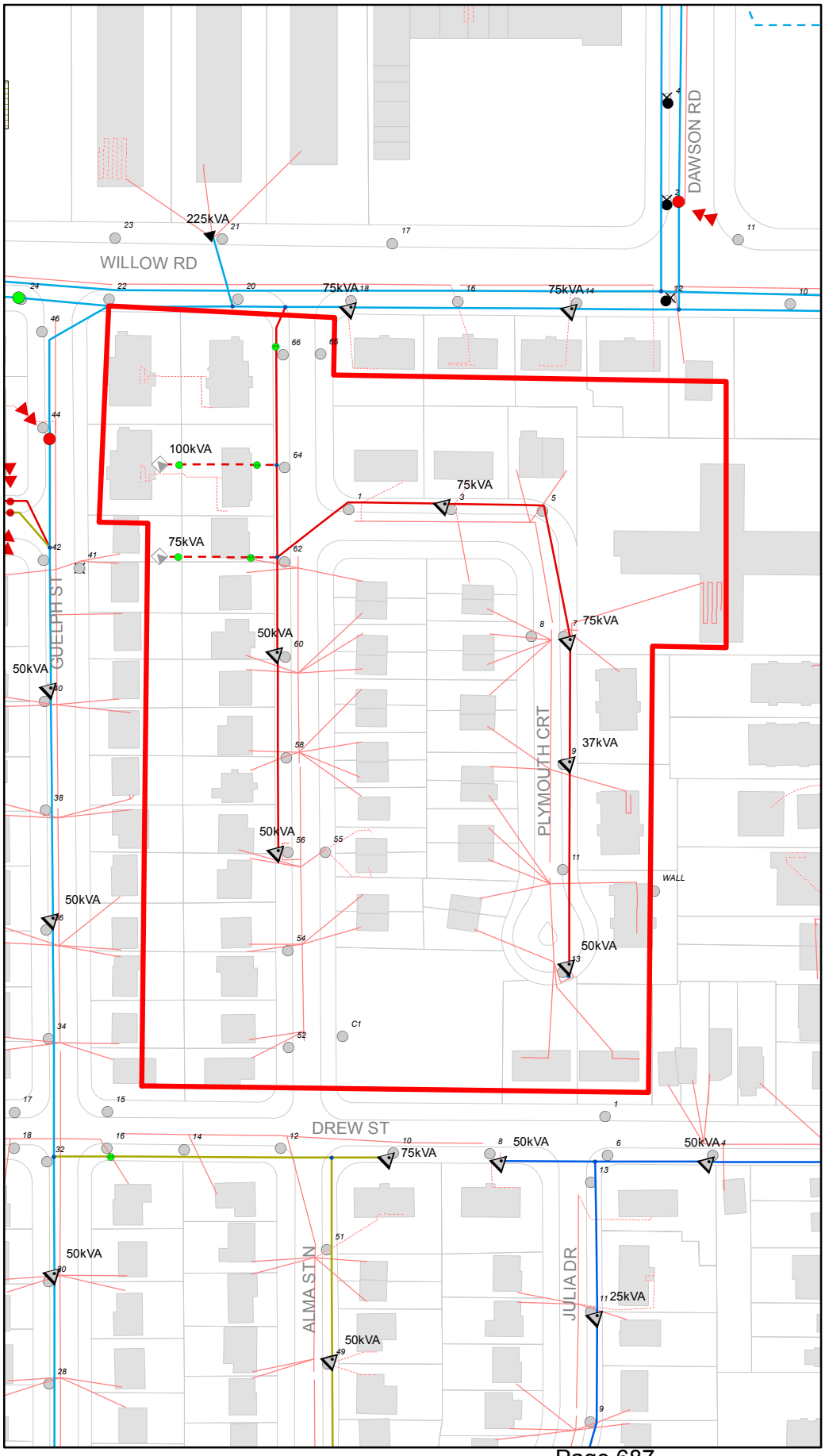
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

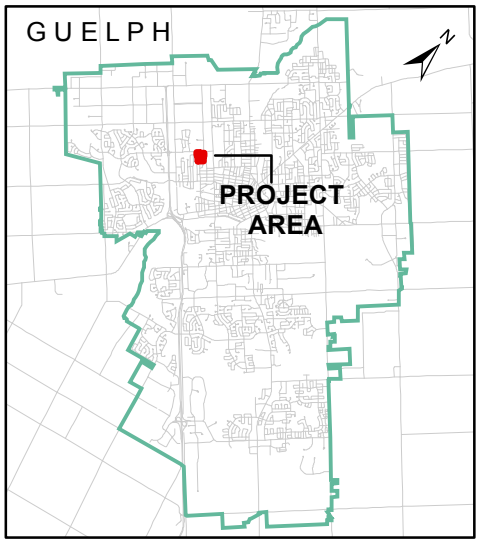
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 4 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by removing transite duct in the area which will reduce the time and cost involved with restoration and by renewing the poles which will reduce inspection and treatment costs. The timing of this project could be affected by the need to complete other major projects first, such as the Willlow Road reconstruction project.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to possible asset failure related restoration work, which will be far more costly with transite duct in place.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 35' in length and do not meet GHESI's current standards for pole length, given the current framing. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Other alternatives, such as undergrounding the system or using a different pole material would present a higher cost per customer and in the case of an alternative pole material, will not provide any substantial benefit above what the planned project will provide. The use of transite duct for new installations is not permitted at GHESI and like-for-like is therefore not an option for the underground work.

Alma Street North (Willow Road to Drew Street) & Plymouth Court





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Alma Street North - Drew Street to Mercer Street, Julia Drive and Drew Street from Bagot Street to Guelph Street					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$216,000
Capital contribution						$0
Net Cost						$216,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 104
Customer load within project area: 255 kW
Customer attachments downstream of project area: 104
Customer load downstream of project area: 255 kW

Start Date (5.4.5.2 A.3)	27-Jun-16		**In-Service Date (5.4.5.2 A.3)**			30-Sep-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**		
			$216,000			

Project Summary

This reconstruction project includes the replacement of 24 poles on Alma Street North, Julia Drive and Drew Street within the project area and the replacement of 6 underground services in the project area due to conductor age and the presence of transite duct. The poles on Alma Street North, Julia Drive and Drew Street are 58 years old on average and are in poor condition. Ongoing maintenance to replace broken or damaged connections and equipment has occurred and has extended the lives of these poles to their present age. The poles are a mix of 30' and 35' length poles and will be replaced with 45' long poles to meet current standards and improve clearances for equipment and working space. The existing poles utilize pin type insulators and tie wire to secure the primary conductor. These insulators are prone to failure from cracking and will be replaced with modern polymer insulators. Additionally, the poles are currently located in close proximity to mature trees. New locations will be found for many of the poles to avoid vegetation contact issues and excessive annual tree trimming costs. The underground cables being replaced on Alma Street North, Julia Drive and Drew Street are 57 years old on average and are installed in transite duct which is an asbestos containing material. Due to the health hazards in working with transite duct, completely new services are installed upon failure which can mean very lengthy outages or the use of costly generators to provide temporary power. GHESI has a transite duct removal program that seeks to proactively replace these services in a controlled manner on a priority basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to other major projects. The reconstruction of Alma Street North from Willow Road to Drew Street, including Plymouth Court, is planned for completion in mid-2016, and precedes this project. This project risks being started late if the preceding year's work is not completed and if the ground frost conditions persist beyond March. Both projects rely on civil work and coordinated outages in order to replace the underground services to low-rise apartment buildings and risk being late if GHESI's general contractor cannot handle the large civil construction workload in 2016. The mitigation plan for these risks are bi-weekly internal project meetings and monthly meetings with the general contractor to review projects underway and identify action plans to keep construction on schedule. This project must be completed between August and November to ensure that the underground services are replaced outside of frost season. If the project goes into the frost season, the probability of failure for the underground services in transite is increased and the consequence will greatly increase due to the difficulty in digging through the frost to install a new service, and the need to supply emergency power to the customers due to cold weather, this results in a risk to cost, customer satisfaction and reliability. This risk is minimized by scheduling the work to begin in the early fall and planning to complete the civil work first, thereby allowing the largest window of frost-free time to construct.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope was completed in 2013 on Hearn Avenue between Waterloo Avenue and Inkerman Street. The total cost of construction for the Hearn Avenue project was $146,087. Both projects were single-phase pole lines of approximately the same age, however, the Alma Street North, Julia Drive, Drew Street project includes the replacement of 24 poles (versus 14 poles on Hearn Avenue) and underground secondary services that must be fully replaced. The underground services on Alma Street North, Julia Drive and Drew Street supply low-rise apartment buildings and are in transite duct under asphalt driveways, which will increase the cost of installation due to the need to remove and replace asphalt, use a specialized contractor to remove cable from transite duct and to hire an electrician to perform the work inside of the customers' electrical rooms. A comparable service replacement project was completed in 2014 at 188 Waterloo Avenue, where an underground secondary service that was in transite duct was replaced under asphalt to a commercial building at a cost of $10,679. There are six services of this type to be replaced in the project area. Based on these comparable projects, the proposed construction cost is in-line with the historic costs and considering the Alma Street North, Julia Drive and Drew Street project has a greater scope than the combined scope of the comparable projects.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Alma-Julia-Drew

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". The risk to reliability is evidenced by a high risk score, driven by a high composite probability of failure. This project also has a low dollar per risk point abated score which makes it a particularly prudent project. The high probability of failure score is related primarily to the age of the underground secondary cable and secondarily to the age and condition of some of the poles in the project area.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Customer Value". The underground services in transite duct have a high probability of failure and a long duration to repair due to the number of parties involved and limited options for providing an alternate supply. These services supply small apartment buildings which results in a large number of customers out of power if a failure occurs. By proactively targeting this difficult services, the majority of the replacement work can be done without customer interruptions and planned, which spares lengthy outages that would negatively affect the customers' experience, satisfaction and safety.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's transite duct removal program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with transite duct.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to a high composite probability of failure and to follow the completion of similar transite removal efforts on Willow Road that are occurring in 2015 as well as on Alma Street North and Plymouth Court in the first half of 2016. This project ties into other projects on Willow Road and further North on Alma Street North, including Plymouth Court, which have been identified and has been placed in order considering risk and dollars per risk point abated, as well as to best allow for constructability of the future associated projects by building on lessons learned. This project has a composite probability of failure of approximately 93.4% which indicates that an asset failure within this project area is imminent. This project is ranked at number 5 of 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of secondary services in transite duct in this project will greatly decrease the duration and cost of outages. Through experience with past cable failures in transite duct, the repair process is very lengthy due to the need to obtain emergency locates, organize contractors to install new duct work and to bring in an asbestos management contractor to remove the damaged cable. Typically customers have been connected to emergency generators that are contracted by GHESI during the repair process. By installing the replacement service in a planned and proactive way, the majority of this cost can be reduced and the duration of outage is reduced to a minimum. This is a more cost-effective approach. Additionally, the installation of poles that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner in the future due to easier access and safer working conditions. Future costs in this project area will also be reduced by relocating the pole line away from mature trees where possible, thereby reducing tree-trimming costs and improving operational efficiency.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide. Because the suspect services supply apartment buildings, many customers would be affected by a single cable failure, therefore the benefits of this project also reach a large number of customers per service replaced.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages on the overhead portion of the project from animal contact will be replaced due to improved framing standards, increased spacing between energized conductors and second points of contact, the use of modern insulators and improved clearance from vegetation. The risk of failure on the underground portion of the project will be greatly reduced due to the replacement of aging cable and the duration of outages will be greatly reduced by the elimination of hazardous materials such as transite duct.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, in this case the line is single-phase and does not supply customers downstream of the project area, therefore the benefits would be very limited. Reliability issues in this area are primarily related to damaged overhead conductor due to tree contacts. Replacement of the conductor and connectors as part of this project and the relocation of poles away from trees combined with tree trimming, will reduce the future occurrences of these types of failures.
- Like-for-like replacement is not a practical solution for this project because of the health and safety risks associated with transite duct. Additionally, like-for-like replacement would not provide the additional reliability benefits of a taller pole line with improved conductor spacing.
- A "Do-Nothing" solution is not practical for this project. GHESI's experience with services in transite duct are that failures result in long and expensive restoration efforts. By delaying the project, there is an increased risk of a failure during winter conditions, which will futher increase the duration and cost of the restoration effort.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete replacement work on Alma Street North and Plymouth Court, due to resource allocation, prior to beginning construction.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles with taller 45' long poles and replacing the existing framing to improve spacing on the pole. The replacement of transite duct with PVC duct will remove the risk of asbestos particles being carried into the environment or customers' premises by disturbances to the service or during a failure event. Public safety will also be improved by relocating poles away from vegetation, which will reduce the risk of burning limbs and pole fires caused by vegetation contact with energized equipment.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line does not directly impact economic development. This pole line serves two mature, fully developed residential streets.

Environmental Benefits (5.4.5.2.B6) (where applicable)

This project will remove or decommission asbestos containing materials which will prevent the future distribution of asbestos particles from disturbing the duct or the cable within the duct. The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed services in transite duct.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles in this project area were installed (on average) in 1957 and have an average age of 58 years. From an age perspective, the poles have surpassed the typical end of useful life for fully dressed wood poles. This effective age, combined with the relatively low rate of spot replacement demonstrates that the pole line has had an above-average performance record relative to other pole lines in GHESI's system of the same age, however these poles have passed their useful life and have a high probability of failure, and must be replaced to avoid failure. The secondary cable in this project is 57 years old, which is just below the maximum useful life for underground secondary cables and therefore the cables have performed very well relative to other cables in GHESI's system of the same age. Because of the age and high probability of failure of the secondary cables, and their installation in transite duct, these cables must be replaced soon to avoid lengthy outages. Similarly, because of the age of the poles and their proximity to mature vegetation, it is prudent to replace the poles within this project area to avoid potential failure due to electrical or mechanical stress.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

98 Residential and 6 General Service (less than 50 kW) are within this project area and would be affected by an asset failure. No additional customers outside of this project area would be affected by a failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

This project area has sustained 180 customer minutes of unplanned outages over a five year period. However, due to the number of customers living in each apartment building and the known typical duration of outages sustained during the repair of defective transite services, combined with the high probability of failure, this area is at risk for developing very poor reliability in the next few years if the project is not completed. Completing this project will renew the system in this area and provide many years of good reliability performance for the customers in the area.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this line segment performs at or above reliability targets. Changes to the configuration of the equipment in this project will result in better operational performance, which will reduce future outage and construction times. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from reducing the risk of exposure to transite duct.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies residential customers who will not have a high cost of failure, however, most residential customers have no backup supply arrangements and a failure in the underground secondary cable will result in a much longer than typical outage due to the need for multiple parties on site and the challenges of working with and around transite duct. The general service customers in this area are the common amenities and offices of the residential buildings and are not expected to have a significantly higher cost of failure than the residential customers.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
This project requires System Renewal work on Alma Street North and Plymouth Court to be completed prior to commencing, but does not rely on any System Access, System Service or General Plant projects.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources weather conditions into account. This project has been ranked at number 5 of 9 material system renewal projects planned for 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- Modifications to spacing and relocation of poles away from vegetation will reduce the number of animal contacts. This will reduce the costs associated patrol and repair time.
- Relocation of poles away from vegetation will reduce the instances of blown fuses and damaged conductor from limb contacts, which will reduce maintenance activities such as line patrolling, splicing repairs to overhead conductor and fuse replacement.
- Repair and restoration times will be reduced for future outages due to the replacement of transite duct with PVC duct.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances will reduce the number of animal contact related outages, thereby improving reliability performance.
- Tree trimming and conductor replacement will improve reliability by reducing the amount of storm damage sustained by this project area.
- Relocating poles away from vegetation will improve safety by reducing the instances of equipment fires and mechanical damage from contact.
- The removal of transite duct will allow for shorter duration outages in the future, as cable can simply be pulled out of and pulled in to PVC duct.
- The removal of transite duct in a controlled manner will improve worker and public safety due to the elimination of the risk of improper handling resulting in exposure to asbestos particles.

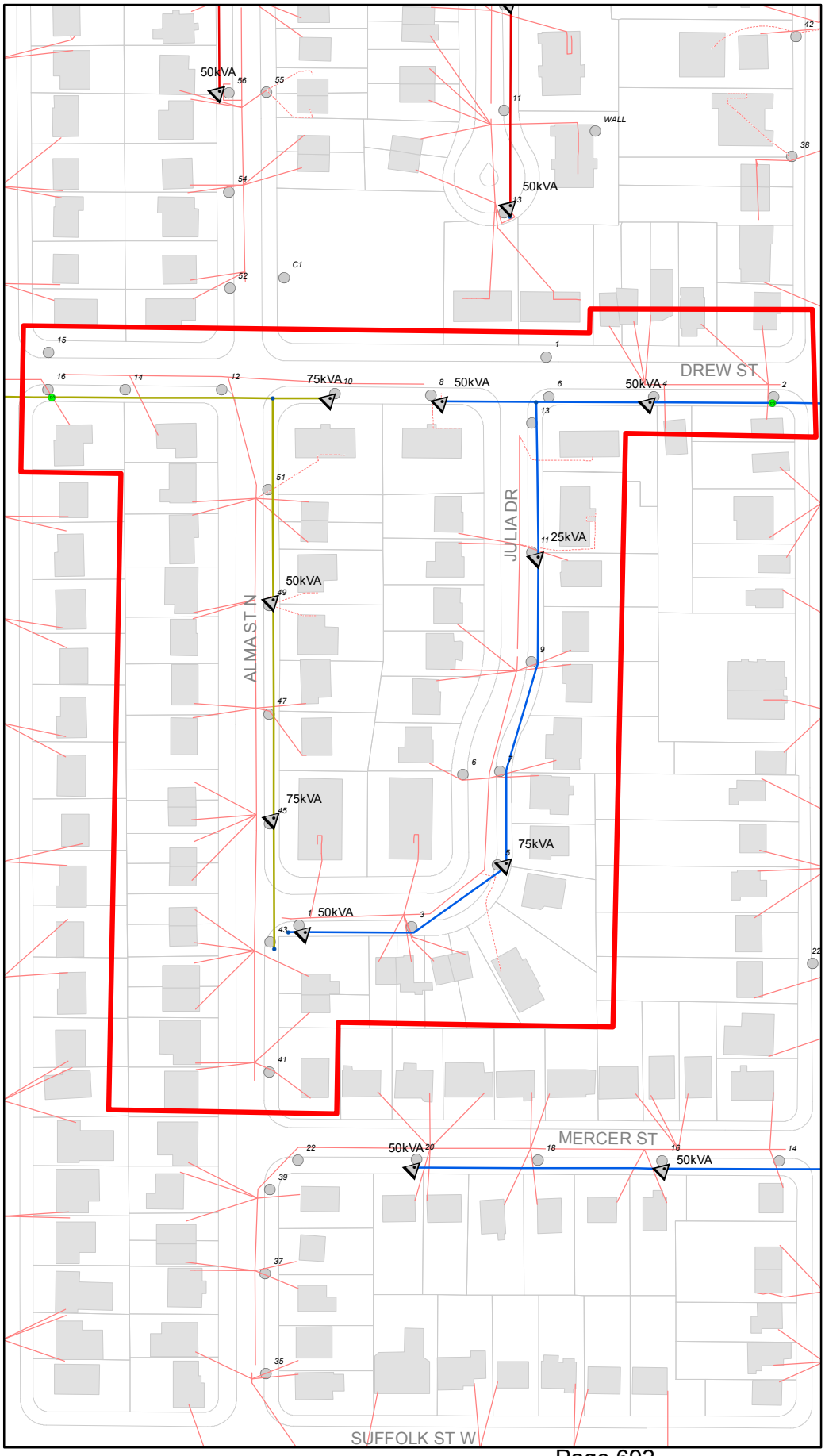
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

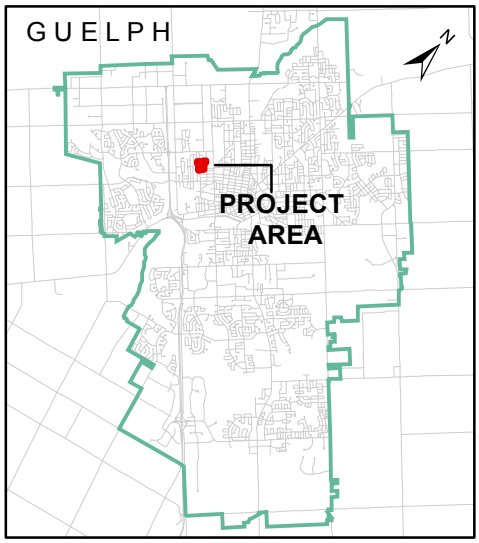
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 5 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by removing transite duct in the area which will reduce the time and cost involved with restoration and by renewing the poles which will reduce inspection and treatment costs. The timing of this project could be affected by the need to complete other major projects first, such as the Willlow Road reconstruction project.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to possible asset failure related restoration work, which will be far more costly with transite duct in place.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 30' and 35' in length and do not meet GHESI's current standards for pole length, given the current framing. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Other alternatives, such as undergrounding the system or using a different pole material would present a higher cost per customer and in the case of an alternative pole material, will not provide any substantial benefit above what the planned project will provide. The use of transite duct for new installations is not permitted at GHESI and like-for-like is therefore not an option for the underground work.

Alma Street North (Drew St. to Mercer St.), Julia Drive & Drew Street (Bagot St. to Guelph St.)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Arrow Road and Fair Road					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$432,000
Capital contribution						$0
Net Cost						$432,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 77 (2 GS >50, 75 GS <50)
Customer load within project area: 6.63 MW
Customer attachments downstream of project area: 77
Customer load downstream of project area: 6.63 MW

Start Date (5.4.5.2 A.3)	3-Oct-16	**In-Service Date (5.4.5.2 A.3)**		23-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
				$432,000

Project Summary

This reconstruction project includes the replacement of 24 poles on Arrow Road and Fair Road due to low health index scores and insufficient pole length. This project will also include the replacement of underground primary cable in the project area due to the length being insufficient to reach the height of the riser switches on the new, taller poles. The majority of the poles on Arrow Road and all poles on Fair Road are Douglas fir poles and are suspect to sudden failure from below grade rot. Several failures of poles of the same species and vintage have been experienced on the nearby Edinburgh Road North and have a high impact on reliability due to the number of industrial customers connected to these two streets. Only one pole in this project area has been spot replaced and the vast majority of poles are still original. The poles are a mix of 45' and 50' length poles and will be replaced with 55' long poles to meet current standards and improve clearances for equipment and working space, as well as to allow for future additions of circuits to the pole line in order to supply future increases in the industrial loads on Arrow Road.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to system capacity and other major projects. The reconstruction of Arrow Road and Fair Road risks not being completed in 2016 due the number of required planned interruptions. Experience with comparable projects has shown that arranging specific interruptions to the satisfaction of customers has to be done on a pole-by-pole basis, typically on weekends. This causes the duration of the project to extend far beyond what is typical for the number of poles being replaced. The mitigation plan for this risk is bi-weekly internal project meetings to review projects underway and identify action plans to keep construction on schedule as well as early and continual communication with customers, in order to plan interruptions as close to each other as possible and in a mutually beneficial way. A final option to mitigate this risk is the use of generators to provide power to customers and allow for more flexibility for interruptions. This method was tested on the Lewis Road project and the lessons learned will be used to mitigate risks on this project. This project is planned to begin in the fourth quarter of 2016, in order to avoid overlap with the Westgate Drive, Lonsdale Drive and June Avenue project, due to the high feeder demand that project puts on Campbell Transformer Station. Additionally, by scheduling the project to begin in Q4 of 2016, large customer chiller loads will be avoided, making interruptions earlier to plan. An additional benefit to scheduling the project in Q4 is that many industrial customers schedule plant shutdowns leading into the holiday season, which can make arranging interrutions easier. This type of project can be completed during frost months if all ductwork is completed prior to frost setting in, making it a prime fall/winter project.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the scope was completed on Lewis Road in 2014. The work was a single-circuit pole line reconstruction including the replacement of 22 poles on a similar industrial road with similar types of customers, albeit in lower numbers (2.37 MW, 22 General Service Customers). The total cost of construction of the Lewis Road project was $558,710.45, however the scope of work was only 22 poles, whereas Fair Road and Arrow Road require a total of 24 pole replacements. Additionally, the Lewis Road project included the replacement of 8 pad-mounted transformers at a net cost of $70,972.57, while this project does not plan to replace transformers on Fair Road and Arrow Road, due to their age, condition and dead-front configuration. Based on this comparable project, the proposed construction cost is in-line with the historic costs considering the similar number of poles and the fact that this project does not involve the replacement of dead front transformers.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Arrow Rd and Fair Rd

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". The risk to system reliability is evidenced by a low composite health index score, driven the poor condition of the Douglas fir poles in the area. Many of the Douglas fir poles have been treated for internal decay, have feathered pole tops and have low ground line ultimate fiber stress results common for poles of this species.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Employee Safety". The poles in this project area are not long enough to provide adequate space between primary conductors and the system neutral. Greater than 90% of the poles in this project area have an additional form of equipment, such as a riser, switch or transformer, installed on them. GHESI's current standards require 10'6" between the neutral and primary conductors to allow for adequate clearances and working conditions at the pole. The limited space at each pole in this location, coupled with the difficulty in arranging outages with the connected customers results in a high degree of danger when working on these poles, compared to other lines in the GHESI system.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Employee Safety".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's transite duct removal program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with Douglas fir poles.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to a low health index score, resulting from a the prevalence of Douglas fir poles with confirmed internal decay and low ground line strength readings. This project has a composite probability of failure of approximately 74.2%, however the conditions are consistent with nearby pole lines that have exhibited sudden pole failures due to below grade rot. Additionally, there is a high probability of load growth in this corridor in the near future, which would require the reconfiguration of poles. The current pole heights are insufficient to allow this reconfiguration, therefore the replacement of poles will be done in such a manner as to avoid future re-work costs, thereby increasing customer value and investment efficiency. This project is ranked at number 9 of 9 material system renewal projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of Douglas fir poles will greatly decrease the probability of a failure in this project area. Because this project area is located on the extreme opposite side of the City from the GHESI service center, outage and restoration times are longer than typical and it is desirable to limit the probability of a failure for this reason. Additionally, the installation of poles that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner in the future due to easier access and safer working conditions.
Spot replacement of poles for this project was not considered to be a viable option due to the fact that only one pole has been replaced among the original poles, and the pole that was replaced is not compatible with GHESI's current standards. Due to the high concentration of poles with poor health index scores and which are exhibiting symptoms conducive to sudden failure, it is more efficient and practical to replace all of the poles in the project area.
Because this pole line is at the extreme end of GHESI's service territory and feeds a dead-end road, there are no other supply options that will alleviate the impact of future load growth on this pole line.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers both within the project area and downstream will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers within this project area are all commercial and industrial operations and would see high costs associated with outages.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from pole failure will be reduced through the use of western red cedar poles, which do not exhibit the below grade decay and sudden failure issues associated with Douglas fir poles. This will reduce the frequency of outages. This area does not exhibit issues with vegetation or animal contact, therefore no further improvements are needed to combat those outage causes. The duration of outages will not be improved by this project since the area is already connected with remote operated SCADA switches and the travel time to reach the project area cannot be changed.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. Reliability issues in this area are primarily related to pole condition which is a function of the species and age of the current assets. Replacement of the poles with Western Red Cedar poles will dramatically reduce the probability of outages.
- Like-for-like construction is not a practical solution for this project. GHESI does not use Douglas fir poles due to their poor performance in the system. Additionally, the existing framing does not allow enough space for riser switches to meet current GHESI standards, which impacts Employee Safety.
- A "Do Nothing" solution is not an option for this project area because the existing poles have exhibited, and been treated for, internal decay. The poles have a high probability of failure and an asset failure would impact several commercial and industrial customers.
Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the construction outside of peak load seasons, therefore the project cannot be completed between the last half of the second quarter and the start of the fourth quarter.
Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles with taller 55' long poles and replacing the existing framing to improve spacing on the pole. Public safety will also be improved by removing suspect Douglas fir poles which are prone to mechanical failure.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.
GHESI will be coordinating with Hydro One to discuss options for reconfiguring the line on Arrow Road where it crosses beneath a partially decommissioned Hydro One transmission circuit. Currently GHESI's circuit crosses underground, however conversion to overhead is preferable due to the lower installation costs and the lower future upgrade costs if additional capacity is required. An overhead line at this location will not negatively influence reliability.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will be built to easily accommodate an additional circuit in the future, as the area has shown a high probability for load increases and a second circuit will be required to supply more load in this area.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line does positively impact economic development. This pole line serves commercial and industrial customers who have commented on the possibility of load increases in the near future. By reconstructing the pole line in the proposed configuration, an additional circuit can be added to Arrow Road, which will provide the required supply.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed poles at a long distance from the GHESI service center. Replacing Douglas fir poles with western red cedar poles will result in asset lifecycles that are in line with GHESI's targets for wood pole lines. Since Douglas fir pole lines have historically performed much worse than average, the removeal of such poles will reduce overall life cycle costs for the refurbished line.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles on Fair Road were installed (on average) in 1988 and have an average age of 27 years. The poles on Arrow Road were installed (on average) in 1987 and have an average age of 28 years. From an age perspective, the poles are far below the typical end of useful life for fully dressed wood poles. However, due to the condition of the poles such as the internal decay, low ground line resistance and Douglas fir species of the poles, the average effective age of the pole lines is 38 years, while 18 of the poles have an effective age greater than or equal to 50 years. The large difference between effective age and actual age as well as the very low rate of spot replacement demonstrates that the pole line has had a below-average performance record relative to other pole lines in GHESI's system. GHESI has observed sudden failure in other Douglas fir pole lines of the same age on nearby streets.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

75 General Service (less than 50 kW) and 2 General Service (greater than 50 kW) customers are within this project area and would be affected by an asset failure in this project area. No additional customers are downstream of this project area.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Several reliability events have occurred within this project area, however they have all been partial power, or customer equipment breakdowns and have not resulted in customer interruption minutes. However, GHESI's past experiences with sudden failure in Douglas fir poles puts this project area at risk for contributing outages to the customers within it unless the pole line is reconstructed.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this line segment performs at or above reliability targets. Replacement of the poles with western red cedar poles will reduce the risk of sudden failure in the future. These improvements will enhance overall customer satisfaction.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a high impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies a large number of commercial and industrial customers who will have a high cost of failure and have no backup supply arrangements. General service customers downstream may have a larger cost of failure due to the interruption to their commercial operations. Additionally, failures will impact the commercial and industrial customers in this project area more than in other areas of GHESI's service territory because of the distance from GHESI's service center.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
Due to the location of this project near Campbell Transformer Station, this project requires coordination amongst other projects in the system to ensure that sufficient feeder capacity is maintained. This project requires the reconstruction project on Westgate Drive, Lonsdale Drive and June Avenue to be completed but does not rely on any System Access, System Service or General Plant projects. However, this project must be completed before additional load increases requests are received in order for an additional feeder to be able to be constructed at that time.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources, and weather conditions into account. This project is ranked number 9 of 9 material system renewal projects planned for construction in 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections.
- Poles in this project area have been receiving treatment for internal decay. The need for treatment will be alleviated by installing new poles, which will reduce maintenance costs for pole treatment.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Replacement of suspect Douglas fir poles with western red cedar poles will improve reliability due to the elimination of the risk of sudden failures.

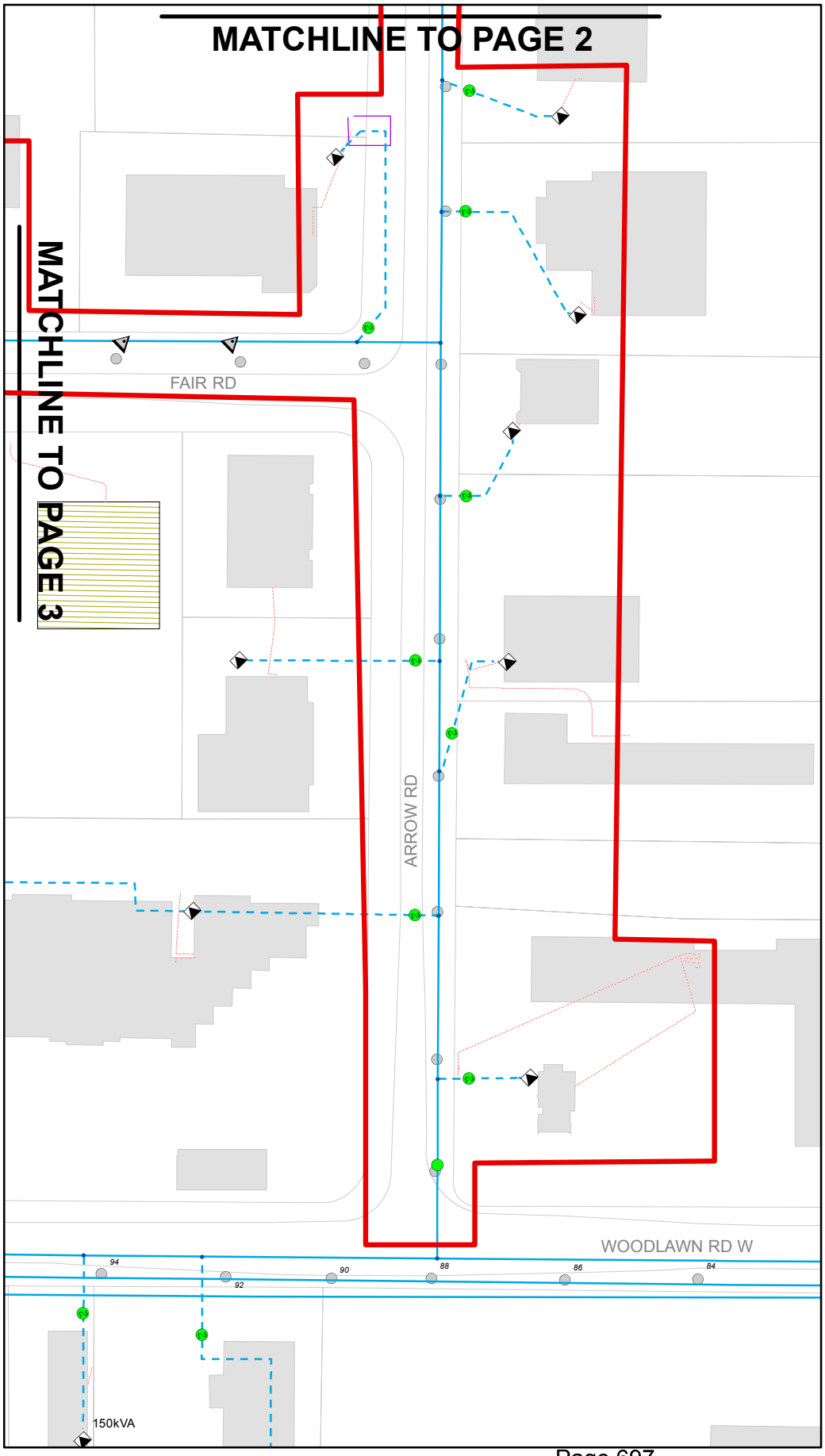
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

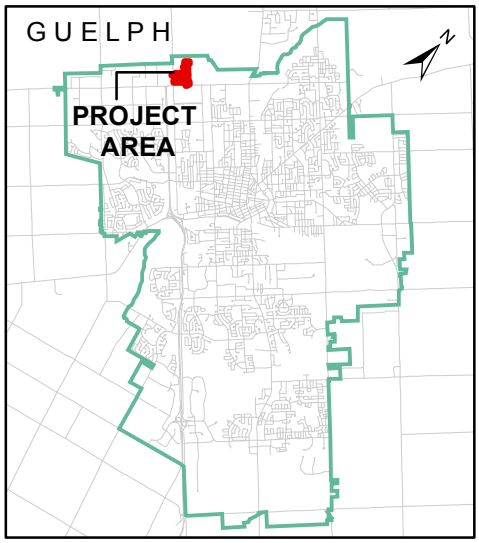
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 9 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by alleviating the need for pole treatment. The timing of this project could be affected by the ability to obtain the necessary outages, due to the need to work around the schedules of commercial and industrial customers to minimize impacts to their business.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to asset condition related maintenance and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 45' to 50' in length and do not meet GHESI's current standards for pole length, given the current framing, additionally the poles must be reframed to accommodate future circuits. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Other alternatives, such as undergrounding the system will be much more costly and will not provide any reliability benefits based on the types of reliability events which have occurred in this project area in the past. Using a different pole material such as concrete or composite poles would present a higher cost per customer and in the case of an alternative pole material, will not provide any substantial benefit above what the planned project will provide.

Arrow Road and Fair Road





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

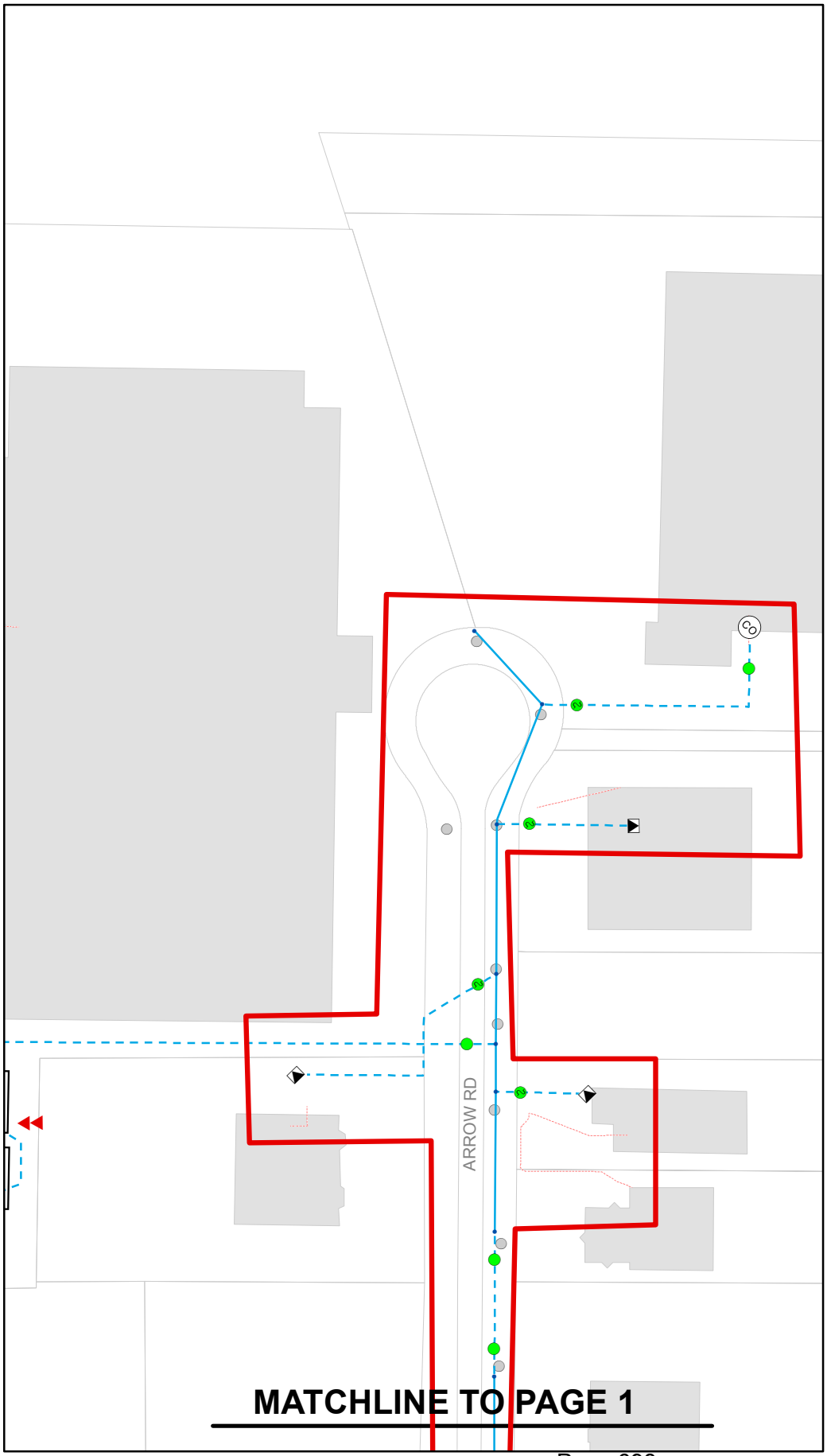
Poles

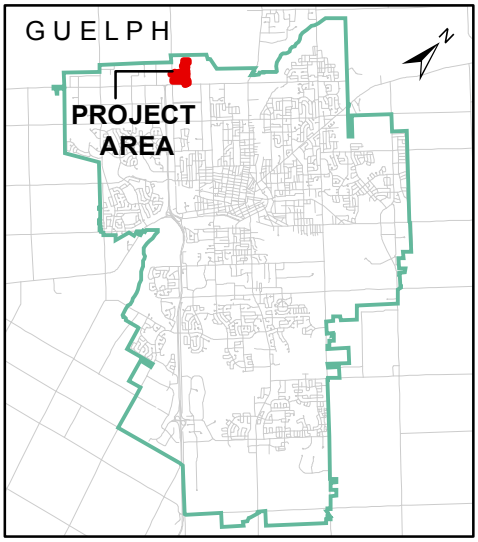
- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 3

0 50 100 Meters

Arrow Road and Fair Road





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
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- Y

UG Primary

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- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

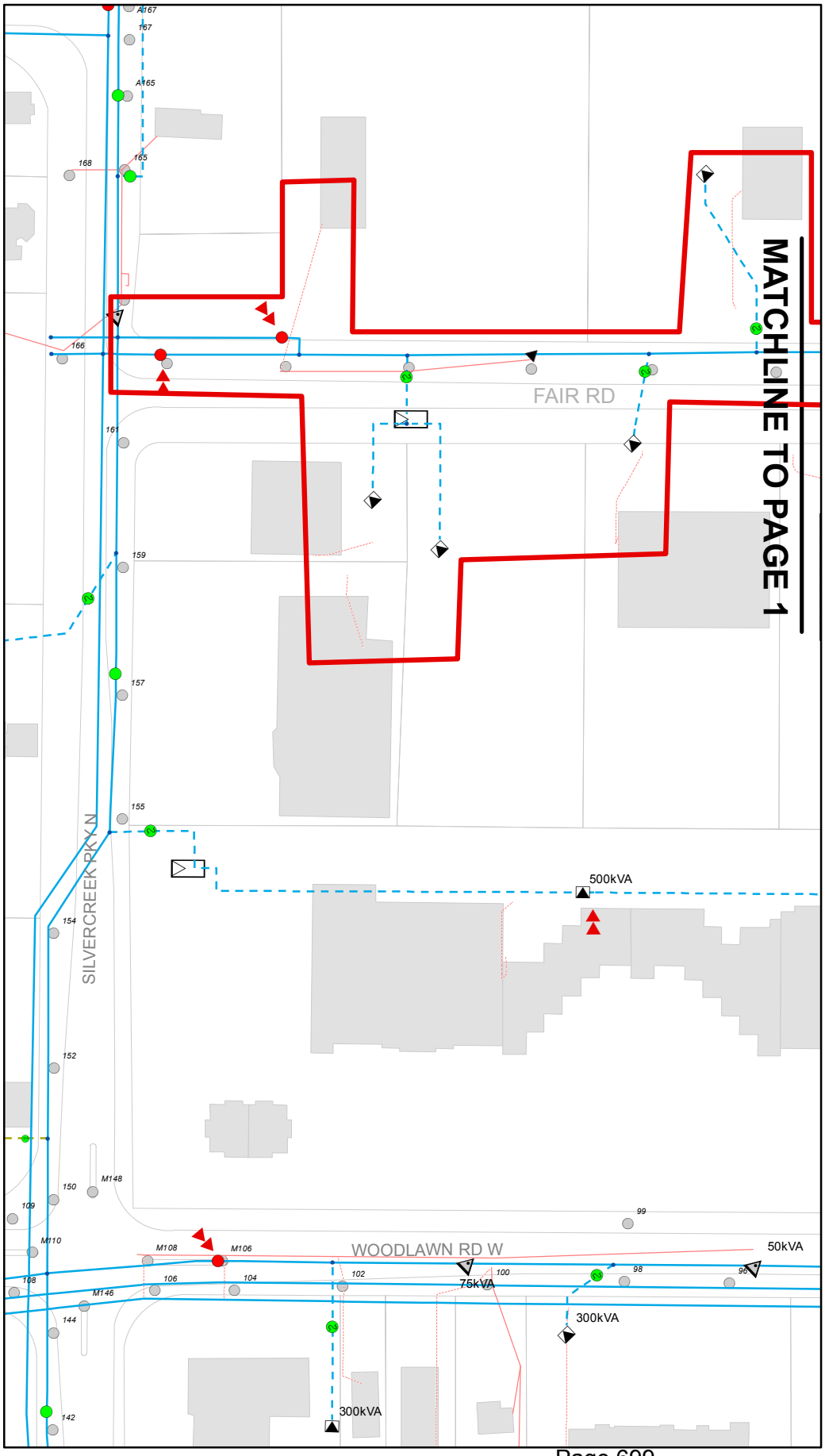
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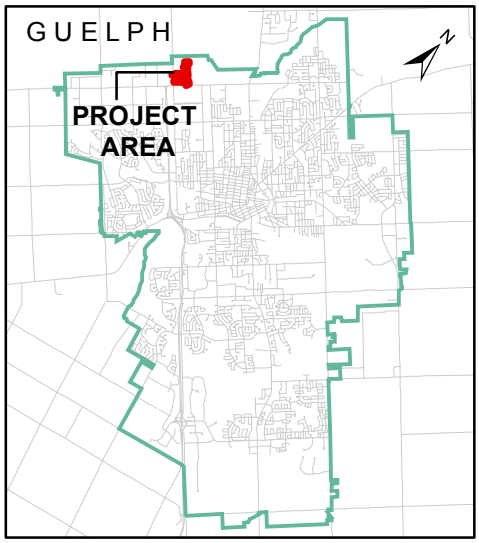
MATCHLINE TO PAGE 1

Page 2 of 3

0 50 100 Meters

Arrow Road and Fair Road





LEGEND

Transformers

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- POLE MOUNT, 1
- POLE MOUNT, 3
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- POLE TRAN, 1
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- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 3 of 3

0 50 100 Meters

A. General Information						
Project /Activity	Fife Road (Wellington Street West to Gateway Drive)					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$173,000
Capital contribution						$0
Net Cost						$173,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 43 (41 Residential, 2 General Service - less than 50 kW)
Customer load within project area: 211 kW
Customer attachments downstream of project area: 1,353
Customer load downstream of project area: 6.8 MW

Start Date (5.4.5.2 A.3)	26-Sep-16	**In-Service Date (5.4.5.2 A.3)**		16-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
				$173,000

Project Summary

Replacement of the overhead pole line on Fife Road from Wellington Road West to Gateway Drive (14 poles). Concrete poles along this road have shown rebar rusting and concrete spalling in inspection and are to be replaced with composite poles, due to the lower lifecycle costs and lower installation costs that composite poles present over concrete poles. Obsolete framing style is to be replaced to vertical framing standards, which allows for easier access during maintenance operations and easier installation of future circuits. The line is to be reinsulated with modern self-cleaning polymer insulators. Existing in-line solid-blade disconnects are to be replaced with a tiered outboard load-break switch to allow for easier operation from the ground. Existing steel crossarms are to be replaced with fiberglass crossarms to mitigate animal contact issues.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to external contractors and with other major projects. In order to mitigate this, internal meetings are held on a biweekly basis to review project progress and make adjustments as needed.
Materials and Third-Party Risk: This project is subject to risks due to the long lead time for composite poles and railway crossing permits. In order to mitigate this risk, GHESI will design this project at the end of 2015 and place pole orders and permit requests well in advance of the project commencing.
Consequences of Delay: If the project is not completed in 2016, the probability of failure will be greatly increased due to the exposure of the rebar to additional winter road salting operations.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of scope was completed in 2014 on Westwood Road between Silvercreek Parkway North and Rhonda Road. The total cost of construction of the Westwood Road project was $109,808. However, the Westwood Road project involved the replacement of approximately 10 poles. Additionally there are several more customer connections on the Fife Road project, requiring a different approach to work zone isolation. Another similar project was completed in 2014 on Imperial Road North at Speedvale Avenue West. The cost of construction of the Imperial Road North project was $101,801, however the scope of the project was the replacement of approximately 10 poles. Based on these comparative projects, (single circuit pole lines on streets of similar character and in a similar location), the proposed construction cost of the Fife Road project is in-line with the it being approximately one and half times the scope of the comparable projects and including a railroad crossing, which contributes some extra cost.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Fife - Wellington to Gateway

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver is a risk to Reliability demonstrated in low health index scores, driven by the age and condition of the concrete poles. GHESI has experienced premature deterioration of concrete poles due to manufacturer defects, installation defects and excessive road salting. This pole line has reached the typical useful life of concrete poles in GHESI's system and is exhibiting the level of concrete spalling and rebar exposure and corroding that is consistent with concrete distribution poles of this age throughout the GHESI system.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver of this project is Public Safety. The deteriorating condition of the concrete poles presents a danger to the public in the event of a failure. Concrete poles present a higher degree of danger to the public in the event of a failure due to their far greater weight than other materials. Where lighter poles may be held in place after failure by line tension, the higher weight of the concrete poles makes them more prone to breaking free and falling into either the travelled road way or pedestrian accessible boulevard space as the result of a failure.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objectives is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Public Safety".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's Concrete Pole Line program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with concrete distribution poles.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to low health index scores. This project has a composite probability of failure of approximately 70.7% and has been prioritized based on the condition of concrete poles in this location in relation to the rest of the GHESI system. This project is ranked 8 out of the 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The replacement of in-line solid-blade disconnect switches with a tiered-outboard load break switch will allow for easier work isolation, reducing the duration of future work in the project area and improving restoration time in the event of a failure in the area. The reframing of the pole line to a one-sided vertical framing provides easier access to all overhead conductors, allowing for more efficient and safer access for employees. Reframing the pole line allows for future lines to be installed without cutting and splicing the existing lines to make way for them, thereby reducing future time and expense during construction. Utilizing composite poles instead of concrete poles for the replacement improves cost effectiveness due to the longer expected life of composite poles and lower installation costs, which results in lower lifecycle costs. Additionally, working on the reconstructed line will be more efficient due to the use of composite poles which allow for some live-line work in proximity to the primary attachments on the pole, whereas GHESI's policy is to fully isolate concrete poles when performing similar work, which takes additional time.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from enhanced reliability as this project feeds a number of subdivisions downstream with a high downstream customer count as well as a large commercial development at Elmira Road South and Paisley Road. The replacement of deteriorating concrete poles reduces the risk of a pole failure which would result in an outage for customers in the project area and downstream of the area.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The new design will use composite poles which do not exhibit the spalling and rebar corrosion problems which has reduced the life of the existing concrete poles and will therefore have a lower probability of failure and a longer service life. This will provide a more consistent and low cost life cycle for the new assets, as well as a higher degree of safety for pedestrians and vehicles travelling near the poles. The use of composite cross arms will mitigate the incidents faults caused by animal contacts. The changes being made to the line will decrease the frequency of outages. Additionally, the replacement of in-line solid-blade disconnect switches with a tiered-outboard load break switch will improve isolation and reduce restoration times and therefore reduce the total duration of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- This area has been identified by the City of Guelph and the original developer as an improved aesthetic area. Currently, composite poles are the only overhead solution approved for improved aesthetic areas. Because of this, wood poles are not an option for this project.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, in this case there is no significant vegetation or structures near the overhead lines. Reliability issues in this area are primarily related to animal contact with steel cross arms, which will be corrected through the use of composite cross arms. Additionally, because this project crosses a railway, undergrounding the line crossing this railway would be extremely expensive.
- Like-for-like replacement is not an option for this project. GHESI does not support the installation of new concrete distribition poles due to the excessive wear and tear they impose on vehicles and equipment (due to their weight). Additionally, GHESI has concerns over Employee Safety when handling extremely heavy loads. Finally, concrete poles present added complications in terms of isolation due to conductivity of the internal rebar structure and have generally performed poorly in GHESI's distribution system.
- A "Do-Nothing" solution is not practical for this project. The existing poles have spalled to the extent of exposing the internal rebar structure. This means a large reduction in strength, as well as accelerated further decay due to corrosion of the exposed rebar, which is unprotected from moisture and salt spray.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers both within and downstream of the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing framing to a single-sided vertical framing, which will make the equipment on the poles easily accessible from a bucket truck in the roadway. Additionally, the installation of a tiered-outboard load break switch will provide an enhanced ability to isolate areas within this project and minimize the need to work in close proximity to energized plant. The use of composite poles also improves safety for workers by eliminating the risk of conduction that is present with rebar reinforced concrete poles. The use of composite poles also improves safety for the public due to their light weight, which reduces the impact of a pole failure.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. Additionally, this pole line will easily accept a second circuit at a later date due to the change to single-sided vertical framing. Spare brackets are installed on all poles and structural analysis is completed assuming a second circuit to avoid future rework costs.

Economic Development (5.4.5.2.B5) (where applicable)

While the reconstruction of this pole line does not present an immediate benefit to economic development, the reframing to accommodate a second circuit allows for capacity to be easily increased in the future in order to support economic development. A large commercial development is currently planned at Elmira Road South and Paisley Road and is supplied via this project area. The improvement to reliability and the ability to easily add a second circuit to this area that this project will provide is beneficial to this particular commercial development.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives and a lower lifecycle cost for the assets than with the concrete pole line.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles in this project area were installed in 1975 on average and have an average age of 40 years. This is in-line with the typical useful life of concrete poles GHESI has experienced and from this perspective, the poles have reached their end of useful life. This pole line has had average performance relative to other concrete pole lines in the GHESI system and poor performance relative to wood pole lines in the system.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

1328 Residential and 20 General Service (less than 50 kW) and 5 General Service (greater than 50 kW) are downstream of this project and would be affected by an asset failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Customer specific reliability data is not currently available, however the 5M71 feeder supplying this project area and the downstream customers has had 247,874 customer minutes interrupted in the past 10 years and 77,922 momentary customer outages in the past 10 years. The reconstruction work planned will minimize the influence of this feeder segment on future reliability impacts. This feeder is the 13th worst performing feeder within the system of 56 13.8kV feeders in Guelph from a customer minutes interrupted perspective (over a 10 year timeframe).

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this feeder segment performs at or above reliability targets. Changes to the configuration of the equipment in this project will result in better operational performance, which will reduce future outage and construction times. These improvements will enhance overall customer satisfaction. Additionally the replacement of deteriorating concrete poles with composite poles will improve the margin of safety for the public and will improve the appearance of the pole line in accordance with the improved aesthetic requirements of the street.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a medium impact to customers in this project area in terms of the criticality and cost of an asset failure. This feeder supplies mostly residential customers who will not have a high cost of failure. Additionally, there are some commercial customers connected to this feeder who will have a higher cost of failure if the failure occurs during business hours. There are commercial developments connected downstream of this feeder segment which are currently being constructed and include commercial operations that will have a higher cost of failure.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
This project does not require any other specific projects to be completed prior to commencing, and does not rely on any System Access, System Service or General Plant projects.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources and available feeder capacity into account. This project has been prioritized against other concrete pole lines that will require replacement due to premature deterioration of the poles. This project has been ranked at number 8 of 9 material system renewal projects planned for 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- The installation of tiered-outboard load break switch will allow for quicker isolation and restoration of the feeder segment.
- The modification of framing along this street to one-sided vertical framing will allow the equipment and connections to be more readily accessed, which will reduce operational and maintenance costs by reducing the time spent maneuvering vehicles to access the equipment.
- Installation of composite cross arms instead of steel cross arms will reduce the number of animal contacts. This will reduce the costs associated with clearing nests and will reduce the number of animal contacts on this feeder segment, resulting in less patrol and repair time.
- The use of composite poles instead of concrete poles will allow for more flexibility in working near the poles in an energized state, which will reduce costs related to switching and isolation.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances and the installation of fiberglass crossarms will reduce the number of animal contact related outages, thereby improving reliability performance.
- The removal of deteriorated concrete poles from the system will improve reliability performance and provide an enhanced margin of safety for the general public, as these poles are far heavier than the composite poles that will replace them. Pole failures can result in large forces being transmitted to the line and cause other mechanical failure, putting the public at risk from both a falling pole and other mechanical failures along the line related to the damage.

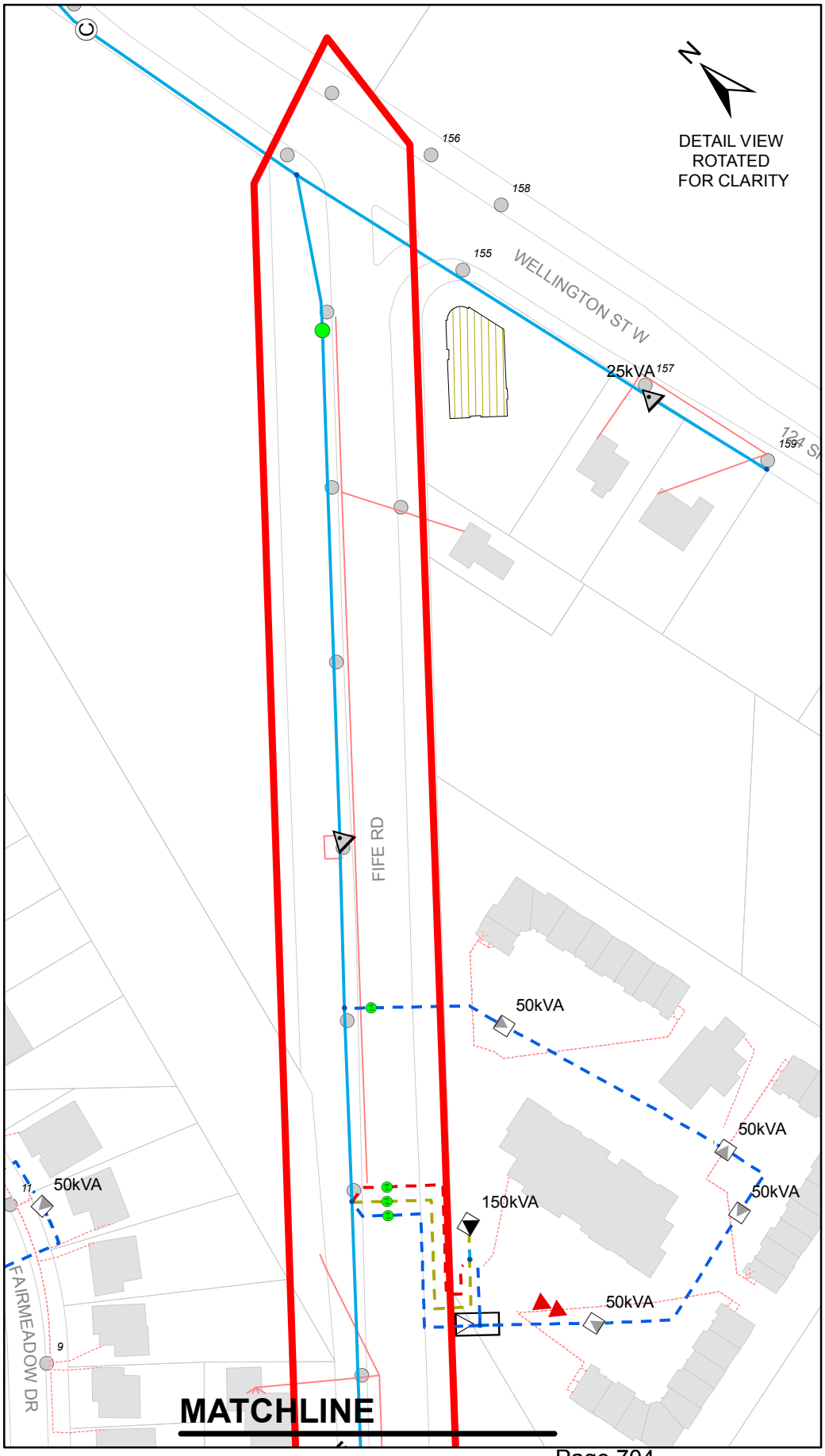
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

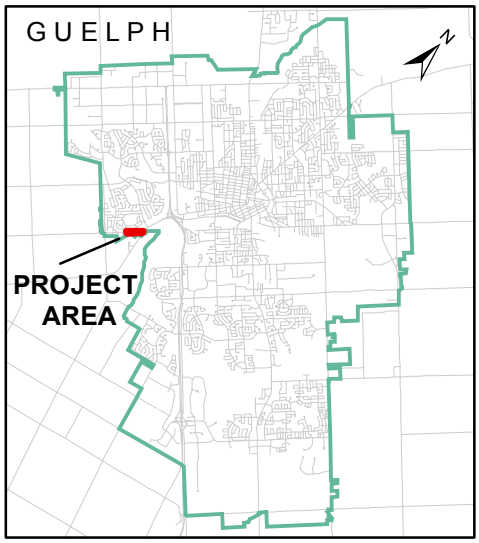
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The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by increasing the operational efficiency of the area. The timing of this project could be affected by permit delays for the railway crossing and delays in material shipping due to fluctuations in availability and demand levels.
Costs of the project may be affected by increases in material costs due to fluctuating availability and economic factors (some materials must be purchased from the United States and are impacted by the trade value of the Canadian Dollar).
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to asset condition related maintenance and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent further reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 45' in length and do not meet GHESI's current standards for pole length, given the current framing. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Additionally, GHESI does not permit the use of concrete distribution poles due to difficulty in installation (such as requiring cranes to lift the greater weight) and difficulty in working on the poles (due to additional isolation requirements above and beyond the requirements associated with wood and composite poles). Other alternatives, such as undergrounding the system would be prohibitively expensive, especially since an underground railroad crossing would be required. Using wood poles is not an option due to the requirements for improved aesthetics imposed by the City of Guelph and original developer. This project was determined not to meet the requirements for like-for-like renewal.

Fife Road (Wellington Street West to Gateway Drive)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

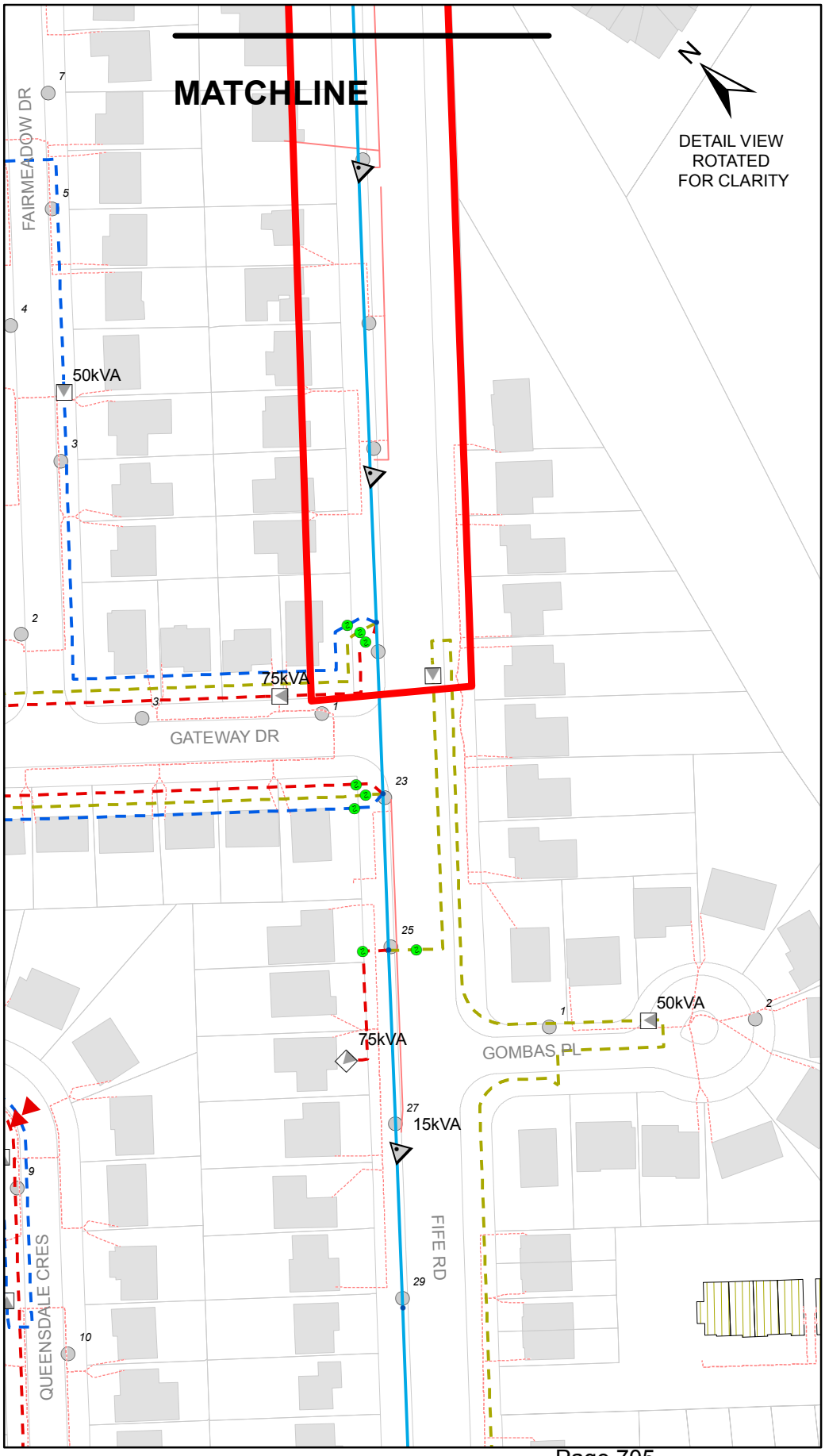
- SECONDARY

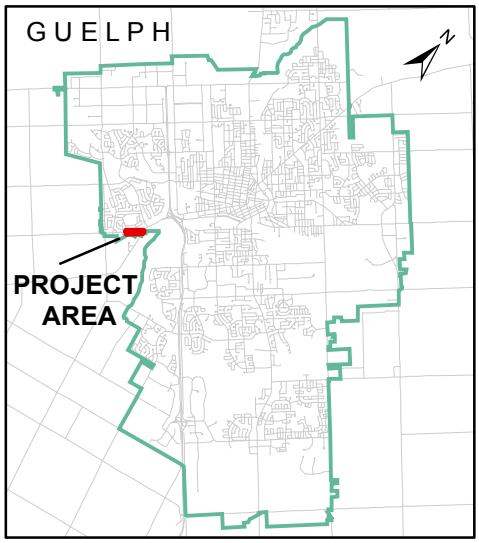
Poles

- EXISTING
- NEW
- TO BE REMOVED

0 37.5 75 Meters

Fife Road (Wellington Street West to Gateway Drive)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 2 of 2

0 37.5 75 Meters

A. General Information						
Project /Activity	Imperial Road S - West Acres Drive to CNR Railroad (Including Samantha Court)					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$247,000
Capital contribution						$0
Net Cost						$247,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 34
Customer load within project area: 109.9 kW
Customer attachments downstream of project area: 803
Customer load downstream of project area: 3.26 MW

Start Date (5.4.5.2 A.3)	4-Jan-16	**In-Service Date (5.4.5.2 A.3)**		25-Mar-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$247,000			

Project Summary

This project involves the replacement of the overhead pole line on Imperial Road South from West Acres Drive to one span South of the CNR Railroad (10 poles). Douglas Fir poles along this road have shown internal rot in testing and are to be replaced with Western Red Cedar poles, due to historical experience with sudden failure in similar conditions. The obsolete framing style is to be replaced to vertical framing standards, which allows for easier access during maintenance operations and easier installation of future circuits. The line is to be reinsulated with modern self-cleaning polymer insulators. The feeder riser one span South of the CNR Railroad currently has no means of disconnection without workers being in close proximity to the line. This riser is to be replaced with a new riser complete with a solid blade disconnect. The feeder riser one span North of the CNR tracks is to be replaced with a new riser and switch, configured as per current standards to provide increased clearance. Both poles are to be equipped with critter guard to mitigate future animal contact issues. The feeder cable crossing under the CNR Railroad is to be replaced due to age (non tree-retardant insulation and known jacket shrinkage issues with cable vintage) and synergy with riser work.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: This project is subject to scheduling risks with respect to external contractors and with other major projects. Because of the large scale overhead projects planned for completion in 2015, this project risks being started late if the preceding year's work is not completed. The mitigation plan for this risk is bi-weekly project meetings to review projects underway and identify action plans to keep construction on schedule. The 5M71 feeder that runs through this project supplies the City of Guelph Pollution Control Plant. Due to the severe impact of a plant failure on the City of Guelph, interruptions to this service must be carefully planned. Therefore this project risks schedule overruns if the alternate supply to the Pollution Control Plant cannot be guaranteed throughout construction. The mitigation strategy is to carefully plan other scheduled work such that no work is planned at the same time which will affect the alternate supply feeder.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of scope was completed in 2014 on Westwood Road between Silvercreek Parkway North and Rhonda Road. The total cost of construction was $109,808. However, the Imperial Road South project has approximately double the number of poles and they are wood poles, rather than concrete poles as were used on the Westwood Road project. Additionally there are several more customer connections on this project, requiring a different approach to work zone isolation. Another similar project was completed in 2014 on Imperial Road North at Speedvale Avenue West. The cost of construction was $101,801, however the size of the Imperial Road North project was approximately half of the Imperial Road South one and did not include the replacement of underground feeder cable. Based on these comparative projects, (single circuit pole lines on streets of similar character and in a similar location), the proposed construction cost is in-line with the Imperial Road South project being between two and three times the scope of the comparable projects.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Imperial-Samantha

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver is the asset management objective "Reliability". This area presents low health index scores, driven primarily by Douglas fir poles with internal rot. GHESI has a program in place to replace suspect Douglas fir poles due to historic incidents of sudden failure from rot below the ground line. This project also involves the replacement of riser switches and feeder cable which present a risk to reliability. Failure of the feeder cable or riser switch will result in a lengthy outage due to lack of isolation at the riser pole and the need to redirect existing spare ducts to a new riser, prior to installing new cable.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver of this project is the asset management objective "Public Safety". The deteriorating condition of the Douglas fir poles presents a danger to the public in the event of a failure. The poles are located close to a highly travelled road and they may break free and fall or lean into either the travelled road way or pedestrian accessible boulevard space as the result of a failure.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objectives is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Public Safety".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's Douglas fir program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with Douglas Fir poles and 1980's vintage 1000 kcmil Aluminum feeder cable.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to low health index scores and the risk of sudden failure of Douglas fir poles from below grade rot. This project ties into other projects along Imperial Road S which have been identified and has been placed in descending order of risk and to best allow for constructability of the future associated projects. This project has a composite probability of failure of approximately 86.5%. This project is ranked at number 7 of 9 material system renewal projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The installation of riser switches at the existing riser location will allow for easier work isolation, reducing the duration of future work in the project area and improving restoration time in the event of a failure in the area. The reframing of the pole line to a one-sided vertical framing provides easier access to all overhead conductors, allowing for more efficient and safer access for employees. Reframing the pole line allows for future lines to be installed without cutting and splicing the existing lines to make way for them, thereby reducing future time and expense during construction.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from enhanced reliability as this project feeds a number of subdivisions with a high customer count downstream. The replacement of suspect poles reduces the risk of a pole failure which would result in an outage for customers in the project area and downstream of the area. Because this feeder supplies a critical load (the City of Guelph Pollution Control Plant), a failure in this project area would put the City's pollution control system at risk.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The new design will use western red cedar poles which do not exhibit the pronounced below grade rot and sudden failure characteristics experienced with Douglas fir poles. This will provide a more consistent and low cost life cycle for the new assets, as well as a higher degree of safety for pedestrians and vehicles travelling near the poles. Reconstructed feeder risers will be protected from animal contact through the use of critter guard and increased spacing, mitigating potential pole fires and feeder lockouts caused by animal contacts at the riser switches. Underground feeder cable that is not tree-retardant and is prone to water ingress due to jacket shrinkage will be replaced with new cable, lowering the risk of failure.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, in this case there is no significant vegetation or structures near the overhead lines. Reliability issues in this area are primarily related to the species of wood pole currently in place and can be mitigated at a far lower cost by replacing the existing poles with western red cedar poles.
- Like-for-like construction is not an option for this project because GHESI no longer uses Douglas fir poles due to their poor performance in the system. Additionally, the existing cable risers have no protection or means of isolation, which does not meet current GHESI standards for construction or safety.
- A "Do-Nothing" solution is not practical for this area due to the low health index scores and high probability of failure of the Douglas fir poles along this section of the road. These assets are likely to fail soon and doing nothing would present possible risks to public safety and would negatively impact system reliability.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to avoid concurrent projects that impact feeder 5M54 (the alternate supply to the City of Guelph Pollution Control Plant).

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers both within and downstream of the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing framing to a single-sided vertical framing, which will make the equipment on the poles easily accessible from a bucket truck in the roadway. Additionally, the installation of solid-blade disconnect switches will provide an enhanced ability to isolate areas within this project and minimize the need to work in close proximity to energized plant.
The replacement of suspect Douglas fir poles will improve public safety by mitigating the risk of sudden failure due to below grade rot. Additionally, the installation of critter guard on the riser poles will reduce future occurrences of animal contact and bird nesting, which will reduce the probability of pole fires.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. Additionally, this pole line will easily accept a second circuit at a later date due to the change to single-sided vertical framing. Spare brackets are installed on all poles and structural analysis is completed assuming a second circuit to avoid future rework costs.

Economic Development (5.4.5.2.B5) (where applicable)

While the reconstruction of this pole line does not present an immediate benefit to economic development, the reframing to accommodate a second circuit allows for capacity to be easily increased in the future in order to support economic development.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles in this project area were installed in 1985 and have an average age of 30 years, however the average effective age of the poles is 50 years, as determined through inspections. From an effective age perspective, the poles have reached their end of useful life. This effective age, combined with the sudden failures experienced with other Douglas fir pole lines demonstrates that the pole line has had a poor performance record relative to other pole lines in GHESI's system. (The poles have effectively reached the end of their useful life much sooner than the typical pole). The underground feeder cable in this project is 30 years old, however the cable would need to be spliced to have additional length added to meet current framing standards at the risers. Because the cable is approaching end of life and due to water ingress issues with cable of this vintage, it is prudent to replace the cable at the same time as the poles.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

788 Residential and 13 General Service (less than 50 kW) and 2 General Service (greater than 50 kW) are downstream of this project and would be affected by an asset failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Customer specific reliability data is not currently available, however the 5M71 feeder supplying this project area and the downstream customers has had 247,874 customer minutes interrupted in the past 10 years and 77,922 momentary customer outages in the past 10 years. The reconstruction work planned will minimize the influence of this feeder segment on future reliability impacts. This feeder is the 13th worst performing feeder of 56 from a total customer minutes interrupted perspective (over a 10 year timeframe).

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this feeder segment performs at or above reliability targets. Changes to the configuration of the equipment in this project will result in better operational performance, which will reduce future outage and construction times. These improvements will enhance overall customer satisfaction. Additionally, by reducing the probability of an outage on the City of Guelph Pollution Control Plant, customers City-wide will indirectly benefit from this project.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a medium impact to customers in this project area in terms of the criticality and cost of an asset failure. This feeder supplies mostly residential customers who will not have a high cost of failure, however, most residential customers have no backup supply arrangements and failure of the portion of underground cable may potentially be a longer than typical outage due to isolation challenges and the suspect condition of ductwork passing below the railroad crossing. Additionally, there are relatively few commercial customers connected to this feeder and they are less than 1 MW in capacity. These customers will have a higher cost of failure if the failure occurs during business hours. Finally, a failure may have an impact on the Pollution Control Plant, which would greatly increase the criticality of the failure, should the ability to operate the plant be impacted.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
This project does not require any other specific projects to be completed prior to commencing, and does not rely on any System Access, System Service or General Plant projects.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources and available feeder capacity into account. This project has been ranked at number 7 of 9 material system renewal projects planned for construction in 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- The installation of solid-blade riser switches will reduce the operational costs associated with isolating the underground cable in this project area as the switches can be operated by a load-break tool from a distance.
- The modification of framing along this street to one-sided vertical framing will allow the equipment and connections to be more readily accessed, which will reduce operational and maintenance costs by reducing the time spent maneuvering vehicles to access the equipment.
- Modifications to spacing and the installation of critter guard will reduce the number of animal contacts and the occurrence of bird nesting. This will reduce the costs associated with clearing nests and will reduce the number of animal contacts on this feeder segment, resulting in less patrol and repair time.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances and the installation of critter guard will reduce the number of animal contact related outages, thereby improving reliability performance.
- The removal of suspect Douglas fir poles from the system will improve reliability performance and provide an enhanced margin of safety for the general public, as these poles are known to fail suddenly at or below the ground line. Pole failures can result in large forces being transmitted to the line and cause other mechanical failure, putting the public at risk from both a falling pole and other mechanical failures along the line related to the damage.

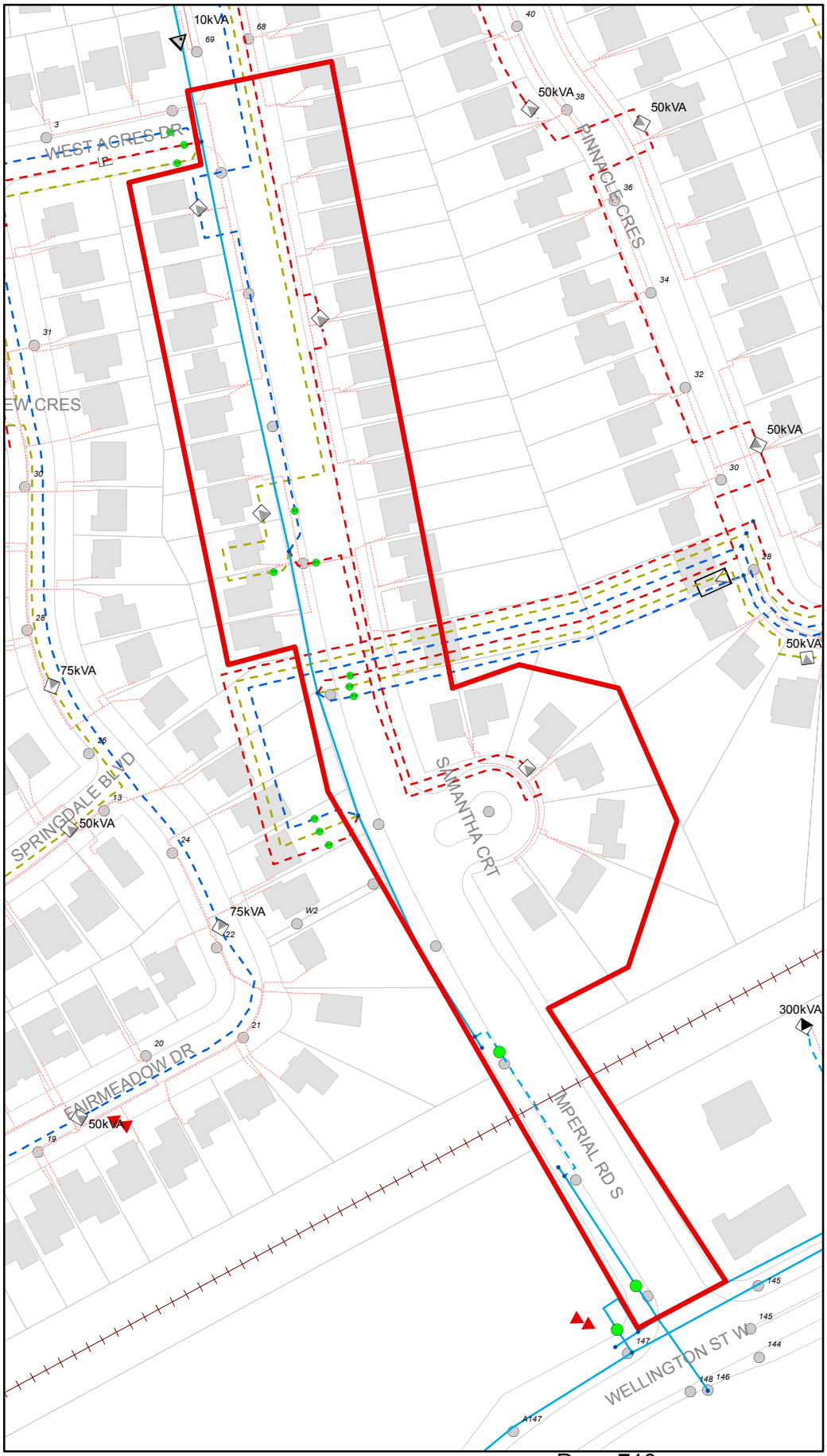
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

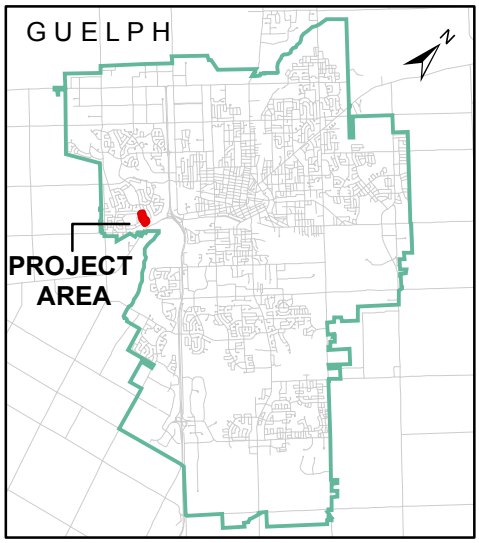
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 7 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by increasing the operational efficiency of the area through the addition of riser isolating means. The timing of this project could be affected by the ability to obtain the necessary outages, due to the need to maintain supply to the Guelph Pollution Control plant.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to asset condition related maintenance and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 45' in length and do not meet GHESI's current standards for pole length, given the current framing. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Other alternatives, such as undergrounding the system or using a different pole material would present a higher cost per customer and in the case of an alternative pole material, will not provide any substantial benefit above what the planned project will provide.

Imperial Road South (West Acres Drive to CNR Railroad) & Samantha Court





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
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OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Elmira Road South (Rochelle Drive to Freshmeadow Way)					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$388,000
Capital contribution						$0
Net Cost						$388,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 24 (24 residential)
Customer load within project area: 81 kW
Customer attachments downstream of project area: 329
Customer load downstream of project area: 3.17 MW

Start Date (5.4.5.2 A.3)	4-Apr-16	**In-Service Date (5.4.5.2 A.3)**		24-Jun-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
		$388,000		

Project Summary

This reconstruction project includes the replacement of 11 Douglas fir poles and the replacement of 4 pad mounted transformers and underground cable (approximately 760m of primary cable and 1.85km of secondary cable) and four-point connectors. The pole are Douglas fir species and are suspect to sudden failure from below grade rot. These particular poles have been identified and remedially treated for internal rot through GHESI's pole inspection program. The poles were installed in 1985 on average and have an average effective age of 51 based on their health index ratings. The existing 45' poles will be replaced with new 50' western red cedar poles consistent with GHESI's framing standards. The new poles will improve safety and reliability and will not be prone to the sudden failure issues that Douglas fir poles exhibit. Additionally, the primary riser in this project area has had a large number of recurring animal contacts over the past 10 years and the new framing, pole length and the addition of critter guard on the riser pole will alleviate the reliability concern.
The transformers have an average age of 27 years. The existing underground primary and secondary cable was installed in 1988 and is 27 years old. The existing primary cable is unjacketed cable which is prone to burn off failure from corroded concentric neutrals. A underground secondary system consists of single runs of triplex secondary cable which supply multiple homes via direct buried four-point connections at the lot lines. This method is not consistent with GHESI's current standards of separate cable runs for each property and carries a higher risk to reliability due to the number of homes connected to a single point of supply and the high numbers of direct-buried four-point failures GHESI has experienced due to moisture issues. The new underground system will consist of jacketed primary cable and single runs of secondary cable supplying each customer, installed in duct completely from the transformers to the meterbases. This method provides a higher margin of reliability and limits the number of customers impacted in the event of a failure.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to external contractors and with other major projects. The mitigation plan for this risk is bi-weekly internal project meetings and monthly contractor meetings to review projects underway and identify action plans to keep construction on schedule. This project is planned to begin in the second quarter of 2016, in order to minimize the conflict with other large projects occurring in 2016.
Materials Risk: This project has some risk with respect to availability of materials. Due to the large amount of secondary cable being replaced, there is a small risk that insufficient cable will be available to complete the project. The mitigation plan for this risk is to inform GHESI's suppliers with the requirements for this project well in advance and bring the materials into stock in advance of the project, to ensure sufficient supply is available.
If this project is not completed in 2016, the consequences include a large risk of a pole failing, which would impact significant customers downstream, as well as suffering additional cable faults which would result in interruptions to smaller groups of customers, but will impact customer satisfaction, especially in the case of direct buried four-point connectors, which may require disturbing the customer's property and landscaping to excavate and repair the unit.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of overhead scope was completed in 2012 on Nicklin Road between Woodlawn Road West and Brentwood Drive. The total cost of construction for the Nicklin Road project was $195,481. However, the Nicklin Road project has approximately double the number of poles that the Elmira Road South project has. A similar project to the underground work was completed in 2014 on Glenburnie Drive. The cost of the underground construction was $88,607, however the size of the underground portion project on Glenburnie Drive was approximately one third of the size of the underground portion of the Elmira Road South project. Based on these comparative projects, the proposed construction cost for the Elmira Road South project is in-line with half the scope of the Nicklin Road project plus three-times the scope of the underground portion of the Glenburnie Avenue project.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map -Elmira at Freshmeadow

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". The underground system in this site is made up of unjacketed cable. Unjacketed cable has an exposed concentric neutral which is prone to failure due to the exposure to moisture in the soil from being directly buried. The secondary system in this site is made up of single runs of secondary cable feeding multiple customers, connected by direct-buried four-point connectors. Four-point connectors direct buried in the soil are prone to failure from moisture ingress and GHESI has experienced a growing frequency of outages in the system due to four-point failures. Additionally, the risers have experienced a large number of animal contacts, resulting in outages. Finally, the Douglas fir poles in this project area have been identified as having internal rot and are prone to sudden failure. Due to the large amount of customers and load downstream of this project area, a pole failure would have a significant impact on reliability.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver is the asset management objective "Public Safety". This project area has low health index scores, driven primarily by Douglas fir poles with internal rot. GHESI has a program in place to replace suspect Douglas fir poles due to historic incidents of sudden failure from rot below the ground line. Pole failure is a risk to public safety due to the mechanical damage to property that can result from a catastrophic failure. This project area is a medium trafficked road through a primarily residential area, increasing the risk to public safety, should a failure occur.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management "Public Safety".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are Asset Condition Assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's Douglas-fir pole program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, and expert opinion based on known past issues with Douglas-fir poles and direct-buried four-point connectors.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to a low composite health index score, resulting in a high composite probability of failure. This project has a composite probability of failure of approximately 98.5% which indicates that an asset failure within this project area is imminent and the project area is ranked number 6 of 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

This use of modern framing standards will bring the framing to one side of the pole and provide adequate working space at the poles. The changes to the framing will improve operational efficiency by allowing workers to more easily access equipment and to work at a longer distance from energized equipment. This reduces the amount of isolation and reconfiguration work needed to work safely on the pole line.
Additionally, operational efficiency will be improved by using a single cable per duct secondary system and elminating four-point connectors. The use of a single cable per duct system allows cable to be quickly pulled-out and in if a cable fails, additionally, cutting power to a customer to allow work internal to their property, or for service upgrading purposes will be a much quicker process. With four-point connectors, either two or more customers must be interrupted, or connectors must be excavated and disconnected to properly isolate the whole service.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers within the project area will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers will also indirectly benefit from the lower maintenance costs a new system will provide.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from sudden failure of the Douglas fir poles will be reduced through the use of western red cedar poles, which do not exhibit the below grade rot problems prevalent in Douglas-fir poles. This will reduce the probability of a long duration outage.
The replacement of the four-point connected secondary system with a single cable per customer system will decrease the probability and duration of outages. The new cable will be connected from the transformer to the meterbases and will be free of splices which will improve the reliability of the new system. Additionally, the duration of outages will be reduced because the faulted cables can be supplied with service jumpers during the repair (which can supply one meterbase from another, to bypass the faulted cable), whereas this technique cannot be used to supply four-point connected customers if the supply cable faults due to distance and the number of customers that need to be restored (up to four customers would be interrupted and no nearby healthy supply cable may be available to use since customers share supply cables in a four-point arrangement). Finally, the installation of critter guard on the riser poles will eliminate the animal contact problems that have occurred several times in the past 10 years. This will reduce the frequency of outages the customers in the area will experience.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- Replacing the secondary cable only is not a practical solution due to the amount of construction work needed to install the separate cable per customer solution. Upgrading the secondary system will require the reconfiguration of secondary spades on the transformers. Additionally, the construction will necessitate the replacement of the primary cable due to the reconfiguration of the duct work. This work will require the existing transformers to be fully disconnected and removed from the pads, therefore reducing the additional cost of replacing the transformers with new units when reinstating the transformers.
- The replacement of only the underground or overhead system will not alleviate the high probability of failure in the project area and would therefore not be an effective solution.
- Like-for-like construction is not a practical solution for this project for several reasons. GHESI no longer uses Douglas fir poles due to their poor performance in the system, additionally, installing the new poles in the same configuration as they currently are in would not provide the benefits of enhanced clearances and easier working conditions, or of mitigated animal contact. For the underground system, GHESI no longer uses four-point connectors due to their poor performance in the system and due to the number of customers affected by a failure, as well as the limitations the single supply per connector system puts on customer service size (requiring expensive upgrading when customers increase their service size).
- Spot replacement of poles for this project was not considered to be a viable option due to the fact all of the poles are in similar condition, of a similar age and probability of failure. Replacement of the four-point connectors with new units is not a possible option as this connection method is no longer used due to reliability issues experienced with the units. In order to replace the connections with a more reliable system, separate conductors must be installed to each lot.
- A "Do-Nothing" approach is not a practical solution for this project area. This area has a very low health index score and high probability of failure. The Douglas fir poles in the area are prone to sudden failure from below grade rot and their failure will affect a large number of customers downstream. Additionally, GHESI has experienced a high number of primary and secondary cable faults in cables of this vintage and installation method. Doing nothing would result in the development of cable faults requiring long customer outages during repair (due to the use of the four-point connectors).

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project has been scheduled to begin construction in the second quarter of 2016 to level the scheduling of resources throughout the year.

Ownership Alternatives:
- Because this overhead and underground system supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI. Third parties will be approached to seek out opportunities for joint construction in order to reduce costs. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles with taller 50' long poles and replacing the existing framing to improve spacing on the pole. Public safety will also be improved by removing suspect Douglas fir poles which are prone to mechanical failure.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will be contacted to coordinate construction wherever possible. This will allow for multiple utilities to be installed in a common trench, reducing capital costs and limiting the amount of space utilized in the site.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will not be built to accommodate an additional circuit as the surrounding areas are fully developed and supplied and an additional feeder route through this project area is not required.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line does not directly impact economic development. This pole line serves mature, fully developed residential areas with limited commercial customers.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the removal of Douglas fir poles. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed Douglas fir poles or four-point secondary connectors.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The original transformers in the project area were purchased and installed in 1988. The units are 27 years old which falls in line below the typical useful life of pad-mounted transformers in GHESI's system. Given the current health index rating of the transformers, they have performed averagely from an age perspective. The primary and secondary cable in the project area was installed in 1988 and no complete cables have been replaced. The secondary system is connected by four-point connectors. GHESI has historically experienced a large number of failures in four-point connectors of the same age and installation method. Additionally, cable of this vintage is unjacketed and has non-tree retardant insulation which increases the probability of asset failure by means of burn-off, corroded and disconnected neutrals and insulation break-down.
The poles in this project area are Douglas fir poles installed in 1985 on average giving them an average age of 30. However, the poles have an average effective age of 51 which is above the typical useful life of wood poles in GHESI's system. This pole line has performed very poorly compared to other poles in the GHESI system.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

24 Residential customers are within this project area and would be affected by an asset failure in this project area. 4 General Service (greater than 50kW), 11 General Service (less than 50 kW) and 314 Residential customers are downstream of this project area and would be affected by an asset failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Several reliability events have occurred within this project area. The events are all related to animal contacts at the existing riser poles. There have been seven incidents of animal contact in the past ten years, resulting in a total of 129,864 customer minutes interrupted. However, the Douglas fir poles in this area have a very low health index rating and have been identified as having internal rot. Douglas fir poles have historically failed suddenly from decay below groundline which is not readily apparent above grade. Because these particular poles are already showing signs of this symptom, they need to be replaced in a controlled manner, before a failure occurs which would result in a large interruption of power and potential safety risks. Additionally, for several years, GHESI has been experiencing an increasingly high rate of failure in unjacketed primary cable with non-tree retardant insulation, as well as with direct buried four point connectors. Systems of this age are prone to failure and will cause reliability impacts to customers if not replaced.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this line segment performs at or above reliability targets. Replacement of the poles with western red cedar poles will reduce the risk of sudden failure in the future. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from the reduction in animal contact related outages, which will improve customer satisfaction. Finally, in the event of a secondary cable failure, less customers will be affected and customers will be restored more quickly due to the use of a single cable per customer system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies residential subdivisions of customers who will have a relatively low cost of failure and tend not to have backup supply arrangements. The impact of a failure on customers downstream of this project area is great. This project area services a large number of customers. Residential customers downstream of this project area will have minimal costs associated with a failure, however the general service customers downstream may have a larger cost of failure due to the interruption to their commercial operations. Additionally, due to the large service area that will be interrupted by a failure in this project area, additional impacts may be experienced, such as traffic signal and street lighting outages over a large area which will cause an increased risk to safety.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
Due to the amount of civil construction required, this project requires coordination amongst other projects in the system to ensure that sufficient contractor resources are available to complete the project in 2016. This project does not rely on any System Renewal, System Access, System Service or General Plant projects being completed first. This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources into account. This project is ranked 6 of 9 material system renewal projects planned for construction in 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- The installation of critter guard will reduce the frequency of animal contact related outages. This will reduce the costs associated with replacing fuses at the risers and reinstating the interrupted customers.
- The installation of a single cable per customer secondary system will reduce the time and cost associated with restoring power to customers in the event of a secondary cable fault. The existing system utilizes four-point connectors which connect up to four services to a single supply cable. When a failure in the supply cable occurs, there is typically not another service close enough to utilize service jumpers to quickly restore customer power, additionally, the nearest supply cables may not have sufficient capacity to accept the faulted customers' loads since they may already be servicing multiple customers. A single cable per customer system will ensure that another supply is nearby and will likely have sufficient capacity to utilize service jumpers and restore power to the faulted customers quickly.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances and the installation of critter guard will reduce the number of animal contact related outages, thereby improving reliability performance.
- The removal of a single cable per customer secondary system will allow for shorter duration outages in the future, as service jumpers can be used to temporarily reinstate customers during a failure.

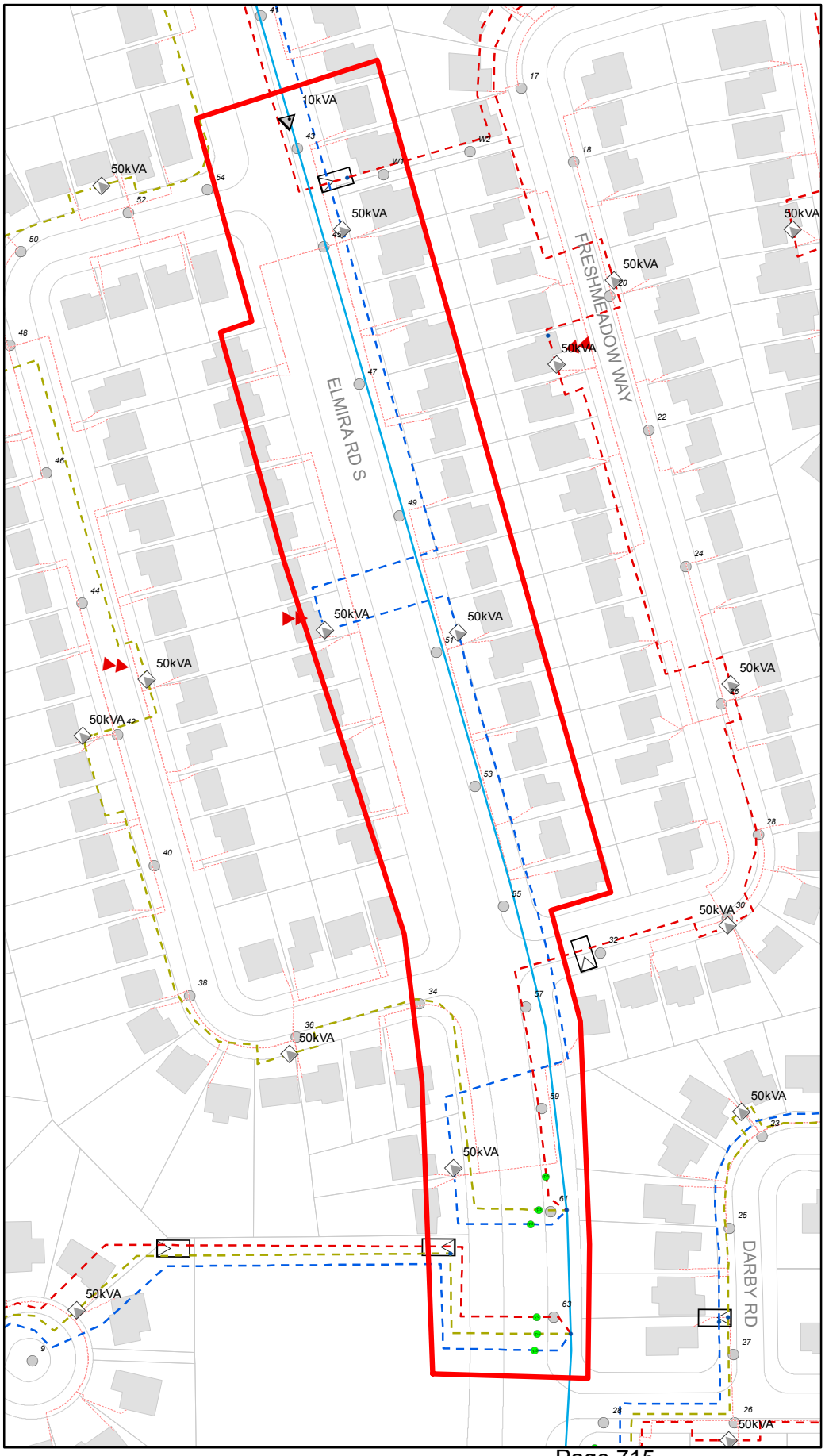
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

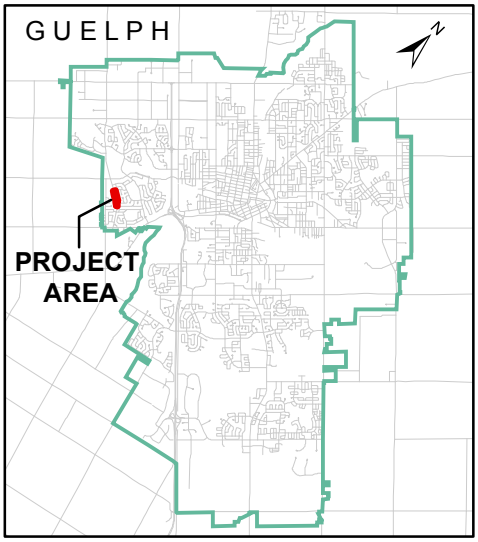
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 6 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by increasing the operational efficiency of the area. The timing of this project could be affected by the availability of contractor crews and secondary cable, however mitigation plans are in place for these possibilities
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to asset condition related maintenance and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project because but both the installation of Douglas fir poles and four-point secondary connectors are no longer supported by GHESI due to reliability impacts and decreased asset life. This project does not meet the requirements for like for like construction.

Elmira Road South
(Rochelle Drive to Freshmeadow Way)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Westgate Drive, Lonsdale Drive and June Avenue from Edinburgh Road North to Brentwood Drive					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$285,000
Capital contribution						$0
Net Cost						$285,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 89 (2 GS <50 - apartments, 87 Res)
Customer load within project area: 223 kW
Customer attachments downstream of project area: approximately 7,141
Customer load downstream of project area: 28.03 MW

Start Date (5.4.5.2 A.3)	**11-Jan-16**		**In-Service Date (5.4.5.2 A.3)**		**27-Mar-16**
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**	
	$285,000				

Project Summary

This reconstruction project includes the replacement of all poles on Westgate Drive, Lonsdale Drive, and June Avenue (between Edinburgh Road North and Brentwood Drive) area and the replacement of underground services at 47/49, 51/53 and 55/57 Westgate Drive in the project area due to conductor age and the presence of transite duct. The poles on Westgate Drive and June Avenue are Douglas fir poles and are suspect to sudden failure from below grade rot. Several failures of poles of the same species and vintage have been experienced in the immediate area and have a high impact on reliability due to their proximity to Campbell Transformer Station, which supplies the area. The poles on Lonsdale are cedar poles but have an average age of 52 years old on average and are in poor condition, while the oldest poles on this street have an age of 69 years. Very few poles in this project area have been spot replaced and the vast majority of poles are still original. The poles are a mix of 40', 45' and 50' length poles and will be replaced with 45' and 55' long poles to meet current standards and improve clearances for equipment and working space. The existing poles on Lonsdale Drive utilize pin type insulators and tie wire to secure the primary conductor. These insulators are prone to failure from cracking and will be replaced with modern polymer insulators. Additionally, the poles on Lonsdale are currently located inline with very large mature trees, resulting in high tree trimming costs to provide clearance for bare primary conductor. New locations will be found for some of the poles to avoid vegetation contact issues and excessive annual tree trimming costs. The underground cables being replaced on Westgate Drive are 51 years old and are installed in transite duct which is an asbestos containing material. Due to the health hazards in working with transite duct, completely new services are installed upon failure which can mean very lengthy outages or the use of costly generators to provide temporary power. GHESI has a transite duct removal program that seeks to proactively replace these services in a controlled manner on a priority basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to system capacity and other major projects. Specifically, the scheduling of this project is affected by its proximity to Campbell Transformer Station and competing demands on the feeders that will be affected during construction. This project risks not being completed on time if the reconstruction of Speedvale Avenue West at Woolwich Street is not completed by the end of 2015. Both projects rely on the same feeders and the Speedvale Avenue West project is downstream of this project, therefore this project cannot begin until the feeders within the project area are free to be taken out of service. The mitigation plan for these risks are bi-weekly internal project meetings to review projects underway and identify action plans to keep construction on schedule. This project is planned to begin in the first quarter of 2016, in order to avoid tying up the 36M21 and 36M62 feeders throughout the busier Q2 and Q3 seasons of the year. This project must be completed before May 2016 in order to avoid impacting supply during the peak load season as these feeders supply mainly residential load in the North-East quadrant of the City of Guelph and will see large air conditioning loads in the summer. Additionally the construction of this project will require a prolonged outage on part of the 36M62 feeder, which is one of two feeders connecting the Eastview Landfill Gas Energy Plant to the GHESI system. This increases the risk of the generator being disconnected from the system as there will be no backup feeder during construction. In order to minimize the impact of this risk on area supply levels, this construction is planned for the first quarter of 2016, when demand levels are lower.
If this project is not completed in 2016, GHESI risks significant negative impacts to system reliability due to the high probability of failure in the area and large number of downstream customers that would be affected.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope on Westgate Drive and June Avenue was completed in 2014 on Bristol Street, at Fountain Street. The work was a double-circuit pole line reconstruction in a similar residential area and at a similar distance from a transformer station. The total cost of construction for the Bristol Street project was $33,544, however the scope of work was only three poles, whereas Westgate Drive and June Avenue require a total of fourteen pole replacements. A single-phase pole replacement project that is comparable to the scope of work on Lonsdale Drive was completed in 2013 on Hearn Avenue, where fourteen poles (versus twelve poles on Lonsdale Drive), having the same configuration, were replaced on a similar style of street for $146,087. Based on these comparable projects, the proposed construction cost for Westgate Drive, Lonsdale Drive and June Avenue is in-line with the historic costs considering that the Westgate Drive and June Avenue portions of the project are approximately 4.5 times the scale of the Bristol Street project and the Lonsdale Drive portion of the project is approximately 85% of the scale of the Hearn Avenue project.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Westgate Lonsdale and June

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is a risk to Reliability evidenced by a high risk score, which is driven by a high composite probability of failure and an above average consequence of failure (since this project affects a large number of customers and large amount of downstream load). The high probability of failure score is related primarily to the low health index scores of the Douglas fir poles in this project area, as well as the low health index scores of some of the pole mounted transformers in the project area.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is Customer Value. This project area is at the start of two feeders which supply a large number of customers who would be affected by outages in this project area. By proactively replacing the suspect and high risk assets in this project area, long and widespread outages can be avoided. Due to the distance of this area from the GHESI service center, other measures such as remote operated switches will be considered to reduce restoration times. By avoiding widespread and potentially lengthy outages, we can ensure good value and satisfaction for our customers.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's transite duct removal program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on known past issues with Douglas fir poles and transite duct.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 due to a high risk score, resulting from a high composite probability of failure and the high consequence of failure. This project has a composite probability of failure of approximately 99% which indicates that an asset failure within this project area is imminent. This project is ranked 1 out of the 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of Douglas fir poles will greatly decrease the probability of a failure in this project area. Because this project area is located on the other side of the City from the GHESI service center, outage and restoration times are longer than typical and it is desirable to limit the probability of a failure for this reason. The replacement of secondary services in transite duct in this project will greatly decrease the duration and cost of outages for the affected customers. Through experience with past cable failures in transite duct, the repair process is very lengthy due to the need to obtain emergency locates, organize contractors to install new duct work and to bring in an asbestos management contractor to remove the damaged cable. Typically customers have been connected to emergency generators that are contracted by GHESI during the repair process. By installing the replacement service in a planned and proactive way, the majority of this cost can be reduced and the duration of outage is reduced to a minimum. This is a more cost-effective approach. Additionally, the installation of poles that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner in the future due to easier access and safer working conditions. The installation of remote switches will improve restoration time since travel time will become less of a controlling factor in the restoration process, thereby improving operational efficiency.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers both within the project area and downstream will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide. Because the suspect services supply residential homes, these customers would be impacted by a cable failure.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from pole failure will be reduced through the use of western red cedar poles, which do not exhibit the below grade decay and sudden failure issues associated with Douglas fir poles. The risk of future outages on the overhead portion of the project from animal contact will be replaced due to improved framing standards, increased spacing between energized conductors and second points of contact, the use of modern insulators and improved clearance from vegetation. The risk of failure on the underground portion of the project will be greatly reduced due to the replacement of aging cable and the duration of outages will be greatly reduced by the elimination of hazardous materials such as transite duct.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, the high number of customer connections in this project area would mean significant costs to covert the system to underground. Reliability issues in this area are primarily related to transformer faults and loose connections, which are a function of the ages of the current assets. Replacement of the conductor and connectors as part of this project and the relocation of poles away from trees combined with tree trimming, will reduce the future occurrences of these types of failures.
- Like-for-like replacement is not an option for this project area because GHESI does not support the use of Douglas fir poles due to reliability concerns, or transite duct, due to health and safety, as well as reliability concerns.
- A "Do-Nothing" solution is not practical for this project. This project has a very high probaility of failure and utilizes a variety of asset types which are suspect to sudden failure. Additionally, the project supplies a very large number of downstream customers. Doing nothing would put the system reliability and customer satisfaction values at jeopardy.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the construction outside of peak load seasons, therefore the project cannot be completed between the last half of the second quarter and the start of the fourth quarter.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles with taller 45' and 55' long poles and replacing the existing framing to improve spacing on the pole. The replacement of transite duct with PVC duct will remove the risk of asbestos particles being carried into the environment or customers' premises by disturbances to the service or during a failure event, which will improve both public and Employee Safety. Public safety will also be improved by removing suspect Douglas fir poles which are prone to mechanical failure.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve Employee Safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will not be built to accommodate an additional circuit as the surrounding areas are fully developed and supplied and an additional feeder route through this project area is not required.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line does not directly impact economic development. This pole line serves mature, fully developed residential areas with limited commercial customers.

Environmental Benefits (5.4.5.2.B6) (where applicable)

This project will remove or decommission asbestos containing materials which will prevent the future distribution of asbestos particles from disturbing the duct or the cable within the duct. The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the reconfiguration of the line section and the removal of transite duct. Additionally, the selected course of reconstruction has a lower cost per customer and cost per kilometer of line than other alternatives. This project supports Emergency Response targets by allowing for awareness and control over local power flow via remote switches. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed services in transite duct.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The poles on Lonsdale Avenue were installed (on average) in 1963 and have an average age of 52 years. From an age perspective, the poles have surpassed the typical end of useful life for fully dressed wood poles. This effective age, combined with the relatively low rate of spot replacement demonstrates that the pole line has had an above-average performance record relative to other pole lines of the same age in GHESI's system, however the poles have now reached their end of life and must be replaced. The poles on Westgate Avenue and June Avenue (within the project area) were installed (on average) in 1982 and have an average age of 33. The age of these poles indicates that they have performed poorly compared to other pole lines of the same age. GHESI has observed sudden failure in other Douglas fir pole lines of the same age on adjacent streets. The secondary cable in this project is 48 years old, which is above the typical useful life for underground secondary cables and therefore the cables have performed well relative to other cables in GHESI's system. Because of the age and high probability of failure of the secondary cables, and their installation in transite duct, these cables must be replaced soon to avoid lengthy outages.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

87 Residential and 2 General Service (less than 50 kW) customers are within this project area and would be affected by an asset failure in this project area. 6056 Residential, 194 General Service (less than 50 kW) and 9 General Service (greater than 50 kW) customers are downstream of this project area and may be affected by an asset failure.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Five outage events have occurred within this project area, resulting in 16,320 customer minutes of unplanned outages throughout the system over a five year period. Three of these events have been at customer premises and have had a limited impact, one event was related to vegetation and one event which caused the majority of the outage minutes was related to a transformer fault which did not trip the internal protection of the transformer. This indicates that events affecting the primary circuits in this project area have a very large downstream impact due to the high number of customers downstream of the project area. This fact combined with GHESI's past experiences with sudden failure in Douglas fir poles puts this project area at a high risk for contributing significant outages unless the pole line is reconstructed.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this line segment performs at or above reliability targets. Replacement of the poles with western red cedar poles will reduce the risk of sudden failure in the future. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from reducing the risk of exposure to transite duct and from avoiding the long outages that are associated with cable failure inside transite duct.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies residential customers who will not have a high cost of failure, however, most residential customers have no backup supply arrangements. For the customers supplied by underground secondary cable in transite duct, a failure in the underground secondary cable will be a much longer than typical outage due to the need for multiple parties on site and the challenges of working with and around transite duct. The general service customers in this area are the common amenities and offices of two residential buildings and are not expected to have a significantly higher cost of failure than the residential customers.
The impact of a failure on customers downstream of this project area is great. This project area services a large number of customers. Residential customers downstream of this project area will have minimal costs associated with a failure, however the general service customers downstream may have a larger cost of failure due to the interruption to their commercial operations. Additionally, due to the large service area that will be interrupted by a failure in this project area, additional impacts may be experienced, such as traffic signal and street lighting outages over a large area which will cause an increased risk to safety.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
Due to the location of this project near Campbell Transformer Station, this project requires coordination amongst other projects in the system to ensure that sufficient feeder capacity is maintained. This project requires the reconstruction project on Speedvale Avenue West to be completed but does not rely on any System Access, System Service or General Plant projects.
This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources, weather conditions, and generation demand into account. This project ranks 1st amongst the 9 material system renewal projects planned for 2016 and has been prioritized accordingly to be completed in the first quarter of 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Replaced poles will not need inspection immediately, and poles less than 15 years old receive only a visual inspection, which will reduce maintenance costs for pole inspections and treatment.
- The installation of remotely controlled switches will reduce the time and effort required to isolate and restore feeders in the project area.
- Removal of transite duct will prevent lengthy restoration work, reducing future O&M costs.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Enhanced clearances will provide safer working conditions for both GHESI employees and third-party employees working at the poles.
- Enhanced clearances will reduce the number of animal contact related outages, thereby improving reliability performance.
- Tree trimming and conductor replacement will improve reliability by reducing the amount of storm damage sustained by this project area.
- Relocating poles away from vegetation will improve safety by reducing the instances of equipment fires and mechanical damage from contact.
- The removal of transite duct will allow for shorter duration outages in the future, as cable can simply be pulled out of and pulled in to PVC duct.
- The removal of transite duct in a controlled manner will improve worker and public safety due to the elimination of the risk of improper handling resulting in exposure to asbestos particles.

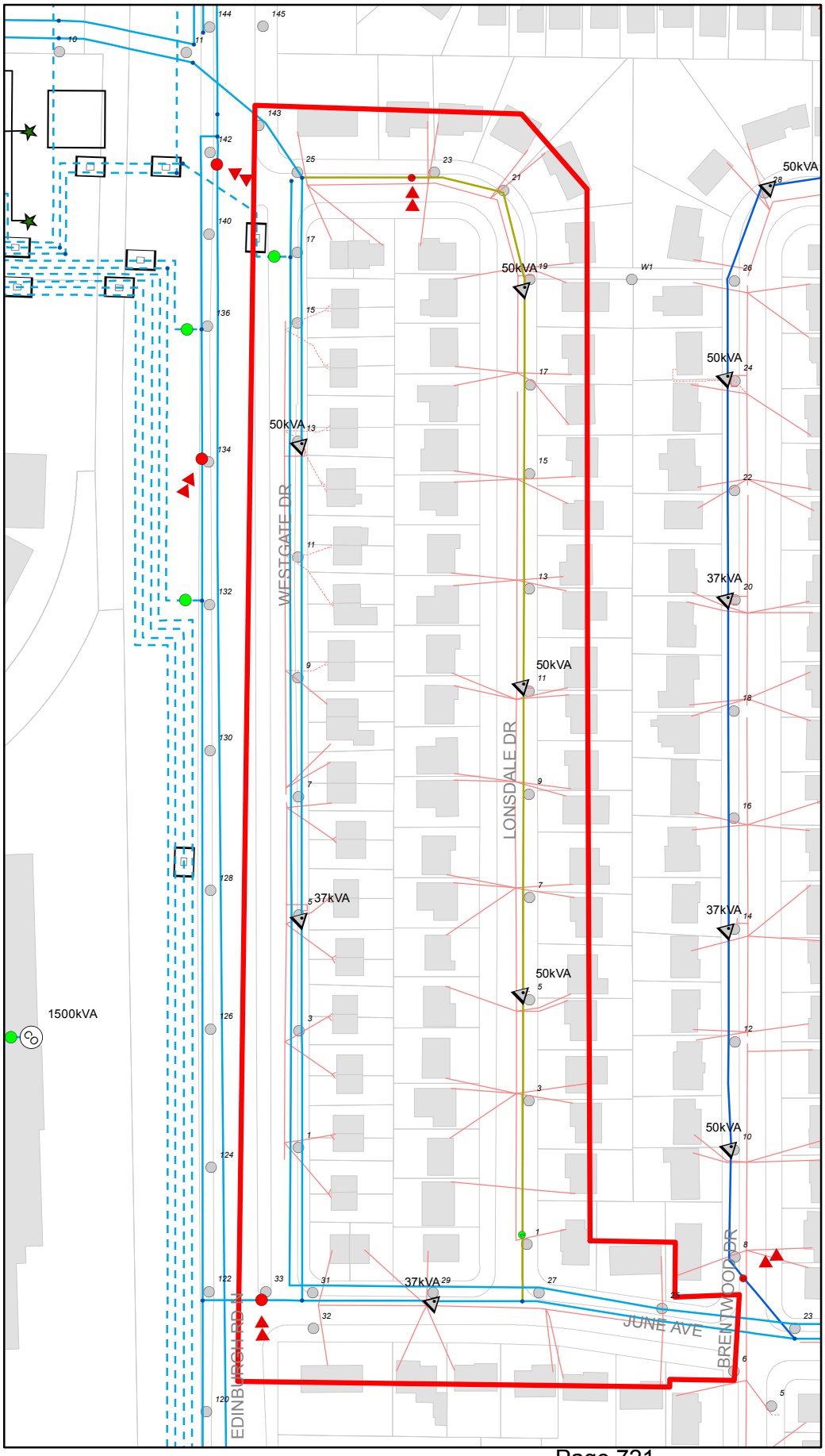
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

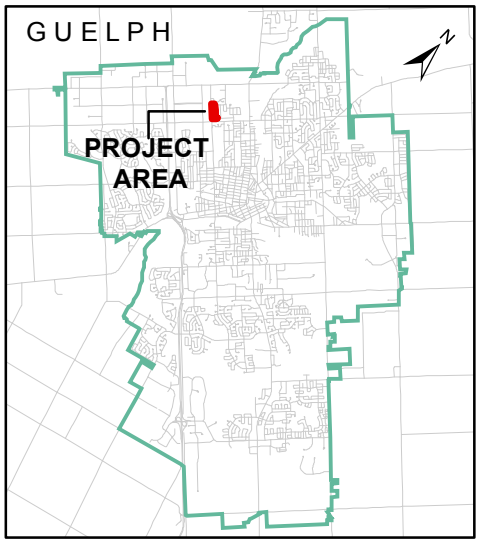
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 1 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by increasing the operational efficiency of the area. The timing of this project could be affected by the ability to obtain the necessary outages, due to the proximity to Campbell Transformer Station.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to asset condition related maintenance and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project, however the existing poles are 40' to 50' in length and do not meet GHESI's current standards for pole length, given the current framing. In order to realize the benefits to safety that the changes to framing and spacing will provide, the pole lengths must be increased. Other alternatives, such as undergrounding the system will be extremely costly due to the number of customer connections that must be converted. Using a different pole material such as concrete or composite poles would present a higher cost per customer and in the case of an alternative pole material, will not provide any substantial benefit above what the planned project will provide. The use of transite duct for new installations is not permitted at GHESI and like-for-like is therefore not an option for the underground work.

Westgate Drive, Lonsdale Drive & June Avenue (Edinburgh Road North to Brentwood Drive)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	Kortright Road West / Rickson Avenue Reconstruction - Phase 2 (a.k.a Yewholme Rehabilitation Project)					
Project Number	Unassigned					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						$986,000
Capital contribution						$0
Net Cost						$986,000
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 252 (249 residential, 2 GS <50)
Customer load within project area: 884 kW
Customer attachments downstream of project area: 252
Customer load downstream of project area: 884 kW

Start Date (5.4.5.2 A.3)	28-Mar-16	**In-Service Date (5.4.5.2 A.3)**		26-Aug-16

Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
		$493,000	$493,000	

Project Summary

This reconstruction project includes the removal of 17 pole-trans transformers and the replacement of the existing direct-buried distribution system with a new underground distribution system in duct, supplied by pad-mounted dead front transformers. Pole-trans units have been prone to failure due to tracking and flash-over faults. Pole-trans units are live-front units with less clearance between energized and non-energized conducting surfaces than other transformer types. This has presented a higher degree of danger for employees working on the units. Additionally, the units are no longer manufactured, and maintenance to existing units is conducted using spare parts harvested during other reconstruction projects. Guelph Hydro has a long standing program in place to remove all pole-trans transformers from the system. Additionally, cable faults in direct buried cable result in higher costs to locate and repair faults. Guelph Hydro's practice is to install all underground conductors in duct.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to external contractors and with other major projects. This project risks not being completed in 2016 due to the requirement for phase 1 to be complete prior to beginning the project, and the requirement that the project be completed before frost sets in the ground (due to the large amount of civil work required and the high cost of constructing in frost). The mitigation plan for this risk is bi-weekly internal project meetings and monthly contractor meetings to review projects underway and identify action plans to keep construction on schedule. This project is planned to begin in the second quarter of 2016, in order to allow all of phase one to be completed and to allow frost to leave the soil. By scheduling the project to begin in Q2 of 2016, the amount of available time for construction before frost returns will be maximized.
Materials Risk: This project requires the procurements and delivery of a large number of single phase pad mounted transformers and concrete street light poles. This project risks delays due to materials having long lead times. Delays in material procurement will be mitigated through finalizing the design well ahead of construction and starting the procurements process. Additionally, GHESI's purchasing department regularly contacts material suppliers to inform them of upcoming purchases and to determine the current lead times. Suppliers will be informed as soon as possible, in order to secure appropriate delivery dates.
If this project is not completed in 2016, GHESI risks significant impacts to system reliability and exhausting pole-trans replacement parts due to additional asset failures.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

GHESI has completed a number of similar projects over the past five years. Most recently, projects have been completed at Sherwood Drive, Parkwood Gardens and Hands Drive and Latenda Drive. The projects were all reconstruction projects involving the replacement of pole-trans transformers and direct buried underground cable with pad-mounted transformers and cable in duct systems. The approximate average cost of construction of these projects on a per pole-trans basis is $58,000. Based on this information, the Kortright Road West / Rickson Avenue Reconstruction (Phase 2) project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 17 pole-trans units.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Fife - Yewholme Rehab

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". Pole-trans have a history of failing due to flashover faults. The units are no longer manufactured and GHESI does not have access to sufficient spare parts to maintain the remaining units. Additionally, the underground system in this subdivision is made up of direct buried, unjacketed cable. Unjacketed cable has an exposed concentric neutral which is prone to failure due to the exposure to moisture in the soil from being directly buried. When a fault occurs, the combination of these two asset types results in outages which are very difficult and time-consuming to repair. In order to maintain reliability at target levels, GHESI has implemented a program to remove the remaining pole-trans from the system and replace them with dead-front pad-mounted transformers and a cable in duct system that facilitates the quick replacement of faulted cables.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Operational Efficiency". Currently GHESI maintains some spare parts for the maintenance of pole-trans units and also invests in dry ice cleaning to reduce the incidents of flashover faults. The replacement of the system will significantly reduce the yearly maintenance costs.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Reliability". The secondary related investment objective is the asset management objective "Operational Efficiency".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are Asset Condition Assessment, GIS system (asset database), reliability data from incident reports and Guelph Hydro's pole-trans removal program, as detailed in the Asset Management Plan. Much of the data used in these assesments originated from visual inspection visual inspection and testing data collected in the field, and expert opinion based on known past issues with pole-trans transformers.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 as part of a multiyear pole-trans removal program and to reduce the risk of incurring significant outages. This completion of this project will conclude the removal of pole-trans transformers in the GHESI system as well as the replacement of a significant amount of direct-buried cable. This project is prioritized ahead of other direct-buried cable projects due to the presence of pole-trans transformers, which cannot be easily replaced (whereas other direct-buried cable projects have pad-mounted transformers which can more easily be replaced). This project has been ranked at number 2 out of 9 material system renewal projects planned for 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The proactive replacement of pole-trans units and direct-buried cable will greatly decrease the probability of a failure in this project area. Because the cables are not in duct, faults must be located, exposed and spliced out in order to repair the cable, and pole-trans transformers must be disassembled and repaired using spare parts, both of which are very time consuming processes and it is desirable to limit the probability of a failure for this reason. Additionally, the installation of pad-mounted transformers that meet current standards will allow for the operation of equipment in a safer and more efficient manner in the future due to improved clearance and dead-front operation.
Spot replacement of poles for this project was not considered to be a viable option due to the fact that pole-trans units are no longer manufactured, therefore replacement involves locating space for a pad-mounted transformer base, and either replacing the attached primary and secondary cables due to the change in physical location, or splicing of all cables to extend them to the new location. This option is not preferable due to the amount of work and duration required to repair each transformer location and the weakening of the remaining system due to the excessive splicing required by the repair.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers within the project area will benefit from this project through the reduction of the risk of an outage that the new system will provide. Customers will also indirectly benefit from the lower maintenance costs a new system will provide.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from transformer failure will be reduced through the use of pad-mounted transformers, which do not exhibit the high rate of flashovers that pole-trans transformers exhibit. This will reduce the frequency of outages. Additionally, pad-mounted transformers are more readily available than pole-trans units and transformer replacement is a much simpler and quicker process than the replacement of pole-trans units, which will reduce the duration of outages cause by transformer failure.
The replacement of the direct-buried cable system with a cable in duct system will improve the probability and duration of outages. The new cable is fully jacketed cable, which protects the concentric neutral from damage due to exposure to moisture. Additionally, the duct system allows faulted cables to easily be pulled out and replaced. This eliminates the process of digging up faulted cable and splicing in new segments. Finally, GHESI utilizes elbow-mounted faulted circuit indicators on padmount transformers which allow faulted cable segments to be quickly identified for replacement. This reduces the duration of outages by removing the need to use time-domain reflectometers to locate faults for repair.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of an overhead system would not result in significantly lower capital costs, due to the need to convert all existing customers to overhead supplies. Additionally, an overhead system in a residential subdivision will lower the system reliability due to proximity to vegetation and higher rates of animal contacts. Finally, an overhead system is not conducive to the design and aesthetic of the existing subdivision.
- Like-for-like replacement is not an option for this project since utilizing pole-trans transformer units is not a practical solution since the units are no longer produced. Additionally, the replacement of direct buried cable with cable in duct follows current industry best practices.
- Replacing the transformers only is not a practical solution due to the amount of splicing that would be required to connect the new transformers to the existing cable. This would further weaken the direct buried cable system and expose the system to lower reliability.
- A "Do-Nothing" solution is not an option for this project area. Pole-trans units are no longer manufactured and replacement part stocks are nearing depletion. The existing units have high failure rates and maintenance costs which will increase if the project is delayed.

Scheduling Alternatives:
- The scheduling of this project is based on its prioritization against other proposed projects. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the construction outside of the winter season due to the amount of civil construction required and the increased cost and complexity involved with excavating in frost conditions, therefore the project cannot be completed in either the first or fourth quarters of the year.

Ownership Alternatives:
- Because this underground system supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI. Third parties will be approached to seek out opportunities for joint construction in order to reduce costs.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing live-front pole-trans units with dead-front equipment.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will be contacted to coordinate construction wherever possible. This will allow for multiple utilities to be installed in a common trench, reducing capital costs and limiting the amount of space utilized in the boulevard.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future operational requirements will be allowed for in the design. This design will include the provision of duct work for the future reconstruction of Karen Avenue, Birch Street, Oak Street and Hickory Street, which are all currently supplied by overhead lines located in limited accessibility areas (rear-lot construction). Additionally the use of pad-mounted equipment and a cable in duct system allows for future technological functionality to be easily integrated without the need to replace ducts or transformer bases, should the need arise.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this underground system does not impacts economic development. This system serves a residential subdivision which is fully developed.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will also include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the removal of live-front equipment. Additionally, the selected course of reconstruction has a lower life-cycle cost than other underground alternatives due to the reduction in ongoing maintenance requirements. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from failed pole-trans units and direct buried cable.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

The pole-trans transformers in the project area were purchased and installed in 1975. The units are 40 years old which falls in line with the typical useful life of pad-mounted transformers in GHESI's system. However, these units have been continuously maintained with dry ice cleaning and multiple repairs over this period of time. The transformers have performed adequately well from an age perspective but have carried a high maintenance cost. Therefore, overall the transformers have not performed well compared to other transformers in the GHESI system. The primary cable in the project area was also installed in 1975. Only 115 m of primary cable has been replaced out of the 2.2 km of cable in the project area. The remaining cable has reached the typical useful life for primary cable in duct. Given the fact that the cable is direct buried, which tends to reduce the useful life of the cable, this cable has performed very well compared to other underground primary cable in the GHESI system of the same age. However, the cable is now exceeding the typical useful life, dramatically increasing its probability of failure. Additionally, cable of this vintage is unjacketed and has non-tree retardant insulation which increases the probability of asset failure by means of burn-off, corroded and disconnected neutrals and insulation break-down.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

249 Residential customers and 2 General Service (less than 50 kW) are within this project area and would be affected by an asset failure in this project area. No additional customers are downstream of this project area.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

Several reliability events have occurred within this project area. Two pole-trans related failures have occurred, as well as five cable failures. The pole-trans failures have resulted in 5,986 customer minutes interrupted and the cable failures have resulted in 14,015 customer minutes interrupted. These high customer minute counts illustrate the extended duration required to repair failures on pole-trans units and direct buried cable (each event that has occurred within this project area has effected less than 50 customers).

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this project will ensure that this subdivision's distribution system performs at or above reliability targets. Replacement of the pole-trans transformers and direct buried cable system will reduce the probability of a long duration failure occurring. Long duration failures have a negative impact on customer satisfaction, especially if the failure occurs during the winter season or during a holiday or other important event. Additionally, many customers in this subdivision utilize electric baseboard heating, further compounding the problems of the loss of power during the winter.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

There is a low impact to customers in this project area in terms of the criticality and cost of an asset failure. This line supplies a large residential subdivision of customers who will have a relatively low cost of failure; however, these customers tend to not have backup supply arrangements.

Timing & Priority of Project (5.4.5.2 SR - C2)

This project is part of an overall capital replacement plan for 2016. The assets being replaced fall within the planned, levelized replacement quantities.
Due to the amount of civil construction required, this project requires coordination amongst other projects in the system to ensure that sufficient contractor resources are available to complete the project before the fourth quarter of 2016. This project requires phase one of the reconstruction project (Rickson Avenue) to be completed but does not rely on any System Access, System Service or General Plant projects. This project has been prioritized amongst other System Renewal projects and its position in the construction schedule also takes available resources, and weather conditions (such as winter frost conditions) into account. This project has been ranked at number 2 of the 9 material system renewal projects planned for construction in 2016.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- New pad-mounted transformers will not require dry ice cleaning or the stockpiling and refurbishment of used parts.
- Reduced restoration times and costs for future cable faults

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Removal of live-front equipment will improve Employee Safety by providing inherently safe interfaces on the transformers.
- Replacement of pole-trans transformers will improve reliability by reducing the probability of failures and the duration of restoration.
- Replacement of a direct-buried cable system with a cable in duct system will improve reliability by greatly decreasing restoration times.

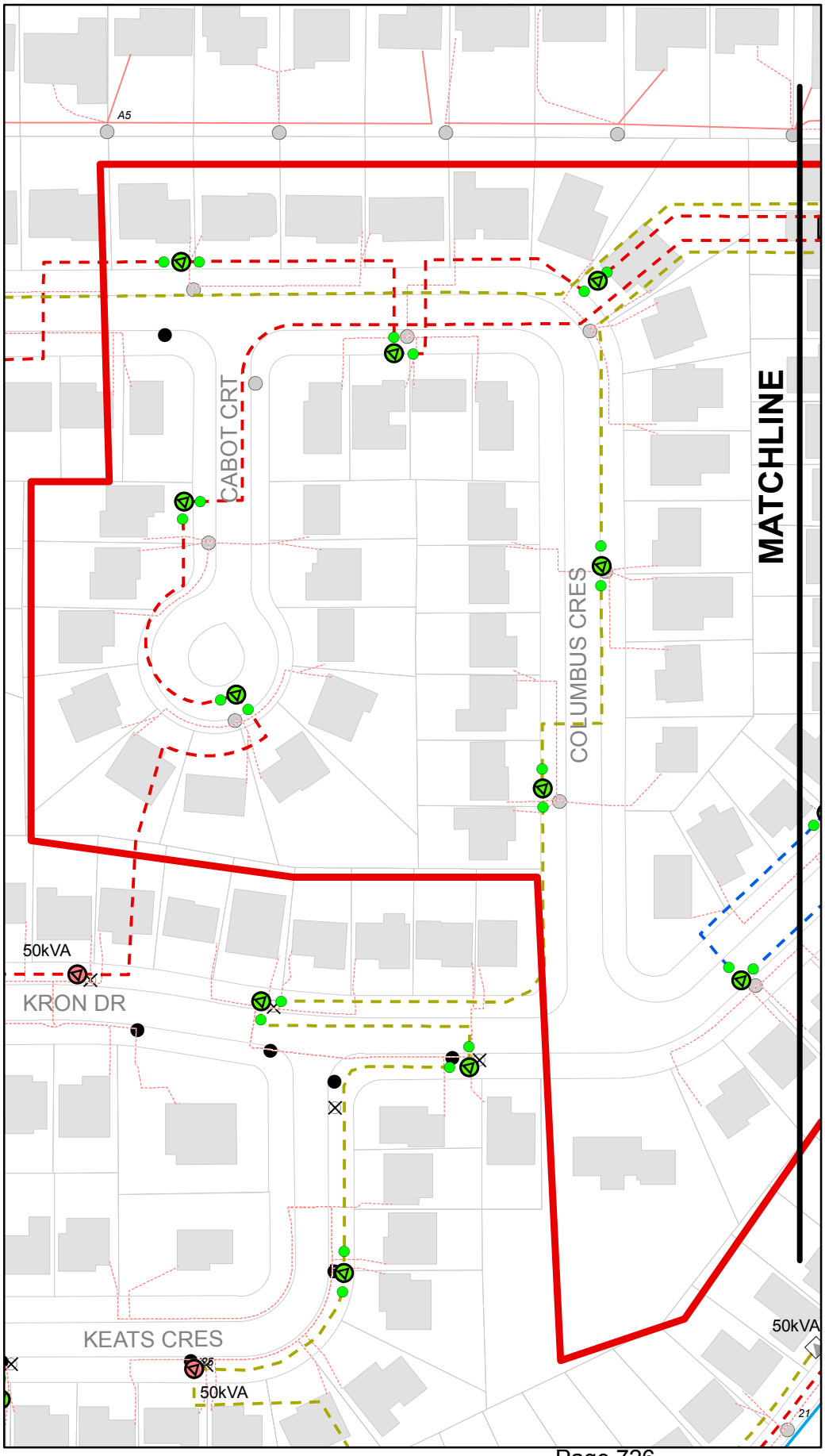
Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

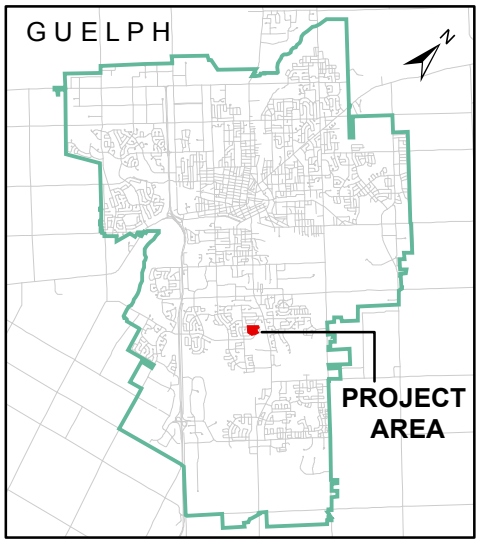
GHESI has implemented a project prioritization system for all system renewal and system service projects, starting in 2015. The system optimizes capital expenditure planning by establishing risk levels for project areas (from asset health information and by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction). This particular project has been ranked 2 of the 9 material system renewal projects planned for completion in 2016.
The timing of the project also considers the benefits and costs described in this project summary. Completing this project will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by removing assets that require excessive maintenance work and by replacing the difficult to repair direct-buried cable system with a cable in duct sustem. The timing of this project could be affected by the ability to obtain sufficient contractor resources, poor weather and long lead times on large orders of transformers and poles.
Costs of the project may be affected by increases in contractor and material prices.
While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. Additionally, O&M costs for the project area will increase due to continual pole-trans maintenance requirements and possible asset failure related restoration work.
GHESI has considered several alternatives for the design and timing of this project, which are discussed in this project summary. GHESI has weighed these alternatives and determined that this expenditure is required in 2016 to prevent signficant reliability issues and impacts to safety and customer satisfaction.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction was considered for this project but because pole-trans transformers are no longer produced, like for like renewal is not an option for this project. Other alternatives, such as installing an overhead system will result in negative impacts to reliability. Construction during winter months is not feasible due to the increased costs and time involved with excavating in frost conditions and the large amount of excavation required for this project.

Kortright Road West / Rickson Avenue Reconstruction - Phase 2





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

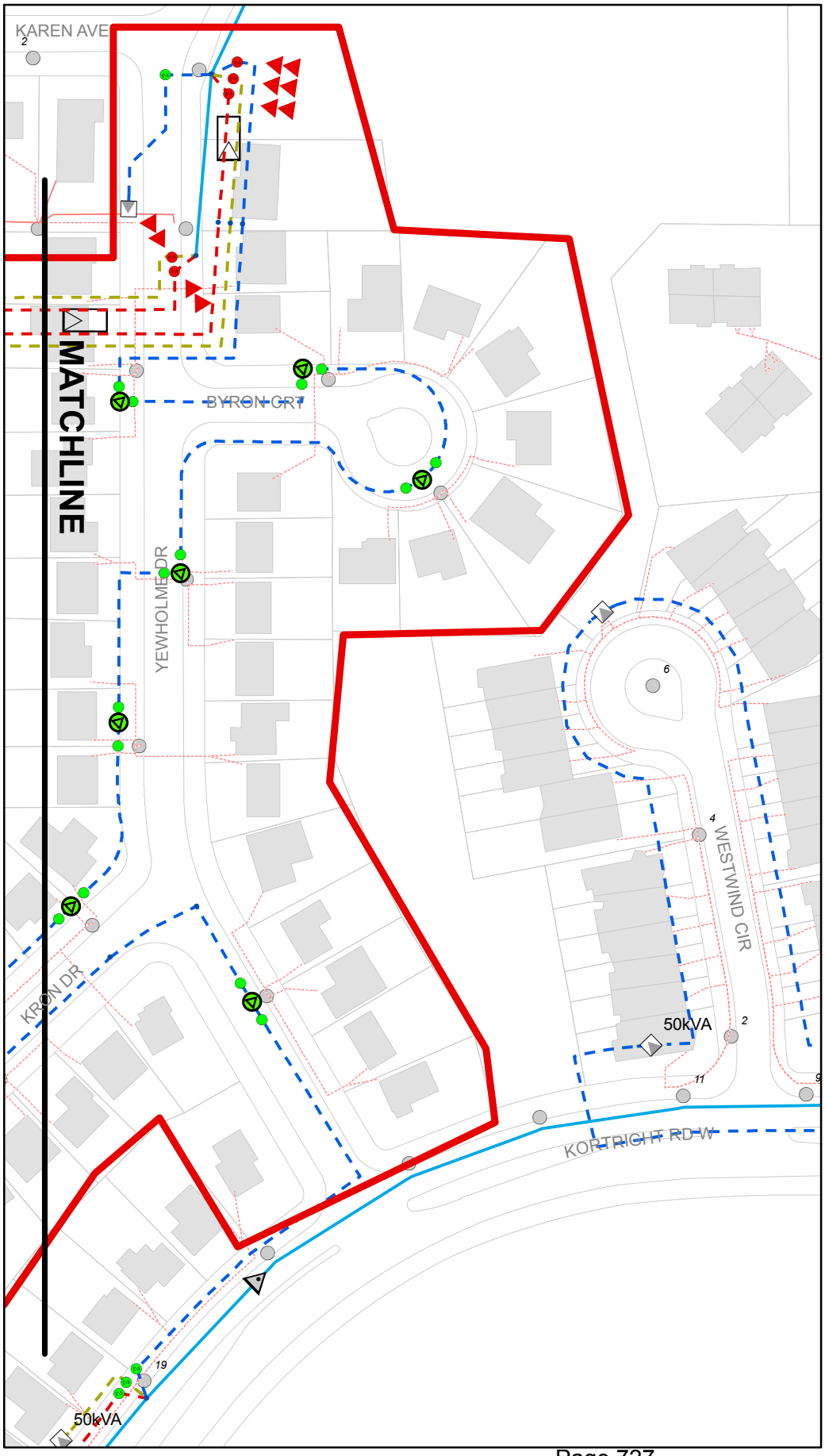
Poles

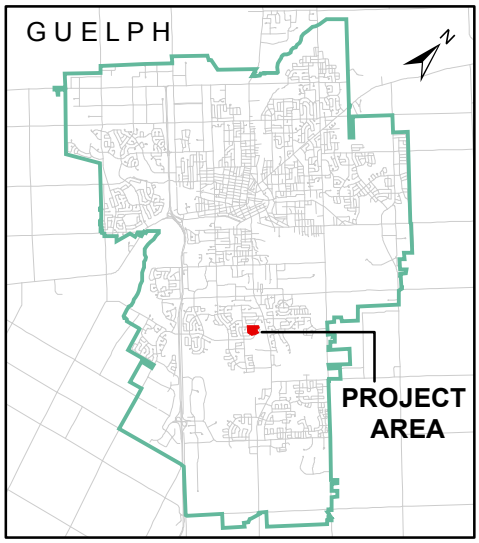
- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 2

0 37.5 75 Meters

Kortright Road West / Rickson Avenue Reconstruction - Phase 2





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

0 37.5 75 Meters

A. General Information						
Project /Activity	Distribution Transformer Replacements and Upgrades					
Project Number	CTRU					
Investment Category	System Renewal					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	$144,433	$91,051	$151,523	$322,307	$306,013	$315,193
Capital contribution	$0	$0	$0	$0	$0	$0
Net Cost	$144,433	$91,051	$151,523	$322,307	$306,013	$315,193
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	N/A	N/A	N/A	N/A	N/A

Customer Attachments and Load (5.4.5.2 A.2)

Specific projects are not contemplated at this time. In a typical year, GHESI will replace or upgrade approximately 21 transformers as specific projects, each affecting 1 to 100's of customers from 1 or 2kVA to 1.5 MW. In a typical year, GHESI will scrap 85 transformers, which will not affect customers.

Start Date (5.4.5.2 A.3)	1-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$78,798	$78,798	$78,798	$78,798

Project Summary

This is a program consisting of individual projects and investments related to the upgrade and replacement of distribution transformers in GHESI's distribution system. Work within this section covers the replacement of faulty overhead and underground transformers with new units, replacing overloaded overhead and underground transformers with higher capacity units and recovering value from scrapping defective unrepairable transformers. The overall capital requirements for this project is an estimate based on past spending levels, given typical annual transformer failure rates and typical overloaded transformer rates. Detailed planning is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

Transformer upgrade projects are partially driven by customer requests. GHESI has very limited control over the scope and timing of these projects.
GHESI will review customer upgrade requests on a regular basis such that transformer upgrades are identified in a timely manner to accommodate all customer needs. GHESI will work with customers to control timing of these projects such that customer expectations are met. Transformer replacement projects are driven by asset health. GHESI performs inspections and maintenance work to prolong asset life and to identify assets that are at risk for failure, in order to plan replacement requirements.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Transformer upgrade and replacement project/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

Transformers are provided in accordance with GHESI's Conditions of Service. Connection details vary widely within that standard. Transformer replacement forecasts are informed by GHESI's Asset Condition Assessment and Asset Management Plan, however, this project considers only transformers that are replaced or upgraded as stand-alone projects.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Reliability". Transformers are regularly inspected and flagged for replacement based on their condition. Transformers that are in very poor condition, or which have failed, will be replaced on an as-needed basis in order to minimize unplanned outages and environmental and safety concerns such as leaking oil and fires. Additionally, overloaded transformers are identified for replacement using GHESI's metering data and GIS system. Overloaded transformers are upgraded in a controlled fashion, to avoid unnecessary and unplanned interruptions to customers.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver is the asset management objective "Customer Value". Upgrading overloaded transformers, and transformers serving customers who request upgrades beyond the existing transformer capacity, ensures that service is maintained to customers during periods of higher loading. Additionally, changes to capacity in the transformer enable customers to upgrade their service size without affecting service reliability. GHESI also creates customer value by recovering salvage value from scrapping defective transformers.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective of this program is to ensure reliable service to customers and meet existing and future demand levels. The primary investment objective is the asset management objective "Reliability" and the secondary investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

This program was planned incorporating elements of GHESI's Asset Condition Assessment, load forecasting and past replacement and upgrade spending levels. Transformer scrapping information is also informed by asset condition assessments and inspection data. Upgrade requirements are partially informed by contact between GHESI and customers.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This program is of high priority relative to other material investments as it directly affects GHESI's ability to supply electricity to its customers. Additionally, part of its allocation is the replacement of transformers that have failed unexpectedly and result in an interruption to customers' services until they are replaced and therefore cannot be deferred. Project planning will be coordinated with other projects/programs of the same priority level.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

Replacement transformers will be sized according to known loads and will be sized with appropriate spare capacity. By running the transformers below their rated capacity, the life of the transformers is prolonged and copper losses are reduced. Additionally, the spare capacity is available in case of future customer service upgrades. This reduces the needs for system modifications in the future and helps GHESI achieve better system operation efficiency and cost-effectiveness in the long term.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Although this program is not intended for system access improvements, it is expected to have a positive impact on GHESI's ability to process customer service upgrade requests and new connections.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This program decreases the frequency and duration of outages by seeking to replace transformers which are in very poor condition in a controlled manner. In some cases, transformers can be temporarily connected in parallel to maintain power during the replacement work. In other cases, construction activities can be coordinated with customers to find the minimize disruption to customer service. Overloaded transformers are replaced with transformers of appropriate capacity, which avoids interruptions due to the integral transformer protective device operating from extreme overloading conditions.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Developments are planned and funded in accordance with GHESI's Asset Condition Assessments and transformer inspections. The replacement of transformers also follows GHESI's Conditions of Service. Where ownership and funding opportunities exist due to the size of a customer's service or where the upgraded transformer would exceed the capacity provided for in the Conditions of Service, alternate arrangements for ownership will be made. In general, where options are available with respect to design, scheduling, funding or ownership, the most effective overall alternative will be selected.

Safety (5.4.5.2.B2)

This program helps to mitigate potential safety risks associated with events such as transformer oil leaking, transformer fires and internal equipment faults. New units will be constructed and installed in accordance to current safety standards. This program will have no adverse affects on health and safety protection and performance.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

Not applicable.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

Transformer replacements at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers and electricians is part of every project. Authorization from the Electrical Safety Authority may be required prior to reconnection of services if activities are being coordinated with a change to the customer's service and will be handled through an established process.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Transformers are sized to the latest standards for operational needs, which could include available capacity for future load increases. Transformers that meet the current standards will be installed, which include modern internal protective devices such as current limiting fuses and breakers, disconnect switches, pressure relief devices and internal fault identifying devices.

Economic Development (5.4.5.2.B5) (where applicable)

This program is not designed to directly enable economic development, however the additional capacity provided through transformer upgrades may have a positive effect on enabling economic development on a small scale.

Environmental Benefits (5.4.5.2.B6) (where applicable)

Projects within this program will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Renewal

Asset performance-related operational targets and asset lifecycle optimization policies and practices (refer to 5.2.3 and 5.3.3) (5.4.5.2 SR - C1.1)

This project fulfills Operational Effectiveness reliability targets by contributing to lowering SAIDI, SAIFI, CAIFI and MAIFI index results, while improving IOR. This project also supports safety targets by creating a safer work environment through the removal of transformers in poor condition, which often includes the replacement of live front transformers with inherently safer dead front units. Finally, this project supports Customer Focus and Service Quality targets by removing the risk of lengthy and unplanned outages from unexpectedly failed or overloaded distribution transformers.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR - C1.2)

Assets within this program are flagged for replacement based on condition. The asset condition, determined through inspection, is related to an effective age and probability of failure by its health index, as detailed in GHESI's Asset Management Plan. Assets that have been flagged for replacement have effective ages beyond the useful life of distribution transformers, however in some cases this effective age will be either above the actual age (indicating good performance), or below the actual age (indicating poor performance). The actual performance of transformers being replaced or upgraded is determined on a case-by-case basis, however GHESI employs basic maintenance such as painting, repairing connections, replacing bushings and landscaping to prolong asset life and reduce overall life-cycle costs for distribution transformers.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR - C1.3)

Transformer failures can affect 1 to 100's of customers depending on how many customers are attached to the transformer. Typically, smaller distribution transformers will have 12 or less customers attached, while larger units will typically have less than 5 customers attached. The largest units in GHESI's system often have only 1 customer attached and are servicing large commercial or industrial customers. Some transformer units supply individually metered apartment buildings and therefore can have 100's of customers attached. The number of customers affected by a failure is therefore variable on a case-by-case basis.

Quantitative customer impacts (5.4.5.2 SR - C1.4)

At this time GHESI does not have sufficient data to quantitatively predict the customer impacts related to this program. Actual interruptions will depend on the number of failed transformers, number of customers attached to the failed transfomers, and the configuration and location of the transformers (ease of replacement). Additionally, the number of customers potentially impacted by overloaded transformer will depend on load increases throughout the year and the number of transformers and associated customers affected. The number of customers affected by requests that trigger transformer upgrades will depend on customer demand for service upgrades.

Qualitative customer impacts (5.4.5.2 SR - C1.5)

The completion of this program will ensure that GHESI's system reliability is not negatively impacted by excessive transformer failures. Replacement of overloaded transformers with appropriately sized units will also reduce the risk of overload related service interruptions in the future. These improvements will enhance overall customer satisfaction. Additionally, customers will benefit from the upgrading of overloaded transformers through the enabling of potential service upgrades.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (5.4.5.2 SR - C1.6)

The characteristics of customers potentially affected by transformer failures varies widely from a high number of residential customers with a low per customer cost of failure, to single large industrial customers with a very high cost of failure. Where conflicting demands prevent all transformers falling within this program from being completed, the most critical units (those affecting the largest number of customers, and those having the largest cost of failure) will be prioritized over others.

Timing & Priority of Project (5.4.5.2 SR - C2)

This program is comprised of multiple projects. The timing and priority of these projects vary. Timing is directed by incidents of failure, when overloading is detected or when an asset becomes flagged for replacement after investigating its condition data. Units which have failed and are out of service have the highest priority and must be replaced immediately to restore power to customers. Units which are overloaded or in poor condition will be prioritized based on the potential impact to connected customers and the ability to perform the work.

Consequences for system O&M costs (5.4.5.2 SR - C3)

O&M costs are expected to be reduced by this project for the following reasons:
- Overloaded transformers will be replaced with units having adequate capacity. This will reduce the frequency of trouble calls due to overloaded accessory equipment (blown fuses, damaged connectors, etc.). This will also reduce copper losses in the transformers which will improve the efficiency of operation and reduce system distribution losses.
- Some units flagged for replacement are live-front transformers and will be replaced with dead-front transformers. Dead-front transformers can be isolated more easily and have lower incidents of failure from tracking and flash-over which will reduce maintenance costs over the life of the replaced unit.

Impact on Reliability performance and or Safety (5.4.5.2 SR - C4)

The impact this project will have on reliability performance and safety is as follows:
- Modern transformer units have integrated protection systems such as current limiting fuses or breakers, internal fault indication, disconnect switches, dead-front deep-well bushing systems, pressure relief systems, overload warning indicators and animal guard on energized parts. These protection systems will reduce the frequency of faults causing customer interruptions and will in some cases minimize the extent of danger to public safety during a failure event.
- Worker safety is enhanced through the use of dead-front equipment when replacing live-front units.
- Reliability is improved by removing assets with very low health from the system prior to an uncontrolled failure, upgrading overloaded transformers prior to an overcurrent related failure and coordinating construction activities to minimize service interruptions.

Analysis of Project Benefits and Timing (5.4.5.2 SR - C5)

GHESI uses a risk based asset management system which identified asset health indices through inspection and data analysis, and relates this information to probabilities of failure and risk levels for assets. GHESI's Asset Condition Assessment includes estimated numbers of transformers which will require replacement either through this program or through line reconstruction work. The estimated timing of asset replacement investments is levelized over a twenty year period. GHESI uses this information in addition to past investment levels to determine the expected project timing. Completing this annual program will reduce system outage frequency and duration and improve public and Employee Safety. O&M costs will also be reduced by increasing the operational efficiency of the assets. The timing of this project could be affected by the availability of materials and the unknown timing of sudden asset failures, or shifts in load causing overloaded conditions. Mitigation plans are in place for these possibilities including spare stock management, load forecasting and monitoring and Asset Condition Assessments, which seek to predict replacement timing and needs and ensure appropriate resources are in place.
Costs of the project may be affected by the actual rates of failures and overloading, as well as the capacities and configurations of the transformers affected.
While there is some uncertainty in the cost and timing of the project, delaying portions of this project beyond 2016 may cause the risk of failure to increase dramatically and will reduce some of the project benefits such as the reduction of risk and outages. More transformers will likely need to be replaced at a later date after failure, which will result in longer unplanned outages and a decrease in customer satisfaction. Additionally, O&M costs for distribution transformers will increase due to asset condition related maintenance and possible asset failure related restoration work.

Like for Like Renewal Analysis, Alternatives Comparison (like-for-like vs. not like-for-like, timing, rate of replacement, etc. (5.4.5.2 SR - C6)

Like for like construction will be utilized where practical. If existing transformers that are being replaced meet the current safety standards, a similar unit will be installed in the same location and fashion. Where transformers are being upgraded, like for like construction is not an option due to the need to install larger capacity units, which may involve upgrading other accessory devices to match the higher capacity. The rate of replacement is informed by GHESI's Asset Condition Assessment and past practices. The replacement of some assets is performed as the assets fail.

A. General Information						
Project /Activity	Edinburgh Road North (Foster Avenue to Raglan Street)					
Project Number	Unassigned					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						**$176,000**
Capital contribution						**$0**
Net Cost						**$176,000**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 35 (2 GS <50, 34 Res)
Customer load within project area: 94 kW
Customer attachments downstream of project area: approximately 2,069
Customer load downstream of project area: 7.49 MW

Start Date (5.4.5.2 A.3)	4-Jan-16	**In-Service Date (5.4.5.2 A.3)**		25-Mar-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$176,000			

Project Summary

This project consists of the replacement of a single circuit pole line on Edinburgh Road North between Foster Avenue and Raglan Street (16 poles). Additionally, the pole line supports the 5M13 feeder which was recently reassigned from Campbell Transformer Station to Cedar Transformer Station as part of a program to improve supply capacity in the North-end of Guelph. The current pole line uses 4/0 primary conductor which must be upgraded to support the load along the feeder, now that the feeder orientation has been reversed. Additionally, the pole line will be framed to accept a second circuit with the intent of extending the double-circuit line that terminates to the South, through to Campbell Transformer Station over the course of 3 to 5 years. The upgraded pole line will provide a tie between the area supplied by Campbell Transformer Station and Cedar Transformer Station to improve system flexibility. The project has the additional benefit of replacing an old pole line that has a risk score due to the condition of the existing assets.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: This project is subject to scheduling risks with respect to external contractor and other major projects. This project risks not being completed on time if the reconstructions of Edinburgh Road North between Bristol Street and Foster Avenue, Wellington Road West at Edinburgh Road North, Roland Avenue or Wellington Road West at Gordon Street are not all completed prior to construction beginning. All of these projects rely on the same feeders and are upstream of this project area, therefore this project cannot begin until the feeders within the project area are free to be taken out of service. The mitigation plan for these risks are bi-weekly internal project meetings to review projects underway and identify action plans to keep construction on schedule. However, the Wellington Road West project at Gordon Street project is a City of Guelph initiated project which limits the control GHESI has on project schedules. GHESI attends regular project meetings and monthly utility coordination meetings to minimize the risk to the project schedule.

Additionally, construction in the downtown core by external developers and contractors will put pressure on the 5M13 feeder and its backup feeders during the busy Q2 and Q3 construction season. This project is planned to begin in the first quarter of 2016, in order to avoid tying up the 5M13 and 5M64 feeders throughout the busier Q2 and Q3 seasons of the year.

This project also has a risk to schedule due to external parties. There are four railway crossings in this project area which will require permits from the railway owners and operators to be approved prior to construction. A delay in permitting could delay this project. The mitigation plan for this is to contract an external engineering firm with significant experience in submitting plans to these authorities and obtaining approvals. This will minimize the amount of time required to design this portion of the project and will also increase the probability of approved permits being returned on time for construction.

System Constraints Risk: This project has a risk with respect to system constraints. The project is located near Cedar Transformer Station. Constantly changing system loads and configuration present a significant unknown and possible constraint to completing this project. GHESI plans to mitigate this risk by completing major feeder work in the area prior to starting this project to provide additional capacity support and flexibility in the area.

The consequences of this project not being completed in 2016 are significant system constraints in the central region of Guelph. A large development on Silvercreek Parkway North and residential developments on Wellington Road East and Arthur Street South will significantly increase demand on the feeders in the area and restrict the ability to obtain outages and move load. These projects are currently slated for construction within the three year horizon. Additionally, increases in demand in the north part of Guelph are increasing loads at Campbell Transformer Station. If this project is not completed in 2016, the practical load limit at Campbell Transformer Station may be reached and expensive and time intensive upgrades will be required to support the north end. By allowing load to be transferred from Campbell Transformer Station to Cedar Transformer Station, this project will delay the need for such upgrades. This project is also critical to the successful completion of the 5M82 feeder project since the overall feeder capacity will be limited by the current conductor in the project area, if this project is not completed prior to energizing the new 5M82 feeder.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope was completed in 2014 on Victoria Road South between MacAlister Boulevard and Stone Road East. The work was a single-circuit pole line reconstruction (framed for a second circuit) with primary conductor replacement. The Victoria Road South project included the replacement of 21 poles, while the Edinburgh Road North project includes the replacement of 16 poles on a busier road with more customer connections. The total cost of construction on the Victoria Road South project was $146,964, however the working conditions were such that road was able to be closed or to have lanes reduced, which made construction more efficient than construction on the Edinburgh Road North project will be. Based on this comparable project, the proposed construction cost is in-line with the historic costs considering the more complicated conditions on the Edinburgh Road North project.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - Edinburgh Road North - Foster to Sultan

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Operational Efficiency". There is a risk to area supply due to the conductor size through the project area. Supply transfer ability is currently limited and will be relieved by upgrading the conductor to 556 kcmil aluminum conductor. The upgrade in conductor size will improve operational efficiency by reducing line losses along the feeder and will assist in maintaining voltage levels within their required operational ranges during heavy loading periods. The conductor upgrade will also greatly reduce the number of switching operations and load shifting required to limit line current and maintain appropriate voltage levels during periods of increased load. The reduction in time to switch feeder segments will reduce operational costs because line crews will not need to be regularly dispatched to assist in these switching operations.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Customer Value". This project area is at the junction of two feeders which supply a large number of customers who would be affected by outages in this project area. By proactively replacing the high risk assets in this project area and upgrading the conductor and switches in the project area, long and widespread outages can be avoided and area supply flexibility will be improved. Due to the distance of this area from the GHESI service center, the proximity to the Cedar Transformer Station and the feeder route's role of tying together Cedar and Campbell Transformer Station supply areas, other measures such as remote operated switches will be installed to reduce restoration times. By avoiding widespread and potentially lengthy outages, we can ensure good value and satisfaction for our customers. Additionally, the poles will be framed to accept a second circuit, reducing the need for expensive rework when the additional circuit is installed at a later date.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Operational Efficiency" The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports, as well as loading data, GHESI's switching schedule and expert advice from GHESI's control room. Much of the data used in these assessments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on system control and operation.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 as part of a program to direct supply capacity towards the North half of the City of Guelph as well as due to the high composite probability of failure and the high consequence of failure scores determined for this project area using GHESI's asset management processes. This project has a composite probability of failure of approximately 81.6% which indicates that an asset failure within this project area is imminent. This project is ranked at number 2 out of 4 material system service projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The upgrading of lines in this project area to 556 kcmil conductor will increase the feeder rating and greatly improve operational efficiency by reducing line losses and improving the flexibility of the system. There are also some Douglas fir poles in the pole line which are prone to sudden failure from below grade rot. The replacement of these poles will greatly decrease the probability of a failure in this project area. Additionally, the installation of poles that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner in the future due to easier access and safer working conditions. The installation of remote switches will improve restoration time and improve system flexibility and awareness, thereby improving operational efficiency.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers both within the project area and downstream will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

The risk of future outages from pole failure will be reduced through the use of western red cedar poles, which do not exhibit the below grade decay and sudden failure issues associated with Douglas fir poles. The risk of future outages on the overhead portion of the project from animal contact will be replaced due to improved framing standards, increased spacing between energized conductors and second points of contact, the use of modern insulators and improved clearance from vegetation. Additionally some equipment failures, such as loose connectors and damaged lightning arrestors have occurred due to ageing equipment. The replacement of the connectors and protection devices through the project area will improve reliability.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, the high number of customer connections in this project area would mean significant costs to covert the system to underground. Interruptions in this area are primarily due to vegetation and animal contact issues. Additionally, many reliability issues in this area are related to damaged equipment and loose connections, which are a function of the ages of the current assets. Replacement of the conductor and connectors as part of this project and the relocation of poles away from trees combined with tree trimming, will reduce the future occurrences of these types of failures at a much lower cost than installing an underground system.
- A "Like-for-like" approach is not practical for this project. The current conductor ampacity is insufficient to handle the planned loading on the feeder. Additionally, the existing poles are too short to support a future second circuit. Constructing this line "like-for-like" would not allow GHESI to adequately supply this portion of the system while maintaining adequate voltage levels.
- A "Do-Nothing" solution is not possible for this project. The current assets are in very poor condition and need to be replaced prior to failure. Additionally, the current conductor is insufficient to support the loads in the area without excessive switching operations to redirect additional supply to the area during high loading periods. There is a risk that the additional capacity will not always be available on adjacent feeders and there could be a supply shortfall.

Scheduling Alternatives:
- The scheduling of this project is based on its sequence with other projects in the program. This project follows after the reconstruction of Edinburgh Road South directly to the South of this area and before the next phase of the Edinburgh Road North reconstruction. The scheduling is then further refined based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the several other projects along Wellington Road West first.
- The scheduling of this project is also impacted by the low composite health index in the project area. The project area has a composite probability of failure of 81.6%, suggesting an imminent asset failure in this area. The project is scheduled with the goal to be constructed before an asset failure occurs.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing 45' poles with taller 55' long poles and replacing the existing framing to improve spacing on the pole, as well as to allow for a future second circuit. Public safety will also be improved by removing suspect Douglas fir poles which are prone to mechanical failure.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve worker safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will also be built to accommodate an additional circuit to allow for additional flexibility and to accommodate the future splitting of existing feeders in the Silvercreek Parkway South and downtown areas of the system.

Economic Development (5.4.5.2.B5) (where applicable)

Although not directly related to economic development, the reconstruction of this pole line upgrade will allow for economic development in the Silvercreek Parkway South area providing additional capacity for load intensification in the downtown area.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

This project is part of a program designed to move additional supply capacity to the North half of the City of Guelph. Because transformer stations in the south-end of Guelph have available capacity, the reconfiguration and reconstruction of pole lines is generally a more cost-effective way to move supply than transformer station upgrade work. GHESI's estimates of the costs to perform upgrades at Campbell Transformer Station in order to alleviate loading concerns are more expensive than the combined estimated costs of the proposed system service projects needed to achieve the same load reduction. These projects have the additional benefit of replacing assets that are either at or near the end of their useful life. By combining necessary reconstruction work with upgrade and reconfiguration work, the overall cost of the projects are reduced while the benefits are increased. Customers will also benefit from feeder level improvements that will improve reliability and system flexibility, reducing outage frequency and restoration times.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

Regional electricity infrastructure requirements do not apply to this project.

Advanced technology (5.4.5.2 SS - C3)

This project includes the replacement of manual tiered-outboard load break switches and in-line solid blade switches with remote operated SCADA switches. The use of SCADAmate switches allow for online insight into electrical load flow, remote isolation of line segments, switching of feeders, and fault indication.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project integrates reliability, efficiency and safety benefits. Reliability will be improved through the removal of Douglas fir poles, relocating poles away from vegetation, tree-trimming, the use of critter guard and the replacement of ageing assets. Efficiency will be improved through the conversion to vertical framing and the installation of SCADAmate switches which allow for faster, remote operation of the system. This project also has safety benefits from the use of western red cedar poles, which do not have the same sudden failure characteristics that Douglas fir poles have, as well as the increase in spacing which will allow for safer working conditions in proximity to energized equipment.

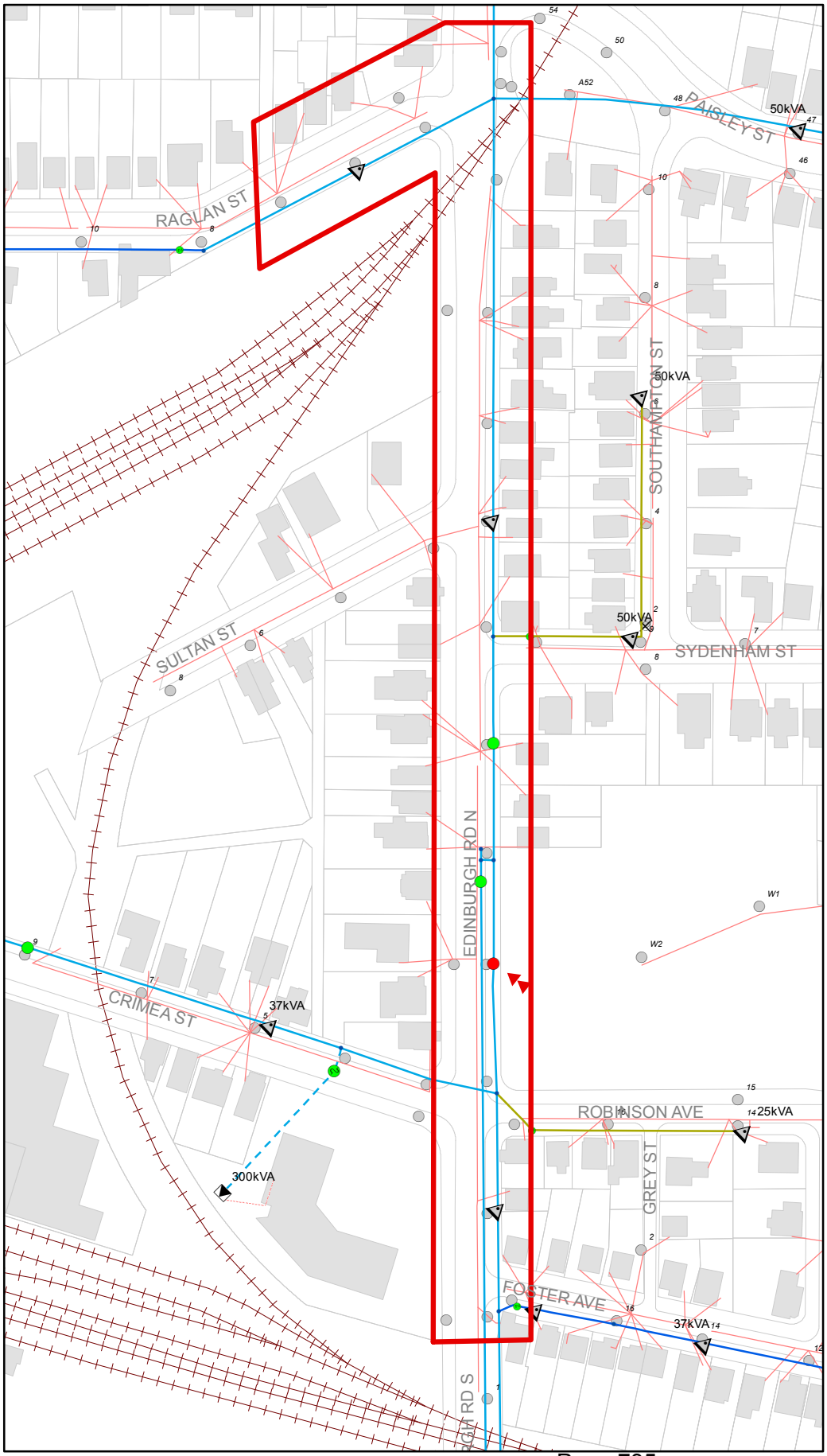
Timing & Priority of Project (5.4.5.2 SS - C5)

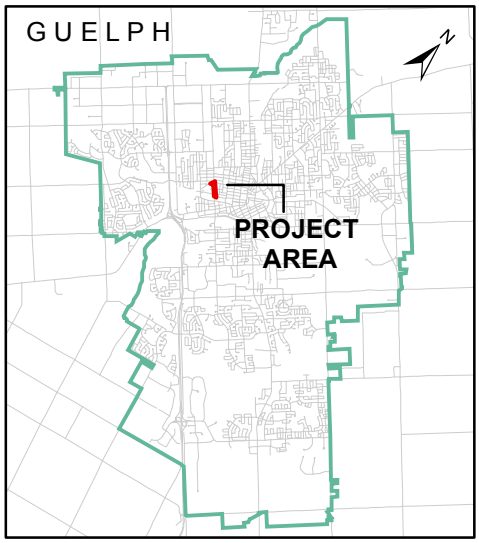
The timing of this project is influenced by the need to move supply capacity to the North end of the City of Guelph. Load forecasting has demonstrated that a need for additional supply in the North end is required and Edinburgh Road reconstruction program allows the supply to be shifted North without upgrading the Campbell Transformer Station. This project must be completed in 2016 to allows sufficient time for two additional phases of work on Edinburgh Road North to be completed by the end of 2018. The timing of this project is also constrained by the need to complete projects south of this project area prior to starting construction, due to competing feeder demands and their part in the overall reconstruction program.
The priority of this project is also impacted by the probability of failure in the project area. This project area currently has a composite probability of failure of 81.6% and the completion of this project in 2016 will reduce the risk in the project area to an acceptable level before additional outages and asset failures occur.
If this project is deferred to 2017, there is a risk of exceeding the practical load limit at Campbell Transformer Station. Forecasts have determined that the loads will surpass the practical load limit at Campbell Transformer Station by 2018. The Edinburgh Road North (Foster Avenue to Raglan Street) feeder project is part of an overall program to shift load to the south and must be completed prior to 2018. Additionally, if the project is deferred to 2017, there is a risk of an asset failure as illustrated by the high composite probability of failure in the project area. The poles in the project area are in poor condition and an asset failure may result in a significant impact to system reliability due to the large number of residential customers supplied by this project area.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

This project has been compared to the options of "Do Nothing" and technically feasible alternative projects. The Edinburgh Road North (Foster Avenue to Raglan Street) project has the following benefits and costs relative to those projects:
- A "Do Nothing" alternative is not practical in this case because load forecasts indicate that the practical load limit at Campbell Transformer Station will be surpassed if the load shifting program is not completed. Additionally, this project works synergistically with the 5M82 feeder project by increasing the capacity in this project area to the required levels. Without this project, the 5M82 feeder project (and 5M64 feeder that was recently installed) would not be able to effectively supply customers in this project area. This project also has the added benefit of renewing the assets that have a high probability of failure, while relieving the capacity constraints at Campbell Transformer Station.
- The alternative to this project that was considered is the installation of a new bus-pair at Campbell Transformer Station. That bus-pair expansion solution also relieves the capacity constraints in the north-end but is does not renew the assets in this project area and does not provide the enhanced flexibility for moving loads between Campbell and Cedar Transformer Stations that the Edinburgh Road North project provides. The bus-pair solution would address the capacity within this project area, but a higher frequency of line switching would be required to segment the feeder and move portions back and forth between Campbell and Cedar Transformer Stations in order to keep line current within acceptable limits for the existing conductor.

Edinburgh Road North
(Foster Avenue to Raglan Street)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 1

0 50 100 Meters

A. General Information						
Project /Activity	New 5M53 Feeder (Cedar Street, Maple Street, Water Street and McCrae Boulevard)					
Project Number	Unassigned					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						**$500,000**
Capital contribution						**$0**
Net Cost						**$500,000**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 66 (2 GS <50, 1 GS >50, 63 Res)
Customer load within project area: 398 kW
Customer attachments downstream of project area: approximately 2,430
Customer load downstream of project area: 17.87 MW

Start Date (5.4.5.2 A.3)	4-Jul-16	**In-Service Date (5.4.5.2 A.3)**		30-Sep-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
			$500,000	

Project Summary

This project consists of the installation of a new feeder (5M53) from Cedar Transformer Station to Royal City Park in order to provide additional capacity to feeders downstream. In order to install the new feeder, a total of 25 poles on Cedar Street, Maple Street, Water Street and McCrae Boulevard will need to be replaced with taller poles that can accommodate a third feeder. The new feeder will take over the existing 5M11 feeder running East through Downtown Guelph, as well as part of the 5M61 feeder East of Downtown Guelph and part of the 36M52 feeder in the East end of Guelph. This project will allow the 5M11 to supply new commercial development planned on Silvercreek Parkway North, as well as allowing the 36M21 feeder to be repurposed to supply new industrial development on Arrow Road. This project also increases the supply capacity to the downtown area by replacing the downtown portion of 5M11.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: This project is subject to scheduling risks with respect to external contractor and other major projects. The project has a high risk of not being completed within 2016 due to the demand on feeders in the area, which may lengthen the duration of the project. This project requires work on Edinburgh Road North to be completed, as well as projects on Wellington Road West at Gordon Street and on Wellington Road West at Roland Avenue. These projects must be completed to provide adequate backup supply during construction of the new 5M53 feeder. The mitigation plan for these risks are bi-weekly internal project meetings to review projects underway and identify action plans to keep construction on schedule. However, the Wellington Road West project at Gordon Street project is a City of Guelph initiated project which limits the control GHESI has on project schedules. GHESI attends regular project meetings and monthly utility coordination meetings to minimize the risk to the project schedule.
This project is planned to begin in the third quarter of 2016, after the completion of the Edinburgh Road North construction project while allowing sufficient time to complete the 5M53 project.
Materials Risk: This project will require tall poles (65' in length) to support a third feeder. These poles may have a long lead time, which poses a risk to the project. In order to mitigate this risk, GHESI will determine pole requirements well in advance of the project and notify suppliers to ensure sufficient lead times are in accounted for.
System Constraints Risk: This project has a risk with respect to system constraints. The project is located near Cedar Transformer Station. Constantly changing system loads and configuration present a significant unknown and possible constraint to completing this project. GHESI plans to mitigate this risk by completing major feeder work in the area prior to starting this project to provide additional capacity support and flexibility in the area.
The consequences of this project not being completed in 2016 are significant system constraints in the central region of Guelph. A large development on Silvercreek Parkway North and residential developments on Wellington Road East and Arthur Street South will significantly increase demand on the feeders in the area and restrict the ability to obtain outages for future distribution system work in the area and move load. These projects are currently slated for construction within the three year horizon. Additionally, increases in demand in the north part of Guelph are increasing loads at Campbell Transformer Station. If this project is not completed in 2016, the practical load limit at Campbell Transformer Station may be reached and expensive and time intensive upgrades will be required to support the north end. By allowing load to be transferred from Campbell Transformer Station to Cedar Transformer Station, this project will delay the need for such upgrades.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope was completed in 2015 on Edinburgh Road South from Cedar Street to Bristol Street. The work was the reconstruction of an existing two-circuit pole line to accommodate a third circuit. However, the Edinburgh Road South project included underground work that would not be included in the 5M53 project scope. The Edinburgh Road South project also included the installation of 27 poles, whereas the scope of the 5M53 project includes the replacement of 25 poles. The total cost of overhead construction on the Edinburgh Road South project was $486,141. Based on this comparable project, the proposed construction cost of the 5M53 project is in-line with the historic costs considering the additional poles on the 5M53 project and the higher removal cost for the concrete poles on Cedar Street.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - 5M53

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is Operational Efficiency. Currently the 5M11 feeder supplies the Edinburgh Road North, Wellington Street West and the Downtown Guelph areas. Increased load on Silvercreek Parkway North requires additional capacity to be supplied to the region. Additionally, proposed load increases on Arrow Road require additional capacity in the North end of the City of Guelph. Installing the new 5M53 feeder will relieve the 5M11 feeder in the Downtown area, allowing it to supply Silvercreek Parkway North, as well as relieving the 36M21 feeder in the North-end of the City to allow it to supply Arrow Road. This will greatly reduce the number of switching operations and load shifting required to support the load increases, which will improve flexibility in the North-end of the City to deal with construction work and will delay the need for upgrades at Campbell Transformer Station. The reduction in time to switch feeder segments will reduce operational costs because line crews will not need to be regularly dispatched to assist in the switching operations when loads increase at Campbell Transformer Station.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is Customer Value. This project will improve flexibility throughout both the Downtown and North-end sections of the City of Guelph. The improved flexibility will allow for quicker isolation and restoration times. It will also segregate customers onto multiple feeders, which will reduce the number of customers impacted by faults on the system. The improved reliability and the ability to respond to customer requests for planned outages will improve customer satisfaction.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Operational Efficiency". The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports, as well as loading data, GHESI's switching schedule and expert advice from GHESI's control room. Much of the data used in these assessments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on system control and operation.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 as part of a program to direct supply capacity towards the North half of the City of Guelph as well as the need to supply commercial development at Silvercreek Parkway North, which is planned to be constructed in 2016. This project is ranked at number 3 out of 4 material system service projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

This project improves Operational Efficiency by separating the Downtown area and the East-end of Guelph from the Silvercreek Parkway North section of the City onto separate feeders. This will reduce the dependency each of these areas have on each other and will allow for greater flexibility in supply. The current configuration results in significant difficulty in arranging outages through the central portion of the city. Additionally the changes in configuration will allow load increases on Silvercreek Parkway North and Arrow Road to be supplied while minimizing system losses and switching operations. The improved flexibility will allow for more cost-effective operation of the system by minimizing the effort required to switch and isolate the affected feeders by reducing the number of steps in associated switching orders, and reducing the reliance on manual switches in the process.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers both within the project area and downstream will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide. Customers will also benefit from the reduction in the number of customers that will be affected by faults on the affected feeders. Finally, commercial and industrial customers will benefit from the additional supply that will be provided to developments on Silvercreek Parkway North and Arrow Road.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This investment will reduce the frequency of outages by separating the 5M11 feeder from the new 5M53 feeder. This will reduce the number of customers impacted by outages. The project area has had 13,139 customer momentary interruptions over the past 10 years, almost entirely due to animal contacts. Tree trimming and the installation of critter guard will reduce the number of contacts resulting in momentary outages, and will therefore reduce the frequency of outages. The duration of outages will also be reduced because this project will lower the load levels on several feeders. This allows line segments to be more easily transferred, which reduces the number of operations required and therefore reduces restoration times on the affected feeders.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:

- The use of concrete or composite poles to replace all poles in the project area would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic. However, the existing concrete poles will be replaced with composite poles to maintain the improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, the high number of customer connections in this project area would mean significant costs to covert the system to underground. Interruptions in this area are primarily due to vegetation and animal contact issues. Relocation of poles away from trees combined with tree trimming and the installation of critter guard, will reduce the future occurrences of these types of failures at a much lower cost than installing an underground system.
- "Like-for-Like" construction is no a practical solution for this project because the existing poles are not tall enough to support a third feeder. Additionally, the current framing does not allow for an additional feeder to be integrated. Finally, GHESI no longer supports the installation of concrete distribution poles due to their poor historical performance in terms of asset longevity, and due to difficulty in work zone isolation and concerns to public and worker safety, as well as damage to equipment, due to their much greater weight than comparable wood or composite poles.
- A "Do-Nothing" strategy is not possible for this project unless expensive upgrades are completed at Campbell Transformer Station. However, even with upgrades at Campbell Transformer Station, additional feeders would need to be installed into the downtown area to provide the capacity benefit of this project (Cedar Transformer Station is located closer to the downtown area than Campbell Transformer Station). Additionally, a "Do-Nothing" approach would result in losing the benefits associated with the project, such as improved reliability and asset renewal.

Scheduling Alternatives:

- The scheduling of this project is based on supply requirements at Silvercreek Parkway North, which is planned for construction starting in 2016. The scheduling is also based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the several other projects along Wellington Road West and Edinburgh Road North first.

Ownership Alternatives:

- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing 45' and 50' poles with taller 55' and 65' long poles and replacing the existing framing to improve spacing on the pole for worker and equipment clearances, as well as to allow for the third circuit. Public safety will also be improved by removing suspect Douglas fir poles which are prone to mechanical failure and worker safety will be improved by replacing difficult to lift and handle concrete poles with lightweight composite poles.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve worker safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will not be built to accommodate a fourth circuit to because GHESI's policy is to limit the number of feeders on a pole to three in order to minimize the impact of asset failures and to minimize the difficulty in isolating the pole line.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line upgrade allows for economic development in the Silvercreek Parkway South area and for load intensification in the Arrow Road area. This project also supplies capacity support to the downtown area. Historically, the downtown area had been considered built-out in terms of load, however the City of Guelph is allowing high-rise condominium buildings to be built in the core, which will increase loads in the area and dramatically increase customer counts supplied by the downtown feeders. This project will support these initiatives by segregating the customers onto multiple feeders, to reduce the impact of outages, and providing additional capacity input to the downtown area, which will allow the load density in the area to increase.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

This project is part of a program designed to move additional supply capacity to the North half of the City of Guelph. Because transformer stations in the south-end of Guelph have available capacity, the reconfiguration and reconstruction of pole lines is generally a more cost-effective way to move supply than transformer station upgrade work. GHESI's estimates of the costs to perform upgrades at Campbell Transformer Station in order to alleviate loading concerns are more expensive than the combined estimated costs of the proposed system service projects needed to achieve the same load reduction. These projects have the additional benefit of replacing assets that are either at or near the end of their useful life. By combining necessary reconstruction work with upgrade and reconfiguration work, the overall cost of the projects are reduced while the benefits are increased. Customers will also benefit from feeder level improvements that will improve reliability and system flexibility, reducing outage frequency and restoration times.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

Regional electricity infrastructure requirements do not apply to this project.

Advanced technology (5.4.5.2 SS - C3)

The feeder being installed as part of this project is designed to be an express feeder until it reaches the East-end of Guelph. There is no need for advanced technology such as SCADAmate switches as the feeder is designed to be static through the project area and not to have interconnections.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project integrates reliability, efficiency and safety benefits. Reliability will be improved through the removal of some Douglas fir poles that are within the project area, relocating poles away from vegetation, tree-trimming, the use of critter guard and the replacement of deteriorating assets. The reduction of loading levels on the adjacent feeders will allow for the more efficient operation of the distribution system due to lower line losses and easier line switching. This project also has safety benefits from the increase in spacing which will allow for safer working conditions in proximity to energized equipment.

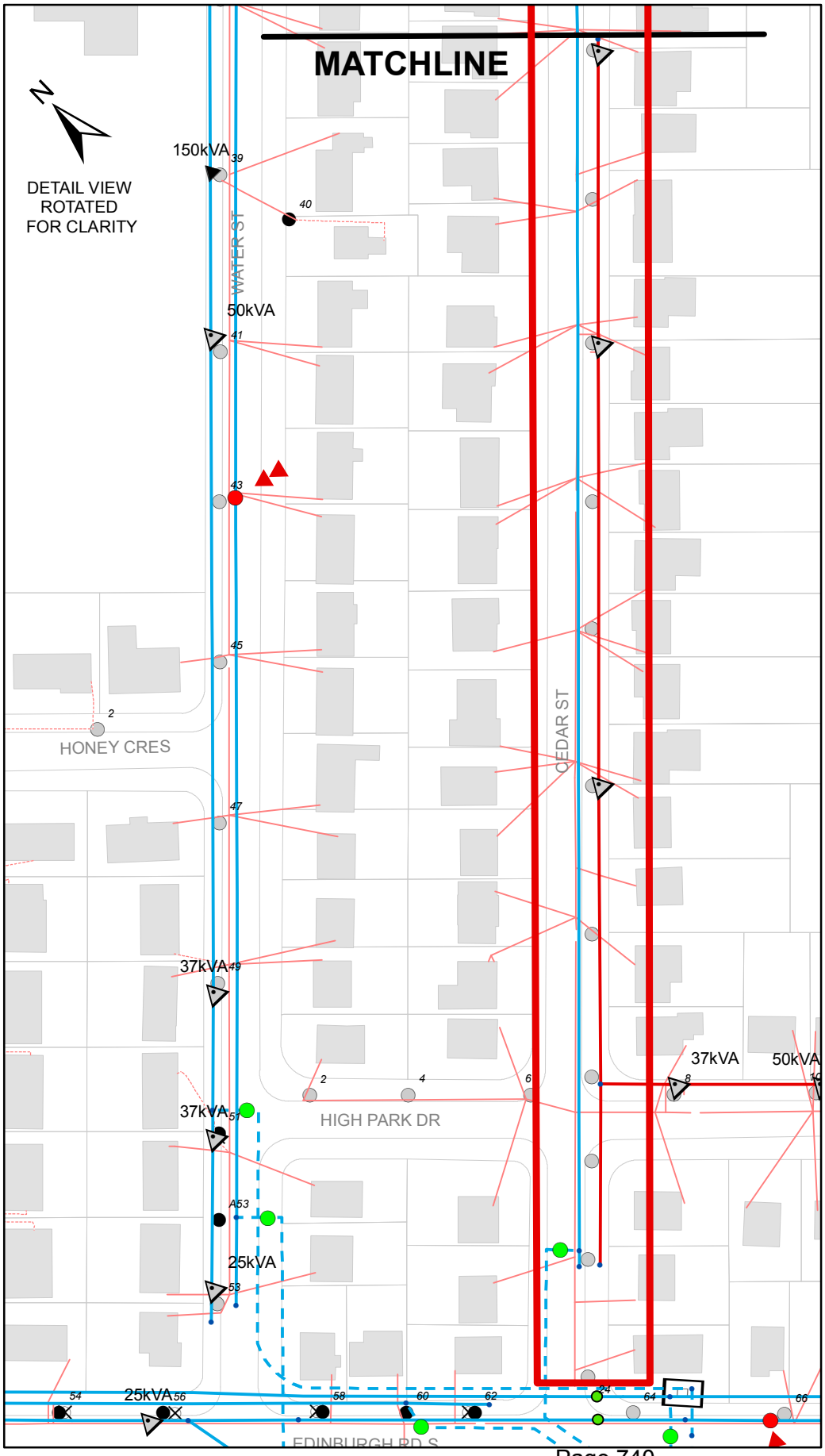
Timing & Priority of Project (5.4.5.2 SS - C5)

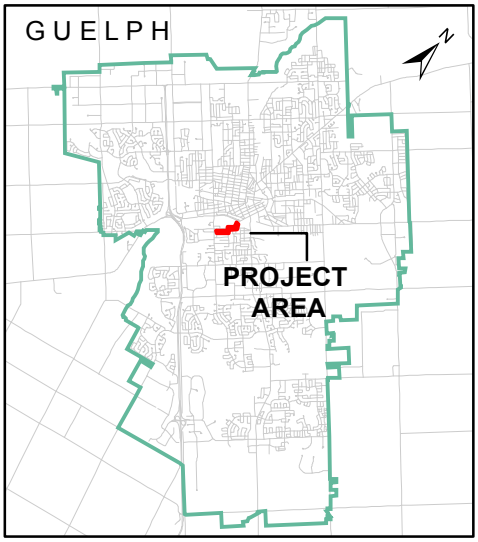
The timing of this project is influenced by the need to move supply capacity to the North end of the City of Guelph and the need to supply development on Silvercreek Parkway North. Load forecasting has demonstrated that a need for additional supply in the North end is required and the 5M53 project is part of a program that allows the supply to be shifted North without upgrading the Campbell Transformer Station. This project must be completed in 2016 to allow development on Silvercreek Parkway North to be connected without negatively impacting system operation. The timing of this project is also constrained by the need to complete projects along Wellington Road West and Edinburgh Road North prior to starting construction, due to competing feeder demands and their part in the overall reconstruction program. If this project is deferred to 2017, there is a risk of exceeding the practical load limit at Campbell Transformer Station. Forecasts have determined that the loads will surpass the practical load limit at Campbell Transformer Station by 2018. The 5M53 feeder project is part of an overall program to shift load to the south and must be completed prior to 2018.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

This project has been compared to the options of "Do Nothing" and technically feasible alternative projects. The 5M53 project has the following benefits and costs relative to those projects:
- A "Do Nothing" alternative is not practical in this case because load forecasts indicate that the practical load limit at Campbell Transformer Station will be surpassed if the load shifting program is not completed. Additionally, this project works synergistically with the 5M82 feeder project by relieving the downtown area load from the 5M11 feeder which will allow it to take on back up duty to the new 5M82 feeder on Edinburgh Road North (the 5M11 feeder's primary function will be to supply the Silvercreek Parkway North area). Doing both projects together provides a greater benefit to system reliability and flexibility. This project has the added benefit of renewing the assets while relieving the capacity constraints at Campbell Transformer Station.
- The alternative to this project that was considered is the installation of a new bus-pair at Campbell Transformer Station. That bus-pair expansion solution also relieves the capacity constraints in the north-end but is does not renew the assets in this project area and does not provide the enhanced flexibility for moving loads between Campbell and Cedar Transformer Stations that the 5M53 project provides. The bus-pair solution does not address the benefit of increased capacity in the downtown area to support the City of Guelph's position on residential intensification in that part of the City.
- Other feeder routes were considered but are not as practical due to the limited corridors crossing the Speed River. The nearest practical alternate corridor would be Edinburgh Road South, but this path cannot accept additional overhead feeders beyond the 5M82 project due to congestion and the desire for route diversity.

5M53 Feeder (Cedar Street, Maple Street, Water Street and McCrae Boulevard)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

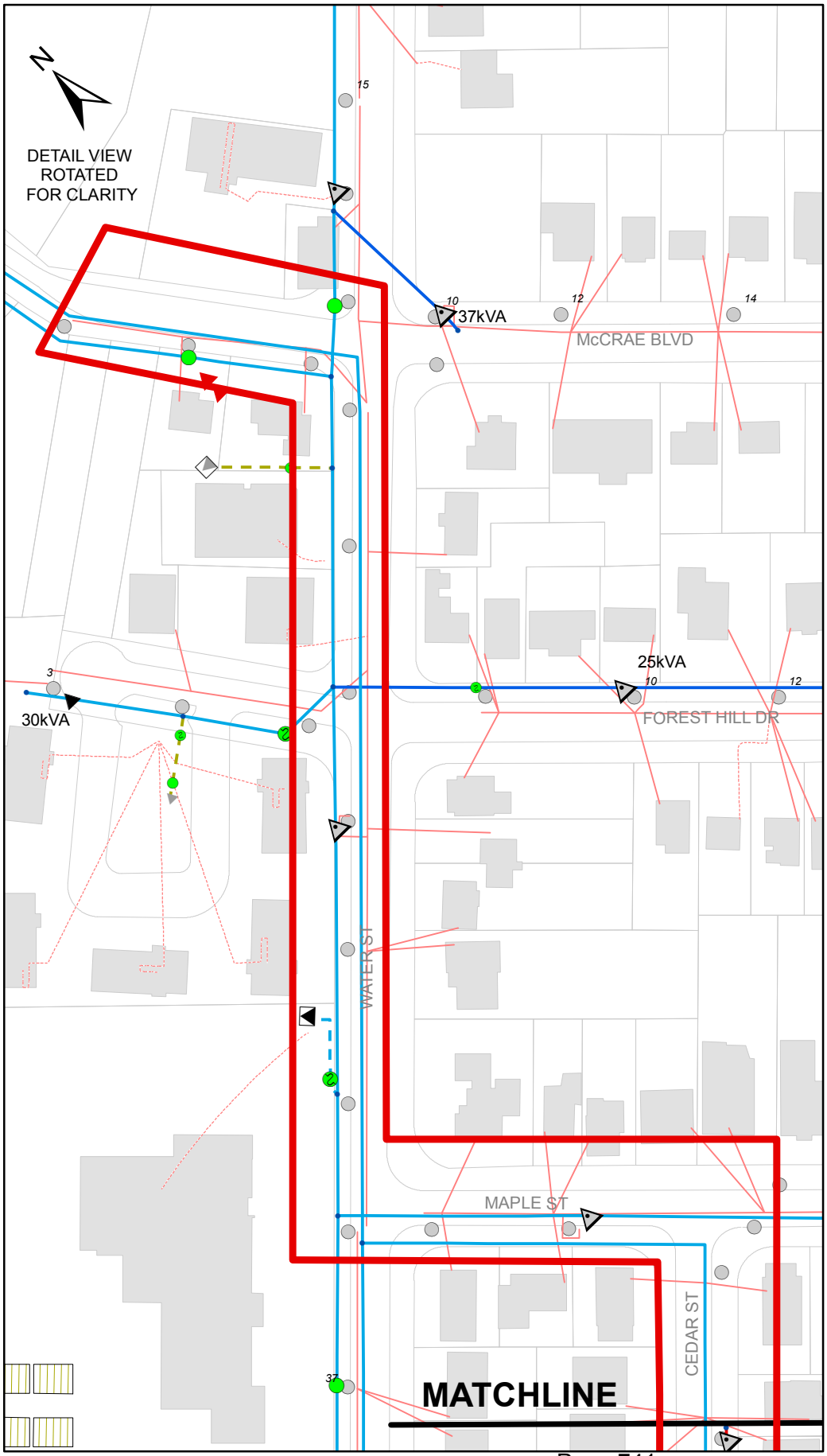
Poles

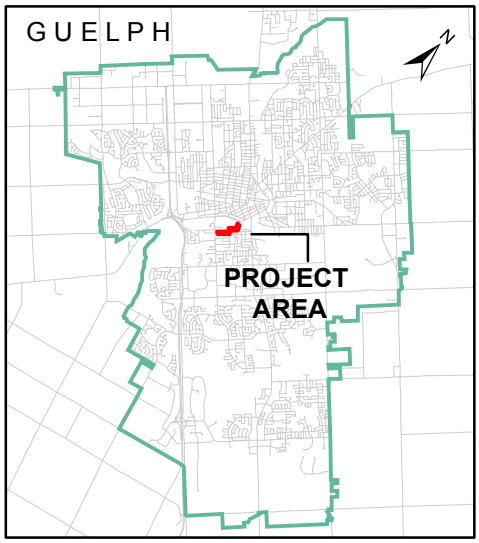
- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 2

0 37.5 75 Meters

5M53 Feeder (Cedar Street, Maple Street, Water Street and McCrae Boulevard)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 2 of 2

0 37.5 75 Meters

A. General Information						
Project /Activity	New 5M82 Feeder on the West-side of Edinburgh Road South from Cedar Transformer Station to Bristol Street					
Project Number	Unassigned					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						**$407,000**
Capital contribution						**$0**
Net Cost						**$407,000**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
						Undetermined

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments within project area: 7 (1 GS <50, 6 Res)
Customer load within project area: 41 kW
Customer attachments downstream of project area: approximately 3,007
Customer load downstream of project area: 25.71 MW

Start Date (5.4.5.2 A.3)	3-Oct-16	**In-Service Date (5.4.5.2 A.3)**		23-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
				$407,000

Project Summary

This project consists of the installation of a new feeder (5M82) on the west-side of Edinburgh Road South from Cedar Transformer Station to Bristol Street to support downstream capacity. In order to install the new feeder, 24 poles on the west-side of Edinburgh Road South within the project area will need to be replaced with taller poles that can accommodate a third feeder. At the north end of the project area, the new 5M82 feeder will connect into and take over the existing 5M54 feeder running north along Edinburgh Road North, downstream of the project. This project 5M82 will allow Edinburgh Road North to be double-circuited in the future between Bristol Street and Speedvale Avenue West, which will ultimately improve downstream capacity (the 5M64 and 5M82 feeders will take over the 36M43 feeder in the Central and West part of Guelph which will allow Cedar Transformer Station to take-over additional load from Campbell Transformer Station and will delay the need for expensive upgrades at Campbell Transformer Station).

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: This project is subject to scheduling risks with respect to external contractor and other major projects. The project has a high risk of not being completed within 2016 due to the demand on feeders in the area, which may lengthen the duration of the project. This project requires work on Edinburgh Road North, as well as projects on Wellington Road West at Gordon Street, and on Wellington Road West at Roland Avenue to be completed prior to construction beginning. The project also cannot be constructed at the same time as the 5M53 project on Cedar Street, Water Street, Maple Street and McCrae Boulevard. These projects must be completed prior to the 5M82 feeder project to provide adequate backup supply during construction of the new 5M82 feeder. The mitigation plan for these risks are bi-weekly internal project meetings to review projects underway and identify action plans to keep construction on schedule. However, the Wellington Road West project at Gordon Street project is a City of Guelph initiated project which limits the control GHESI has on project schedules. GHESI attends regular project meetings and monthly utility coordination meetings to minimize the risk to the project schedule.
In an effort to mitigate the scheduling risk, this project is planned to begin in the fourth quarter of 2016, after the completion of the 5M53 project and outside of peak load season.
Materials Risk: This project will require tall poles (65' in length) to support a third feeder. These poles may have a long lead time, which poses a risk to the project. In order to mitigate this risk, GHESI will determine pole requirements well in advance of the project and notify suppliers to ensure sufficient lead times are in accounted for.
System Constraints Risk: This project has a risk with respect to system constraints. The project runs through a major distribution corridor for the GHESI system and is located adjacent to the Cedar Transformer Station. Constantly changing system loads and configuration present a significant unknown and possible constraint to completing this project. GHESI plans to mitigate this risk by completing major feeder work in the area prior to starting this project, and completing the installation of the 5M53 feeder project before this project, to provide additional capacity support and flexibility in the area.
The consequences of this project not being completed in 2016 are significant system constraints in the central region of Guelph. A large development on Silvercreek Parkway North and residential developments on Wellington Road East and Arthur Street South will significantly increase demand on the feeders in the area and restrict the ability to obtain outages and move load. These projects are currently slated for construction within the three year horizon. Additionally, increases in demand in the north part of Guelph are increasing loads at Campbell Transformer Station. If this project is not completed in 2016, the practical load limit at Campbell Transformer Station may be reached and expensive and time intensive upgrades will be required to support the north end. By allowing load to be transferred from Campbell Transformer Station to Cedar Transformer Station, this project will delay the need for such upgrades.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

A similar project in terms of the overhead scope was completed in 2015 on the east side of Edinburgh Road South from Cedar Street to Bristol Street. The work was the replacement of an existing two-circuit pole line with taller poles to accommodate a third circuit and the installation of a new feeder. However, the east-side Edinburgh Road South project included underground work that would not be included in the 5M82 project scope. The east-side Edinburgh Road South project also included the installation of 27 poles, whereas the scope of the 5M82 project includes the replacement of 24 poles. The total cost of overhead construction on the east-side Edinburgh Road South project was $486,141. Based on this comparable project, the proposed construction cost is in-line with the historic costs considering the lower number of poles on the 5M82 project and the fact that there are fewer pole mounted transformers and customer connections on the west side of Edinburgh Road South.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Since this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is a distribution line under 2 km in length and below 50 kV, therefore Leave to Construct is not required, as per O.Reg 161/99

Attach Other project reference material i.e. Images, Drawings and or reference material

Project Map - 5M82

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Operational Efficiency". Currently the 36M43 feeder supplies Edinburgh Road North between Bristol Street and Speedvale Avenue West, as well as side streets to the West between Edinburgh Road North and Silvercreek Parkway North and the area between Edinburgh Road North and downtown Guelph. Installing the new 5M82 feeder will relieve the 36M43 feeder in central Guelph, allowing it to supply the downtown area with greater flexibility, while transferring load off of Campbell Transformer Station to Cedar Transformer Station. This will greatly reduce the number of switching operations and load shifting required to support load increases and construction in both the north-end of Guelph and Downtown Guelph. Operational costs will be decreased due to the fact that line crews will not need to be regularly dispatched to complete switching orders to move the feeder segments around when the loads increase at Campbell Transformer Station.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Customer Value". This project will improve flexibility throughout both the Downtown and north-end sections of the City of Guelph. The improved flexibility will allow for quicker isolation and restoration times. It will also segregate customers onto multiple feeders, which will reduce the number of customers impacted by faults on the system. The improved reliability and the ability to respond to customer requests for planned outages will improve customer satisfaction.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The primary related investment objective is the asset management objective "Operational Efficiency". The secondary related investment objective is the asset management objective "Customer Value".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The sources of the information used to justify the investment are pole inspection data, Asset Condition Assessment, area consequence of failure assessment, area probability of failure assessment, GIS system (asset database), reliability data from incident reports, as well as loading data, GHESI's switching schedule and expert advice from GHESI's control room. Much of the data used in these assessments originated from visual inspection and testing data collected in the field, calculations and modelling based on the collected data, and expert opinion based on system control and operation.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

GHESI prioritized this project in 2016 as part of a program to direct supply capacity towards the North half of the City of Guelph. This project is ranked at number 4 of 4 material system service projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

This project improves Operational Efficiency by separating the Downtown area from the Edinburgh Road North corridor. This will reduce the dependency each of these areas have on each other and will allow for greater flexibility in supply. The current configuration results in significant difficulty in arranging outages through the downtown portion of the city due to loading on the 36M43 feeder. Additionally the changes in configuration will split the side-streets along Edinburgh Road North onto the 5M82 and 5M64 feeders which will minimize system losses and switching operations. The improved flexibility will allow for more cost-effective operation of the system by minimizing the effort required to switch and isolate the affected feeders by reducing the number of steps in associated switching orders, and reducing the reliance on manual switches in the process.
Separating the downtown supply from the Edinburgh Rd N feeder will create a third independent North-South supply through the central part of Guelph, linking the Cedar and Campbell Transformer Stations (Silvercreek Parkway Supply Corridor, Edinburgh Road Corridor and Norfolk Corridor).

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers both within the project area and downstream will benefit from this project through the reduction of the risk of an outage and through the reduction in restoration times that the new system will provide. Customers will also benefit from the reduction in the number of customers that will be affected by faults on the affected feeders due to the separation of the downtown area and splitting the Edinburgh Road North corridor between two feeders.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This investment will reduce the frequency of outages by separating the 36M43 downtown feeder from the new 5M82 and 5M64 feeders. This will reduce the number of customers impacted by outages. While the project area has performed very reliability, the work in the project area is primarily directed to improving system capacity and must be completed for that reason. In addition to addressing the system capacity issues, this project area has had two events that resulted in outages over the past 10 years (resulting in 3,144 customer momentary interruptions) and this project will address those issues to further improve area reliability. Tree trimming and the installation of critter guard will reduce the number of contacts resulting in momentary outages, and locating the poles farther back from the curb will reduce the probability that they will be hit by vehicles.
The duration of outages will also be reduced because this project will lower the load levels on several feeders. This allows line segments to be more easily transferred, which reduces the number of operations required and therefore reduces restoration times on the affected feeders.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Project Design Alternatives:
- The use of concrete or composite poles to replace all poles in the project area would result in higher capital costs, which are not warranted in this case as this area has not been identified by the City of Guelph as requiring an improved aesthetic.
- Placing this section of line underground would present a significantly higher capital cost. While underground systems tend to provide greater reliability than overhead systems, this area has very good performance and the significant costs to covert the system to underground are not warranted.
- Like for like construction is not a practical solution for this project because a new feeder is required, which requires taller poles with different framing.
- A "Do-Nothing" strategy is not possible for this project unless expensive upgrades are completed at Campbell Transformer Station. Additionally, a "Do-Nothing" approach would result in losing the benefits associated with the project, such as improved reliability and asset renewal.

Scheduling Alternatives:
- The scheduling of this project is based on availability of resources and other project related constraints. This particular project is also constrained by the need to complete the several other projects along Wellington Road West and Edinburgh Road North first.
- The scheduling of this project is also impacted by the low composite health index in the project area. The project area has a composite health index score of 66.8% and a composite probability of failure of 99.7%, suggesting an imminent asset failure in this area. The project is scheduled with the goal to be constructed before an asset failure occurs.

Ownership Alternatives:
- Because this pole line supports GHESI equipment and supplies a large number of customers within the project area, ownership will be by GHESI and space will be dedicated to allowing up to three third-parties to connect to the pole as per GHESI's current standards. Funding for the construction and transfer of joint-use parties to the new poles will be borne solely by the joint-use parties.

Safety (5.4.5.2.B2)

This investment will improve work safety by replacing the existing poles (which range between 45' and 60' in length) with taller 65' long poles and replacing the existing framing to improve spacing on the pole for equipment and worker clearances, as well as to allow for the third circuit.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

This project does not impact Cyber-Security or privacy.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

GHESI is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed by GHESI. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. Additionally, GHESI is a member of the GridSmartCity Cooperative which allows GHESI to benefit from shared material specifications and purchasing power across a group of utilities in Ontario. GHESI is currently exploring options for participating in group purchasing. This will result in lower construction costs due to economies of scale.
Coordination with other electrical utilities is not applicable to this project because the project area is fully embedded within GHESI's service territory and does not contain and connections to other utilities.
Regional planning is not applicable to this project because there is no additional capacity being installed as part of this project.
Third party providers will benefit from GHESI's current standards which ensure that adequate working space is provided on every pole to improve worker safety. The standards also allow for each third party to have a dedicated space on the pole and adequate round clearance to meet the requirements of CSA 22.03 No.1. Third parties will be consulted with to request participation in transferring to the new poles.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

Future functionality will be allowed for in the design. GHESI's current standards provide 10'6" between the lowest phase and neutral on every pole (as per USF standards). This allows equipment to be easily added to the pole at a later date. This pole line will not be built to accommodate a fourth circuit to because GHESI's policy is to limit the number of feeders on a pole to three in order to minimize the impact of asset failures and to minimize the difficulty in isolating the pole line.

Economic Development (5.4.5.2.B5) (where applicable)

The reconstruction of this pole line upgrade allows for potential economic development through load intensification in the Downtown area.

Environmental Benefits (5.4.5.2.B6) (where applicable)

The redesign of this project area will include an assessment of existing transformer loading and where necessary, transformers will be replaced with an appropriately sized unit to reduce distribution losses. All transformers will continue to use Envirotemp FR3 oil, which is produced from renewed vegetable oils.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

This project is part of a program designed to move additional supply capacity to the North half of the City of Guelph. Because transformer stations in the south-end of Guelph have available capacity, the reconfiguration and reconstruction of pole lines is generally a more cost-effective way to move supply than transformer station upgrade work. GHESI's estimates of the costs to perform upgrades at Campbell Transformer Station in order to alleviate loading concerns are more expensive than the combined estimated costs of the proposed system service projects needed to achieve the same load reduction. These projects have the additional benefit of replacing ageing assets on Edinburgh Road South that are near the end of their useful life. By combining necessary reconstruction work with upgrade and reconfiguration work, the overall cost of the projects are reduced while the benefits are increased. Customers will also benefit from feeder level improvements that will improve reliability and system flexibility, reducing outage frequency and restoration times.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

Regional electricity infrastructure requirements do not apply to this project.

Advanced technology (5.4.5.2 SS - C3)

The feeder being installed as part of this project is designed to be an express feeder until it reaches Bristol Street. There is no need for advanced technology such as SCADAmate switches as the feeder is designed to be static through the project area and not to have interconnections.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project integrates reliability, efficiency and safety benefits. Reliability will be improved through the removal of the existing assets which are approaching their end of useful life and have a low health index score and relocating poles away from the roadway. The reduction of loading levels on the adjacent feeders will allow for the more efficient operation of the distribution system due to lower line losses and easier line switching. This project also has safety benefits from the increase in conductor spacing which will allow for safer working conditions in proximity to energized equipment.

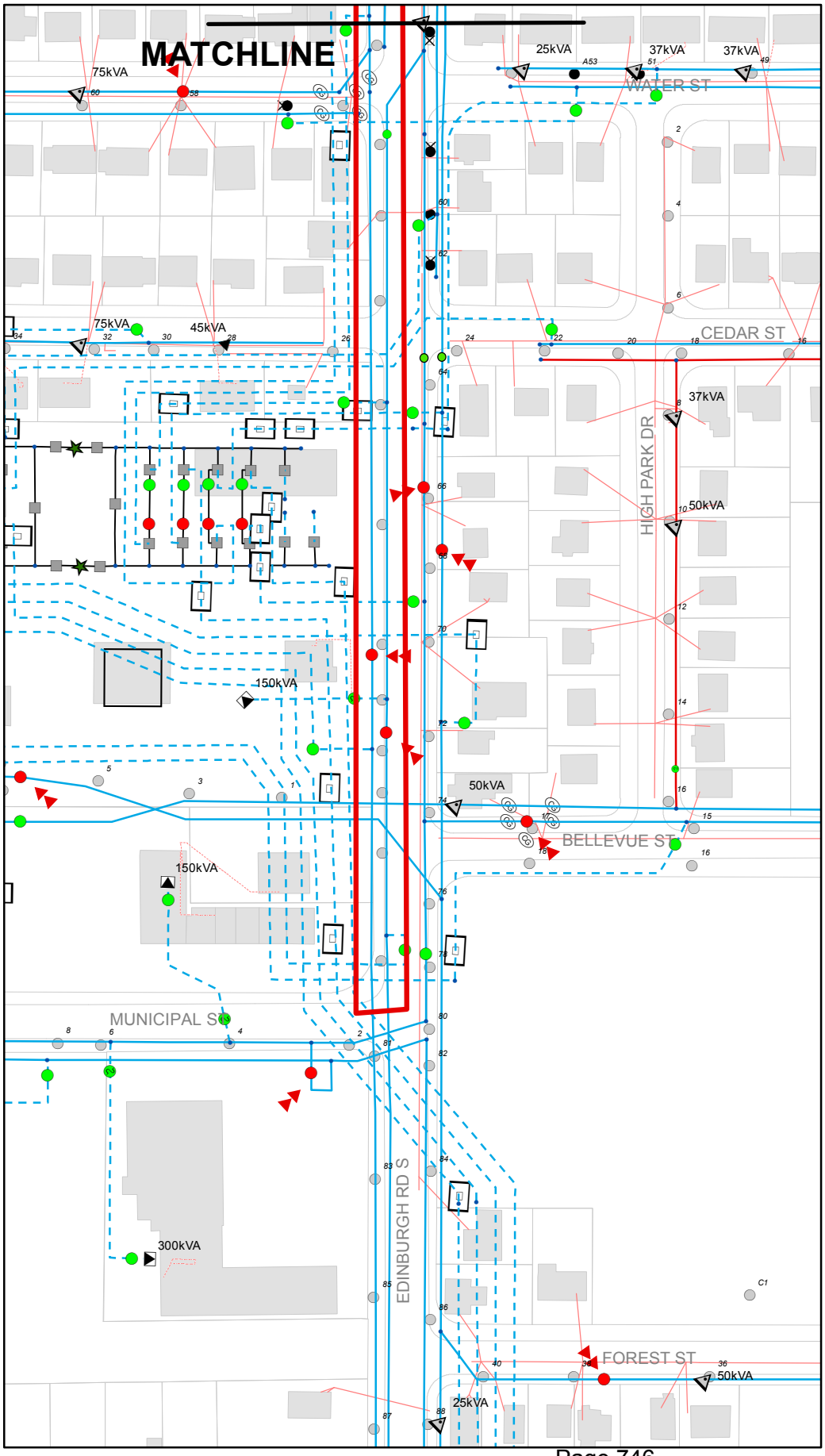
Timing & Priority of Project (5.4.5.2 SS - C5)

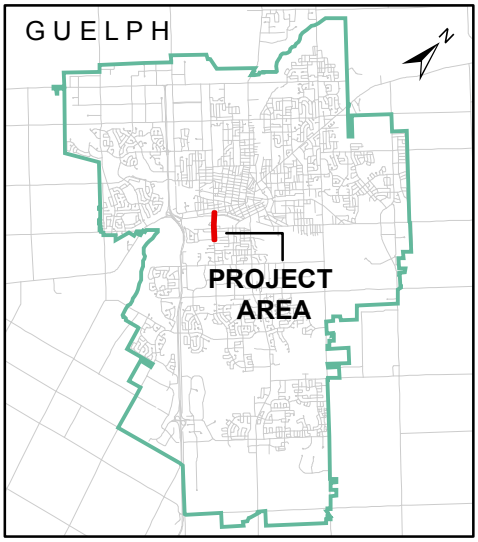
The timing of this project is influenced by the need to move supply capacity to the North end of the City of Guelph and the need to improve supply flexibility in Downtown Guelph. Load forecasting has demonstrated that a need for additional supply in the North end is required and the 5M82 project is part of a program that allows the supply to be shifted North without upgrading the Campbell Transformer Station. This project must be completed in 2016 due to the low health index scores of the assets in the project area and the immediate need to alleviate loading at Campbell Transformer Station in order to defer expensive transformer station upgrades (in favour of lower cost pole line based solutions). The timing of this project is also constrained by the need to complete projects along Wellington Road West, Edinburgh Road North and the 5M53 project prior to starting construction, due to competing feeder demands and their part in the overall reconstruction program. If this project is deferred to 2017, there is a risk of exceeding the practical load limit at Campbell Transformer Station. Forecasts have determined that the loads will surpass the practical load limit at Campbell Transformer Station by 2018. The 5M82 feeder project is part of an overall program to shift load to the south and must be completed prior to 2018.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

This project has been compared to the options of "Do Nothing" and technically feasible alternative projects. The 5M82 project has the following benefits and costs relative to those projects:
- A "Do Nothing" alternative is not practical in this case because load forecasts indicate that the practical load limit at Campbell Transformer Station will be surpassed if the load shifting program is not completed. Additionally, the poles on the west side of Edinburgh Road South have low health index scores and will soon need to be replaced from a System Renewal perspective. This project has the added benefit of renewing the assets while relieving the capacity constraints at Campbell Transformer Station.
- The alternative to this project that was considered is the installation of a new bus-pair at Campbell Transformer Station. That bus-pair expansion solution also relieves the capacity constraints in the north-end but is does not renew the assets in this project area and does not provide the enhanced flexibility for moving loads between Campbell and Cedar Transformer Stations that the 5M82 project provides.
- Other feeder routes were considered but are not as practical due to the limited corridors crossing the Speed River.

5M82 - Edinburgh Road South (west side from Cedar Transformer Station to Bristol Street)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

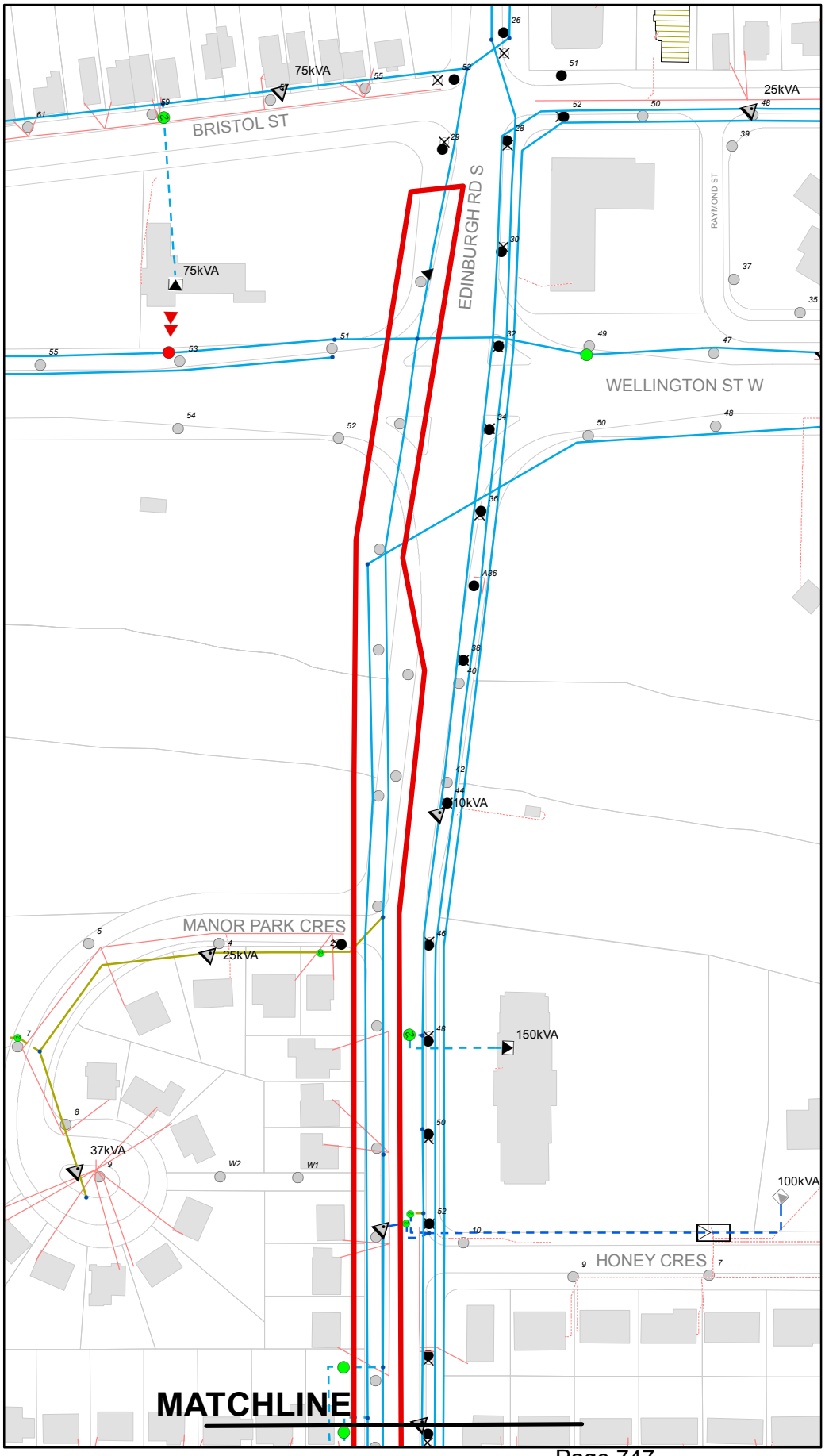
Poles

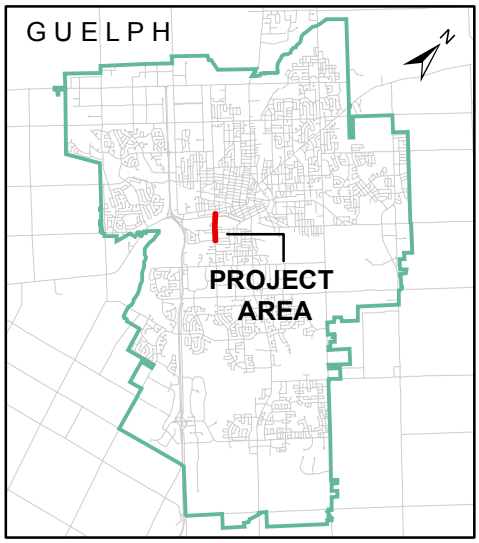
- EXISTING
- NEW
- TO BE REMOVED

Page 1 of 2

0 50 100 Meters

5M82 - Edinburgh Road South (west side from Cedar Transformer Station to Bristol Street)





LEGEND

Transformers

- CUSTOMER OWNED, 1, 3
- PAD MOUNT D F/ L F, 1
- PAD MOUNT D F/L F, 3
- POLE MOUNT, 1
- POLE MOUNT, 3
- POLE TRAM E, 1
- POLE TRAN R, 1
- POLE TRAN, 1
- SUBMERSIBLE, 1
- TRANSCLOSURE, 3
- VAULT D F/ L F, 1
- VAULT D F/ L F, 3
- VAULT, 1
- VAULT,3
- OPEN SYMBOL

Switches

- BLADE, False
- BLADE, True
- FUSED, False
- FUSED, True
- VACUUM INTERRUPTER, False
- VACUUM INTERRUPTER, True
- CAPACITOR
- MANHOLE
- PMH
- VAULT
- SWITCH CABINET

OH Primary

- B
- R
- RYB
- Y

UG Primary

- B
- R
- RYB
- Y

OH Secondary

- SECONDARY

UG Secondary

- SECONDARY

Poles

- EXISTING
- NEW
- TO BE REMOVED

Page 2 of 2

0 50 100 Meters

A. General Information						
Project /Activity	SCADA Infrastructure					
Project Number	CSC					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	**$234,219**	**$248,002**	**$167,530**	**$174,290**	**$218,360**	**$224,911**
Capital contribution	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Cost	**$234,219**	**$248,002**	**$167,530**	**$174,290**	**$218,360**	**$224,911**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Customer Attachments and Load (5.4.5.2 A.2)

Specific projects are not contemplated at this time. In a typical year, GHESI will install software and hardware to support the SCADA and two-way radio system as needed. The projects in this program do not directly affect specific customers, however they impact GHESI's ability to support its SCADA system, which indirectly impacts all customers connected to GHESI's distribution system from 1 or 2kVA to 10's of MW.

Start Date (5.4.5.2 A.3)	01-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$56,228	$56,228	$56,228	$56,228

Project Summary

This program includes projects related to upgrading software and hardware for servers, workstations, monitors, UPS, networking and related equipment, upgrading and expanding NAN (local mesh) and WAN (Wide area network) communications used for remotely operable switch controllers/RTUs, embedded generation monitoring, wholesale metering real-time load monitoring, upgrade or expansion of two-way master radio, and upgrade of remotely operable switch controllers/RTUs. Detailed planning is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

SCADA infrastructure projects are determined based on operational needs in response to changes in the distribution system. As system loads grow and change and advanced technology such as distributed generation is integrated into the distribution system, the need for the use of SCADA technology to provide awareness and control of the distribution system increases. SCADA infrastructure investments are identified based on known SCADA-mate projects and changes to the distribution system.

In order to mitigate the risk of uncertainty with respect to project needs, GHESI evaluates its SCADA system on an annual basis to determine what improvements to SCADA infrastructure may be required to allow optimal operational efficiency. Delaying investments in this program could result in the inability to expand the SCADA network and could impact the ability to maintain system reliability or reduce O&M costs through the installation of SCADA-mate installations.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

SCADA infrastructure upgrade projects/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

SCADA infrastructure upgrades installed in accordance with GHESI's construction standards.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Operational Efficiency". SCADA infrastructure supports SCADA-mate and remotely operated switches, remote line sensors, intelligent fault current indicators, embedded generation load monitoring, revenue metering point load monitoring and two-way radio communications. The various SCADA technologies enabled by GHESI's SCADA infrastructure allow for efficient system operation by allowing system control operators to communicate with line staff and to monitor and control the distribution system, including responding to line loading and faults. SCADA infrastructure also allows the time and costs related to dispatching line crews to make changes to the distribution system to be reduced by allowing remotely operated switches to be controlled from the service centre and allowing system control operators to efficiently dispatch line crews as needed utilizing the two-way radio and GIS system. Additionally, SCADA infrastructure allow insight into line current flows, which enables system control operators to effectively reconfigure the system to a more efficient configuration, while respecting loading limits of equipment and regulatory operational limits of the distribution system. By upgrading SCADA infrastructure, GHESI can greatly improve the operational efficiency of its distribution system.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Reliability". SCADA infrastructure allows for the quick rerouting of line flows through remote operation of the switches. Additionally, SCADA systems have supervisory functions that alert system control operators to fault conditions downstream. The combination of these technologies allows for quicker restoration times, which reduced the duration of outages on the distribution system.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective of this program is to ensure reliable service to customers through quick system restoration and meet existing and future flexibility needs on the distribution system, in order to efficiently operate the system. The primary investment objective is the asset management objective "Operational Efficiency" and the secondary investment objective is the asset management objective "Reliability".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

This program was planned incorporating elements of GHESI's existing SCADA system and analysis of its efficiency through expert opinion and historical investment levels.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This program is of subsequent priority relative to other system service material investments as it does not currently affect GHESI's ability to supply electricity to its customers. However, this program supports operational efficiency and reliability improvements on GHESI's distribution system, while supporting the integration of advanced technology which provides good value to GHESI's customers and it is therefore an important investment in securing the future of GHESI's service quality and efficiency. Project planning will be coordinated with other projects/programs of the same priority level.
Timing of the projects within the program are spaced throughout the year and coordinated with the required in-service date of SCADA infrastructure upgrades (which are a function of the devices the upgrades support). The timing of the projects is such that it enables GHESI to install the required SCADA infrastructure upgrades each year with the goal of continual improvement to system operational efficiency and reliability.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The completion of this program will have a positive effect on system operation efficiency and cost-effectiveness. SCADA infrastructure upgrades will enable system switching to be carried out much faster. SCADA infrastructure will also allow system control operators to have insight into real-time line loading and to make decisions to reconfigure the system into a more efficient state. This reduces overall system losses, which improves the operational efficiency of the distribution system. SCADA infrastructure upgrades also provide supervisory information to the system control operators, which greatly reduces the amount of troubleshooting time required for fault locating. GHESI's SCADA infrastructure also supports a two-way radio system that is integrated into GHESI's GIS system, which supports operational efficiency by allowing system control operators to efficiently dispatch line crews when required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from reduced restoration times and a lower probability of line loading related outages occurring.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Investment in SCADA infrastructure will reduce the duration of outages on the distribution system by allowing system control operators insight into fault locations and allowing them to quickly make and implement decisions regarding line segment transfers. The ability to remotely operate the switches greatly decreases the time required to perform switching operations, and will decrease restoration times, thereby decreasing the duration of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Designs are planned in accordance with GHESI's analysis of its SCADA infrastructure and the expert opinion of system control operators. Scheduling of the work is based on available resources, past investment levels and the desire to enable advanced technology on the distribution system. Because the SCADA systems operated by GHESI's system control operators solely for the purposes of the GHESI distribution system, ownership of the equipment will be by GHESI. Where funding opportunities exist due to shared benefits with specific customers or third-parties, alternate arrangements for funding will be made. In general, where options are available with respect to design, scheduling, funding or ownership, the most effective overall alternative will be selected.

Safety (5.4.5.2.B2)

This program has the benefit of allowing system control operators insight into system conditions, which allows for action to mitigate safety concerns due to system loading levels. Informed decisions can be made regarding line switching to avoid overload conditions. Additionally, the use of SCADA infrastructure to control remotely operated switches benefits employee safety because switches can be operated from a distance, minimizing employee exposure to flash-over or arcing that may occur if the switch being operated is defective, or if line current exceeds the interrupting capability of the switch. Finally, investment in SCADA infrastructure allows for two-way communication between system control operators and line crews. This is a critical item with respect to employee safety since both teams work in tandem when administering the work protection code and the radio system allows insight into crew locations in case of emergencies.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

GHESI's SCADA infrastructure utilizes a private network with firewall security and standard communications protocols utilized by by most utilities with SCADA systems. GHESI conducts an annual information technology security audit, which includes an audit of the cyber-security of the SCADA system.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

Modifications to SCADA infrastructure do not impact inter-utility coordination or regional planning activities. Coordination with customers is required whenever a modification might impact their service, or where access to customer premises is required.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

SCADA systems are a technologically advanced feature of distribution systems. GHESI's SCADA infrastructure allows insight into line loading, advanced fault detection capabilities and the possibility of self-healing grids. Upgrades to the SCADA communication network enables future additions of equipment using similar communications technology and supports GHESI's Advanced Metering Infrastructure (**"AMI"**) system. GHESI selects its preferred SCADA technology based on robustness, features, expandability and the ability to seamlessly integrate into the existing network.

Economic Development (5.4.5.2.B5) (where applicable)

The installation of SCADA infrastructure does not directly impact economic development, however some installations have the added indirect benefit of supporting economic development through quicker restoration times and, in some cases, automatic source transfer. These benefits can lower the operational costs of large industrial customers connected downstream of the switch by improving service reliability, which may impact further development of their business activities in the area.

Environmental Benefits (5.4.5.2.B6) (where applicable)

GHESI's SCADA infrastructure allows switches to be operated from GHESI's service centre. This reduces crew dispatching and travel which has a minor environmental benefit.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

GHESI does not have the ability to directly measure the added benefit of upgrades to its SCADA infrastructure. Because the SCADA system supports many diverse business functions, it is difficult to express an exact time and labour savings. However, the installation of SCADA infrastructure does reduce the amount of time and labour required to operate switches and the effort required in determining the feasibility of specific system operations (working within both equipment constraints and regulatory operational requirements). Additionally, the SCADA infrastructure can reduce the amount of time spent locating faults and restoring system service compared to manual efforts. These benefits affect system operational efficiency and are ongoing, therefore GHESI feels that the benefits of improving system operational efficiency are greater than the costs of the SCADA infrastructure upgrades.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

Regional electricity infrastructure requirements do not apply to this program.

Advanced technology (5.4.5.2 SS - C3)

The installation and upgrade of SCADA infrastructure incorporates advanced technology into GHESI's distribution system. SCADA infrastructure switches allow for system supervisory awareness, including alarm reporting, real-time loading data, fault locating technology and, in some cases, smart self-healing grids. Standards relating to interoperability and cybersecurity do not specifically impact this program, over and above the requirements already in existence for GHESI's SCADA system.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project will enhance system reliability, efficiency and safety of the GHESI system when compared to the "do nothing" option. Other alternatives provide less functionality and do not provide the same benefits to system reliability and operational efficiency.

Reliability: SCADA infrastructure allows for the quick rerouting of line flows through remote operation of the switches. Additionally, SCADA systems have supervisory functions that alert system control operators to fault conditions downstream. The combination of these technologies allows for quicker restoration times, which reduced the duration of outages on the distribution system.

Efficiency: The various SCADA technologies enabled by GHESI's SCADA infrastructure allow for efficient system operation by allowing system control operators to communicate with line staff and to monitor and control the distribution system, including responding to line loading and faults. SCADA infrastructure also allows the time and costs related to dispatching line crews to make changes to the distribution system to be reduced by allowing remotely operated switches to be controlled from the service centre and allowing system control operators to efficiently dispatch line crews as needed utilizing the two-way radio and GIS system.

Safety: This program has the benefit of allowing system control operators insight into system conditions, which allows for action to mitigate safety concerns due to system loading levels. Informed decisions can be made regarding line switching to avoid overload conditions. Additionally, the use of SCADA infrastructure to control remotely operated switches benefits employee safety because switches can be operated from a distance, minimizing employee exposure to flash-over or arcing that may occur if the switch being operated is defective, or if line current exceeds the interrupting capability of the switch. Finally, investment in SCADA infrastructure allows for two-way communication between system control operators and line crews. This is a critical item with respect to employee safety since both teams work in tandem when administering the work protection code and the radio system allows insight into crew locations in case of emergencies.

Timing & Priority of Project (5.4.5.2 SS - C5)

This is an annual program. Timing of the projects within the program are spaced throughout the year and coordinated with the required in-service date of SCADA infrastructure upgrades (which are a function of the devices the upgrades support). The timing of the projects is such that it enables GHESI to install the required SCADA infrastructure upgrades each year with the goal of continual improvement to system operational efficiency and reliability.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

This program has been compared to the options of "Do Nothing" and technically feasible alternative projects. The SCADA infrastructure program has the following benefits and costs relative to those options:
- A "Do Nothing" alternative would result in limiting GHESI's ability to install SCADA-mate switches, remote line sensors, and load monitoring devices. The addition of field devices necessitates that the master system be capable of supporting them in order for them to be functional. This alternative does not benefit system reliability or operational efficiency and does not support the enabling of advanced technology on the distribution system.
- Partial completion of the program is essentially the same as the "Do Nothing" approach being applied to specific devices. For example, if GHESI installs a SCADA-mate switch in a location that is outside the current reach of the SCADA network, but does not install the Remote Terminal Unit ("RTU") for the switch or does not install the necessary networking equipment to expand the network to reach the switch, then the SCADA-mate switch will not be able to integrate into the SCADA system, and the operational efficiency and reliability benefits associated with the switch will be lost.

A. General Information						
Project /Activity	SCADA / Remotely Operated Switches (CSW)					
Project Number	CSW					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)	**$119,131**	**$78,394**	**$241,920**	**$289,419**	**$248,784**	**$256,248**
Capital contribution	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Cost	**$119,131**	**$78,394**	**$241,920**	**$289,419**	**$248,784**	**$256,248**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Customer Attachments and Load (5.4.5.2 A.2)

Specific projects are not contemplated at this time. In a typical year, GHESI will install approximately 10 SCADA-mate switches as specific projects. Switches are installed as disconnect switches in series with primary lines of feeders, or as tie-switches connected between two feeders, and therefore typically each affect 100's to 1000's of customers from 1 or 2kVA to 10's of MW.

Start Date (5.4.5.2 A.3)	01-Jan-16	**In-Service Date (5.4.5.2 A.3)**		31-Dec-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**
	$64,062	$64,062	$64,062	$64,062

Project Summary

This is a program consisting of individual projects and investments related to the installation of SCADA-mate remotely operated switches. Work within this section covers the replacement of existing manually operated switches with fully automated switches, as well as the installation of SCADA-mate switches in new locations. GHESI's system control operators and Engineering department identify locations where additional insight into line flows and fault locating would be beneficial to the efficient operation of the system, as well as switches that have historically been operated often, where the use of a remotely operated switch would significantly reduce operations and maintenance costs associated with switching activities. The overall capital requirements for this project is an estimate based on past spending levels, system line loading information and switch operation records. Detailed planning is not available for this program.

Risk Identification & Mitigation (5.4.5.2 A.4)

SCADA-mate switch installation projects are determined based on operational needs in response to changes in line loading and feeder configuration, or experience with high number of operations at switches. Additionally, as system loads grow and change, lines are reconfigured to optimize the efficient operation of the distribution system and to maximize system reliability and flexibility. In order to mitigate the uncertainty associated with system loading and flexibility needs, GHESI tracks switch operation counts, typical line loads and load factors and historical switching orders and determines the optimal rate of SCADA-mate installations and optimal locations for switches. Delaying investments in this program could result in delays to reduction in O&M costs that would results from SCADA-mate installations. Additionally, in cases where a switch is required to permit proper system operation, delaying the installation of SCADA-mate switches will require the installation of less efficient manual switches.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

SCADA-mate and remotely operated switch installation projects/activities do not have a direct comparator other than previous year's expenditures as indicated in the summary table above.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

There are no REG investments associated with this work.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Leave to Construct approval is not required.

Attach Other project reference material i.e. Images, Drawings and or reference material

SCADA-mate switches are installed in accordance with GHESI's construction standards. Construction details vary widely within that standard. SCADA-mate replacement forecasts are informed by GHESI's switch operation database and expert opinions of the system control operators.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is the asset management objective "Operational Efficiency". Disconnect and tie switches are used on GHESI's distribution system to control line loading by moving line segments between feeders, to restore power by rerouting line flows after an interruption has occurred, and to isolate work zones to allow for the safe construction of distribution projects. Due to the nature and configuration of the system, some switches are operated more frequently than others. SCADA-mate and remotely operable switches benefit efficient system operation by allowing switches to be operated from the service centre through a SCADA system. This reduces time and costs related to dispatching line crews to the affected switches and manually operating the switches. Additionally, SCADA-mate switches allow insight into line current flows, which enables system control operators to effectively reconfigure the system to a more efficient configuration, while respecting loading limits of equipment and regulatory operational limits of the distribution system. Finally, SCADA-mate systems allow for advanced technology such as fault locating through supervisory functions and automated "self-healing" technology, such as smart source transfer systems. By installing SCADA-mate switches in targeted locations, GHESI can greatly improve the operational efficiency of its distribution system.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

The secondary driver for this project is the asset management objective "Reliability". SCADA-mate systems allow for the quick rerouting of line flows through remote operation of the switches. Additionally, SCADA-mate systems have supervisory functions that alert system control operators to fault conditions downstream. The combination of these technologies allows for quicker restoration times, which reduced the duration of outages on the distribution system.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The objective of this program is to ensure reliable service to customers through quick system restoration and meet existing and future flexibility needs on the distribution system, in order to efficiently operate the system. The primary investment objective is the asset management objective "Operational Efficiency" and the secondary investment objective is the asset management objective "Reliability".

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

This program was planned incorporating elements of GHESI's line loading database, switch operation database, existing SCADA system and analysis of its efficiency through expert opinion and historical investment levels.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This program is of subsequent priority relative to other system service material investments as it does not currently affect GHESI's ability to supply electricity to its customers. However, this program supports operational efficiency and reliability improvements on GHESI's distribution system, while supporting the integration of advanced technology which provides good value to GHESI's customers and it is therefore an important investment in securing the future of GHESI's service quality and efficiency. Project planning will be coordinated with other projects/programs of the same priority level.
Timing of the projects within the program are spaced throughout the year and coordinated with the ability to obtain outages in order to install SCADA-mate switches, as well as resource availability. The timing of the projects is such that it enables GHESI to install the target number of SCADA-mate switches each year with the goal of continual improvement to system operational efficiency and reliability.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The completion of this program will have a positive effect on system operation efficiency and cost-effectiveness. SCADA-mate and remotely operated switches will enable system switching to be carried out much faster and, in most cases, without the need to physically dispatch crews to the switch location. This greatly reduces the operations costs per switching event. Additionally, SCADA-mate switches allow system control operators to have insight into real-time line loading and to make decisions to reconfigure the system into a more efficient state. This reduces overall system losses, which improves the operational efficiency of the distribution system. SCADA-mate switches also provide supervisory information to the system control operators, which greatly reduces the amount of troubleshooting time required for fault locating.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customers will benefit from reduced restoration times and a lower probability of line loading related outages occurring.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Investment in the SCADA-mate and remotely operated switches program will reduce the duration of outages on the distribution system. SCADA-mate switches allow system control operators insight into fault locations and allow them to quickly make and implement decisions regarding line segment transfers. The ability to remotely operate the switches greatly decreases the time required to perform switching operations, and will decrease restoration times, thereby decreasing the duration of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Designs are planned in accordance with GHESI's analysis of past switching orders, switch operation database and line loading database, as well as the expert opinion of system control operators. Scheduling of the work is based on available resources, past investment levels and the desire to enable advanced technology on the distribution system. Because SCADA-mate switches are installed on the primary voltage lines of GHESI's distribution system, and operated by GHESI's system control operators and line staff, ownership of the equipment will be by GHESI. Where funding opportunities exist due to shared benefits with specific customers or third-parties, alternate arrangements for funding will be made. In general, where options are available with respect to design, scheduling, funding or ownership, the most effective overall alternative will be selected.

Safety (5.4.5.2.B2)

This program has the benefit of mitigating safety concerns due to system loading levels. Because SCADA-mate switches allow system control operators insight into real-time line loading, informed decisions can be made regarding line switching to avoid overload conditions. Additionally, the use of remotely operated switches benefits employee safety because switches can be operated from a distance, minimizing employee exposure to flash-over or arcing that may occur if the switch being operated is defective, or if line current exceeds the interrupting capability of the switch.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

SCADA-mate switches are installed on a private network utilizing firewall security and standard utility protocols (DNP-3). GHESI conducts an annual information technology security audit, which includes an audit of the cyber-security of the SCADA system.

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

Switch replacements at this level do not impact inter-utility coordination or regional planning activities. Coordination with customers is part of every project if the installation will require an interruption to service.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

SCADA systems are a technologically advanced feature of distribution systems. The installation of SCADA-Mate switches on GHESI's distribution system allows insight into line loading, advanced fault detection capabilities and the possibility of self-healing grids. The installation of SCADA-Mate switches also expands the SCADA communication network, which enables future additions of equipment using similar communications technology. GHESI selects its preferred SCADA technology based on robustness, features, expandability and the ability to seamlessly integrate into the existing network. Future line load increases and system flexibility needs are assessed when determining the optimal location and configuration of each switch.

Economic Development (5.4.5.2.B5) (where applicable)

The installation of SCADA-mate and remotely operated switches does not directly impact economic development, however some installations have the added indirect benefit of supporting economic development through quicker restoration times and, in some cases, automatic source transfer. These benefits can lower the operational costs of large industrial customers connected downstream of the switch by improving service reliability, which may impact further development of their business activities in the area.

Environmental Benefits (5.4.5.2.B6) (where applicable)

SCADA-mate and remotely operated switches allow switches to be operated from GHESI's service centre. This reduces crew dispatching and travel which has a minor environmental benefit.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

GHESI does not have the ability to directly measure the added benefit of remotely operating switches relative to their cost impact. Because switches are located throughout the distribution system at various distances from GHESI's service centre and from crew locations, it is difficult to express an exact time and labour savings. However, the installation of SCADA-mate and remotely operated switches does (in all cases) reduce the amount of time and labour required to operate switches. Additionally, SCADA-mate switches can reduce the amount of time locating faults and restoring system service compared to manual efforts. These benefits affect system operational efficiency and are ongoing, therefore GHESI feels that over the life-cycle of the switches being installed, the benefits of improving system operational efficiency are greater than the costs of installing the switches.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

Regional electricity infrastructure requirements do not apply to this program.

Advanced technology (5.4.5.2 SS - C3)

The installation of SCADA-mate switches incorporates advanced technology into GHESI's distribution system. SCADA-mate switches allow for system supervisory awareness, including alarm reporting, real-time loading data, fault locating technology and, in some cases, smart self-healing grids. Standards relating to interoperability and cybersecurity do not specifically impact this program, over and above the requirements already in existence for GHESI's SCADA system.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project will enhance system reliability, efficiency and safety of the GHESI system when compared to the "do nothing" option. Other alternatives provide less functionality and do not provide the same benefits to system reliability and operational efficiency.

Reliability: SCADA switches allow for the quick rerouting of line flows through remote operation of the switches. Additionally, SCADA switches have supervisory functions that alert system control operators to fault conditions downstream. The combination of these technologies allows for quicker restoration times, which reduced the duration of outages on the distribution system.

Efficiency: The various SCADA technologies enabled by GHESI's SCADA switches allow for efficient system operation by allowing system control operators to monitor and control the distribution system, including responding to line loading and faults. SCADA switches also allows the time and costs related to dispatching line crews to make changes to the distribution system to be reduced by allowing remotely operated switches to be controlled from the service centre .

Safety: This program has the benefit of allowing system control operators insight into system conditions, which allows for action to mitigate safety concerns due to system loading levels. Informed decisions can be made regarding line switching to avoid overload conditions. Additionally, the use of SCADA switches benefits employee safety because switches can be operated from a distance, minimizing employee exposure to flash-over or arcing that may occur if the switch being operated is defective, or if line current exceeds the interrupting capability of the switch.

Timing & Priority of Project (5.4.5.2 SS - C5)

This is an annual program. Timing of the projects within the program are spaced throughout the year and coordinated with the ability to obtain outages in order to install SCADA-mate switches, as well as resource availability. The timing of the projects is such that it enables GHESI to install the target number of SCADA-mate switches each year with the goal of continual improvement to system operational efficiency and reliability.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

This program has been compared to the options of "Do Nothing" and technically feasible alternative projects. The SCADA-mate and remotely operated switch program has the following benefits and costs relative to those options:
- A "Do Nothing" alternative would result in leaving frequently operated manual switches as they are and not installing switches where additional system flexibility is required. This alternative does not benefit system reliability or operational efficiency and in the case of not improving system flexibility, may pose an additional cost to system operational efficiency, as loads change on the system.
- The alternative to this project that was considered is the installation of manual switches where needed to benefit system flexibility. This option has a lower initial capital cost but would require additional travel and operational time with each switch operation. Additionally, manual load-interrupting switches have exposed swinging blade systems which require additional maintenance, due to alignment and animal contact issues, above and beyond the requirements of SCADA-mate systems (which utilize encapsulated current shunting and interrupting switches). Manual switches would not have the benefit of enabling advanced technology or system awareness and may have an overall higher life-cycle cost, depending on frequency of operation.

A. General Information						
Project /Activity	Arlen MTS Fault Current Reduction Project					
Project Number	CTS/CDS					
Investment Category	System Service					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)					**$800,000**	**$150,000**
Capital contribution					**$0**	**$0**
Net Cost					**$800,000**	**$150,000**
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**

Customer Attachments and Load (5.4.5.2 A.2)

Arlen MTS has a planning load of approximately 60MVA, and will support up to 4MVA of Energy Storage and 10MVA of Renewables Generation (Solar) in future FIT projects.
The following customer and load numbers are currently attached to Arlen MTS, however these numbers fluctuate as feeders are moved between Arlen MTS and Hanlon TS. Additionally, several feeders are planned to be installed within a three year planning horizon to move load to Arlen MTS.
Customer attachments currently attached to Arlen MTS: 368 (30 GS <50, 17 GS >50, 321 Res)
Customer load currently attached to Arlen MTS: 19.98 MW

Start Date (5.4.5.2 A.3)	10-Feb-15		**In-Service Date (5.4.5.2 A.3)**			29-Apr-16
Expenditure Timing for the Test Year	**2016 Q1**	**2016 Q2**	**2016 Q3**	**2016 Q4**		
	$150,000					

Project Summary

This project is needed to reduce fault levels at Arlen Municipal Transformer Station **("MTS")** based on future changes to the transmission system in the region of Guelph due to a Hydro One Project known as the Guelph-Area Transmission Refurbishment Program **("GATR")** (The GATR Program will upgrade the supply to and transformation at the Cedar TS from 115kV to 230kV to improve the adequacy and reliability of supply in the Kitchener-Waterloo-Cambridge-Guelph **("KWCG")** area). A study on station fault levels and feasible solutions ("Arlen MTS Fault Current Reduction Study") was completed with the following conclusions: While the station is currently operating within the short-circuit ratings defined in the Ontario Transmission System Code **("TSC"),** acceptable short-circuit ratings will be exceeded when system changes are completed. Installing a current limiting reactor (**"CLR"**) at the Arlen MTS bus tie has been selected as the preferred and most feasible solution to the increased fault levels.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risks: An installation project such as this is exposed to standard project risks relating to schedule, cost control and quality. GHESI will use best practice project management techniques to ensure the project is delivered successfully, and on time and on budget. There are limited technical risks to the project as reactor technology is well understood in the industry. A deferral in the GATR project would result in a potential delay in the need for this project since the end date scheduling constraint for this project is the completion date of the GATR project. The GATR project is currently under construction which mitigated the risk of a complete cancellation. However, uncertainty still exists with respect to the end date of the GATR project and its impact on the end date of the Arlen MTS CLR project. In order to mitigate this risk, GHESI will meet periodically with Hydro One staff to review the projected end date of the GATR project and revise the Arlen MTS CLR project schedule as required.
Materials Risks: There is a risk that delays could be incurred if materials are not delivered on time and with sufficient quality. GHESI plans to mitigate these risks by meeting with vendors to discuss delivery schedules and to make the appropriate inspections during manufacturing, to ensure that the final products meet the requirements for the project. Lead-times for long delivery materials such as circuit breakers and the CLR have been integrated into the project schedule and consideration to supply lead times are a consideration for awarding the tenders for the same.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

GHESI does not have comparative information for equivalent projects due to the uniqueness of this project on the GHESI system. Costs for design and construction of such facilities are well understood in the industry and planning estimates have been used for budgetary purposes.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

This is not an REG Investment project as contemplated by the "Filing Requirements" as the fault current limitation is not driven by renewable sources. However, should this project be deferred, an excessive fault current situation will occur, which may require future REG projects to be deferred until the situation is resolved.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project is not a transmission line over 2 km in length, or over 50 kV, and therefore Leave to Construct is not required, as per O.Reg 161/99.

Attach Other project reference material i.e. Images, Drawings and or reference material

Attached is the document "Arlen MTS Fault Current Reduction Study" Appendix G, which includes the Hydro One Networks document "Customer Impact Assessment Guelph Area Transmission Refurbishment Project" Appendix H.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

The main driver for this project is regulatory requirements related to the TSC. Meeting all regulatory requirements is an operational objective for GHESI. The TSC mandates that allowable fault levels be kept below 21 kA (for a three phase, bolted fault) and 10 kA (for a single line to ground fault) for a 13.8 kV distribution system. Fault current limits are an accepted technical limitation that has an impact on safety and equipment operation. If this project is not completed, fault levels will exceed TSC requirements.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

A secondary driver of this project is the need to enable Renewable Energy Generation Connections. REG sources are not the cause of the fault current violation, but if this project is deferred, future REG projects may not be able to cannot until the unacceptable fault levels are corrected.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

The attached document "Arlen MTS Fault Current Reduction Study" establishes that with the changes to the supply configuration determined in GATR project, fault current limitations at Arlen TS will be violated. If this project is deferred, fault levels are expected to reach 23.6 kA (three phase, bolted fault) and 10.8 (single line to ground fault). This project is targeted to reduce these levels to 19.6 kA and 11.5 kA for a three-phase, bolted fault and a single line to ground fault, respectively. Additional distribution feeder level projects will be explored to further reduce the single line to ground fault levels.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The attached document "Arlen MTS Fault Current Reduction Study" establishes that with the changes to the supply configuration determined in GATR project, fault current limitations at Arlen TS will be violated. This situation will put GHESI electrical assets and public safety at an unacceptable risk. This study utilizes data from the Hydro One report "Customer Impact Assessment: Guelph Area Transmission Refurbishment Project", input impedance data provided by Hydro One, Arlen MTS configuration data provided by GHESI from construction records, and system modelling data maintained in GHESI's distribution system modelling software. Further details regarding the study inputs and assumptions can be found in the attached "Arlen MTS Fault Current Reduction Study".

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project impacts public safety and system operations. The system cannot operate with excessive fault current. If this project were deferred or delayed, alternate less favorable system changes would be required which would tend to increase outage frequency and duration, decrease power quality and increase complexity of system operations. This project has been ranked at number 1 of the 4 material system service projects planned for construction in 2016.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The attached document "Arlen MTS Fault Current Reduction Study" establishes that with the proposed Series Reactor Option is preferred option to mitigate the fault current violation. The proposed preferred solution will result in estimated copper losses of 0.5 kW per coil when Arlen MTS is operating at full load. While an exact cost would depend on system configuration and loading, this solution has the lowest operational cost of the feasible solutions studied because other reactor based solutions result in higher losses per coil, and running the station with bus tie open at all times, results in greater losses due to the increased system input impedance, as well as reduced system reliability and flexibility (which would have additional indirect financial costs associated with operating the system within these constraints).

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

With this project in place, customers of GHESI will have improved safety of supply. This project will allow the Arlen MTS fault levels to be kept below TSC limits and within equipment ratings, and will reduce available fault levels at customer equipment. This project will also maintain system reliability by allowing Arlen MTS to be normally operated with the bus tie closed, as per accepted industry best practices for dual-element spot network stations. New REG applications will not be limited by fault current constraints.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Absent this project, GHESI will be forced to operate with the tie-breaker at Arlen MTS open which removed the option to operate the station transformers in parallel, would increase the number of outages and increase the duration of outages while loads are transferred manually. In terms of reliability, operating with the bus tie open results in a higher frequency of system outages. If one of the transmission lines supplying Arlen MTS is interrupted due to a fault, the entire associated bus of Arlen MTS will be interrupted as well. Additionally, if a long duration transmission outage occurs, feeder will need to be manually transferred to the remaining station bus, which will increase restoration times and decrease reliability performance.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

The attached study, "Arlen MTS Fault Current Reduction Study", details the options analysis in detail. In summary, 5 options were considered including i) Current Limiting Reactors on the Transformer Primary, ii) Current Limiting Reactors on the Transformer Secondary, iii) Current Limiting Reactors in Series on the Main Bus Tie, iv) Station Transformer Upgrade, or v) Tie Breaker Change, (effectively the "do nothing" option). The preferred option based on economic, power quality, reliability, and technical factors is option iii) Current Limiting Reactors in Series on the Main Bus Tie

Safety (5.4.5.2.B2)

This project is necessary to mitigate safety concerns due to high fault levels. The resulting system will satisfy safety requirements. If fault levels are allowed to increase above TSC limits, available fault current at customer premises will be increased, which may violate customer equipment ratings and Ontario Electrical Safety Code requirements. This increase in available fault energy at the customer's equipment (especially above design levels) poses a significant hazard to life and limb during a fault. Additionally, if fault levels are increased beyond distribution system fault interrupting capabilities, explosive damage could result which poses a safety risk to people nearby the equipment.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

Not applicable

Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)

This project is driven by projects occurring from the Regional Planning level, which is coordinated with neighbouring LDCs and the Supply Authority, however this project itself is not subject to this level of coordination. GHESI has made Hydro One that this project is proceeding.

Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)

This project is designed and specified to accommodate future operational requirements specifically in the area of REG connections.

Economic Development (5.4.5.2.B5) (where applicable)

This GATR project is in place to support load growth that accompanies local development in the service region of GHESI.

Environmental Benefits (5.4.5.2.B6) (where applicable)

This project enables futre REG connections which can have a positive environmental impact.

C. Category-Specific Requirements – System Service

Benefits to Customers vs. Cost Impact (5.4.5.2 SS - C1)

The attached document "Arlen MTS Fault Current Reduction Study" establishes that with the changes to the supply configuration determined in GATR project, fault current limitations at Arlen TS will be violated. The analysis of options demonstrates that the preferred option maximizes the benefit for the cost incurred. The "do nothing" option does not satisfactorily maintain system reliability, and all other options are similar or greater in cost.

Regional electricity infrastructure requirements (5.4.5.2 SS - C2)

GATR was identified in the Regional Planning Process as a necessary project to maintain the reliability and adequacy of supply the Kitchener-Waterloo-Cambridge-Guelph (KWGC) area. The result of that project is an increase in available fault current at the Arlen MTS and through the GHESI distribution system. The project to reduce fault currents at Arlen MTS itself is not the subject of the RPP process. There will be no cost sharing from the transmitter for the Arlen MTS Fault Current Reduction project.

Advanced technology (5.4.5.2 SS - C3)

The addition of a CLR in series with the main bus tie will create a need for some additional advanced technology to be incorporated in the system. Relay upgrades will be required to ensure the reactor is operating correctly under a variety of operating conditions. Standards relating to interoperability and cybersecurity do not specifically impact on this project, over and above the requirements already in existence at Arlen MTS.

Reliability, efficiency, safety and coordination benefits (5.4.5.2 SS - C4)

This project will enhance system reliability, efficiency and safety of the GHESI system when compared to the "do nothing" option once the changes created by the GATR are in service. Other alternatives cost the same or more for less functionality or significantly impact system reliability and operational practices.

Timing & Priority of Project (5.4.5.2 SS - C5)

This project needs to be completed prior to completion of the works proposed in the GATR project. GHESI proposed completion in early 2016 to meet the system needs, and to coincide with the anticipated completion date of the GATR project. Currently, a completion date of April 29th, 2016 has been factored into the project schedule based on best information available with respect to the completion date of GATR, however GHESI is in periodic contact with Hydro One to confirm the validity of the estimated completion date. In terms of priority amongst similar projects, this project is ranked at number 1 of the 4 system service projects planned for completion in 2016.

Analysis of project benefits and costs i.e. "Do Nothing" & "Technically feasible alternatives" (5.4.5.2 SS - C6)

The attached study details the options analysis in detail. In summary, 5 options were considered including i) Current Limiting Reactors on the Transformer Primary, ii) Current Limiting Reactors on the Transformer Secondary, iii) Current Limiting Reactors in Series on the Main Bus Tie, iv) Station Transformer Upgrade, or v) Tie Breaker Change, (effectively the "do nothing" option). The preferred option based on Economic, Power Quality, Reliability, and Technical Factors is Option iii) Current Limiting Reactors in Series on the Main Bus Tie.

A. General Information							
Project /Activity	Administration Building Addition						
Project Number							
Investment Category	General Plant						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	
Capital Cost (5.4.5.2 A.1)					**$500,000**	**$650,000**	
Capital contribution							
Net Cost							
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	
	N/A	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	

Customer Attachments and Load (5.4.5.2 A.2)

Not applicable.

Start Date (5.4.5.2 A.3)	Apr-15	**In-Service Date (5.4.5.2 A.3)**	Jul-16

Project Summary

The existing building facility is located at 395 Southgate Drive in Guelph and includes approximately 52,645 square feet in office space. This includes common areas as well as the Control Room. About 5,000 s.f. of new space exists above the Operations Department - adjacent to Finance and the existing Control Room. This section was purposely reinforced for a second floor addition when the building was originally built and, by good planning, reroofing of this area was not completed in 2014. This expansion will accommodate office space requirements for at least the next 10 years with every department's needs considered and an optimal floorplan developed as part of the project plan. Another important consideration is that access to the existing second floor for the Control Room is not AODA (Accessibility for Ontarians with Disabilities Act) compliant as it currently has stair access only and an elevator shaft would have to be built in order to meet compliance requirements. The contemplated addition would connect the Control Room area to the main second floor and elevator access, eliminating the need for the new elevator.

Risk Identification & Mitigation (5.4.5.2 A.4)

Risks associated with this project include construction delays, disruption to operations/existing workflows, and cost overruns. Risk mitigation includes close coordination with the construction contractor, ensuring backup temporary space is available, and minimizing scope creep via detailed construction specifications and a clear definitions of project boundaries.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

No information exists on comparative expenditures - the most recent office expansion occurred in 2006 and this project was of a much larger scale.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not applicable.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable.

Attach Other project reference material i.e. Images, Drawings and or reference material

Not applicable.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

Guelph Hydro consolidated two locations into one (moving administrative and office staff from Dawson Road to 395 Southgate) in 2006. At that time, there were a total of 63 office staff. The number of office staff has since grown to 93 or 45% more than in 2006 (excluding contract/temporary employees) and will increase to 96 in 2016. The current administrative building lacks the space to accommodate this growth in employees. Accordingly, the main driver is to relieve overcrowding of staff at the administrative building.

The estimated cost of this addition is $1.25 million, complete with space fit-up, work stations and additional meeting space. Part of the cost will also include relocating and reusing the existing skylights and rerouting fresh air intake from an existing air handling unit. Main building heating, cooling and electrical capacity will not have to be upgraded to handle the additional space. The plan for 2015 will be to engage an Architect and proceed with design drawings, call tenders and close in the space before next winter. The balance will be completed in 2016 with space occupancy by mid-year. The impact on capital budgets is expected to be an estimated $500,000 in 2015 and the balance $750,000 in 2016.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

Not applicable.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

Investment objectives include minimizing the potential for impact to Guelph Hydro's office and operations activities to ensure proper allocation of investments in general plant assets

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

See internal memo to the COO dated April 22, 2015. This memo provides more qualitative analysis with respect to analysis of all options attached as Appendix Q in the DSP.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

This project has a moderate to high priority ranking with respect to other capital projects. This ranking exists due to the fact that space constraint issues will grow over time and with the arrival of anticipated new employees. Also, current timing is key since the control room currently is not accessible - in the event the addition is not completed, an elevator will need to be constructed which is a potential significant throwaway cost given that it will not address the space issue. The timing of the two projects together is an important cost efficiency consideration.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

This investment will improve operation efficiency and cost effectiveness over the longer term (10 years). This expansion will provide space for Control Room staffing levels to provide 24/7 coverage which will increase power restoration response and improve distribution system reliability over time. Consolidation of CDM, Communications, and Regulatory areas will allow for improved internal department communication and associated efficiencies.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Customer benefits include improved response to power system issues.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

With respect to power outages, providing 24/7 Control Room coverage will save an estimated

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Few alternatives exist for the execution stage of this project as three of the walls for the expansion are already existing and funding will be part of Guelph Hydro's capital asset expansion. Design will be done by an external architect and construction/material supply will be tendered out to multiple contractors upon completion of the detailed design drawings.
Scope alternatives -
Do nothing: Do nothing was not an option given the increasing space constraints in the office. By 2016, there will be no space for the planned additional office staff. Also, the plan to move to 24/7 coverage in the control room and the lack of locker, office, and meeting space will delay this transition.
Reconfiguring space: GHESI has reconfigured the space a number of times over the last several years in the Customer Service, Billing, and IT areas. This is no longer an option due to the fact that minimum office and cubicle size has already been reached. Also, remaining common areas are under main building skylights and are in areas where converting to office space would not make sense due to the lack of space and structural modifications that would be required.
Renting space: GHESI considered renting space, but this presented significant draw backs. A suitable available space for rent is not readily available and was more expensive in the long term than the addition.

Safety (5.4.5.2.B2)

Not applicable.

Cyber-Security, privacy (5.4.5.2.B3) (where applicable)

Not applicable.
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Not applicable.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
This project will address projected office space requirements over the next 10 years that have been identified by the departments.
Economic Development (5.4.5.2.B5) (where applicable)
Local construction contractors and material suppliers will be included as part of the tendering process.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable.

C. Category-Specific Requirements – General Plant

Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.5.2 GP - C1)

Available office space has become constrained in multiple work areas and some smaller departments are scattered throughout the building due to the lack of available space where it's needed. Given that GMHI personnel will continue to work in specific areas within the building, the additional space is now required to satisfy needs in areas including Finance, Regulatory, Engineering, and Operations. Also, CDM personnel are mostly scattered throughout the existing building and addressing departmental needs will be particularly important as two more employees are added by mid-year 2015 lasting until at least 2020. Finally, the new addition will allow for expansion of the Control Room to allow for the planned migration to 24/7 coverage and based on the accelerated growth potential of shared services to other LDC's. Other areas that could benefit from additional space include Safety/Training and Communications. Another important consideration is that access to the existing second floor for the Control Room is not AODA (Accessibility for Ontarians with Disabilities Act) compliant as it currently has stair access only and an elevator shaft would have to be built in order to meet compliance requirements. The contemplated addition would connect the Control Room area to the main second floor and elevator access, eliminating the need for the new elevator.

Item	Estimated Cost	Normalized Cost (10 year)	Additional Sq.ft.	Total (10 year) Cost per sq.ft.
Build a new facility	$2M	$3.5M	5,000	$700
Rent additional space	$300k / year	$3.0M	5,000	$600
Existing building addition	$1.25M	$2.5M	5,000	$500
Utilize existing space	$1.0M	$1.15M	1,500	$767

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term)

See internal memo to the COO dated April 22, 2015. This memo provides more qualitative analysis with respect to analysis of all options attached as Appendix Q in the DSP.

A. General Information						
Project /Activity	Fleet/Rolling Stock - Truck 9 Replacement					
Project Number						
Investment Category	General Plant					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Capital Cost (5.4.5.2 A.1)						**$300,000**
Capital contribution						
Net Cost						
O&M Cost (5.4.5.2 A.1)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	N/A	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

Customer Attachments and Load (5.4.5.2 A.2)

Not applicable.

Start Date (5.4.5.2 A.3)	Apr-16	**In-Service Date (5.4.5.2 A.3)**	Jul-16

Project Summary

This project includes all capital costs associated with GHESI's fleet "Truck 9" replacement. Truck 9 is a large (dual axle) hydro truck that includes a 46' reach single bucket with material handler. It is a 2005 that was purchased in 2004. By 2016 it will be 12 years old which is the normal life expectancy for large trucks in our fleet. Due to changing needs in the department, Truck 9 will be replaced with another single bucket truck with an extended reach of 62'.

Risk Identification & Mitigation (5.4.5.2 A.4)

Risks associated with not allowing for timely equipment replacement include an aging fleet where eventually, multiple pieces of equipment will need replacement requiring large investments in one year versus levelled out spending over multiple years. Other risks associated with aging vehicles and equipment for employees include ergonomic, employee safety, and efficiency issues including increased response times to trouble call sites and delays in capital construction projects due to equipment availability issues.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Truck purchase cost changes very little year over year. The most recent bucket truck replacement (Truck 7, delivered in 2014) purchase totaled approximately $400k - similar to the overall budget for this purchase.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not applicable.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

Not applicable.

Attach Other project reference material i.e. Images, Drawings and or reference material

See the GHESI fleet replacement philosophy OP-GUI-001 (Appendix L) for more information.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1.a)

Guelph Hydro's fleet replacement policy includes maintaining the average age of the fleet to 10 years old or newer. This includes an average life expectancy for large trucks of 12 years. Truck 9 will be 12 years old in 2016 and, based on costs for maintenance and other factors included in GHESI's fleet replacement philosophy OP-GUI-001, it was determined that this vehicle will need to be replaced in 2016.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers/Investment Category (5.4.5.2 B.1.a)

Not applicable.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1.a)

To ensure proper allocation of investments in general plant assets

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Repair costs, total km, and engine/PTO hours are among several things that are tracked and reported on a monthly basis. These are among several factors considered when contemplating large vehicle replacements.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority Relative to Other Investments

Prioritization of replacement of fleet vehicles is determined in accordance with GHESI's fleet replacement philosophy OP-GUI-001. This process aim is to create a sustainable, levelized five-year capital plan for the forecast period. In prioritizing replacement, GHESI considers:
a) Age of the vehicle;
b) Odometer reading;
c) Engine/power take-off (PTO) hours;
d) Maintenance costs;
e) Annual vehicle test results, including stress/electrical testing;
f) Practicality of existing vehicle including new technology available;
g) Changing emissions, weight, and road safety regulations obsoleting some existing units; and
h) Crew/other department needs.
Truck 9 is the oldest bucket truck in the GHESI fleet and has reached its average life expectancy. Replacement of the vehicle is important as it forms a vital part of GHESI's fleet. Accordingly, replacement of truck 9 is considered a mid-level priority in 2016, as it is projected that its performance will continue to deteriorate going forward.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1.c)

The reliability of the large trucks in the fleet impact several areas including construction project and response time to trouble efficiency. Equipment availability directly impacts crew productivity as well so new Truck 9 maintains and improves these efficiencies.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci),

Net benefits to customers include maintaining and improving response times to outages, system reliability, and crew effectiveness.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Net benefits to customers include maintaining and improving response times to outages, system reliability, and crew effectiveness.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

If the truck were not replaced, replacement would become a requirement very quickly and when it does, chance are it will be coincident with another large vehicle replacement requirement therefore causing the capital budget to quickly become unpredictable on a year over year basis. This contradicts the idea of predictable, levelized capital budget spending.

Safety (5.4.5.2.B2)
Not applicable.
Cyber-Security, privacy (5.4.5.2.B3) (where applicable)
Not applicable.
Co-Ordination, Interoperability (5.4.5.2.B4i) Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable)
Not applicable.
Co-Ordination, Interoperability (5.4.5.2.B4ii) Future Technological functionality and/or future operational requirements (where applicable)
Not applicable.
Economic Development (5.4.5.2.B5) (where applicable)
Not applicable.
Environmental Benefits (5.4.5.2.B6) (where applicable)
Not applicable.

C. Category-Specific Requirements – General Plant
Results of quantitative and qualitative analyses, business case documenting the justifications for the expenditure (5.4.5.2 GP - C1)
Prioritization of replacement of fleet vehicles is determined in accordance with GHESI's fleet replacement philosophy OP-GUI-001. This process aims to determine the most cost effective time for vehicle replacement considering factors such as age of the vehicle, odometer reading, engine/power take-off (PTO) hours, maintenance costs, annual vehicle test results, including stress/electrical testing, practicality of existing vehicle including new technology available, changing emissions, weight, and road safety regulations obsoleting some existing units, and crew/other department needs. Applying this policy, it was determined that the test year is the most cost efficient time for the replacement of truck 9 within the context of its own role and within the renewal schedule for the entire fleet. Quantitative analysis, including tendering, exists for larger expenses through the normal purchasing policy and results are stored and filed appropriately. See GHESI fleet replacement philosophy OP-GUI-001 for more information.
Alternatives include varying replacement intervals and different fleet equipment suppliers. All purchases are made in accordance with existing approval and policy requirement (i.e. See Project Alternatives).
Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term)
GHESI does not consider this investment to substantially exceed the materiality threshold, based on previously approved budget levels and the nature of the equipment purchase.

APPENDIX O: Integrated Regional Resource Planning (IRRP)

LDC Gross Forecast Assumptions and Methodologies Document

LDC Gross Forecast Assumptions and Methodology

[Guelph Hydro Electric Systems Inc.]

Guelph Hydro Electric Systems Inc. (GHESI) owns and operates the electricity distribution system in its licensed service area in the City of Guelph and the Village of Rockwood serving approximately 52,000 customers. GHESI's customer base is represented by a mixture of residential customers (91% by customer count, 22% by load) and Commercial/Industrial /Institutional customers (9% by customer count and 78% by load). GHESI services 5 large use customers represented by a university and industrial/manufacturing facilities.

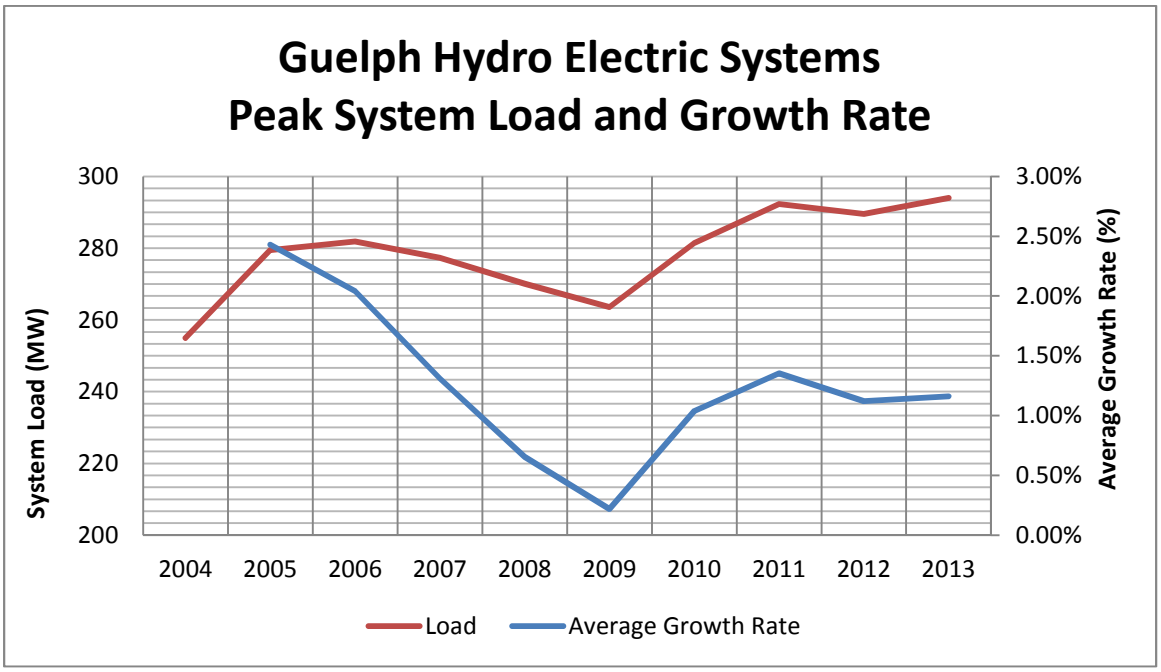
GHESI is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV within the City of Guelph. Electricity is then distributed through Guelph Hydro's service territory by 3 Hydro One owned transformer stations, Campbell TS, Cedar TS and Hanlon TS and 1 Guelph Hydro owned Municipal Transformer station Arlen MTS. The GHESI distribution system in the City of Guelph is serviced at 13.8kV. The Village of Rockwood is supplied through the Hydro One distribution system at a primary voltage of 44kV. Electricity is then distributed through the Village of Rockwood by 2 Guelph Hydro owned Municipal Stations and 1 Hydro One distribution station. The GHESI distribution system in the Village of Rockwood is serviced at 8.32kV

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A. Historical Electricity Demand

GHESI has experienced an on average system growth rate of approximately 1.88% over the past 25 years and an average growth rate of 1.16% between 2004 and 2013. GHESI reached an all-time system peak of 293.2 MW in July 2011.

Conservation and Distributed Generation efforts have made an impact to the average system growth rate within the Guelph service territory since being initiated in 2002 with a net reduction of approximately 1.25% towards the overall average growth rate between 2004 and 2013.



B. Factors that Affect Electricity Demand

The major variables affecting electricity demand within GHESI's service territory in the City of Guelph are related to population growth rate associated with the provincial places to grow targets as well as Economic development within both the current industrial / manufacturing rate class sector and future development and use of industrial parks. The rate and level of future demand increases are highly dependent on the each one of these factors.

The City of Guelph has been designated as one of twenty-five municipalities listed in the Growth Plan as an Urban Growth Centre. The city is directed to increase its population to 175,000, which is an increase of over 50,000 people.

Another significant factor in the demand of electricity is linked to Economic development within both our current and future customer base. A significant portion of the electricity demand within GHESI service territory is associated with the manufacturing sector.

Economic development as it relates to future utilization of industrial park land represents a large portion of future increase to electricity demand within the City. The most significant development is the Hanlon Creek Business Park located in the south end of GHESI's service territory and represents a total land mass of over 370 Acres. Approximately 8% of the land within the business park has been consumed to date and reflective in the current electricity demand with the remaining accounted for in the forecast.

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C. Forecast Methodology and Assumptions

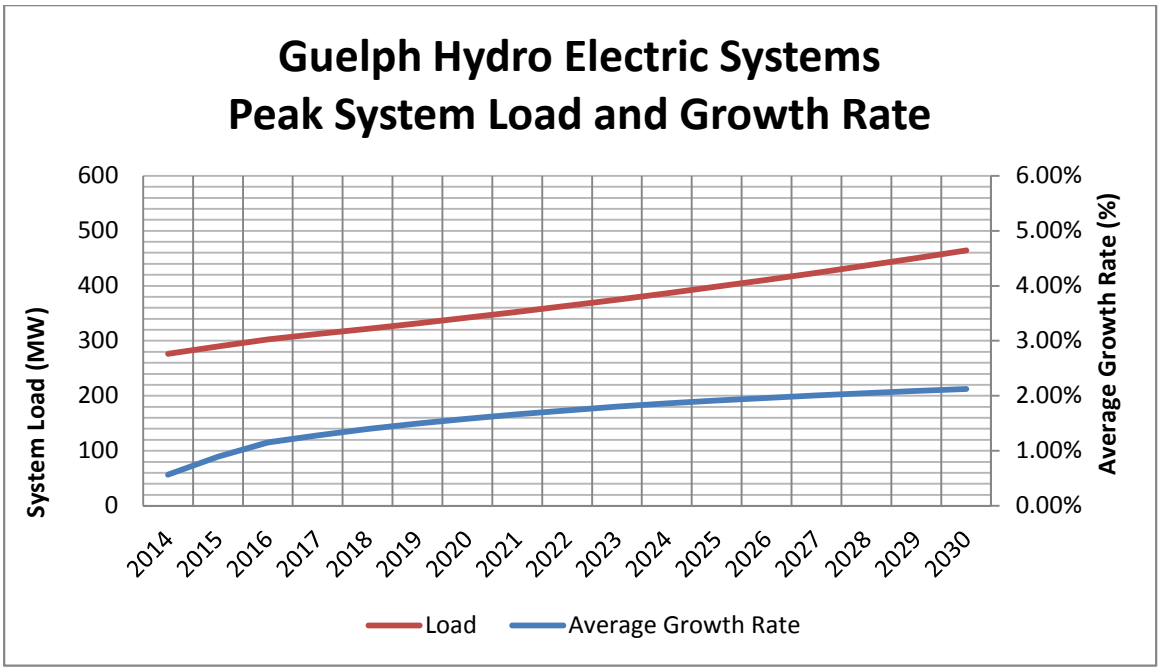
GHESI's methodology for developing the base load forecast consisted of a number of elements including historical loading trends, local knowledge of planned development and City of Guelph development planning information. Planning information from the City of Guelph was the starting point to formulate a maximum development forecast in order to set the parameters of the long range load forecast for our service territory given the study period. Using this information along with 30+years of historic peak loading information, local knowledge and information regarding transformer stations service areas within our service territory, the load forecast was created for each delivery point location.

D. Gross Demand Forecast

The below information represents the gross load projections for the GHESI service territory within the KWCG region with no adjustments made for distributed generation or conservation.

[This section will be included in the KWCG IRRP Appendices]

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Gross Demand Forecast (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Campbell TS	126	131	136	139	141	144	147	150	155	160	166	171	177	182	188	193	197	197	197	197
Cedar TS T1/T2	67	70	73	74	76	78	80	81	84	87	89	92	95	96	96	96	96	96	96	96
Cedar TS T7/T8	29	30	32	32	33	33	34	35	35	36	37	38	39	39	40	40	40	40	40	40
Hanlon TS	28	29	30	31	32	33	34	35	36	36	37	37	38	38	38	38	38	38	38	38
Arlen MTS	27	29	32	36	40	43	48	52	54	56	58	60	62	67	75	83	93	93	93	93
Total	276	290	303	312	322	332	342	353	364	375	387	399	411	424	437	450	464	464	464	464

APPENDIX P: 2015 Customer Survey Summary Report

Summary Report
Guelph Hydro 2015 Online Customer Survey

In December, 2014, Guelph Hydro launched its first ever online Customer Survey in an effort to obtain feedback from customers on Guelph Hydro's services and investment plans.

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Overall Customer Satisfaction

Results indicate that **91 per cent** of respondents **rated Guelph Hydro's performance** in serving them as **"Good" or "Excellent."**

This high rate of customer satisfaction is in line with results of previous customer satisfaction surveys conducted by telephone which have repeatedly reported satisfaction levels above 90 per cent.

Overall Value

Overall, Guelph Hydro customers are satisfied with the service and value Guelph Hydro provides to Guelph and Rockwood. **77 per cent** of respondents rated the value of the services they receive from Guelph Hydro as **"Good" or "Excellent,"** and only **4 per cent** rated the value of Guelph Hydro's service as **"Poor."**

Suggestions for Adding Value

When asked what they **would like to see** Guelph Hydro do to **add value** for the money they pay, **suggestions were varied and widespread**, from the elimination of smart meters and/or changes made to time-of-use billing, to better cost management, to more and less investment in renewable or "green" infrastructure.

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The results of this online survey were considered by Guelph Hydro in developing its Cost of Service application and Distribution System Plan and will be used as the company continues to seek out new and different ways of adding value and furthering its customer engagement efforts.

Methodology

Two online surveys were launched; one survey was designed for residential customers, and a second survey was designed for commercial customers.

Both surveys were available on Guelph Hydro's website and in hard copy for nine weeks starting December 1, 2014 and ending January 30, 2015. An incentive of the chance to win one of five Apple iPads was offered to participants.

Extensive advertising efforts included:

- Ads in local media outlets including newspapers, community and business papers, and Guelph Chamber of Commerce newsletters
- Bill inserts
- Website banners
- Social media
- Promotion by Customer Service Representatives

Response Rate

A total of **356** online surveys were received, representing 0.7 per cent of the customer base. Of this, **354** were from Residential customers with only two responses received from Commercial customers.

Survey responses do not reflect an accurate sample size since they only representing less than one per cent of Guelph Hydro's residential and commercial customers. However, when considered in relation to past customer surveys conducted by telephone, the results provide insight into customer needs and preferences from customers who are comfortable engaging with Guelph Hydro online.

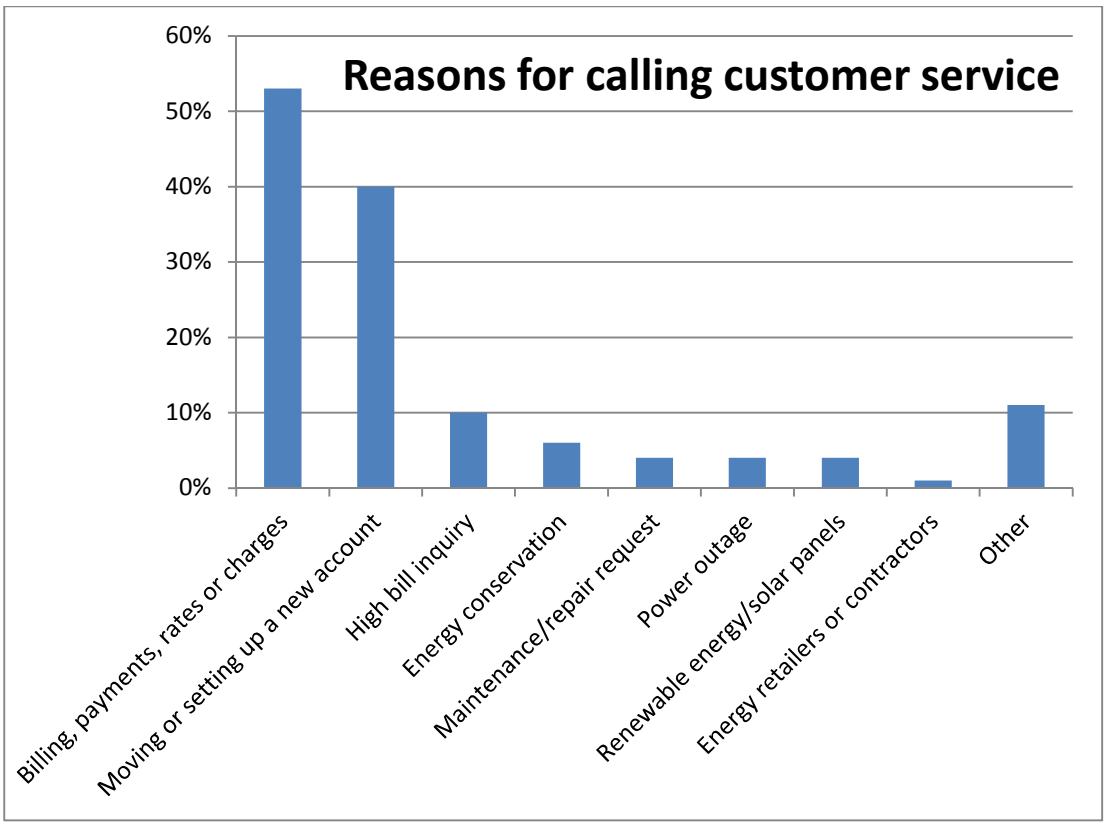
Demographics

- The majority of survey respondents were male between the ages of 35 and 54
- The majority own a fully-detached home.
- The average number of people residing in the home is three (2.87 per cent).

Customer Service

Overall, Guelph Hydro customers are satisfied with the customer service Guelph Hydro provides.

- Only **one third of respondents contacted customer service in the preceding year**, the **majority** calling about **billing, payments, rates or charges**, followed by moving or setting up a new account.
- The **fewest calls** were about **maintenance or repairs, power outages, or renewable energy or solar panels**.

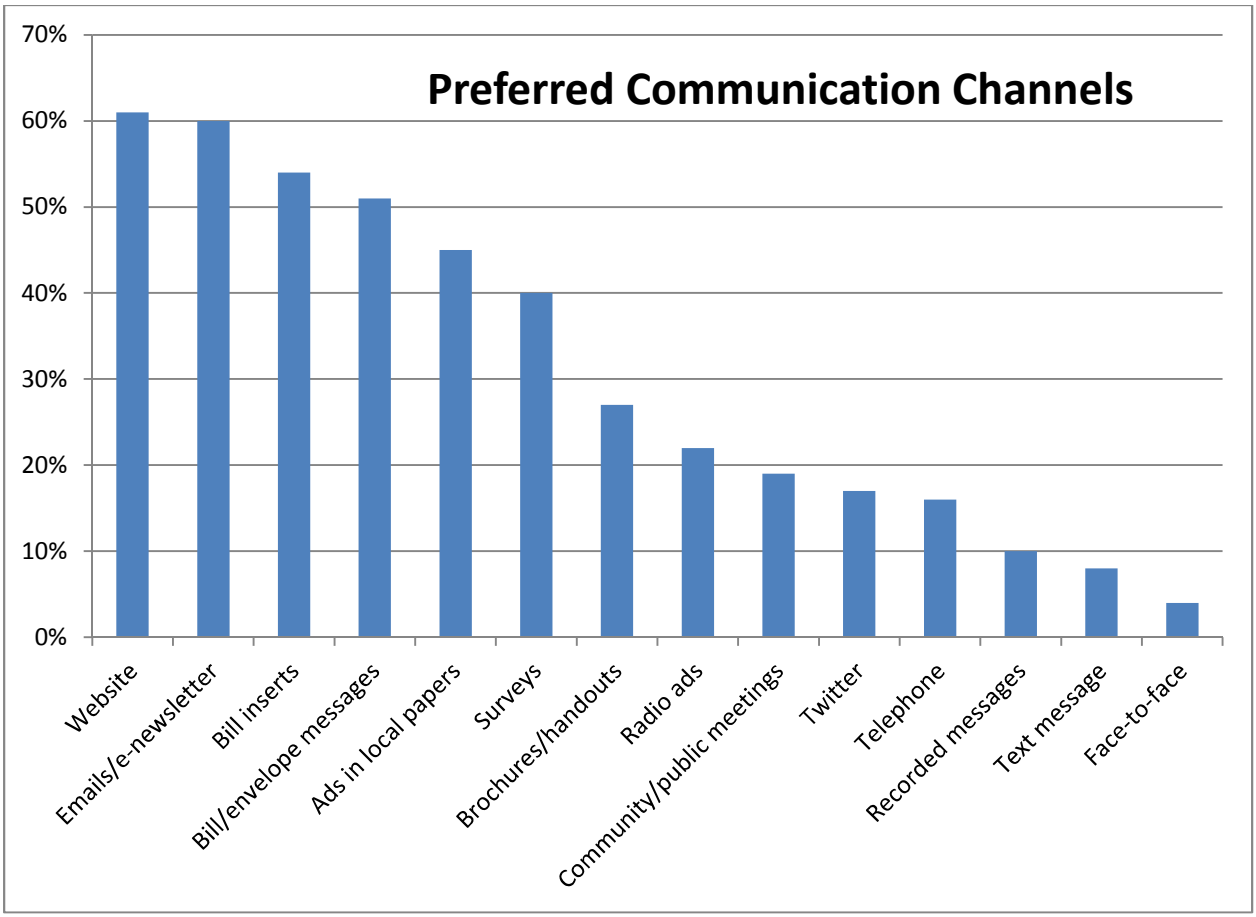


- **85 per cent were very satisfied or satisfied** with the time within which their issue was resolved, the helpfulness of the customer service representative
- **83 per cent were very satisfied or satisfied** with the training and knowledge of the customer service representative.
- **84 per cent per were very satisfied or satisfied** with the courtesy and professionalism of the customer service representative
- **80 per cent were very satisfied or satisfied** with the ability of the customer service representative to resolve their concerns with one email or call.

Communication

With respect to how Guelph Hydro communicates with customers, the **majority** of respondents **like Guelph Hydro's website and would like emails or email newsletters**. Guelph Hydro is actively exploring the feasibility of providing this option.

- Approximately **half** of respondents like **bill inserts, bill and/or envelope messages or ads in local newspapers.**
- The **least preferred methods** of communication are **face-to-face meetings and text or recorded messages**.
- **Less than one third** like **brochures and handouts at community events, radio ads, community or public meetings, or Twitter**
- While **one respondent suggested public information displays in shopping malls**, **78 per cent** of respondents **did not feel** a customer service kiosk in malls or retail stores **was important**



Social Media

When it comes to social media, Guelph Hydro is using Twitter to communicate and educate customers about safety, electricity conservation and other information related to electricity but does not currently have a Facebook page.

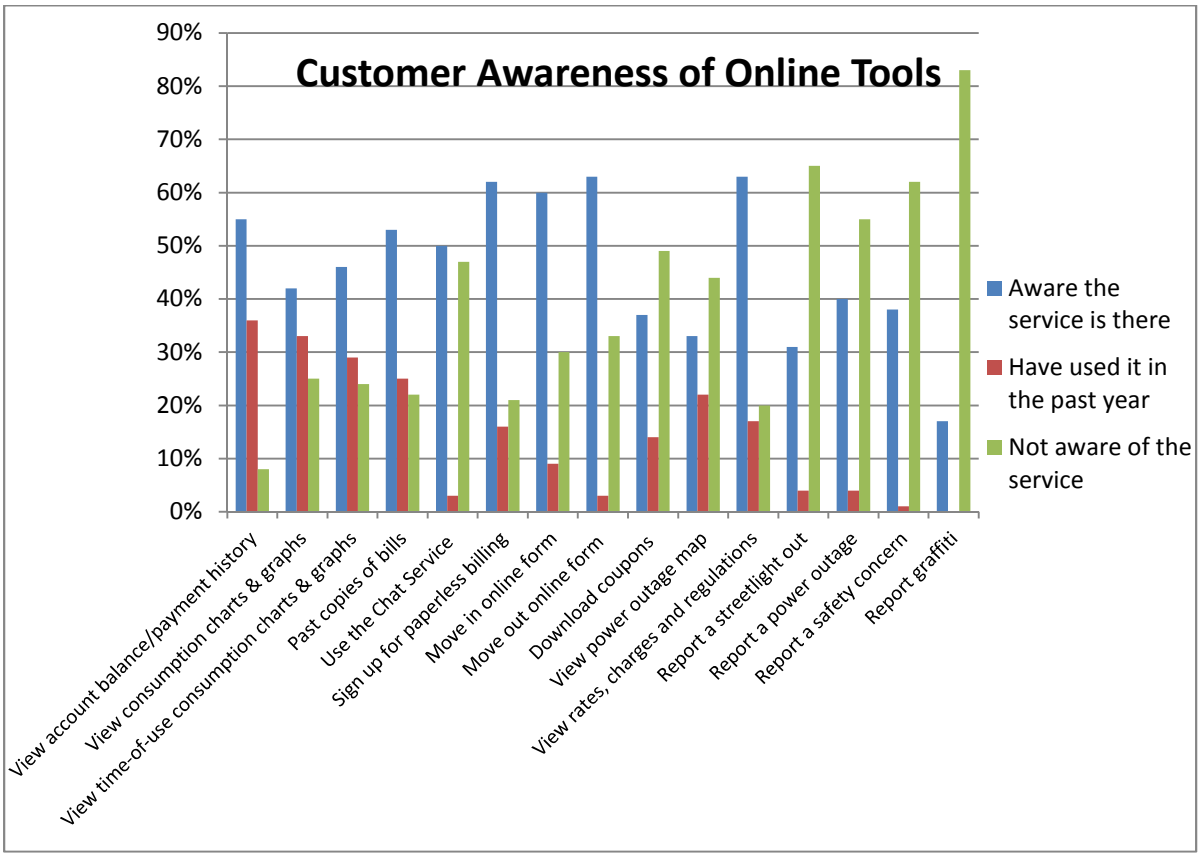
- It appears that at this time **customers are not using social media to address customer service issues**.
- Of the **62 per cent of respondents who use social media, 58 per cent** are **unlikely** to seek information on **customer service issues using Twitter**, and **54 per cent** are **unlikely** to seek information on **customer service issues on Facebook**.

Both these and other social media platforms will continue to be monitored and as customer interests change, social media strategies will be adapted.

Online Services

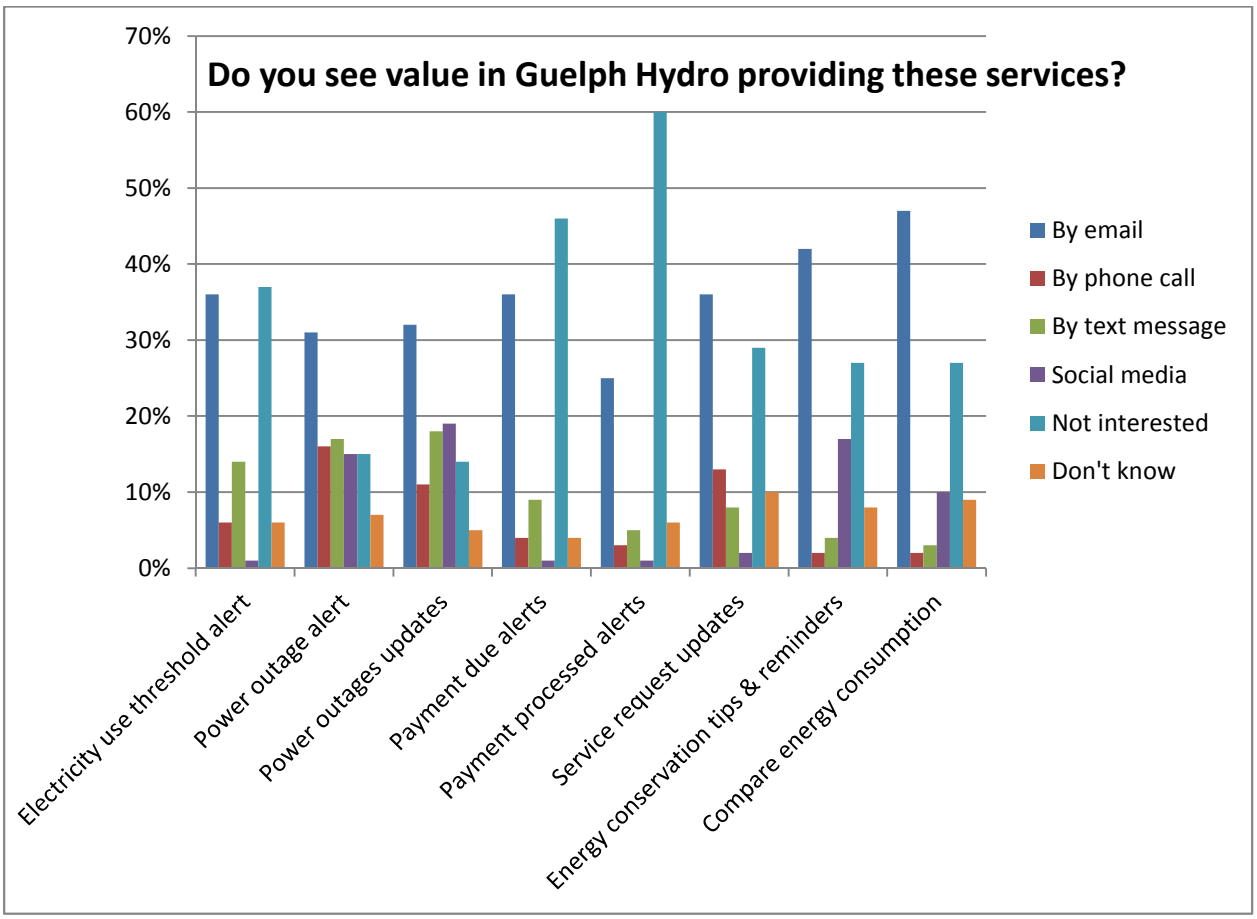
Based on customer feedback, online services present a cost-effective and convenient solution for Guelph Hydro to improve its service to customers.

- **When asked if they learned anything** about Guelph Hydro when completing the survey, **online services was ranked second, with 20 per cent** of respondents **surprised to learn of the number of online services available**.
- Close to **70 per cent** of respondents would **prefer more self-serve options through Guelph Hydro's online and mobile channels** over extended hours to speak with a customer service representative.
- Approximately **half** of the respondents are **aware** that Guelph Hydro offers **online options to manage their account and billing,** but **at most, one third have used one or more** of the available options in the past year.
- Just **over half** of survey respondents reported that they had **visited Guelph Hydro's website or mobile site** in the last two years, and the **majority** of those respondents had **visited the site between one and six times** and said it was **very easy or easy to navigate** the site.



Although customers are aware of some online services, there is a clear opportunity for Guelph Hydro to improve the communication about the availability of its online services and to continue to investigate opportunities to provide self-serve online options on an ongoing basis.

Guelph Hydro also asked questions in an effort to gauge customer interest in additional services Guelph Hydro could provide. This information will be used in planning future online services.



Customers made suggestions on other services Guelph Hydro could provide, including an analysis of high bills (17 per cent), a longer remittance period (11 per cent), notifying customers if their bill is from a meter reading or an estimate, discounts for customers who are already energy-conscious, and a partnership with Nest for Rush Hour Rewards.

The suggestion that Guelph Hydro notify customers if their bill is from a meter reading or estimate reveals that not all customers know how to read their bill. Guelph Hydro will consider “How to read your bill” as part of its energy literacy communications objectives.

Rates and Billing

The **cost of electrical service** is either a **strain or a great strain** on the household budget of **71 per cent of survey respondents**. **21 per cent say it is not much of a strain,** and anecdotal feedback throughout the survey revealed that customers are frustrated by electricity costs. This indicates that Guelph Hydro must do what it can to manage its costs, continue to educate customers about the cause of rising electricity costs and how they can better manage their electricity consumption, and promote a conservation culture in Ontario.

- **All survey respondents** were **surprised** to learn **that only 22 per cent** of a Guelph Hydro bill actually **goes to Guelph Hydro**.
- **84 per cent** of respondents said they find their bill **easy to understand** and only 15 per cent find it hard to read.
- **82 per cent** are **satisfied** with Guelph Hydro's **billing accuracy**
- **Less than half** were **interested** in community **information sessions on how to read and understand their bill** or household energy consumption.
- **Of the two commercial respondents**, **neither understands global adjustment or power factor.**
- When asked if they would **prefer** to receive **a monthly bill** for an additional cost of approximately $8 per month, **the overwhelming majority** of customers (91 per cent), **said "No."**

Paperless Billing

Only **19 per cent** of respondents **have made the switch to paperless billing**. **The majority** of respondents **who hadn't made the switch** said it was because they **preferred the paper bill**. Others said they were unaware of the option, some were afraid they would forget to pay the bills, some said they found it difficult to sign up, and others were rely on paper for tracking or tax purposes.

In 2015, Guelph Hydro is actively working to make its online portal more user-friendly and will be undertaking a marketing and communications strategy to encourage more customers to take advantage of paperless billing.

Rate Application Process

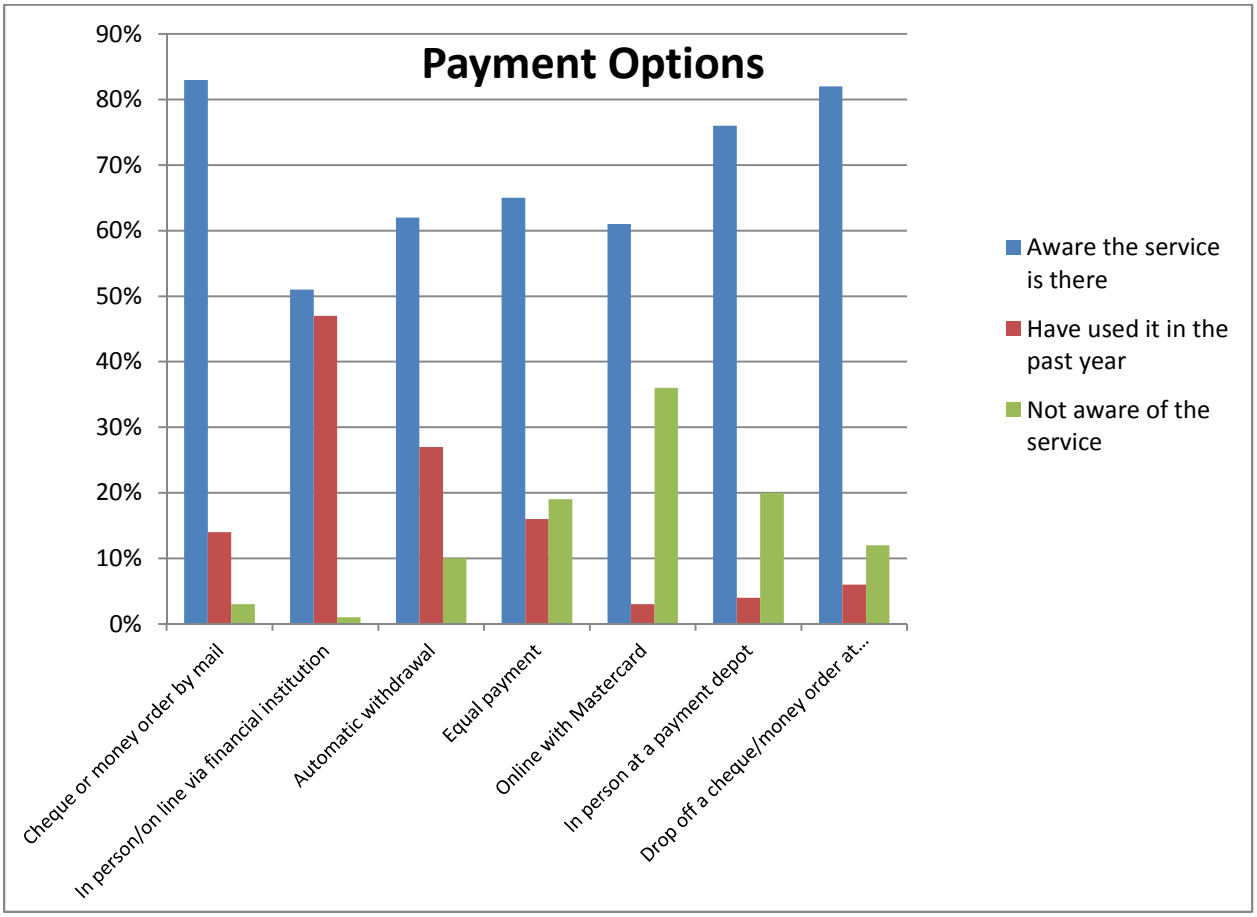
Only **35 per cent of respondents were aware** of their **ability to provide input and comment and actively participate** in Ontario Energy Board hearings with respect to Guelph Hydro's rate applications.

To improve awareness, Guelph Hydro will be actively promoting the content and status of its rate application and encouraging customer feedback as the application proceeds.

Payment Options

When it comes to bill payment options, survey results indicate that there is a good awareness of the payment options available among survey respondents.

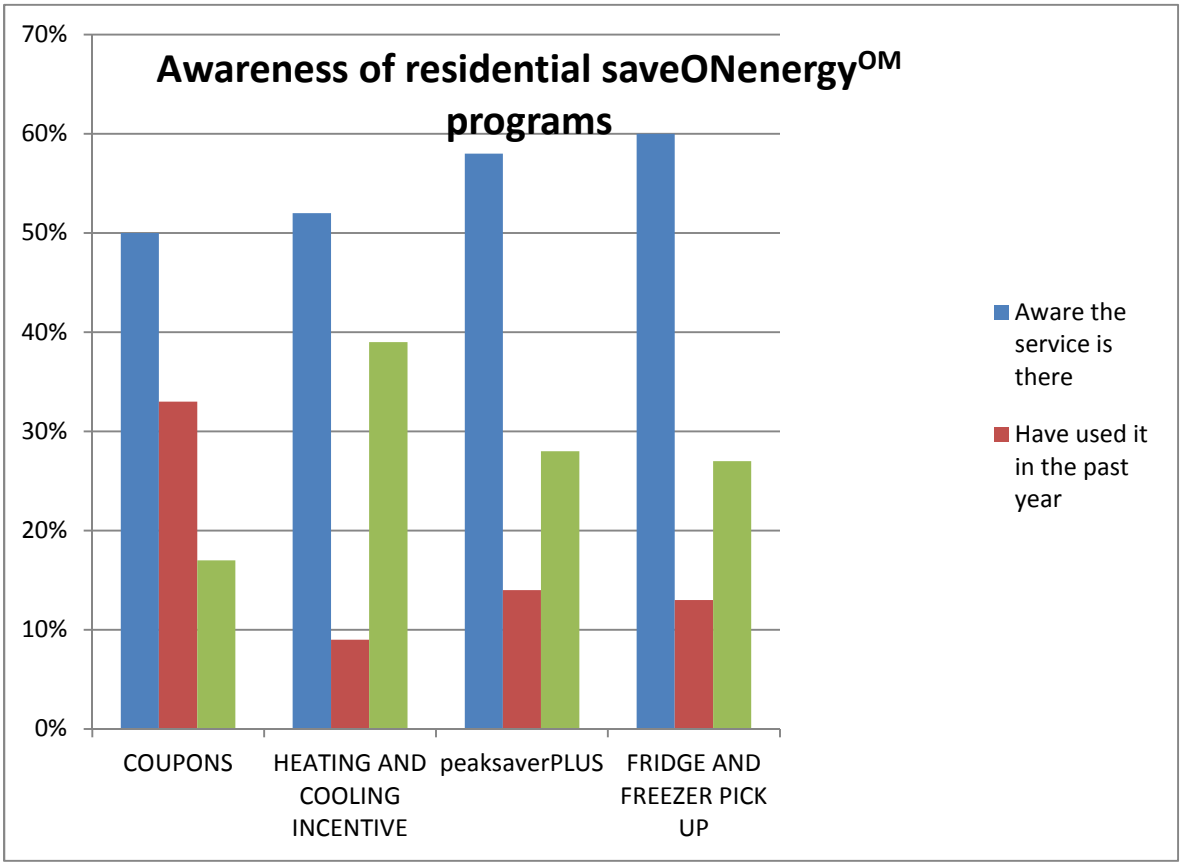
- **Paying in person or online via a financial institution** was the **most popular** option used **at 47 per cent**
- Paying **online with Mastercard, in person** at one of our payment depots, and **dropping off a cheque or money order at the Guelph Hydro office** were the **least popular at three per cent, four per cent and six per cent** respectively.
- **72 per cent** of respondents **do not feel** Guelph Hydro should be looking into systems that will enable them **to pay their bill using a mobile device**.
- **37 per cent** of respondents want to see Guelph Hydro **accept more brands of credit card**. Note: In the time since the survey was conducted, Guelph Hydro has re-introduced VISA as a payment option through Paymentus, and is actively investigating the option of accepting American Express credit cards.



Energy Conservation

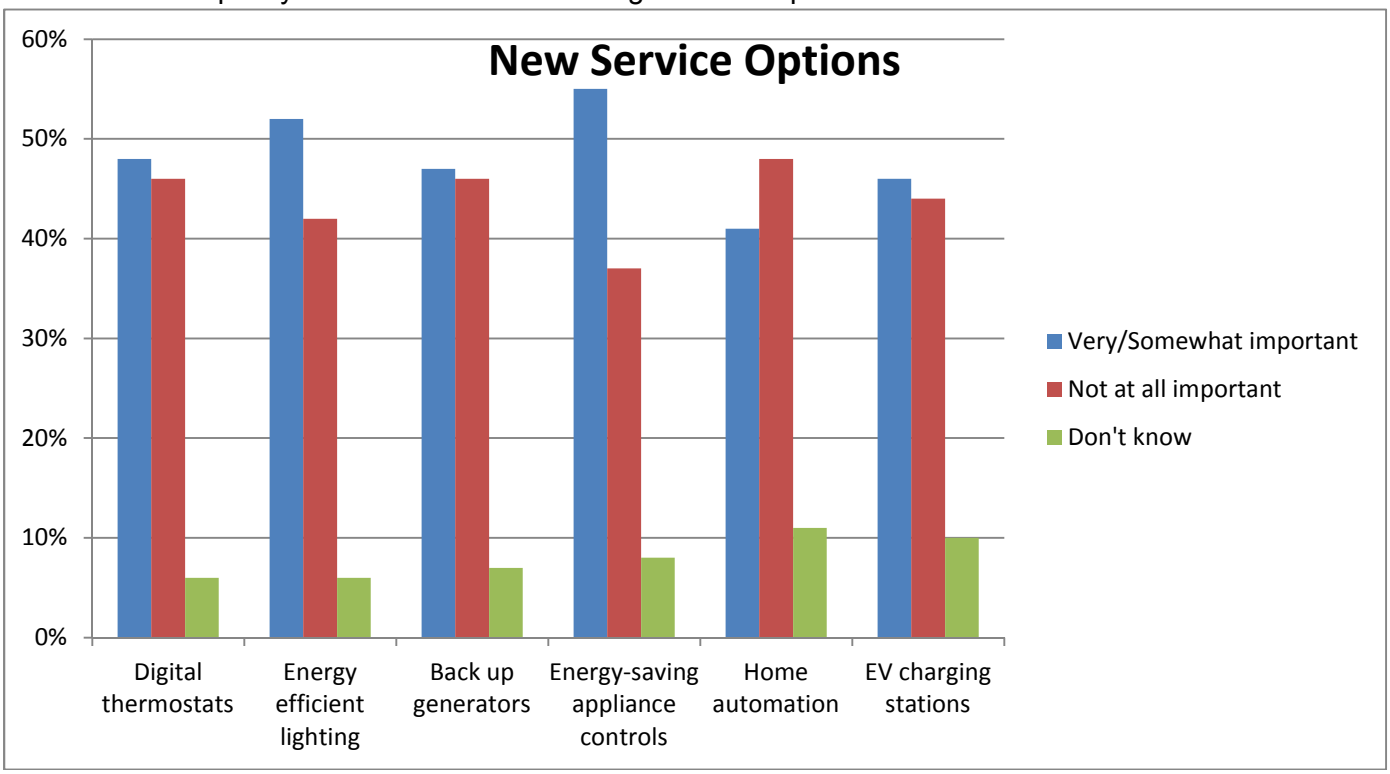
Through the saveONenergy^{OM} programs available through the IESO, Guelph Hydro customers have a great opportunity to take advantage of energy conservation incentives. Survey findings indicate that Guelph Hydro can be doing more the improve awareness of and participation in the programs.

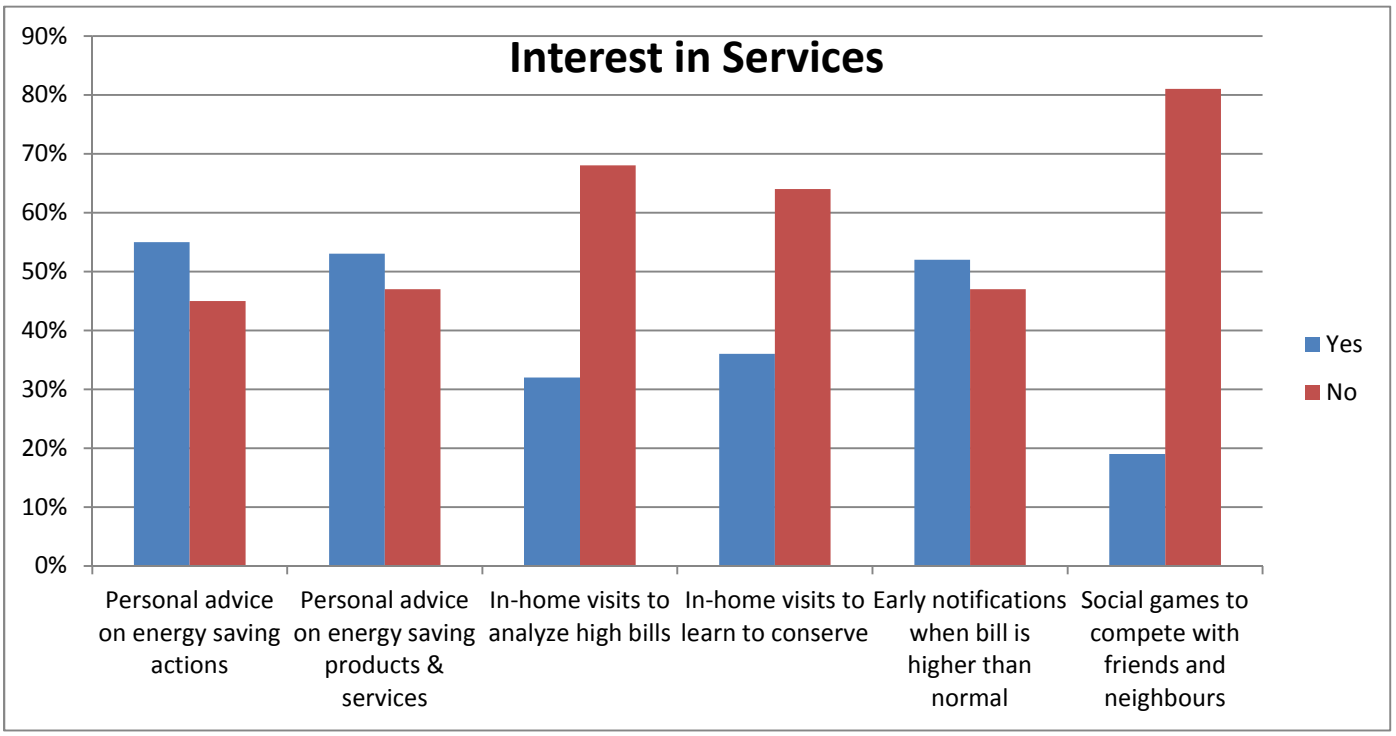
- **82 per cent** of survey respondents said they would like to see Guelph Hydro **invest in more energy conservation programs**
- **70 per cent** said they would like to see **more customer communication and education about energy conservation**.
- **63 per cent** said they felt it was **very or somewhat important** that Guelph Hydro **hire representatives to help business and industries in the community improve their energy efficiency.**
- **56 per cent** felt it was **very or somewhat important** to **offer on-bill financing for energy conservation and efficiency initiatives**
- Approximately **half of respondents** are **aware** of the **saveONenergy^{OM} coupons and the HEATING AND COOLING INCENTIVE**, but only **33 per cent have taken advantage of the coupons**
- **Less than 10 per cent have taken advantage of the HEATING AND COOLING INCENTIVE**.
- **58 per cent** are **aware of peaksaverPLUS**
- **60 per cent were aware of the FRIDGE AND FREEZER PICK UP**



Value Add or New Service Options

In the survey, Guelph Hydro asked questions to gauge customer interest in value-add services or new service options. These results reveal there may value-add options Guelph Hydro can offer to customers. Guelph Hydro will continue to investigate these options.




Interest in Services
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Personal advice on energy saving actions
Personal advice on energy saving products & services
In-home visits to analyze high bills
In-home visits to learn to conserve
Early notifications when bill is higher than normal
Social games to compete with friends and neighbours
Yes
No

Renewable Energy and New Technology

According to survey respondents, interest in renewable energy and new technologies is low.

- **18 per cent** of respondents reporting they are either **planning or considering installing rooftop solar panels** on their home in the next five years
- **10 per cent** of respondents **planning or considering installing an energy storage system,**
- **23 per cent** of respondents **planning on or considering purchasing an electric vehicle** in the next three to five years.

Despite this, **76 per cent** said that it was **very or somewhat important** for Guelph Hydro to **invest in research into future technologies such as smart grids, electric vehicles or electricity storage (see chart on page 11).**

Guelph Hydro will continue to monitor industry developments and growth in these technologies so it is ready to react should interest change.

Service Reliability and Power Outages

With respect to service reliability and power outages, Guelph Hydro customers are satisfied.

- **83 per cent** of respondents rated Guelph Hydro's **performance in minimizing power outages as "Good" or "Excellent,"**
- **82 per cent** of respondents said the **time within which Guelph Hydro restores power** when a power outage occurs is **"Good" or "Excellent."**
- **91 per cent** of respondents said the **overall reliability** of the electricity service is **"Good" or "Excellent,"**
- **83 per cent** of respondents rated the performance of Guelph Hydro's **outside crews as "Good" or "Excellent."**
- Only **five per cent** of respondents reported that their **home or business was negatively affected by a power outage in the past year**, excluding the ice storm in December 2013.

Guelph Hydro's outage reporting communications is generally acceptable but there is room for improvement in this area. Guelph Hydro will be exploring ways to enhance its customer communication efforts during outages.

- **28 per cent** of respondents rated Guelph Hydro "**Good" or "Fair" in being reachable by telephone** during an outage, but **58 per cent** responded **"Don't know."**
- **40 per cent** of respondents rated Guelph Hydro as **"Good" or "Fair" when communicating the cause and estimated time of restoration** during a power outage through Guelph Hydro's website, mobile website, Twitter, customer service department and radio, but **43 per cent responded "Don't know."**

When asked what they attributed power outages to, **79 per cent** of respondents attributed power outages to **weather, animal contacts or "natural occurrences"** and **12 per cent** thought they were the result of **equipment trouble, maintenance, or human interference**.

This indicates that Guelph Hydro is seeing success in communicating the causes of outages as responses are in line with actual causes of power outages.

When asked to think about the Ice Storm in December 2013 and the damaging wind storms that have occurred over the past two years in Guelph, **27 per cent** of respondents said Guelph Hydro could have done a **better job of communication**.

- **17 per cent** said to **improve or continue to keep trimming trees**
- **13 per cent** said to **move service underground**
- **11 per cent** wanted an **estimated time of restoration**
- **8 per cent** wanted **updates by email**.

Guelph Hydro has already taken some of the learnings gained through the ice storm and made some changes to processes including publishing a Crisis Communications Plan and improving its Twitter activities during severe weather and in response to outages.

Investment in Infrastructure

Overall, survey respondents are satisfied with Guelph Hydro's investment in infrastructure.

- **65 per cent** of respondents would like to see Guelph Hydro **replace equipment according to a pre-determined replacement schedule**, even if it means spending more money replacing equipment that is still working
- **83 per cent did not feel** Guelph Hydro **should be investing additional funds and raising rates to reduce the number of power outages in the community**.
- **81 per cent did not want to see** Guelph Hydro budget for a long-term project to **move overhead services underground**.
- **54 per cent were unwilling** to pay extra in order for Guelph Hydro to **staff a System Control Centre 24/7**, and only **35 per cent felt it was very or somewhat important.**

These results were taken into consideration in preparing the Distribution System Plan.

Safety

Overall, respondents are **very satisfied or satisfied** with Guelph Hydro's commitment to employee and public safety, with **87 per cent** reporting they **do not feel Guelph should be doing more** to improve electrical safety. Of those who felt Guelph Hydro could do more, suggestions included:

- Continuous improvement
- More education about electrical safety for children and the public
- Free do-it-yourself (DIY) workshops for electrical wiring of a home

Supporting this suggestion, **76 per cent of respondents** reported they **feel it is important** for Guelph Hydro to **invest in materials for schools to use to teach children about energy conservation and electrical safety,**

While Guelph Hydro currently has a school education program in place and actively promotes electricity safety in the community, it will continue to look for opportunities to further this education, including the potential for DIY workshops.

APPENDIX Q: GHESI Building Addition Project Internal Memo

TO: Kazi Marouf, COO

FROM: Erik Veneman, Director of Operations

DATE: April 22, 2015

RE: Building Addition Project - revised

Hi Kazi,

Below is some additional information regarding the proposed building addition project:

Background:

Guelph Hydro consolidated two locations into one (moving administrative and office staff from Dawson Road to 395 Southgate) in 2006. At that time, there were a total of 90 employees including 63 office staff. The number of office staff has since grown to 93 or 45% more than in 2006 (excluding contract/temporary employees) and will increase to 96 in 2016. Available office space has become constrained in multiple work areas and some smaller departments are scattered throughout the building due to the lack of available space where it's needed.

Given that GMHI personnel will continue to work in specific areas within the building, the additional space is now required to satisfy needs in areas including Finance, Regulatory, Engineering, and Operations. Also, CDM personnel are mostly scattered throughout the existing building and addressing departmental needs will be particularly important as two more employees are added by mid-year 2015 lasting until at least 2020. Finally, the new addition will allow for expansion of the Control Room to allow for the planned migration to 24/7 coverage and based on the accelerated growth potential of shared services to other LDC's. Other areas that could benefit from additional space include Safety/Training and Communications.

Another important consideration is that access to the existing second floor for the Control Room is not AODA (Accessibility for Ontarians with Disabilities Act) compliant as it currently has stair access only and an elevator shaft would have to be built in order to meet compliance requirements. The contemplated addition would connect the Control Room area to the main second floor and elevator access, eliminating the need for the new elevator.

Alternatives:

Alternatives considered are summarized here:

Item	Estimated Cost	Normalized Cost (10 year)	Additional Sq.ft.	Total (10 year) Cost per sq.ft.
Do nothing	$0	$0	0	$0
Build a new facility	$2M	$3.5M	5,000	$700
Rent additional space	$300k / year	$3.0M	5,000	$600
Existing building addition	$1.25M	$2.5M	5,000	$500
Utilize existing space	$1.0M	$1.15M	1,500	$767

Option 1. - Do Nothing

Risks associated with doing nothing numerous and range from moderate to high ranking, depending on the area impacted. High impacts include the Control Room and Finance areas where additional space needs are significant and no option exists for re-organization or movement of existing staff. For the other areas noted above, short to mid-term impacts to workflow are significant while longer term impacts to succession planning and planned expansion are unacceptable due to the fact that, at some point, work certain areas would need to stop.

Option 2. - Build a new facility

The cost of building a new facility is estimated at $2M which would include construction costs, servicing, and land acquisition – provided land is readily available in a suitable location. This option includes inefficiencies associated with separate office locations and additional costs related to connecting communications, IT, and management systems.

Option 3. - Rent the required space

Office space rental in Guelph would come at a premium and would present other complications associated with a remote site. As noted above, inefficiencies associated with renting a separate space include connecting communications, IT, and management systems. For 5,200 square feet, annual rental and operating costs are estimated at $300k. This means that within the 10 year timeframe of the expansion project, roughly $3M would have been paid out in rent and facility operating expenses.

Option 4. - Existing building addition

The existing building facility is located at 395 Southgate Drive in Guelph and includes approximately 52,645 square feet in office space. This includes common areas as well as the Control Room. About 5,000 s.f. of new space exists above the Operations Department - adjacent to Finance and the existing Control Room. This section was purposely reinforced for a second floor addition when the building was originally built and, by good planning, reroofing of this area was not completed in 2014. This expansion will accommodate office space requirements for at least the next 10 years with every department's needs considered and an optimal floorplan developed as part of the project plan.

The estimated cost of this addition is $1.25 million, complete with space fit-up, work stations and additional meeting space. Part of the cost will also include relocating and reusing the existing skylights and rerouting fresh air intake from an existing air handling unit. Main building heating, cooling and electrical capacity will not have to be upgraded to handle the additional space. The plan for 2015 will be to engage an Architect and proceed with design drawings, call tenders and close in the space before next winter. The balance will be completed in 2016 with space occupancy by mid-year. The impact on capital budgets is expected to be an estimated $500,000 in 2015 and the balance $750,000 in 2016.

Option 5. - Utilize Existing Space

This option, at first glance, is the most appealing as it would appear to require the least amount of effort. Given the number of departments requiring additional space, however, the amount of re-organizing that would be required to accommodate space requirements would be significant and would only cover immediate to short term needs. Areas requiring work include –

- Finance (move offices to accommodate 2 new staff and new office for controller position - $75k)
- Regulatory (consolidate existing 2 staff and add 1 – 50k)
- Control Room/SCADA (increase locker and washroom space. add a storm/meeting room, and install second elevator access - $250k)

- CDM (add two spaces with no location currently, and consolidate three other staff into one location - $150k)
- Engineering (one additional space plus meeting room expansion - $50k)
- Communications (consolidate two staff and allow for growth of one - $75k)

The total investment requirement for this scenario would be $650k. This is a short term (two year) solution and includes significant “throw away” costs.

A similar expansion scenario includes utilizing common areas on the second floor that currently exist as open space under the main new building area skylight. This area includes approximately 1,065 s.f. of space. Given the small amount of space that would be gained, and the significant work involved with structural floor installation complete with roof/skylight modifications, cost for this option (estimated at $350k) are higher per square foot than the previously noted alternatives.

Total costs for this option would be $1.0M and would include only 1,500 s.f. of equivalent or additional space.

Recommendation:

It is recommended to proceed with Option 4 – Existing Building Expansion. This option provides the greatest benefit for dollars spent and allows for maximized use of the existing infrastructure and facility. Starting in 2015 with design and material procurement, the project can be complete and ready for occupancy in mid-2016.

Budgetary forecasts include up to $500k to be spent in fiscal 2015 with the remainder to be spent as part of 2016 capital expenditures.

APPENDIX 2-B: Capitalization and Overhead Policy

Guelph Hydro Electric Systems Inc. FINANCIAL POLICY	Subject: CAPITALIZATION AND OVERHEAD POLICY Number: FIN-05 Date: August 2014 Revised: October 2014 Page 1 of 3
Approved by: Chief Financial Officer	Signature:

1. PURPOSE

1.1. This Statement of Policy provides guidance for the recording of costs related to the acquisition or construction of distribution system assets, equipment, building, and other tangible assets. The control objectives addressed by this policy are to ensure that fixed assets are complete, exist and are accurately recorded.

2. POLICY

2.1. All expenditures directly attributable to bringing an asset to the location, and working condition for its intended use should be capitalized.

Examples of directly and "not directly" attributable costs are as follows:

Directly attributable:

- Employee costs and benefits incurred by employees working directly on construction or acquisition of asset
- Costs of site preparation
- Initial delivery and assembly
- Testing costs
- Professional fees

Not directly attributable:

- Administrative and other general overhead costs
- Feasibility studies
- Start-up or pre-opening costs
- Training costs
- Abnormal waste
- Costs incurred when construction is interrupted, unless certain criteria are met
- Cost of opening a new facility
- Relocation costs
- Costs incurred in using or redeploying an item

2.2. Costs attributed to administrative other, general overhead and training are prohibited from being capitalized.

2.3. The attached listing provides a summary of all costs included in Guelph Hydro's burdenable (overhead) costs:

Payroll and Operations:

- Administration expense
- Indirect labour
  - Line crew
  - Maintenance
  - Metering
  - Customer service
  - Inspect/Engineering
- Employee benefits
- Small tools
- Clothing
- Building maintenance
- Insurance
- Outside services
  - Subcontract
- Property taxes
- Supervisory salaries
  - Line supervisors
- Supplies/other
- Vehicle expenses

Fleet Burden:

- Administration expense
- Building and operating costs
- Depreciation
- Employee benefits
- Equipment maintenance
- Freight
- Fuel
- Insurance
- Licensing

Engineering Burden:

- Administration expense
- Employee benefits
- Equipment maintenance
- Freight
- Memberships
- Mini computer
- Outside services
- P.C. expense
- Salary-bargaining unit
- Supplies
- Vehicles
- Work order changes
- Other

These costs are treated as capital costs if they are deemed to be directly attributable to the construction of distribution system assets.

The following listing summarizes the burdenable costs which are not directly attributable to the construction of assets and therefore not capitalized:

- Non-productive time (training costs, safety meetings, adverse weather)
- Property taxes

- Supervisory salaries related to administrative functions
- Insurance
- Information technology expenses
- Office equipment maintenance
- Freight
- Memberships
- Office supplies

2.4. Guelph Hydro uses a work order system to manage and record costs relating to the purchase and construction of property, plant and equipment. The work order system is also used to track and record directly attributable expenses for Capitalization such as labour costs, direct engineering, third party contractor costs, and vehicle costs. All employees who are directly involved in work order projects are required to record their time on timesheets, based on a series of time codes (regular, training, sick, vacation, etc.). This helps to ensure that only eligible costs are capitalized. Management in Engineering and Operations conduct regular reviews of work orders and timesheets to ensure that the Corporation's Capitalization Policy is applied consistently and accurately. For Employees that do not record their costs on timesheets, e.g., Operations Supervisory staff and Engineering staff, estimates are made of the time directly attributable to projects/jobs incurring costs eligible for capitalization. These estimates are reviewed annually by Management in the Engineering, Operations, Finance and Human Resources Departments.

3. SCOPE

3.1. This Capitalization Policy applies to all employees engaged in the acquisition and recording of fixed assets.

4. RESPONSIBILITY

The Manager of Accounting and Accounting Supervisor are responsible for the identification and proper recording of fixed assets. Employees engaged in the acquisition of fixed assets are responsible for ensuring that the costs of acquisition are complete, that the costs exist and that the costs are accurate. The Manager of Accounting and Accounting Supervisor in conjunction with the employee responsible for the acquisition of the fixed asset are responsible for determining the useful life of the item. On an annual basis, the useful lives of assets will be reviewed for reasonableness by Finance in conjunction with Engineering, Operations and Information Services. Useful lives will be adjusted if the change in useful lives is deemed to have a significant impact on the annual depreciation calculation.