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RATE BASE

RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement used in this Application follows *Chapter 2 of the Filing Requirements for Electricity Distribution Applications* issued by the Ontario Energy Board ("Board") on July 18, 2014 (the "Filing Requirements"). In accordance with the Filing Requirements, North Bay Hydro Distribution Limited ("NBHDL") has calculated the rate base as an average of the net capital balances at the beginning and the end of the 2015 Test Year plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses.

NBHDL has submitted this application under the assumption that it will move forward with the change-over to Modified International Financial Reporting Standards ("MIFRS") as of January 1, 2015 with a January 1, 2014 transition date. For rate base purposes, 2014 has been restated under MIFRS. On July 17, 2012 the Board issued a statement that changes to depreciation rates and capitalization policies that would have been implemented under International Financial Reporting Standards ("IFRS") could be made in 2012 under Canadian Generally Accepted Accounting Principles ("CGAAP") (i.e. effective January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the Canadian Accounting Standards Board (AcSB) permitted further deferrals beyond 2012 for the changeover to IFRS (Board Letter, July 17, 2012 *"Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013"*). In 2012, NBHDL implemented the change to depreciation rates and capitalization policies which is explained in further detail in the section "Changes to Capitalization Policy" further below. For rate base purposes, 2012 has been calculated with these changes implemented. Table 2-12 through 2-19 provide the fixed asset continuity schedules, excluding Work In Progress ("WIP"), used for rate base calculations; for comparative purposes 2012 is provided under both CGAAP and Revised CGAAP ("RCGAAP") to reflect depreciation changes and 2014 is provided under both RCGAAP and MIFRS.

Net capital assets include in service assets that are associated with activities that enable the conveyance of electricity for distribution purposes minus accumulated depreciation and contributed capital from third parties. For purposes of this Exhibit, distribution assets refer to those assets that are most directly related to the distribution system, such as poles, overhead and underground lines, and transformers. General plant refers to assets that support the operation of the distribution system such, as computer hardware and software, vehicles, buildings, equipment. Capital assets include property, plant and equipment ("PP&E") and intangible assets; these are referred to as "capital" or "fixed" assets throughout this evidence. The rate base calculation excludes any non-distribution assets. NBHDL has not applied for, nor received, any Incremental Capital Module ("ICM") adjustments.

Controllable expenses include operations and maintenance, billing and collecting, community relations and administration expenses.

NBHDL has provided its rate base calculations for the years 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year and 2015 Test Year in Table 2-1 below:

Table 2-1 - Summary of Rate Base

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Gross Fixed Assets, Opening Balance	80,070,446	80,599,232	86,605,519	93,235,866	96,935,958	102,314,173	108,443,789
Gross Fixed Assets, Closing Balance	89,171,054	86,605,519	93,235,866	96,935,958	102,314,173	108,443,789	115,827,344
Average Gross Fixed Assets	**84,620,750**	**83,602,376**	**89,920,693**	**95,085,912**	**99,625,066**	**105,378,981**	**112,135,566**
Accumulated Depreciation, Opening Balance	46,679,036	46,271,663	48,981,464	51,556,264	53,292,920	55,271,308	55,911,911
Accumulated Depreciation, Closing Balance	49,511,757	48,981,464	51,556,264	53,292,920	55,271,308	55,911,911	57,982,929
Average Accumulated Depreciation	**48,095,396**	**47,626,564**	**50,268,864**	**52,424,592**	**54,282,114**	**55,591,610**	**56,947,420**
Average Net Book Value	**36,525,354**	**35,975,812**	**39,651,829**	**42,661,320**	**45,342,952**	**49,787,371**	**55,188,146**
Working Capital	50,533,016	49,333,491	53,739,867	56,016,728	61,805,639	64,196,390	68,256,125
Working Capital Allowance (%)	15%	15%	15%	15%	15%	15%	13%
Working Capital Allowance	**7,579,952**	**7,400,024**	**8,060,980**	**8,402,509**	**9,270,846**	**9,629,459**	**8,873,296**
Rate Base	**44,105,306**	**43,375,835**	**47,712,809**	**51,063,830**	**54,613,797**	**59,416,830**	**64,061,442**

NBHDL has calculated its 2015 rate base as $64,061,442, an increase of $19,956,136 over the 2010 Board Approved rate base of $44,105,306. This increase in rate base of $19,956,136 is attributable to an increase in the average net book value of capital assets of $18,662,792 and an increase in the working capital allowance of $1,293,344. NBHDL has invested significantly back in its distribution system since the last Cost of Service (COS) application and this is reflected in the net book value variance; 94% of the incremental increase to rate base is driven by investment in the system through an increase in net book value. Approximately 92% of the working capital increase of $17,723,109 is related to cost of power. Controllable OM&A expenses increased 8% over the 2010 Board-Approved amounts for working capital.

NBHDL has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year and 2015 Test Year in Table 2-2 below. Further details of NBHDL's calculation of its cost of power calculations are provided in Table 2-27. The 2014 bridge year includes six (6) months of actual data, to June 2014, and six (6) months of forecasted data.

Table 2-2 - Summary of Working Capital Calculation

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Cost of Power	44,788,315	44,267,559	48,303,086	50,412,615	56,023,658	57,307,862	61,164,705
Operations	691,316	789,643	942,500	860,402	897,622	960,774	1,088,205
Maintenance	1,270,828	1,146,781	1,126,685	1,270,845	1,397,537	1,536,335	1,721,331
Billing & Collecting	1,144,087	910,353	887,267	1,056,107	1,019,133	1,604,983	1,243,810
Community Relations	112,000	0	(784)	35,050	(6,800)	1,502	2,200
Admin & General Expense	2,462,179	2,158,328	2,407,977	2,309,976	2,397,460	2,704,381	2,949,298
Donations - LEAP	0	0	14,550	14,550	14,550	14,550	16,700
Property Taxes	64,292	60,827	58,586	57,183	62,479	66,004	69,876
Working Capital	**50,533,016**	**49,333,491**	**53,739,867**	**56,016,728**	**61,805,639**	**64,196,390**	**68,256,125**

VARIANCE ANALYSIS OF RATE BASE

The following Table 2-3 sets out NBHDL's rate base and working capital calculations for the 2015 Test Year, 2014 Bridge Year, 2013 Actual, 2012 Actual, 2011 Actual, 2010 Board Approved and Actual, and the following variances:

- 2015 Test Year against 2014 Bridge Year;
- 2014 Bridge Year against 2013 Actual;
- 2013 Actual against 2012 Actual;
- 2012 Actual against 2011 Actual;
- 2011 Actual against 2010 Actual; and
- 2010 Actual against 2010 Board Approved.

Table 2-3 - Rate Base Variances

Description	2010 OEB Approved	2010 Actual	Variance from 2010 OEB Approved	2011 Actual	Variance from 2010 Actual	2012 Actual	Variance from 2011 Actual Year	2013 Actual	Variance from 2012 Actual Year	2014 Bridge Year	Variance from 2013 Actual Year	2015 Test Year	Variance from 2014 Bridge Year
Gross Fixed Assets	89,171,054	86,605,519	(2,565,535)	93,235,866	6,630,347	96,935,958	3,700,091	102,314,173	5,378,215	108,443,789	6,129,616	115,827,344	7,383,555
Accumulated Depreciation	49,511,757	48,981,464	(530,292)	51,556,264	2,574,799	53,292,920	1,736,657	55,271,308	1,978,388	55,911,911	640,603	57,982,929	2,071,018
Net Book Value	39,659,298	37,624,055	(2,035,243)	41,679,603	4,055,548	43,643,038	1,963,435	47,042,865	3,399,827	52,531,878	5,489,012	57,844,415	5,312,537
Average Net Book Value	36,525,354	35,975,812	(549,542)	39,651,829	3,676,017	42,661,320	3,009,492	45,342,952	2,681,631	49,787,371	4,444,420	55,188,146	5,400,775
Working Capital	50,533,016	49,333,491	(1,199,526)	53,739,867	4,406,376	56,016,728	2,276,861	61,805,639	5,788,911	64,196,390	2,390,752	68,256,125	4,059,734
Working Capital Allowance (%)	15%	15%		15%		15%		15%		15%		13%	
Working Capital Allowance	7,579,952	7,400,024	(179,929)	8,060,980	660,956	8,402,509	341,529	9,270,846	868,337	9,629,459	358,613	8,873,296	(756,162)
Rate Base	**44,105,306**	**43,375,835**	**(729,471)**	**47,712,809**	**4,336,973**	**51,063,830**	**3,351,021**	**54,613,797**	**3,549,968**	**59,416,830**	**4,803,033**	**64,061,442**	**4,644,613**

NBHDL has calculated the materiality threshold on its rate base to be $69,245 for 2015 in accordance with the Filing Requirements. On this basis, NBHDL has selected a materiality threshold of $65,000. This calculation is summarized in Table 2-4 below:

Table 2-4 - Rate Base Materiality

Description	2015 Test Year
Distribution Revenue Requirement	$13,848,941
Materiality Threshold	0.50%
Materiality Calculated	$69,245
Materiality Used	$65,000

NBHDL offers the following comments in respect of the relevant variances identified above:

- **2015 Test Year:**

Description	2015 Test Year
Gross Fixed Assets	115,827,344
Accumulated Depreciation	57,982,929
Net Book Value	57,844,415
Average Net Book Value	55,188,146
Working Capital	68,256,125
Working Capital Allowance	8,873,296
Rate Base	**64,061,442**

As shown above, the total rate base in the 2015 Test Year is forecast to be $64,061,442. Average net fixed assets account for $55,188,146 of this total. The allowance for working capital totals $8,873,296; $7,951,412 (or 90%) is related to cost of power expenses.

- **2015 Test Year vs. 2014 Bridge Year:**

Description	2015 Test Year	2014 Bridge Year	Variance from 2014 Bridge Year
Gross Fixed Assets	115,827,344	108,443,789	7,383,555
Accumulated Depreciation	57,982,929	55,911,911	2,071,018
Net Book Value	57,844,415	52,531,878	5,312,537
Average Net Book Value	55,188,146	49,787,371	5,400,775
Working Capital	68,256,125	64,196,390	4,059,734
Working Capital Allowance	8,873,296	9,629,459	(756,162)
Rate Base	**64,061,442**	**59,416,830**	**4,644,613**

The total rate base is expected to be $4,644,613 higher in the 2015 Test Year than in the 2014 Bridge Year. This increase is shown above and is attributable primarily to an increase in average net book value of $5,400,775 partially offset by a decrease in working capital allowance of $756,162. The addition to gross fixed assets in 2015 is $7,383,555 and Table 2-24 provides a more detailed variance of year over year changes to gross assets. Details with respect to NBHDL's 2015 capital expenditure program are provided in NBHDL's Distribution System Plan ("DSP"), found in Appendix 2-A. The working capital allowance decrease was primarily a result of a reduction in the working capital allowance percentage from 15% to 13%.

95% of the increase in working capital can be attributed to the increase in cost of power expenses; the detailed calculation of the cost of power expense for the 2015 Test Year can be found in Table 2-27.

- **2014 Bridge Year vs. 2013 Actual:**

Description	2014 Bridge Year	2013 Actual	Variance from 2013 Actual
Gross Fixed Assets	108,443,789	102,314,173	6,129,616
Accumulated Depreciation	55,911,911	55,271,308	640,603
Net Book Value	52,531,878	47,042,865	5,489,012
Average Net Book Value	49,787,371	45,342,952	4,444,420
Working Capital	64,196,390	61,805,639	2,390,752
Working Capital Allowance	9,629,459	9,270,846	358,613
Rate Base	**59,416,830**	**54,613,797**	**4,803,033**

The total rate base for the 2014 Bridge Year is expected to be $59,416,830, which represents an increase of $4,803,033 over the 2013 Actual year. This increase is shown above and is attributable primarily to an increase in average net book value of $4,444,420. Distribution assets increased $6,133,986, general plant assets $1,123,707, offset by contributed capital of ($1,128,077) for a total change of $6,129,616 in gross fixed assets. Table 2-24 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

On February 20, 2014 NBHDL received a Decision and Order (*EB-2013-0157*) regarding its 2014 IRM that included the disposition and recovery of costs related to the Smart Meter deployment initiated in 2009 by NBHDL. The Board granted its approval of historically incurred costs and the costs projected for 2014 and as such NBHDL recorded these costs in its gross fixed assets in May of 2014. NBHDL proposed not to dispose of stranded meter costs through *EB-2013-0157*, but to deal with the disposition in its next rebasing application. As part of this COS application, NBHDL will be seeking disposition of the net book value ("NBV") of its stranded meters and has adjusted its rate based accordingly in 2014 to recognize the disposition; this ensures that the opening value of the 2015 Test Year properly reflects PP&E for rate setting purposes. The treatment and detailed calculation of the stranded assets related to smart meter deployment can be found in the section "Treatment of Stranded Assets Related to Smart Meter Deployment" further below within this Exhibit.

Approximately 54% of the increase in the 2014 working capital allowance can be attributed to the increase in cost of power expenses from 2013. $412,537 related to the smart meter disposition was also recorded in 2014 to OM&A costs, which accounts for 17.5% of the increase in the working capital allowance.

- **2013 Actual vs. 2012 Actual:**

Description	2013 Actual	2012 Actual	Variance from 2012 Actual
Gross Fixed Assets	102,314,173	96,935,958	5,378,215
Accumulated Depreciation	55,271,308	53,292,920	1,978,388
Net Book Value	47,042,865	43,643,038	3,399,827
Average Net Book Value	45,342,952	42,661,320	2,681,631
Working Capital	61,805,639	56,016,728	5,788,911
Working Capital Allowance	9,270,846	8,402,509	868,337
Rate Base	**54,613,797**	**51,063,830**	**3,549,968**

The rate base of $54,613,797 for 2013 Actual increased over 2012 Actual by $3,549,968. This increase is shown above and is driven significantly by an increase in the average net book value of $2,681,631. Distribution assets increased $6,008,990, general plant assets $431,165, offset by contributed capital of ($1,061,939) for a total change of $5,378,216 in gross fixed assets. Table 2-24 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

The primary driver of the increase in working capital of $5,788,911 is related to an increase in the cost of power expense of $5,611,043. A summary of the cost of power expenses for 2010 through 2015 can be found in Table 2-27.

- **2012 Actual vs. 2011 Actual:**

Description	2012 Actual	2011 Actual	Variance from 2011 Actual
Gross Fixed Assets	96,935,958	93,235,866	3,700,091
Accumulated Depreciation	53,292,920	51,556,264	1,736,657
Net Book Value	43,643,038	41,679,603	1,963,435
Average Net Book Value	42,661,320	39,651,829	3,009,492
Working Capital	56,016,728	53,739,867	2,276,861
Working Capital Allowance	8,402,509	8,060,980	341,529
Rate Base	**51,063,830**	**47,712,809**	**3,351,021**

The rate base of $51,063,830 for 2012 Actual increased over 2011 Actual by $3,351,021. This increase is shown above and is made up of a change in average net assets of $3,009,492 as a result of capital expenditures. Distribution assets increased $3,575,569, general plant assets $800,450, offset by contributed capital of ($675,928) for a total change of $3,700,091 in gross fixed assets. Table 2-24 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

The working capital allowance increased by $341,529. A summary of the cost of power expenses can be found in Table 2-27; $316,429 of the change in the working capital allowance is related to the cost of power expenses.

- **2011 Actual vs. 2010 Actual:**

Description	2011 Actual	2010 Actual	Variance from 2010 Actual
Gross Fixed Assets	93,235,866	86,605,519	6,630,347
Accumulated Depreciation	51,556,264	48,981,464	2,574,799
Net Book Value	41,679,603	37,624,055	4,055,548
Average Net Book Value	39,651,829	35,975,812	3,676,017
Working Capital	53,739,867	49,333,491	4,406,376
Working Capital Allowance	8,060,980	7,400,024	660,956
Rate Base	**47,712,809**	**43,375,835**	**4,336,973**

The rate base of $47,712,809 for 2011 Actual increased over 2010 Actual by $4,336,973. This increase is shown above and is made up primarily of a change in average net assets of $3,676,017 as a result of capital expenditures. Distribution assets increased $6,545,981, general plant assets $548,496, offset by contributed capital of ($464,129) for a total change of $6,630,348 in gross fixed assets. Table 2-24 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

The working capital allowance increased by $660,956; $605,329 is a result of increased cost of power expenses.

- **2010 Actual vs. 2010 Board Approved:**

Description	2010 Actual	2010 OEB Approved	Variance from 2010 OEB Approved
Gross Fixed Assets	86,605,519	89,171,054	(2,565,535)
Accumulated Depreciation	48,981,464	49,511,757	(530,292)
Net Book Value	37,624,055	39,659,298	(2,035,243)
Average Net Book Value	35,975,812	36,525,354	(549,542)
Working Capital	49,333,491	50,533,016	(1,199,526)
Working Capital Allowance	7,400,024	7,579,952	(179,929)
Rate Base	**43,375,835**	**44,105,306**	**(729,471)**

The rate base of $43,375,835 for 2010 Actual was lower than the 2010 Board Approved by $729,471.

Capital expenditures were lower than originally planned which contributed to the variance of ($2,035,243) in NBV. Distribution assets were lower by $1,923,227, general plant assets lower by $421,158, and contributed capital was lower by ($221,150) for a total change of ($2,565,535) in gross fixed assets. Table 2-24 and the subsequent narrative provide a more detailed explanation of the change in gross assets year over year. Table 2-34 provides the project level detail of 2010 capital spending as compared 2010 Board Approved amounts. The change in accumulated amortization is a result of changes in capital additions, depreciation expense and disposals.

Cost of power and OM&A expenses were also lower than Board Approved in 2010 which resulted in a decrease to the Board Approved working capital allowance of $179,929.

FIXED ASSET CONTINUITY SCHEDULES, INCLUDING WORK IN PROGRESS

Table 2-6 through Table 2-11 provide the Fixed Asset Continuity Schedules, including WIP for each of 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year, and 2015 Test Year.

The total gross asset balances in NBHDL's Fixed Asset Continuity Statements do not balance to the opening and closing balances of gross assets used to calculate the fixed asset component of rate base. WIP has been removed from the fixed asset continuity schedule balances for rate base calculation purposes, as mandated by the Board. A reconciliation of year-end NBV by year is provided in Table 2-5 below. The opening and closing balances of accumulated depreciation used to calculate the fixed asset component of rate base correspond to the fixed asset continuity schedule. As such there is no reconciliation required for accumulated depreciation.

Table 2-5 – Reconciliation of Opening and Closing Balances

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Total Gross Assets for Rate Base	89,171,054	86,605,519	93,235,866	96,935,958	102,314,173	108,443,789	115,827,344
Work in Progress	0	0	0	625,281	526,120	805,462	21,361
Total Gross Assets, including WIP	**89,171,054**	**86,605,519**	**93,235,866**	**97,561,239**	**102,840,293**	**109,249,251**	**115,848,705**
Total Accumulated Depreciation for Rate Base	49,511,757	48,981,464	51,556,264	53,292,920	55,271,308	55,911,911	57,982,929
Total Accumulated Depreciation, including WIP	**49,511,757**	**48,981,464**	**51,556,264**	**53,292,920**	**55,271,308**	**55,911,911**	**57,982,929**
Total Net Book Value for Rate Base	39,659,298	37,624,055	41,679,603	43,643,038	47,042,865	52,531,878	57,844,415
Work in Progress	0	0	0	625,281	526,120	805,462	21,361
Total Net Book Value, including WIP	**39,659,298**	**37,624,055**	**41,679,603**	**44,268,319**	**47,568,985**	**53,337,340**	**57,865,776**

Table 2-6 - Fixed Asset Continuity Schedule as at December 31, 2010, CGAAP

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

			Cost			Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	368,562	71,626	-	440,188	-	-	-	-	440,188
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	769,641	-	-	769,641	279,985	13,489	-	293,474	476,167
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	9,124,702	266,961	-	9,391,662	3,606,886	280,491	-	3,887,377	5,504,285
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	16,838,396	937,493	-	17,775,889	9,803,635	534,610	-	10,338,245	7,437,644
1835	Overhead Conductors and Devices	13,398,340	606,204	-	14,004,544	7,442,542	433,940	-	7,876,482	6,128,062
1840	Underground Conduit	469,102	123,798	-	592,900	86,848	21,239	-	108,087	484,813
1845	Underground Conductors and Devices	6,195,879	286,428	-	6,482,307	3,962,259	231,995	-	4,194,254	2,288,053
1850	Line Transformers	13,954,575	771,184	-	14,725,760	8,081,956	443,297	-	8,525,252	6,200,507
1855	Services	12,521,188	3,512,092	-	16,033,280	5,001,148	531,145	-	5,532,292	10,500,988
1860	Meters	3,607,923	257,530	-	3,865,453	2,393,625	111,284	-	2,504,910	1,360,544
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	2,027,035	12,656	-	2,039,691	1,054,396	64,445	-	1,118,841	920,850
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	315,127	-	-	315,127	275,236	6,011	-	281,247	33,880
1920	Computer Equipment - Hardware	585,437	27,417	-	612,854	528,378	25,285	-	553,662	59,192
1925	Computer Software	983,376	22,620	-	1,005,996	848,667	41,971	-	890,638	115,357
1930	Transportation Equipment	2,379,846	64,703	79,733	2,364,816	1,369,063	203,184	79,733	1,492,514	872,302
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,106,956	27,751	-	1,134,706	930,279	28,481	-	958,760	175,946
1945	Measurement and Testing Equipment	8,635	-	8,635	-	432	-	432	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	101,871	-	-	101,871	68,978	6,896	-	75,875	25,996
1960	Miscellaneous Equipment	18,079	-	-	18,079	6,217	1,808	-	8,025	10,055
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,232,487	11,193	-	1,243,680	889,817	73,708	-	963,524	280,156
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	17,128	2,461	-	19,589	33,471
1995	Contributions and Grants	- 6,191,811	- 905,001	-	- 7,096,812	- 1,020,088	- 265,774	-	- 1,285,862	- 5,810,951
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**80,599,232**	**6,094,654**	**88,368**	**86,605,519**	**46,271,663**	**2,789,966**	**80,165**	**48,981,464**	37,624,055
	Work in Process		-	-	-	-			-	-
2070	Other Utility Plant - assets not in use		-	-	-				-	-
	Total after Work in Process	**80,599,232**	**6,094,654**	**88,368**	**86,605,519**	**46,271,663**	**2,789,966**	**80,165**	**48,981,464**	37,624,055

Table 2-7 - Fixed Asset Continuity Schedule as at December 31, 2011, CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2011

			Cost			Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	440,188	6,305	-	446,493	-	-	-	-	446,493
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	769,641	-	-	769,641	293,474	13,489	-	306,963	462,678
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	9,391,662	2,508,924	56,181	11,844,406	3,887,377	323,109	53,960	4,156,526	7,687,879
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	17,775,889	1,145,473	-	18,921,361	10,338,245	566,593	-	10,904,838	8,016,523
1835	Overhead Conductors and Devices	14,004,544	813,817	-	14,818,361	7,876,482	455,624	-	8,332,106	6,486,254
1840	Underground Conduit	592,900	174,099	-	766,998	108,087	27,197	-	135,284	631,714
1845	Underground Conductors and Devices	6,482,307	272,928	-	6,755,235	4,194,254	234,042	-	4,428,296	2,326,939
1850	Line Transformers	14,725,760	646,897	-	15,372,657	8,525,252	450,263	-	8,975,516	6,397,142
1855	Services	16,033,280	888,695	-	16,921,975	5,532,292	611,028	-	6,143,320	10,778,655
1860	Meters	3,865,453	145,023	-	4,010,477	2,504,910	114,455	-	2,619,364	1,391,113
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	2,039,691	142,738	-	2,182,429	1,118,841	67,553	-	1,186,394	996,035
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	315,127	24,090	-	339,217	281,247	7,157	-	288,404	50,813
1920	Computer Equipment - Hardware	612,854	135,798	-	748,652	553,662	34,317	-	587,979	160,672
1925	Computer Software	1,005,996	92,399	-	1,098,395	890,638	48,860	-	939,499	158,896
1930	Transportation Equipment	2,364,816	363,462	332,425	2,395,854	1,492,514	209,086	330,011	1,371,589	1,024,264
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,134,706	71,247	-	1,205,954	958,760	32,557	-	991,317	214,636
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	101,871	-	-	101,871	75,875	6,313	-	82,188	19,683
1960	Miscellaneous Equipment	18,079	-	-	18,079	8,025	-	-	8,025	10,055
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,243,680	51,185	-	1,294,866	963,524	48,235	-	1,011,760	283,106
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	19,589	2,045	-	21,635	31,426
1995	Contributions and Grants	- 7,096,812	- 464,129	-	- 7,560,942	- 1,285,862	- 293,156	-	- 1,579,018	- 5,981,924
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**86,605,519**	**7,018,953**	**388,606**	**93,235,866**	**48,981,464**	**2,958,771**	**383,971**	**51,556,264**	41,679,603
	Work in Process	-	-	-	-	-	-	-	-	-
2070	Other Utility Plant - assets not in use	-	-	-	-	-	-	-	-	-
	Total after Work in Process	**86,605,519**	**7,018,953**	**388,606**	**93,235,866**	**48,981,464**	**2,958,771**	**383,971**	**51,556,264**	41,679,603

Table 2-8 - Fixed Asset Continuity Schedule as at December 31, 2012, Revised CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2012

			Cost			Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	446,493	72	-	446,565	-	-	-	-	446,565
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	769,641	980,568	22,202	1,728,007	306,963	48,554	22,202	333,314	1,394,693
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	11,844,406	- 560,784	267,186	11,016,436	4,156,526	256,136	197,195	4,215,467	6,800,969
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	18,921,361	1,133,582	-	20,054,943	10,904,838	272,101	-	11,176,939	8,878,003
1835	Overhead Conductors and Devices	14,818,361	820,774	-	15,639,134	8,332,106	197,186	-	8,529,292	7,109,842
1840	Underground Conduit	766,998	24,324	-	791,323	135,284	14,576	-	149,860	641,463
1845	Underground Conductors and Devices	6,755,235	162,990	-	6,918,226	4,428,296	86,963	-	4,515,259	2,402,967
1850	Line Transformers	15,372,657	630,127	-	16,002,784	8,975,516	219,873	-	9,195,389	6,807,395
1855	Services	16,921,975	604,431	-	17,526,406	6,143,320	384,879	-	6,528,199	10,998,207
1860	Meters	4,010,477	68,874	-	4,079,350	2,619,364	122,674	-	2,742,038	1,337,312
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	2,182,429	231,827	-	2,414,256	1,186,394	75,946	-	1,262,341	1,151,915
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	339,217	31,051	-	370,268	288,404	9,867	-	298,271	71,997
1920	Computer Equipment - Hardware	748,652	68,005	-	816,657	587,979	45,149	-	633,128	183,529
1925	Computer Software	1,098,395	125,138	-	1,223,533	939,499	53,994	-	993,493	230,041
1930	Transportation Equipment	2,395,854	254,425	26,967	2,623,313	1,371,589	271,935	26,967	1,616,558	1,006,755
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,205,954	21,013	-	1,226,966	991,317	36,913	-	1,028,231	198,735
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	101,871	46,452	-	148,322	82,188	6,633	-	88,821	59,501
1960	Miscellaneous Equipment	18,079	1,970	-	20,050	8,025	4,025	-	12,050	7,999
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,294,866	47,535	-	1,342,401	1,011,760	53,114	-	1,064,873	277,528
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	21,635	1,630	-	23,264	29,796
1995	Contributions and Grants	- 7,560,942	- 675,928	-	- 8,236,870	- 1,579,018	- 179,128	-	- 1,758,146	- 6,478,724
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**93,235,866**	**4,016,447**	**316,355**	**96,935,958**	**51,556,264**	**1,983,021**	**246,364**	**53,292,920**	**43,643,038**
	Work in Process	-	625,281	-	625,281	-	-	-	-	625,281
2070	Other Utility Plant - assets not in use	-	-	-	-		-	-		-
	Total after Work in Process	**93,235,866**	**4,641,727**	**316,355**	**97,561,239**	**51,556,264**	**1,983,021**	**246,364**	**53,292,920**	**44,268,319**

Table 2-9 - Fixed Asset Continuity Schedule as at December 31, 2013, Revised CGAAP

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2013

			Cost			Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	446,565	-	-	446,565	-	-	-	-	446,565
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	1,728,007	112,435	9,936	1,830,506	333,314	33,473.69	9,936	356,852	1,473,654
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	11,016,436	2,057,224	60,158	13,013,503	4,215,467	266,126	58,378	4,423,215	8,590,287
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	20,054,943	1,345,153	5,535	21,394,561	11,176,939	299,642.84	3,886	11,472,696	9,921,865
1835	Overhead Conductors and Devices	15,639,134	753,828	-	16,392,963	8,529,292	210,307.81	-	8,739,600	7,653,362
1840	Underground Conduit	791,323	306,052	-	1,097,375	149,860	17,879.60	-	167,739	929,636
1845	Underground Conductors and Devices	6,918,226	389,846	-	7,308,072	4,515,259	93,873.23	-	4,609,132	2,698,940
1850	Line Transformers	16,002,784	519,110	3,599	16,518,295	9,195,389	236,965.70	-	9,432,355	7,085,941
1855	Services	17,526,406	491,910	-	18,018,316	6,528,199	396,989.33	-	6,925,188	11,093,127
1860	Meters	4,079,350	112,657	-	4,192,008	2,742,038	126,842.36	-	2,868,880	1,323,127
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	2,414,256	100,066	-	2,514,322	1,262,341	80,662.06	-	1,343,003	1,171,319
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	370,268	6,292	-	376,560	298,271	11,489.52	-	309,761	66,799
1920	Computer Equipment - Hardware	816,657	8,076	-	824,733	633,128	54,235.73	-	687,364	137,369
1925	Computer Software	1,223,533	94,033	-	1,317,567	993,493	79,965.59	-	1,073,458	244,108
1930	Transportation Equipment	2,623,313	58,916	-	2,682,228	1,616,558	237,948.17	-	1,854,506	827,722
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,226,966	101,630	-	1,328,596	1,028,231	40,808.79	-	1,069,039	259,556
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	148,322	20,789	-	169,111	88,821	7,583.84	-	96,405	72,706
1960	Miscellaneous Equipment	20,050	-	-	20,050	12,050	2,414.36	-	14,464	5,585
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,342,401	41,364	-	1,383,765	1,064,873	51,166.23	-	1,116,040	267,725
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	23,264	1,629.56	-	24,894	28,167
1995	Contributions and Grants	- 8,236,870	- 1,061,939	-	- 9,298,809	- 1,758,146	- 199,416.14	-	- 1,957,562	- 7,341,247
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**96,935,958**	**5,457,443**	**79,228**	**102,314,173**	**53,292,920**	**2,050,588**	**72,200**	**55,271,308**	**47,042,865**
2055	Work in Process	625,281	526,042	625,203	526,120	-	-	-	-	526,120
2070	Other Utility Plant	-	-	-	-		-	-		-
	Total after Work in Process	**97,561,239**	**5,983,486**	**704,431**	**102,840,294**	**53,292,920**	**2,050,588**	**72,200**	**55,271,308**	**47,568,985**

Table 2-10 - Fixed Asset Continuity Schedule as at December 31, 2014, MIFRS

Fixed Asset Continuity Schedule (Distribution & Operations)											
As at December 31, 2014											
			Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	446,565	-	-	446,565	-	-	-	-	446,565
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	1,830,506	-	-	1,830,506	356,852	34,598	-	391,450	1,439,056
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	13,013,503	640,888	25,000	13,629,391	4,423,215	306,674	25,000	4,704,889	8,924,502
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	21,394,561	2,168,186	215,692	23,347,054	11,472,696	339,385	177,276	11,634,805	11,712,249
1835	Overhead Conductors and Devices	16,392,963	734,144	91,894	17,035,212	8,739,600	222,720	81,039	8,881,282	8,153,930
1840	Underground Conduit	1,097,375	140,105	-	1,237,480	167,739	22,341	-	190,081	1,047,399
1845	Underground Conductors and Devices	7,308,072	179,671	-	7,487,743	4,609,132	100,992	-	4,710,124	2,777,619
1850	Line Transformers	16,518,295	667,436	86,852	17,098,879	9,432,355	253,450	70,255	9,615,550	7,483,329
1855	Services	18,018,316	816,567	-	18,834,882	6,925,188	412,199	-	7,337,387	11,497,495
1860	Meters	4,192,008	3,490,231	2,283,802	5,398,437	2,868,880	1,179,636	2,005,716	2,042,800	3,355,637
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	2,514,322	508,280	-	3,022,602	1,343,003	93,847	-	1,436,850	1,585,751
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	376,560	57,280	-	433,840	309,761	13,588	-	323,349	110,491
1920	Computer Equipment - Hardware	824,733	96,303	-	921,036	687,364	62,554	-	749,917	171,119
1925	Computer Software	1,317,567	248,336	-	1,565,903	1,073,458	153,933	-	1,227,391	338,512
1930	Transportation Equipment	2,682,228	72,163	331,838	2,422,552	1,854,506	239,603	331,838	1,762,271	660,282
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,328,596	47,000	-	1,375,596	1,069,039	47,263	-	1,116,302	259,293
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	169,111	-	-	169,111	96,405	9,264	-	105,668	63,443
1960	Miscellaneous Equipment	20,050	-	-	20,050	14,464	2,414	-	16,879	3,171
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,383,765	426,183	-	1,809,948	1,116,040	59,135	-	1,175,174	634,773
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	24,894	1,630	-	26,523	26,537
1995	Contributions and Grants	- 9,298,809	- 1,128,077	-	- 10,426,886	- 1,957,562	- 223,499	-	- 2,181,061	- 8,245,825
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**102,314,173**	**9,164,695**	**3,035,079**	**108,443,789**	**55,271,308**	**3,331,727**	**2,691,124**	**55,911,911**	**52,531,878**
2070	Other utility plant	-	-	-	-		-	-		-
2055	Work in Process	526,120	805,422	526,080	805,462	-	-	-	-	805,462
	Total after Work in Process	**102,840,294**	**9,970,116**	**3,561,159**	**109,249,250**	**55,271,308**	**3,331,727**	**2,691,124**	**55,911,911**	**53,337,339**

Table 2-11 - Fixed Asset Continuity Schedule as at December 31, 2015, MIFRS

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2015

			Cost			Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	446,565	-	-	446,565	-	-	-	-	446,565
1806	Land Rights	-	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	1,830,506	18,551	1,142	1,847,915	391,450	34,784	1,142	425,091	1,422,824
1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1815	Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	13,629,391	2,771,299	136,337	16,264,353	4,704,889	341,137	130,049	4,915,977	11,348,375
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1830	Poles, Towers and Fixtures	23,347,054	1,084,640	235,641	24,196,054	11,634,805	374,294	194,106	11,814,993	12,381,061
1835	Overhead Conductors and Devices	17,035,212	635,167	91,425	17,578,954	8,881,282	234,109	78,342	9,037,049	8,541,905
1840	Underground Conduit	1,237,480	321,443	-	1,558,923	190,081	26,957	-	217,037	1,341,886
1845	Underground Conductors and Devices	7,487,743	328,719	-	7,816,462	4,710,124	107,347	-	4,817,471	2,998,991
1850	Line Transformers	17,098,879	854,251	106,515	17,846,615	9,615,550	272,460	88,966	9,799,044	8,047,570
1855	Services	18,834,882	1,425,342	-	20,260,224	7,337,387	438,238	-	7,775,625	12,484,599
1860	Meters	5,398,437	228,654	-	5,627,091	2,042,800	375,651	-	2,418,451	3,208,639
1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
1906	Land Rights	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	3,022,602	56,652	-	3,079,254	1,436,850	82,735	-	1,519,586	1,559,668
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
1915	Office Furniture and Equipment	433,840	6,000	-	439,840	323,349	16,580	-	339,929	99,911
1920	Computer Equipment - Hardware	921,036	135,800	-	1,056,836	749,917	76,435	-	826,352	230,484
1925	Computer Software	1,565,903	12,000	-	1,577,903	1,227,391	109,329	-	1,336,720	241,183
1930	Transportation Equipment	2,422,552	598,285	83,455	2,937,383	1,762,271	266,797	83,455	1,945,614	991,769
1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
1940	Tools, Shop and Garage Equipment	1,375,596	46,151	-	1,421,746	1,116,302	48,881	-	1,165,183	256,563
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	169,111	-	-	169,111	105,668	8,666	-	114,334	54,777
1960	Miscellaneous Equipment	20,050	-	-	20,050	16,879	2,414	-	19,293	756
1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
1980	System Supervisory Equipment	1,809,948	19,103	-	1,829,051	1,175,174	70,267	-	1,245,441	583,609
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	53,060	-	-	53,060	26,523	1,630	-	28,153	24,907
1995	Contributions and Grants	- 10,426,886	- 503,987	-	- 10,930,872	- 2,181,061	- 241,633	-	- 2,422,693	- 8,508,179
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
	Total before Work in Process	**108,443,789**	**8,038,071**	**654,515**	**115,827,344**	**55,911,911**	**2,647,077**	**576,059**	**57,982,929**	**57,844,415**
2070	Other utility plant	-	-	-	-		-	-		-
2055	Work in Process	805,462	21,320	805,421	21,361	-	-	-	-	21,361
	Total after Work in Process	**109,249,250**	**8,059,391**	**1,459,937**	**115,848,704**	**55,911,911**	**2,647,077**	**576,059**	**57,982,929**	**57,865,775**

FIXED ASSET CONTINUITY SCHEDULES, EXCLUDING WORK IN PROGRESS

Table 2-12 through Table 2-19 below provide the Fixed Asset Continuity Schedules excluding WIP for each of 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year, and 2015 Test Year and are consistent with Appendix 2-BA as required in the Filing Requirements.

As discussed above, NBHDL implemented changes to its capitalization and depreciation policies in 2012, therefore a continuity schedule as at December 31, 2012 is provided for both before and after the policy changes. Table 2-14 provides the comparative continuity schedule assuming no changes to accounting policy and Table 2-15 provides the RCGAAP continuity schedule used for rate base purposes. For NBHDL's MIFRS transition year, as at December 31, 2013, Table 2-17 provides a comparative continuity schedule assuming RCGAAP and Table 2-16 provides the continuity schedule for rate base purposes under MIFRS.

The "CCA Class" for fixed assets agrees with the CCA Class used for tax purposes in NBHDL's tax returns. NBHDL has two asset classes that were different from those shown in Appendix 2-BA as provided by the Board. For tax purposes NBHDL has classified Computer Software and Computer Hardware as Class 50 with a CCA rate of 55%, incorporating a 50% rule in the year of acquisition.

Upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue and amortized to revenue over the service life of the related asset. In addition, historical amounts recorded in Account 1995 prior to the transition year are to be netted against the assets in PP&E that they relate to, no longer accounted separately as an offset to PP&E. For purposes of cost allocation, and continuity within this application, NBHDL has continued to utilize Account 1995 to track customer contributions, including contributed capital forecast for the 2014 Bridge Year and the 2015 Test Year. A breakdown of this account showing the reclassification is provided in Table 2-20. Depreciation is explained in further detail in the "Capitalization Policy" section of this Exhibit and Exhibit 4 – Operating Costs.

For general financial reporting purposes under IFRS, NBHDL has accounted for the retirement of assets within its calculation of rate base for both the 2014 Bridge Year and the 2015 Test Year. The reclassification of losses to depreciation is disclosed separately and explained in further detail in the "Capitalization Policy" section of this Exhibit and Exhibit 4 – Operating Costs.

As part of this application, NBHDL is requesting approval to recover its stranded meter costs as at December 31, 2014. In order to establish proper PP&E continuity in the 2015 Test Year for rate base purposes, NBHDL has recorded the disposal in the 2014 Bridge Year. NBHDL has also segregated the NBV of smart meters from the non-smart to comply with the requirements of Appendix 2-BA.

Table 2-12 - Fixed Asset Continuity Schedule as at December 31, 2010, CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2010

			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 Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 983,376	$ 22,620	$ -	$ 1,005,996	-$ 848,667	-$ 41,971	$ -	-$ 890,638	$ 115,357
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 368,562	$ 71,626	$ -	$ 440,188	$ -	$ -	$ -	$ -	$ 440,188
47	1808	Buildings	$ 769,641	$ -	$ -	$ 769,641	-$ 279,985	-$ 13,489	$ -	-$ 293,474	$ 476,167
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 9,124,702	$ 266,961	$ -	$ 9,391,662	-$ 3,606,886	-$ 280,491	$ -	-$ 3,887,377	$ 5,504,285
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 16,838,396	$ 937,493	$ -	$ 17,775,889	-$ 9,803,635	-$ 534,610	$ -	-$ 10,338,245	$ 7,437,644
47	1835	Overhead Conductors & Devices	$ 13,398,340	$ 606,204	$ -	$ 14,004,544	-$ 7,442,542	-$ 433,940	$ -	-$ 7,876,482	$ 6,128,062
47	1840	Underground Conduit	$ 469,102	$ 123,798	$ -	$ 592,900	-$ 86,848	-$ 21,239	$ -	-$ 108,087	$ 484,813
47	1845	Underground Conductors & Devices	$ 6,195,879	$ 286,428	$ -	$ 6,482,307	-$ 3,962,259	-$ 231,995	$ -	-$ 4,194,254	$ 2,288,053
47	1850	Line Transformers	$ 13,954,575	$ 771,184	$ -	$ 14,725,760	-$ 8,081,956	-$ 443,297	$ -	-$ 8,525,252	$ 6,200,507
47	1855	Services (Overhead & Underground)	$ 12,521,188	$ 3,512,092	$ -	$ 16,033,280	-$ 5,001,148	-$ 531,145	$ -	-$ 5,532,292	$ 10,500,988
47	1860	Meters	$ 3,607,923	$ 146,108	$ -	$ 3,754,031	-$ 2,393,625	-$ 109,056	$ -	-$ 2,502,681	$ 1,251,350
47	1860	Meters (Smart Meters)	$ -	$ 111,423	$ -	$ 111,423	$ -	-$ 2,228	$ -	-$ 2,228	$ 109,194
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,027,035	$ 12,656	$ -	$ 2,039,691	-$ 1,054,396	-$ 64,445	$ -	-$ 1,118,841	$ 920,850
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 315,127	$ -	$ -	$ 315,127	-$ 275,236	-$ 6,011	$ -	-$ 281,247	$ 33,880
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 585,437	$ 27,417	$ -	$ 612,854	-$ 528,378	-$ 25,285	$ -	-$ 553,662	$ 59,192
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,379,846	$ 64,703	-$ 79,733	$ 2,364,816	-$ 1,369,063	-$ 203,184	$ 79,733	-$ 1,492,514	$ 872,302
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,106,956	$ 27,751	$ -	$ 1,134,706	-$ 930,279	-$ 28,481	$ -	-$ 958,760	$ 175,946
8	1945	Measurement & Testing Equipment	$ 8,635	$ -	-$ 8,635	$ -	-$ 432	$ -	$ 432	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 101,871	$ -	$ -	$ 101,871	-$ 68,978	-$ 6,896	$ -	-$ 75,875	$ 25,996
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,079	$ -	$ -	$ 18,079	-$ 6,217	-$ 1,808	$ -	-$ 8,025	$ 10,055
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,232,487	$ 11,193	$ -	$ 1,243,680	-$ 889,817	-$ 73,708	$ -	-$ 963,524	$ 280,156
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 17,128	-$ 2,461	$ -	-$ 19,589	$ 33,471
47	1995	Contributions & Grants	-$ 6,191,811	-$ 905,001	$ -	-$ 7,096,812	$ 1,020,088	$ 265,774	$ -	$ 1,285,862	-$ 5,810,951
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 80,599,232**	**$ 6,094,654**	**-$ 88,368**	**$ 86,605,519**	**-$ 46,271,663**	**-$ 2,789,966**	**$ 80,165**	**-$ 48,981,464**	**$ 37,624,055**
		Less Socialized Renewable Energy Generation Investments (input as negative)	-	-	-	$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	$ -				$ -	$ -
		Total PP&E	**$ 80,599,232**	**$ 6,094,654**	**-$ 88,368**	**$ 86,605,519**	**-$ 46,271,663**	**-$ 2,789,966**	**$ 80,165**	**-$ 48,981,464**	**$ 37,624,055**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 2,789,966**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 129,021
Stores Equipment	$ -
Net Depreciation	-$ 2,660,945

Table 2-13 - Fixed Asset Continuity Schedule as at December 31, 2011, CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2011

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,005,996	$ 92,399	$ -	$ 1,098,395	-$ 890,638	-$ 48,860	$ -	-$ 939,499	$ 158,896
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 440,188	$ 6,305	$ -	$ 446,493	$ -	$ -	$ -	$ -	$ 446,493
47	1808	Buildings	$ 769,641	$ -	$ -	$ 769,641	-$ 293,474	-$ 13,489	$ -	-$ 306,963	$ 462,678
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 9,391,662	$ 2,508,924	-$ 56,181	$ 11,844,406	-$ 3,887,377	-$ 323,109	$ 53,960	-$ 4,156,526	$ 7,687,879
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 17,775,889	$ 1,145,473	$ -	$ 18,921,361	-$ 10,338,245	-$ 566,593	$ -	-$ 10,904,838	$ 8,016,523
47	1835	Overhead Conductors & Devices	$ 14,004,544	$ 813,817	$ -	$ 14,818,361	-$ 7,876,482	-$ 455,624	$ -	-$ 8,332,106	$ 6,486,254
47	1840	Underground Conduit	$ 592,900	$ 174,099	$ -	$ 766,998	-$ 108,087	-$ 27,197	$ -	-$ 135,284	$ 631,714
47	1845	Underground Conductors & Devices	$ 6,482,307	$ 272,928	$ -	$ 6,755,235	-$ 4,194,254	-$ 234,042	$ -	-$ 4,428,296	$ 2,326,939
47	1850	Line Transformers	$ 14,725,760	$ 646,897	$ -	$ 15,372,657	-$ 8,525,252	-$ 450,263	$ -	-$ 8,975,516	$ 6,397,142
47	1855	Services (Overhead & Underground)	$ 16,033,280	$ 888,695	$ -	$ 16,921,975	-$ 5,532,292	-$ 611,028	$ -	-$ 6,143,320	$ 10,778,655
47	1860	Meters	$ 3,754,031	$ 44,078	$ -	$ 3,798,109	-$ 2,502,681	-$ 107,979	$ -	-$ 2,610,660	$ 1,187,449
47	1860	Meters (Smart Meters)	$ 111,423	$ 100,945	$ -	$ 212,368	-$ 2,228	-$ 6,476	$ -	-$ 8,704	$ 203,664
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,039,691	$ 142,738	$ -	$ 2,182,429	-$ 1,118,841	-$ 67,553	$ -	-$ 1,186,394	$ 996,035
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 315,127	$ 24,090	$ -	$ 339,217	-$ 281,247	-$ 7,157	$ -	-$ 288,404	$ 50,813
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 612,854	$ 135,798	$ -	$ 748,652	-$ 553,662	-$ 34,317	$ -	-$ 587,979	$ 160,672
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,364,816	$ 363,462	-$ 332,425	$ 2,395,854	-$ 1,492,514	-$ 209,086	$ 330,011	-$ 1,371,589	$ 1,024,264
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,134,706	$ 71,247	$ -	$ 1,205,954	-$ 958,760	-$ 32,557	$ -	-$ 991,317	$ 214,636
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 101,871	$ -	$ -	$ 101,871	-$ 75,875	-$ 6,313	$ -	-$ 82,188	$ 19,683
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,079	$ -	$ -	$ 18,079	-$ 8,025	$ -	$ -	-$ 8,025	$ 10,055
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,243,680	$ 51,185	$ -	$ 1,294,866	-$ 963,524	-$ 48,235	$ -	-$ 1,011,760	$ 283,106
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 19,589	-$ 2,045	$ -	-$ 21,635	$ 31,426
47	1995	Contributions & Grants	-$ 7,096,812	-$ 464,129	$ -	-$ 7,560,942	$ 1,285,862	$ 293,156	$ -	$ 1,579,018	-$ 5,981,924
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 86,605,519**	**$ 7,018,953**	**-$ 388,606**	**$ 93,235,866**	**-$ 48,981,464**	**-$ 2,958,771**	**$ 383,971**	**-$ 51,556,264**	**$ 41,679,603**
		Less Socialized Renewable Energy Generation Investments (input as negative)	-	-	-	$ -	0	0	0	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	$ -	0	0	0	$ -	$ -
		Total PP&E	**$ 86,605,519**	**$ 7,018,953**	**-$ 388,606**	**$ 93,235,866**	**-$ 48,981,464**	**-$ 2,958,771**	**$ 383,971**	**-$ 51,556,264**	**$ 41,679,603**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 2,958,771**			
			0				0				

		Less: *Fully Allocated Depreciation*
10		Transportation	-$ 132,845
8		Stores Equipment	$ -
		Net Depreciation	-$ 2,825,925

Table 2-14 - Fixed Asset Continuity Schedule as at December 31, 2012, CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP — Comparative Purposes Only
Year: 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,098,395	$ 125,138	$ -	$ 1,223,533	-$ 939,499	-$ 61,213	$ -	-$ 1,000,712	$ 222,822
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,493	$ 72	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 769,641	$ 980,568	-$ 22,202	$ 1,728,007	-$ 306,963	-$ 49,221	$ 22,202	-$ 333,981	$ 1,394,026
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,844,406	-$ 560,784	-$ 267,186	$ 11,016,436	-$ 4,156,526	-$ 324,075	$ 197,195	-$ 4,283,406	$ 6,733,030
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,921,361	$ 1,133,582	$ -	$ 20,054,943	-$ 10,904,838	-$ 599,647	$ -	-$ 11,504,486	$ 8,550,457
47	1835	Overhead Conductors & Devices	$ 14,818,361	$ 820,774	$ -	$ 15,639,134	-$ 8,332,106	-$ 478,941	$ -	-$ 8,811,047	$ 6,828,087
47	1840	Underground Conduit	$ 766,998	$ 24,324	$ -	$ 791,323	-$ 135,284	-$ 31,165	$ -	-$ 166,450	$ 624,873
47	1845	Underground Conductors & Devices	$ 6,755,235	$ 162,990	$ -	$ 6,918,226	-$ 4,428,296	-$ 208,871	$ -	-$ 4,637,167	$ 2,281,059
47	1850	Line Transformers	$ 15,372,657	$ 630,127	$ -	$ 16,002,784	-$ 8,975,516	-$ 454,426	$ -	-$ 9,429,941	$ 6,572,843
47	1855	Services (Overhead & Underground)	$ 16,921,975	$ 604,431	$ -	$ 17,526,406	-$ 6,143,320	-$ 615,185	$ -	-$ 6,758,505	$ 10,767,900
47	1860	Meters	$ 3,798,109	$ 24,901	$ -	$ 3,823,010	-$ 2,610,660	-$ 104,798	$ -	-$ 2,715,458	$ 1,107,552
47	1860	Meters (Smart Meters)	$ 212,368	$ 43,972	$ -	$ 256,341	-$ 8,704	-$ 9,374	$ -	-$ 18,078	$ 238,262
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,182,429	$ 231,827	$ -	$ 2,414,256	-$ 1,186,394	-$ 75,045	$ -	-$ 1,261,439	$ 1,152,817
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 339,217	$ 31,051	$ -	$ 370,268	-$ 288,404	-$ 9,915	$ -	-$ 298,319	$ 71,949
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 748,652	$ 68,005	$ -	$ 816,657	-$ 587,979	-$ 51,665	$ -	-$ 639,644	$ 177,013
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,395,854	$ 254,425	-$ 26,967	$ 2,623,313	-$ 1,371,589	-$ 271,935	$ 26,967	-$ 1,616,558	$ 1,006,755
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,205,954	$ 21,013	$ -	$ 1,226,966	-$ 991,317	-$ 37,136	$ -	-$ 1,028,453	$ 198,513
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 101,871	$ 46,452	$ -	$ 148,322	-$ 82,188	-$ 8,569	$ -	-$ 90,756	$ 57,566
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,079	$ 1,970	$ -	$ 20,050	-$ 8,025	-$ 1,907	$ -	-$ 9,931	$ 10,118
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,294,866	$ 47,535	$ -	$ 1,342,401	-$ 1,011,760	-$ 35,373	$ -	-$ 1,047,133	$ 295,268
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 21,635	-$ 1,630	$ -	-$ 23,264	$ 29,796
47	1995	Contributions & Grants	-$ 7,560,942	-$ 675,928	$ -	-$ 8,236,870	$ 1,579,018	$ 313,647	$ -	$ 1,892,665	-$ 6,344,205
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 93,235,866**	**$ 4,016,447**	**-$ 316,355**	**$ 96,935,958**	**-$ 51,556,264**	**-$ 3,116,441**	**$ 246,364**	**-$ 54,426,341**	**$ 42,509,617**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 93,235,866**	**$ 4,016,447**	**-$ 316,355**	**$ 96,935,958**	**-$ 51,556,264**	**-$ 3,116,441**	**$ 246,364**	**-$ 54,426,341**	**$ 42,509,617**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 3,116,441**			
			$ -			$ -	$ -				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 162,597
Stores Equipment	$ -
Net Depreciation	-$ 2,953,844

Table 2-15 - Fixed Asset Continuity Schedule as at December 31, 2012, Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP **Revised CGAAP - Accounting Policy Changes in Effect**
Year 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,098,395	$ 125,138	$ -	$ 1,223,533	-$ 939,499	-$ 53,994	$ -	-$ 993,493	$ 230,041
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,493	$ 72	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 769,641	$ 980,568	-$ 22,202	$ 1,728,007	-$ 306,963	-$ 48,554	$ 22,202	-$ 333,314	$ 1,394,693
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,844,406	-$ 560,784	-$ 267,186	$ 11,016,436	-$ 4,156,526	-$ 256,136	$ 197,195	-$ 4,215,467	$ 6,800,969
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,921,361	$ 1,133,582	$ -	$ 20,054,943	-$ 10,904,838	-$ 272,101	$ -	-$ 11,176,939	$ 8,878,003
47	1835	Overhead Conductors & Devices	$ 14,818,361	$ 820,774	$ -	$ 15,639,134	-$ 8,332,106	-$ 197,186	$ -	-$ 8,529,292	$ 7,109,842
47	1840	Underground Conduit	$ 766,998	$ 24,324	$ -	$ 791,323	-$ 135,284	-$ 14,576	$ -	-$ 149,860	$ 641,463
47	1845	Underground Conductors & Devices	$ 6,755,235	$ 162,990	$ -	$ 6,918,226	-$ 4,428,296	-$ 86,963	$ -	-$ 4,515,259	$ 2,402,967
47	1850	Line Transformers	$ 15,372,657	$ 630,127	$ -	$ 16,002,784	-$ 8,975,516	-$ 219,873	$ -	-$ 9,195,389	$ 6,807,395
47	1855	Services (Overhead & Underground)	$ 16,921,975	$ 604,431	$ -	$ 17,526,406	-$ 6,143,320	-$ 384,879	$ -	-$ 6,528,199	$ 10,998,207
47	1860	Meters	$ 3,798,109	$ 24,901	$ -	$ 3,823,010	-$ 2,610,660	-$ 106,317	$ -	-$ 2,716,977	$ 1,106,033
47	1860	Meters (Smart Meters)	$ 212,368	$ 43,972	$ -	$ 256,341	-$ 8,704	-$ 16,356	$ -	-$ 25,061	$ 231,280
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,182,429	$ 231,827	$ -	$ 2,414,256	-$ 1,186,394	-$ 75,946	$ -	-$ 1,262,341	$ 1,151,915
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 339,217	$ 31,051	$ -	$ 370,268	-$ 288,404	-$ 9,867	$ -	-$ 298,271	$ 71,997
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 748,652	$ 68,005	$ -	$ 816,657	-$ 587,979	-$ 45,149	$ -	-$ 633,128	$ 183,529
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,395,854	$ 254,425	-$ 26,967	$ 2,623,313	-$ 1,371,589	-$ 271,935	$ 26,967	-$ 1,616,558	$ 1,006,755
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,205,954	$ 21,013	$ -	$ 1,226,966	-$ 991,317	-$ 36,913	$ -	-$ 1,028,231	$ 198,735
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 101,871	$ 46,452	$ -	$ 148,322	-$ 82,188	-$ 6,633	$ -	-$ 88,821	$ 59,501
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 18,079	$ 1,970	$ -	$ 20,050	-$ 8,025	-$ 4,025	$ -	-$ 12,050	$ 7,999
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,294,866	$ 47,535	$ -	$ 1,342,401	-$ 1,011,760	-$ 53,114	$ -	-$ 1,064,873	$ 277,528
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 21,635	-$ 1,630	$ -	-$ 23,264	$ 29,796
47	1995	Contributions & Grants	-$ 7,560,942	-$ 675,928	$ -	-$ 8,236,870	$ 1,579,018	$ 179,128	$ -	$ 1,758,146	-$ 6,478,724
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 93,235,866**	**$ 4,016,447**	**-$ 316,355**	**$ 96,935,958**	**-$ 51,556,264**	**-$ 1,983,021**	**$ 246,364**	**-$ 53,292,920**	**$ 43,643,038**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 93,235,866**	**$ 4,016,447**	**-$ 316,355**	**$ 96,935,958**	**-$ 51,556,264**	**-$ 1,983,021**	**$ 246,364**	**-$ 53,292,920**	**$ 43,643,038**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 1,983,021**			

		$ -	$ -	
			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 162,597
8		Stores Equipment	Stores Equipment	$ -
			Net Depreciation	-$ 1,820,424

Table 2-16 - Fixed Asset Continuity Schedule as at December 31, 2013, Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP **Revised - Accounting Policy Changes in Effect**
Year 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
						Dec. 31/13				Dec. 31/13	
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,223,533	$ 94,033	$ -	$ 1,317,567	-$ 993,493	-$ 79,966	$ -	-$ 1,073,458	$ 244,108
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,728,007	$ 112,435	-$ 9,936	$ 1,830,506	-$ 333,314	-$ 33,474	$ 9,936	-$ 356,852	$ 1,473,654
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,016,436	$ 2,057,224	-$ 60,158	$ 13,013,503	-$ 4,215,467	-$ 266,126	$ 58,378	-$ 4,423,215	$ 8,590,287
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,054,943	$ 1,345,153	-$ 5,535	$ 21,394,561	-$ 11,176,939	-$ 299,643	$ 3,886	-$ 11,472,696	$ 9,921,865
47	1835	Overhead Conductors & Devices	$ 15,639,134	$ 753,828	$ -	$ 16,392,963	-$ 8,529,292	-$ 210,308	$ -	-$ 8,739,600	$ 7,653,362
47	1840	Underground Conduit	$ 791,323	$ 306,052	$ -	$ 1,097,375	-$ 149,860	-$ 17,880	$ -	-$ 167,739	$ 929,636
47	1845	Underground Conductors & Devices	$ 6,918,226	$ 389,846	$ -	$ 7,308,072	-$ 4,515,259	-$ 93,873	$ -	-$ 4,609,132	$ 2,698,940
47	1850	Line Transformers	$ 16,002,784	$ 519,110	-$ 3,599	$ 16,518,295	-$ 9,195,389	-$ 236,966	$ -	-$ 9,432,355	$ 7,085,941
47	1855	Services (Overhead & Underground)	$ 17,526,406	$ 491,910	$ -	$ 18,018,316	-$ 6,528,199	-$ 396,989	$ -	-$ 6,925,188	$ 11,093,127
47	1860	Meters	$ 3,823,010	$ 50,354	$ -	$ 3,873,364	-$ 2,716,977	-$ 105,172	$ -	-$ 2,822,149	$ 1,051,214
47	1860	Meters (Smart Meters)	$ 256,341	$ 62,304	$ -	$ 318,644	-$ 25,061	-$ 21,670	$ -	-$ 46,731	$ 271,913
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,414,256	$ 100,066	$ -	$ 2,514,322	-$ 1,262,341	-$ 80,662	$ -	-$ 1,343,003	$ 1,171,319
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 370,268	$ 6,292	$ -	$ 376,560	-$ 298,271	-$ 11,490	$ -	-$ 309,761	$ 66,799
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 816,657	$ 8,076	$ -	$ 824,733	-$ 633,128	-$ 54,236	$ -	-$ 687,364	$ 137,369
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,623,313	$ 58,916	$ -	$ 2,682,228	-$ 1,616,558	-$ 237,948	$ -	-$ 1,854,506	$ 827,722
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,226,966	$ 101,630	$ -	$ 1,328,596	-$ 1,028,231	-$ 40,809	$ -	-$ 1,069,039	$ 259,556
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 148,322	$ 20,789	$ -	$ 169,111	-$ 88,821	-$ 7,584	$ -	-$ 96,405	$ 72,706
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ -	$ -	$ 20,050	-$ 12,050	-$ 2,414	$ -	-$ 14,464	$ 5,585
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,342,401	$ 41,364	$ -	$ 1,383,765	-$ 1,064,873	-$ 51,166	$ -	-$ 1,116,040	$ 267,725
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 23,264	-$ 1,630	$ -	-$ 24,894	$ 28,167
47	1995	Contributions & Grants	-$ 8,236,870	-$ 1,061,939	$ -	-$ 9,298,809	$ 1,758,146	$ 199,416	$ -	$ 1,957,562	-$ 7,341,247
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 96,935,958**	**$ 5,457,443**	**-$ 79,228**	**$ 102,314,173**	**-$ 53,292,920**	**-$ 2,050,588**	**$ 72,200**	**-$ 55,271,308**	**$ 47,042,865**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 96,935,958**	**$ 5,457,443**	**-$ 79,228**	**$ 102,314,173**	**-$ 53,292,920**	**-$ 2,050,588**	**$ 72,200**	**-$ 55,271,308**	**$ 47,042,865**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 2,050,588**			

			$ -	$ -	
				Less: *Fully Allocated Depreciation*	
10		Transportation		Transportation	-$ 132,911
8		Stores Equipment		Stores Equipment	$ -
				Net Depreciation	-$ 1,917,677

Table 2-17 - Fixed Asset Continuity Schedule as at December 31, 2014, Revised CGAAP

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP — Accounting Policy Changes in Effect - Comparative Purposes Only
Year: 2014

CCA Class	OEB	Description	Cost: Opening Balance Jan.1/14	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance Jan.1/14	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,317,567	$ 248,336	$ -	$ 1,565,903	-$ 1,073,458	-$ 153,933	$ -	-$ 1,227,391	$ 338,512
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ -	$ -	$ 1,830,506	-$ 356,852	-$ 34,598	$ -	-$ 391,450	$ 1,439,056
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,013,503	$ 640,888	-$ 25,000	$ 13,629,391	-$ 4,423,215	-$ 306,674	$ 25,000	-$ 4,704,889	$ 8,924,502
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 21,394,561	$ 2,168,186	$ -	$ 23,562,747	-$ 11,472,696	-$ 339,385	$ -	-$ 11,812,081	$ 11,750,666
47	1835	Overhead Conductors & Devices	$ 16,392,963	$ 734,144	$ -	$ 17,127,106	-$ 8,739,600	-$ 222,720	$ -	-$ 8,962,320	$ 8,164,786
47	1840	Underground Conduit	$ 1,097,375	$ 140,105	$ -	$ 1,237,480	-$ 167,739	-$ 22,341	$ -	-$ 190,081	$ 1,047,399
47	1845	Underground Conductors & Devices	$ 7,308,072	$ 179,671	$ -	$ 7,487,743	-$ 4,609,132	-$ 100,992	$ -	-$ 4,710,124	$ 2,777,619
47	1850	Line Transformers	$ 16,518,295	$ 667,436	$ -	$ 17,185,731	-$ 9,432,355	-$ 253,450	$ -	-$ 9,685,805	$ 7,499,926
47	1855	Services (Overhead & Underground)	$ 18,018,316	$ 816,567	$ -	$ 18,834,882	-$ 6,925,188	-$ 412,199	$ -	-$ 7,337,387	$ 11,497,495
47	1860	Meters	$ 3,873,364	$ 14,296	-$ 2,283,802	$ 1,603,858	-$ 2,822,149	-$ 101,551	$ 2,005,716	-$ 917,984	$ 685,874
47	1860	Meters (Smart Meters)	$ 318,644	$ 3,475,935	$ -	$ 3,794,579	-$ 46,731	-$ 1,078,085	$ -	-$ 1,124,816	$ 2,669,764
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,514,322	$ 508,280	$ -	$ 3,022,602	-$ 1,343,003	-$ 93,847	$ -	-$ 1,436,850	$ 1,585,751
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 376,560	$ 57,280	$ -	$ 433,840	-$ 309,761	-$ 13,588	$ -	-$ 323,349	$ 110,491
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 824,733	$ 96,303	$ -	$ 921,036	-$ 687,364	-$ 62,554	$ -	-$ 749,917	$ 171,119
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,682,228	$ 72,163	-$ 331,838	$ 2,422,552	-$ 1,854,506	-$ 239,603	$ 331,838	-$ 1,762,271	$ 660,282
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,328,596	$ 47,000	$ -	$ 1,375,596	-$ 1,069,039	-$ 47,263	$ -	-$ 1,116,302	$ 259,293
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ -	$ -	$ 169,111	-$ 96,405	-$ 9,264	$ -	-$ 105,668	$ 63,443
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ -	$ -	$ 20,050	-$ 14,464	-$ 2,414	$ -	-$ 16,879	$ 3,171
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,383,765	$ 426,183	$ -	$ 1,809,948	-$ 1,116,040	-$ 59,135	$ -	-$ 1,175,174	$ 634,773
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 24,894	-$ 1,630	$ -	-$ 26,523	$ 26,537
47	1995	Contributions & Grants	-$ 9,298,809	-$ 1,128,077	$ -	-$ 10,426,886	$ 1,957,562	$ 223,499	$ -	$ 2,181,061	-$ 8,245,825
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 102,314,173**	**$ 9,164,695**	**-$ 2,640,640**	**$ 108,838,228**	**-$ 55,271,308**	**-$ 3,331,727**	**$ 2,362,555**	**-$ 56,240,480**	**$ 52,597,748**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 102,314,173**	**$ 9,164,695**	**-$ 2,640,640**	**$ 108,838,228**	**-$ 55,271,308**	**-$ 3,331,727**	**$ 2,362,555**	**-$ 56,240,480**	**$ 52,597,748**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 3,331,727**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 127,313
Stores Equipment	$ -
Net Depreciation	-$ 3,204,414

Table 2-18 - Fixed Asset Continuity Schedule as at December 31, 2014, MIFRS

Appendix 2-BA

Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2014** Transition Year

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
			Jan.1/14				**Jan.1/14**				
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,317,567	$ 248,336	$ -	$ 1,565,903	-$ 1,073,458	-$ 153,933	$ -	-$ 1,227,391	$ 338,512
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ -	$ -	$ 1,830,506	-$ 356,852	-$ 34,598	$ -	-$ 391,450	$ 1,439,056
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,013,503	$ 640,888	-$ 25,000	$ 13,629,391	-$ 4,423,215	-$ 306,674	$ 25,000	-$ 4,704,889	$ 8,924,502
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 21,394,561	$ 2,168,186	-$ 215,692	$ 23,347,054	-$ 11,472,696	-$ 339,385	$ 177,276	-$ 11,634,805	$ 11,712,249
47	1835	Overhead Conductors & Devices	$ 16,392,963	$ 734,144	-$ 91,894	$ 17,035,212	-$ 8,739,600	-$ 222,720	$ 81,039	-$ 8,881,282	$ 8,153,930
47	1840	Underground Conduit	$ 1,097,375	$ 140,105	$ -	$ 1,237,480	-$ 167,739	-$ 22,341	$ -	-$ 190,081	$ 1,047,399
47	1845	Underground Conductors & Devices	$ 7,308,072	$ 179,671	$ -	$ 7,487,743	-$ 4,609,132	-$ 100,992	$ -	-$ 4,710,124	$ 2,777,619
47	1850	Line Transformers	$ 16,518,295	$ 667,436	-$ 86,852	$ 17,098,879	-$ 9,432,355	-$ 253,450	$ 70,255	-$ 9,615,550	$ 7,483,329
47	1855	Services (Overhead & Underground)	$ 18,018,316	$ 816,567	$ -	$ 18,834,882	-$ 6,925,188	-$ 412,199	$ -	-$ 7,337,387	$ 11,497,495
47	1860	Meters	$ 3,873,364	$ 14,296	-$ 2,283,802	$ 1,603,858	-$ 2,822,149	-$ 101,551	$ 2,005,716	-$ 917,984	$ 685,874
47	1860	Meters (Smart Meters)	$ 318,644	$ 3,475,935	$ -	$ 3,794,579	-$ 46,731	-$ 1,078,085	$ -	-$ 1,124,816	$ 2,669,764
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,514,322	$ 508,280	$ -	$ 3,022,602	-$ 1,343,003	-$ 93,847	$ -	-$ 1,436,850	$ 1,585,751
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 376,560	$ 57,280	$ -	$ 433,840	-$ 309,761	-$ 13,588	$ -	-$ 323,349	$ 110,491
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 824,733	$ 96,303	$ -	$ 921,036	-$ 687,364	-$ 62,554	$ -	-$ 749,917	$ 171,119
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,682,228	$ 72,163	-$ 331,838	$ 2,422,552	-$ 1,854,506	-$ 239,603	$ 331,838	-$ 1,762,271	$ 660,282
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,328,596	$ 47,000	$ -	$ 1,375,596	-$ 1,069,039	-$ 47,263	$ -	-$ 1,116,302	$ 259,293
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ -	$ -	$ 169,111	-$ 96,405	-$ 9,264	$ -	-$ 105,668	$ 63,443
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ -	$ -	$ 20,050	-$ 14,464	-$ 2,414	$ -	-$ 16,879	$ 3,171
47	1970	Load Management Controls Customer	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,383,765	$ 426,183	$ -	$ 1,809,948	-$ 1,116,040	-$ 59,135	$ -	-$ 1,175,174	$ 634,773
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 24,894	-$ 1,630	$ -	-$ 26,523	$ 26,537
47	1995	Contributions & Grants	-$ 9,298,809	-$ 1,128,077	$ -	-$ 10,426,886	$ 1,957,562	$ 223,499	$ -	$ 2,181,061	-$ 8,245,825
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 102,314,173**	**$ 9,164,695**	**-$ 3,035,079**	**$ 108,443,789**	**-$ 55,271,308**	**-$ 3,331,727**	**$ 2,691,124**	**-$ 55,911,911**	**$ 52,531,878**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 102,314,173**	**$ 9,164,695**	**-$ 3,035,079**	**$ 108,443,789**	**-$ 55,271,308**	**-$ 3,331,727**	**$ 2,691,124**	**-$ 55,911,911**	**$ 52,531,878**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-$ 65,870			
		Total						**-$ 3,397,597**			

		$ -	$ -	
			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 127,313
8		Stores Equipment	Stores Equipment	$ -
			Net Depreciation	-$ 3,270,284

Table 2-19 - Fixed Asset Continuity Schedule as at December 31, 2015, MIFRS

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2015** Change-Over Year

			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 Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,565,903	$ 12,000	$ -	$ 1,577,903	-$ 1,227,391	-$ 109,329	$ -	-$ 1,336,720	$ 241,183
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ 18,551	-$ 1,142	$ 1,847,915	-$ 391,450	-$ 34,784	$ 1,142	-$ 425,091	$ 1,422,824
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,629,391	$ 2,771,299	-$ 136,337	$ 16,264,353	-$ 4,704,889	-$ 341,137	$ 130,049	-$ 4,915,977	$ 11,348,375
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 23,347,054	$ 1,084,640	-$ 235,641	$ 24,196,054	-$ 11,634,805	-$ 374,294	$ 194,106	-$ 11,814,993	$ 12,381,061
47	1835	Overhead Conductors & Devices	$ 17,035,212	$ 635,167	-$ 91,425	$ 17,578,954	-$ 8,881,282	-$ 234,109	$ 78,342	-$ 9,037,049	$ 8,541,905
47	1840	Underground Conduit	$ 1,237,480	$ 321,443	$ -	$ 1,558,923	-$ 190,081	-$ 26,957	$ -	-$ 217,037	$ 1,341,886
47	1845	Underground Conductors & Devices	$ 7,487,743	$ 328,719	$ -	$ 7,816,462	-$ 4,710,124	-$ 107,347	$ -	-$ 4,817,471	$ 2,998,991
47	1850	Line Transformers	$ 17,098,879	$ 854,251	-$ 106,515	$ 17,846,615	-$ 9,615,550	-$ 272,460	$ 88,966	-$ 9,799,044	$ 8,047,570
47	1855	Services (Overhead & Underground)	$ 18,834,882	$ 1,425,342	$ -	$ 20,260,224	-$ 7,337,387	-$ 438,238	$ -	-$ 7,775,625	$ 12,484,599
47	1860	Meters	$ 1,603,858	$ 14,440	$ -	$ 1,618,298	-$ 917,984	-$ 102,988	$ -	-$ 1,020,972	$ 597,326
47	1860	Meters (Smart Meters)	$ 3,794,579	$ 214,213	$ -	$ 4,008,792	-$ 1,124,816	-$ 272,663	$ -	-$ 1,397,479	$ 2,611,313
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 3,022,602	$ 56,652	$ -	$ 3,079,254	-$ 1,436,850	-$ 82,735	$ -	-$ 1,519,586	$ 1,559,668
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 433,840	$ 6,000	$ -	$ 439,840	-$ 323,349	-$ 16,580	$ -	-$ 339,929	$ 99,911
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 921,036	$ 135,800	$ -	$ 1,056,836	-$ 749,917	-$ 76,435	$ -	-$ 826,352	$ 230,484
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,422,552	$ 598,285	-$ 83,455	$ 2,937,383	-$ 1,762,271	-$ 266,797	$ 83,455	-$ 1,945,614	$ 991,769
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,375,596	$ 46,151	$ -	$ 1,421,746	-$ 1,116,302	-$ 48,881	$ -	-$ 1,165,183	$ 256,563
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ -	$ -	$ 169,111	-$ 105,668	-$ 8,666	$ -	-$ 114,334	$ 54,777
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ -	$ -	$ 20,050	-$ 16,879	-$ 2,414	$ -	-$ 19,293	$ 756
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,809,948	$ 19,103	$ -	$ 1,829,051	-$ 1,175,174	-$ 70,267	$ -	-$ 1,245,441	$ 583,609
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 26,523	-$ 1,630	$ -	-$ 28,153	$ 24,907
47	1995	Contributions & Grants	-$ 10,426,886	-$ 503,987	$ -	-$ 10,930,872	$ 2,181,061	$ 241,633	$ -	$ 2,422,693	-$ 8,508,179
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 108,443,789**	**$ 8,038,071**	**-$ 654,515**	**$ 115,827,344**	**-$ 55,911,911**	**-$ 2,647,077**	**$ 576,059**	**-$ 57,982,929**	**$ 57,844,415**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 108,443,789**	**$ 8,038,071**	**-$ 654,515**	**$ 115,827,344**	**-$ 55,911,911**	**-$ 2,647,077**	**$ 576,059**	**-$ 57,982,929**	**$ 57,844,415**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-$ 78,456			
		Total						**-$ 2,725,533**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 155,871
Stores Equipment	$ -
Net Depreciation	-$ 2,569,662

As explained above, upon the date of IFRS adoption, customer contributions are no longer recorded in Account 1995 Contributions & Grants, but are recorded in Account 2440, Deferred Revenue. Historical contributions are netted against the assets they relate to. For purposes of cost allocation and continuity within this application, NBHDL has included all contributed capital including contributions forecast for the 2014 Bridge Year and the 2015 Test Year in Account 1995 and a breakdown of this account is provided in Table 2-20 below.

Table 2-20 – Account 1995 Breakdown

Account 1995 Breakdown for Financial Reporting Purposes	Cost			Accumulated Amortization			Net Book Value
	Opening	Additions	Closing Balance	Opening	Additions	Closing Balance	
December 31, 2014 - MIFRS:							
Acct 1830 - Poles, Towers & Fixtures	-581,470	-	-581,470	184,901	12,926	197,827	-383,643
Acct 1835 - Overhead Conductor & Devices	-1,155,650	-	-1,155,650	234,049	19,262	253,311	-902,340
Acct 1840 - Underground Conduit	-743,558	-	-743,558	170,838	14,871	185,710	-557,848
Acct 1845 - Underground Conductors & Devices	-1,467,466	-	-1,467,466	295,536	36,687	332,223	-1,135,243
Acct 1850 - Line Transformers	-1,601,662	-	-1,601,662	374,741	40,046	414,787	-1,186,874
Acct 1855 - Services	-3,650,065	-	-3,650,065	675,216	82,913	758,130	-2,891,935
Acct 1860 - Meters	-98,938	-	-98,938	22,280	4,259	26,539	-72,399
Acct 2440 - Deferred Revenue	-	-1,128,077	-1,128,077	-	12,534	12,534	-1,115,543
Amount Reported as Acct 1995	**-9,298,809**	**-1,128,077**	**-10,426,886**	**1,957,562**	**223,499**	**2,181,061**	**-8,245,825**
December 31, 2015 - MIFRS:							
Acct 1830 - Poles, Towers & Fixtures	-581,470	-	-581,470	197,827	12,926	210,753	-370,717
Acct 1835 - Overhead Conductor & Devices	-1,155,650	-	-1,155,650	253,311	19,262	272,573	-883,077
Acct 1840 - Underground Conduit	-743,558	-	-743,558	185,710	14,871	200,581	-542,977
Acct 1845 - Underground Conductors & Devices	-1,467,466	-	-1,467,466	332,223	36,687	368,910	-1,098,556
Acct 1850 - Line Transformers	-1,601,662	-	-1,601,662	414,787	40,046	454,833	-1,146,829
Acct 1855 - Services	-3,650,065	-	-3,650,065	758,130	82,913	841,043	-2,809,022
Acct 1860 - Meters	-98,938	-	-98,938	26,539	4,259	30,798	-68,140
Acct 2440 - Deferred Revenue	-1,128,077	-503,987	-1,632,063	12,534	30,668	43,202	-1,588,861
Amount Reported as Acct 1995	**-10,426,886**	**-503,987**	**-10,930,872**	**2,181,061**	**241,633**	**2,422,693**	**-8,508,179**

GROSS ASSETS – PROPERTY PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

BREAKDOWN BY FUNCTION

Table 2-21 below categorizes NBHDL's assets into four categories; distribution plant, general plant, contributions and grants, and WIP. In accordance with the Uniform System of Accounts ("USoA"), NBHDL has included gross assets as follows:

- Distribution plant asset accounts include USoA 1805 to 1860 - this account includes assets such as substation equipment, poles, wires, transformers and meters;
- General plant asset accounts include USoA 1905 to 1990 and USoA 1611 - this account includes assets such as buildings, computer software and hardware, transportation equipment, and tools;
- Contributions and grants includes USoA account 1995 – this account includes all contributions in aid of capital that NBHDL has received or forecasted to be received as per the Distribution System Code ("DSC"); and
- WIP – this account includes all costs related to assets that are not considered in-service as of December 31st of the applicable fiscal year. Costs are transferred out of WIP and into the appropriate category above once designated in-service in the field.

Table 2-21 – Gross Asset Breakdown by Function

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Distribution Plant	86,004,850	84,081,623	90,627,604	94,203,173	100,212,163	106,346,148	113,443,154
General Plant	10,041,866	9,620,708	10,169,205	10,969,655	11,400,820	12,524,526	13,315,062
Contrbutions and Grants	(6,875,662)	(7,096,812)	(7,560,942)	(8,236,870)	(9,298,809)	(10,426,886)	(10,930,872)
Total Excluding WIP	**89,171,054**	**86,605,519**	**93,235,866**	**96,935,958**	**102,314,173**	**108,443,789**	**115,827,344**
WIP	0	0	0	625,281	526,120	805,462	21,361
Total Including WIP	**89,171,054**	**86,605,519**	**93,235,866**	**97,561,239**	**102,840,293**	**109,249,251**	**115,848,705**

DETAILED BREAKDOWN BY MAJOR PLANT ACCOUNT

Table 2-22 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 2015 Test Year. NBHDL has also included a breakdown of accumulated amortization in the same format in Table 2-23.

Table 2-22 - Gross Assets - Detailed Breakdown by Major Plant Function

Description	2010 OEB Approved	2010 Actual	Variance from 2010 OEB Approved	2011 Actual	Variance from 2010 Actual	2012 Actual	Variance from 2011 Actual	2013 Actual	Variance from 2012 Actual	2014 Bridge	Variance from 2013 Actual	2015 Test	Variance from 2015 Bridge
Reporting Basis	CGAAP	CGAAP		CGAAP		CGAAP		CGAAP		MIFRS		MIFRS	
Land and Buildings													
1805-Land	371,195	440,188	68,994	446,493	6,305	446,565	72	446,565	-	446,565	-	446,565	-
1808-Buildings and Fixtures	769,641	769,641	-	769,641	-	1,728,007	958,366	1,830,506	102,499	1,830,506	-	1,847,915	17,409
Sub-Total-Land and Buildings	1,140,835	1,209,829	68,994	1,216,134	6,305	2,174,572	958,437	2,277,071	102,499	2,277,071	-	2,294,480	17,409
Distribution Stations													
1820-Distribution Station Equipment - < 50 kV	9,446,327	9,391,662	- 54,665	11,844,406	2,452,743	11,016,436	- 827,970	13,013,503	1,997,067	13,629,391	615,888	16,264,353	2,634,962
Sub-Total-Distribution Stations	9,446,327	9,391,662	- 54,665	11,844,406	2,452,743	11,016,436	- 827,970	13,013,503	1,997,067	13,629,391	615,888	16,264,353	2,634,962
Poles and Wires													
1830-Poles, Towers and Fixtures	18,174,544	17,775,889	- 398,656	18,921,361	1,145,473	20,054,943	1,133,582	21,394,561	1,339,618	23,347,054	1,952,493	24,196,054	848,999
1835-Overhead Conductors and Devices	14,309,219	14,004,544	- 304,676	14,818,361	813,817	15,639,134	820,774	16,392,963	753,828	17,035,212	642,249	17,578,954	543,742
1840-Underground Conduit	1,197,597	592,900	- 604,697	766,998	174,099	791,323	24,324	1,097,375	306,052	1,237,480	140,105	1,558,923	321,443
1845-Underground Conductors and Devices	6,753,851	6,482,307	- 271,544	6,755,235	272,928	6,918,226	162,990	7,308,072	389,846	7,487,743	179,671	7,816,462	328,719
Sub-Total-Poles and Wires	40,435,212	38,855,638	-1,579,573	41,261,955	2,406,317	43,403,625	2,141,670	46,192,970	2,789,345	49,107,489	2,914,518	51,150,392	2,042,903
Line Transformers													
1850-Line Transformers	15,607,087	14,725,760	- 881,328	15,372,657	646,897	16,002,784	630,127	16,518,295	515,511	17,098,879	580,583	17,846,615	747,736
Sub-Total-Line Transformers	15,607,087	14,725,760	- 881,328	15,372,657	646,897	16,002,784	630,127	16,518,295	515,511	17,098,879	580,583	17,846,615	747,736
Services and Meters													
1855-Services	15,472,356	16,033,280	560,924	16,921,975	888,695	17,526,406	604,431	18,018,316	491,910	18,834,882	816,567	20,260,224	1,425,342
1860-Meters	3,903,032	3,754,031	- 149,002	3,798,109	44,078	3,823,010	24,901	3,873,364	50,354	1,603,858	- 2,269,506	1,618,298	14,440
1860-Meters - Smart Meters	-	111,423	111,423	212,368	100,945	256,341	43,972	318,644	62,304	3,794,579	3,475,935	4,008,792	214,213
Sub-Total-Services and Meters	19,375,389	19,898,734	523,345	20,932,452	1,033,718	21,605,756	673,304	22,210,323	604,567	24,233,319	2,022,996	25,887,315	1,653,996
General Plant, Land and Buildings													
1905-Land	86,551	86,551	-	86,551	-	86,551	-	86,551	-	86,551	-	86,551	-
1908-Buildings and Fixtures	2,059,313	2,039,691	- 19,622	2,182,429	142,738	2,414,256	231,827	2,514,322	100,066	3,022,602	508,280	3,079,254	56,652
Sub-Total-General Plant, Land and Buildings	2,145,864	2,126,241	- 19,622	2,268,980	142,738	2,500,807	231,827	2,600,873	100,066	3,109,152	508,280	3,165,804	56,652
IT Assets													
1920-Computer Equipment - Hardware	610,968	612,854	1,886	748,652	135,798	816,657	68,005	824,733	8,076	921,036	96,303	1,056,836	135,800
1611-Computer Software	1,129,633	1,005,996	- 123,637	1,098,395	92,399	1,223,533	125,138	1,317,567	94,033	1,565,903	248,336	1,577,903	12,000
Sub-Total-IT Assets	1,740,600	1,618,849	- 121,751	1,847,047	228,197	2,040,190	193,143	2,142,299	102,109	2,486,939	344,640	2,634,739	147,800
Equipment													
1915-Office Furniture and Equipment	340,412	315,127	- 25,285	339,217	24,090	370,268	31,051	376,560	6,292	433,840	57,280	439,840	6,000
1930-Transportation Equipment	2,617,191	2,364,816	- 252,375	2,395,854	31,038	2,623,313	227,459	2,682,228	58,916	2,422,552	- 259,676	2,937,383	514,830
1935-Stores Equipment	75,196	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-
1940-Tools, Shop and Garage Equipment	1,166,050	1,134,706	- 31,344	1,205,954	71,247	1,226,966	21,013	1,328,596	101,630	1,375,596	47,000	1,421,746	46,151
1955-Communication Equipment	101,871	101,871	-	101,871	-	148,322	46,452	169,111	20,789	169,111	-	169,111	-
1960-Miscellaneous Equipment	18,079	18,079	-	18,079	-	20,050	1,970	20,050	-	20,050	-	20,050	-
Sub-Total-Equipment	4,318,798	4,009,795	- 309,003	4,136,170	126,375	4,464,115	327,945	4,651,741	187,626	4,496,345	- 155,396	5,063,326	566,981
Other Distribution Assets													
1970-Load Mgmt Controls - Customer Premises	403,931	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-
1975-Load Mgmt Controls - Utility Premises	165,151	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-
1980-System Supervisory Equipment	1,214,462	1,243,680	29,219	1,294,866	51,185	1,342,401	47,535	1,383,765	41,364	1,809,948	426,183	1,829,051	19,103
1990-Other Tangible Property	53,060	53,060	-	53,060	-	53,060	-	53,060	-	53,060	-	53,060	-
1995-Contributions and Grants - Credit	- 6,875,662	- 7,096,812	- 221,150	- 7,560,942	- 464,129	- 8,236,870	- 675,928	- 9,298,809	-1,061,939	- 10,426,886	- 1,128,077	- 10,930,872	- 503,987
Sub-Total-Other Distribution Assets	- 5,039,058	- 5,230,990	- 191,932	- 5,643,934	- 412,944	- 6,272,327	- 628,393	- 7,292,902	-1,020,575	- 7,994,796	- 701,894	- 8,479,679	- 484,884
WIP													
2055-Construction Work in Progress	-	-	-		-	625,281	625,281	526,120	- 99,161	805,462	279,342	21,361	- 784,101
Sub-Total-WIP	-	-	-	-	-	625,281	625,281	526,120	- 99,161	805,462	279,342	21,361	- 784,101
GROSS ASSET TOTAL	**89,171,054**	**86,605,519**	**-2,565,535**	**93,235,866**	**6,630,347**	**97,561,239**	**4,325,372**	**102,840,293**	**5,279,054**	**109,249,251**	**6,408,958**	**115,848,705**	**6,599,454**
		-		-									

Table 2-23 – Accumulated Amortization - Detailed Breakdown by Major Plant Function

Description	2010 OEB Approved	2010 Actual	Variance from 2010 OEB Approved	2011 Actual	Variance from 2010 Actual	2012 Actual	Variance from 2011 Actual	2013 Actual	Variance from 2012 Actual	2014 Bridge	Variance from 2013 Actual	2015 Test	Variance from 2015 Bridge
Land and Buildings													
1805-Land	-	-	-	-	-	-	-	-	-	-	-	-	-
1808-Buildings and Fixtures	293,508	293,474	- 34	306,963	13,489	333,314	26,351	356,852	23,538	391,450	34,598	425,091	33,642
Sub-Total-Land and Buildings	293,508	293,474	- 34	306,963	13,489	333,314	26,351	356,852	23,538	391,450	34,598	425,091	33,642
Distribution Stations													
1820-Distribution Station Equipment - < 50 kV	3,906,312	3,887,377	- 18,935	4,156,526	269,149	4,215,467	58,941	4,423,215	207,748	4,704,889	281,674	4,915,977	211,088
Sub-Total-Distribution Stations	3,906,312	3,887,377	- 18,935	4,156,526	269,149	4,215,467	58,941	4,423,215	207,748	4,704,889	281,674	4,915,977	211,088
Poles and Wires													
1830-Poles, Towers and Fixtures	10,304,635	10,338,245	33,610	10,904,838	566,593	11,176,939	272,101	11,472,696	295,756	11,634,805	162,109	11,814,993	180,187
1835-Overhead Conductors and Devices	7,926,624	7,876,482	- 50,142	8,332,106	455,624	8,529,292	197,186	8,739,600	210,308	8,881,282	141,682	9,037,049	155,767
1840-Underground Conduit	144,906	108,087	- 36,819	135,284	27,197	149,860	14,576	167,739	17,880	190,081	22,341	217,037	26,957
1845-Underground Conductors and Devices	4,216,597	4,194,254	- 22,343	4,428,296	234,042	4,515,259	86,963	4,609,132	93,873	4,710,124	100,992	4,817,471	107,347
Sub-Total-Poles and Wires	22,592,762	22,517,068	- 75,695	23,800,524	1,283,457	24,371,350	570,826	24,989,168	617,817	25,416,292	427,124	25,886,550	470,258
Line Transformers													
1850-Line Transformers	8,591,350	8,525,252	- 66,097	8,975,516	450,263	9,195,389	219,873	9,432,355	236,966	9,615,550	183,195	9,799,044	183,494
Sub-Total-Line Transformers	8,591,350	8,525,252	- 66,097	8,975,516	450,263	9,195,389	219,873	9,432,355	236,966	9,615,550	183,195	9,799,044	183,494
Services and Meters													
1855-Services	5,577,561	5,532,292	- 45,269	6,143,320	611,028	6,528,199	384,879	6,925,188	396,989	7,337,387	412,199	7,775,625	438,238
1860-Meters	2,509,687	2,502,681	- 7,006	2,610,660	107,979	2,716,977	106,317	2,822,149	105,172	917,984	- 1,904,165	1,020,972	102,988
1860-Meters - Smart Meters	-	2,228	2,228	8,704	6,476	25,061	16,356	46,731	21,670	1,124,816	1,078,085	1,397,479	272,663
Sub-Total-Services and Meters	8,087,248	8,037,202	- 50,046	8,762,684	725,482	9,270,237	507,552	9,794,069	523,832	9,380,187	- 413,882	10,194,076	813,889
General Plant, Land and Buildings													
1905-Land	-	-	-	-	-	-	-	-	-	-	-	-	-
1908-Buildings and Fixtures	1,128,200	1,118,841	- 9,358	1,186,394	67,553	1,262,341	75,946	1,343,003	80,662	1,436,850	93,847	1,519,586	82,735
Sub-Total-General Plant, Land and Buildings	1,128,200	1,118,841	- 9,358	1,186,394	67,553	1,262,341	75,946	1,343,003	80,662	1,436,850	93,847	1,519,586	82,735
IT Assets													
1920-Computer Equipment - Hardware	557,576	553,662	- 3,914	587,979	34,317	633,128	45,149	687,364	54,236	749,917	62,554	826,352	76,435
1925-Computer Software	910,986	890,638	- 20,348	939,499	48,860	993,493	53,994	1,073,458	79,966	1,227,391	153,933	1,336,720	109,329
Sub-Total-IT Assets	1,468,562	1,444,300	- 24,262	1,527,478	83,178	1,626,621	99,143	1,760,822	134,201	1,977,308	216,486	2,163,072	185,764
Equipment													
1915-Office Furniture and Equipment	283,480	281,247	- 2,233	288,404	7,157	298,271	9,867	309,761	11,490	323,349	13,588	339,929	16,580
1930-Transportation Equipment	1,831,173	1,492,514	- 338,659	1,371,589	- 120,925	1,616,558	244,969	1,854,506	237,948	1,762,271	- 92,235	1,945,614	183,343
1935-Stores Equipment	75,196	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-
1940-Tools, Shop and Garage Equipment	964,990	958,760	- 6,230	991,317	32,557	1,028,231	36,913	1,069,039	40,809	1,116,302	47,263	1,165,183	48,881
1955-Communication Equipment	78,313	75,875	- 2,439	82,188	6,313	88,821	6,633	96,405	7,584	105,668	9,264	114,334	8,666
1960-Miscellaneous Equipment	8,164	8,025	- 140	8,025	-	12,050	4,025	14,464	2,414	16,879	2,414	19,293	2,414
Sub-Total-Equipment	3,241,317	2,891,616	- 349,701	2,816,719	- 74,897	3,119,127	302,407	3,419,372	300,245	3,399,666	- 19,706	3,659,549	259,883
Other Distribution Assets													
1970-Load Mgmt Controls - Customer Premises	403,931	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-
1975-Load Mgmt Controls - Utility Premises	165,151	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-
1980-System Supervisory Equipment	965,702	963,524	- 2,178	1,011,760	48,235	1,064,873	53,114	1,116,040	51,166	1,175,174	59,135	1,245,441	70,267
1990-Other Tangible Property	-	19,589	19,589	21,635	2,045	23,264	1,630	24,894	1,630	26,523	1,630	28,153	1,630
1995-Contributions and Grants - Credit	- 1,332,286	- 1,285,862	46,424	- 1,579,018	- 293,156	- 1,758,146	- 179,128	- 1,957,562	- 199,416	- 2,181,061	- 223,499	- 2,422,693	- 241,633
Sub-Total-Other Distribution Assets	202,498	266,334	63,835	23,458	- 242,875	- 100,926	- 124,384	- 247,546	- 146,620	- 410,281	- 162,734	- 580,017	- 169,736
WIP													
2055-Construction Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-Total-WIP	-	-	-	-	-	-	-	-	-	-	-	-	-
ACCUMULATED AMORTIZATION TOTAL	**49,511,757**	**48,981,464**	**- 530,292**	**51,556,264**	**2,574,799**	**53,292,920**	**1,736,656**	**55,271,308**	**1,978,388**	**55,911,911**	**640,603**	**57,982,929**	**2,071,018**

VARIANCE ANALYSIS ON GROSS ASSETS

Table 2-24 below provides the same level of detail as Table 2-21, however, for the purposes of the variance analysis assets are categorized as Distribution Assets and General Plant and explanations on variances over NBHDL's materiality threshold are explained following the table.

Table 2-24 – Variance on Gross Assets

Description	2010 OEB Approved	2010 Actual	Variance from 2010 OEB Approved	2011 Actual	Variance from 2010 Actual	2012 Actual	Variance from 2011 Actual	2013 Actual	Variance from 2012 Actual	2014 Bridge	Variance from 2013 Actual	2015 Test	Variance from 2015 Bridge
Reporting Basis	CGAAP	CGAAP		CGAAP		CGAAP		CGAAP		MIFRS		MIFRS	
Distribution Assets:													
1805-Land	371,195	440,188	68,994	446,493	6,305	446,565	72	446,565	-	446,565	-	446,565	-
1808-Buildings and Fixtures	769,641	769,641	-	769,641	-	1,728,007	958,366	1,830,506	102,499	1,830,506	-	1,847,915	17,409
1820-Distribution Station Equipment - < 50 kV	9,446,327	9,391,662	- 54,665	11,844,406	2,452,743	11,016,436	- 827,970	13,013,503	1,997,067	13,629,391	615,888	16,264,353	2,634,962
1830-Poles, Towers and Fixtures	18,174,544	17,775,889	- 398,656	18,921,361	1,145,473	20,054,943	1,133,582	21,394,561	1,339,618	23,347,054	1,952,493	24,196,054	848,999
1835-Overhead Conductors and Devices	14,309,219	14,004,544	- 304,676	14,818,361	813,817	15,639,134	820,774	16,392,963	753,828	17,035,212	642,249	17,578,954	543,742
1840-Underground Conduit	1,197,597	592,900	- 604,697	766,998	174,099	791,323	24,324	1,097,375	306,052	1,237,480	140,105	1,558,923	321,443
1845-Underground Conductors and Devices	6,753,851	6,482,307	- 271,544	6,755,235	272,928	6,918,226	162,990	7,308,072	389,846	7,487,743	179,671	7,816,462	328,719
1850-Line Transformers	15,607,087	14,725,760	- 881,328	15,372,657	646,897	16,002,784	630,127	16,518,295	515,511	17,098,879	580,583	17,846,615	747,736
1855-Services	15,472,356	16,033,280	560,924	16,921,975	888,695	17,526,406	604,431	18,018,316	491,910	18,834,882	816,567	20,260,224	1,425,342
1860-Meters	3,903,032	3,754,031	- 149,002	3,798,109	44,078	3,823,010	24,901	3,873,364	50,354	1,603,858	- 2,269,506	1,618,298	14,440
1860-Meters - Smart Meters	-	111,423	111,423	212,368	100,945	256,341	43,972	318,644	62,304	3,794,579	3,475,935	4,008,792	214,213
1980-System Supervisory Equipment	1,214,462	1,243,680	29,219	1,294,866	51,185	1,342,401	47,535	1,383,765	41,364	1,809,948	426,183	1,829,051	19,103
1995-Contributions and Grants - Credit	- 6,875,662	- 7,096,812	- 221,150	- 7,560,942	- 464,129	- 8,236,870	- 675,928	- 9,298,809	-1,061,939	- 10,426,886	- 1,128,077	- 10,930,872	- 503,987
2055-Construction Work in Progress	-	-	-		-	625,281	625,281	526,120	- 99,161	805,462	279,342	21,361	- 784,101
Sub-Total- Distribution Assets	80,343,650	78,228,491	-2,115,159	84,361,528	6,133,037	87,933,985	3,572,457	92,823,239	4,889,254	98,534,672	5,711,434	104,362,694	5,828,021
General Plant													
1905-Land	86,551	86,551	-	86,551	-	86,551	-	86,551	-	86,551	-	86,551	-
1908-Buildings and Fixtures	2,059,313	2,039,691	- 19,622	2,182,429	142,738	2,414,256	231,827	2,514,322	100,066	3,022,602	508,280	3,079,254	56,652
1920-Computer Equipment - Hardware	610,968	612,854	1,886	748,652	135,798	816,657	68,005	824,733	8,076	921,036	96,303	1,056,836	135,800
1611-Computer Software	1,129,633	1,005,996	- 123,637	1,098,395	92,399	1,223,533	125,138	1,317,567	94,033	1,565,903	248,336	1,577,903	12,000
1915-Office Furniture and Equipment	340,412	315,127	- 25,285	339,217	24,090	370,268	31,051	376,560	6,292	433,840	57,280	439,840	6,000
1930-Transportation Equipment	2,617,191	2,364,816	- 252,375	2,395,854	31,038	2,623,313	227,459	2,682,228	58,916	2,422,552	- 259,676	2,937,383	514,830
1935-Stores Equipment	75,196	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-	75,196	-
1940-Tools, Shop and Garage Equipment	1,166,050	1,134,706	- 31,344	1,205,954	71,247	1,226,966	21,013	1,328,596	101,630	1,375,596	47,000	1,421,746	46,151
1955-Communication Equipment	101,871	101,871	-	101,871	-	148,322	46,452	169,111	20,789	169,111	-	169,111	-
1960-Miscellaneous Equipment	18,079	18,079	-	18,079	-	20,050	1,970	20,050	-	20,050	-	20,050	-
1970-Load Mgmt Controls - Customer Premises	403,931	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-	403,931	-
1975-Load Mgmt Controls - Utility Premises	165,151	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-	165,151	-
1990-Other Tangible Property	53,060	53,060	-	53,060	-	53,060	-	53,060	-	53,060	-	53,060	-
Sub-Total-General Plant	8,827,405	8,377,028	- 450,376	8,874,339	497,311	9,627,254	752,915	10,017,055	389,801	10,714,578	697,524	11,486,011	771,433
GROSS ASSET TOTAL	**89,171,054**	**86,605,519**	**-2,565,535**	**93,235,866**	**6,630,347**	**97,561,239**	**4,325,372**	**102,840,293**	**5,279,054**	**109,249,251**	**6,408,958**	**115,848,705**	**6,599,454**
		-		-									

2010 Board Approved vs. 2010 Actual:

- Distribution Assets – ($2,115,159)

Distribution assets are less than the 2010 Board Approved amounts by $2,115,159. Voltage Conversion Plan projects (as further discussed in Appendix 2-A) contributed significantly to the gross asset variance due to issues associated with project scope changes, timing, duration and overall changes to the project planning process. Demand driven projects including primary and secondary services, subdivisions and road relocations were also less than forecasted. Transformer costs were lower than forecasted due to the changes in planned and demand construction. 2010 capital contributions were forecasted by job type, however actual contributions collected by NBHDL are in accordance with the DSC and the provisions of NBHDL's Conditions of Service and vary by individual job. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project. Planned asset management activities did not proceed until 2011 which also contributes to the variance. Variances for 2010 Board Approved capital spending compared to 2010 Actual by material project can be found in Table 2-35, including written evidence for projects over NBHDL's materiality.

- General Assets - ($450,376)

General assets are less than the 2010 Board Approved amounts by $450,376 which is primarily caused by fleet disposals and IT related costs. In 2009, NBHDL recorded $239,998 in relation to the retirement of a bucket truck and three pick-up trucks, offset by $53,654 that had been included in the 2009 Bridge Year for the 2010 COS application which accounted for the disposal of two pick-up trucks. In 2010, NBHDL retired 3 additional pick-up trucks for $79,733, however, this was not included in the 2010 COS. The general asset budget in the 2010 COS application also included $102,216 in costs for software customization which NBHDL did not pursue as other NBHDL ultimately discovered more cost efficient options. The remaining $82,083 relates to various individual costs under NBHDL's materiality.

Further detail on the variance between 2010 Actual compared to 2010 Board Approved amounts by material project can be found in Table 2-36.

2011 Actual vs. 2010 Actual:

- Distribution Assets - $6,133,037

Distribution assets are higher than the 2010 Actuals by $6,133,037. In 2011, NBHDL completed the bulk of construction on MS# 20; a new substation that replaced MS# 12. MS# 12 was at end of life, operating at 4kV and Hydro One Networks Inc. ("HONI") required NBHDL to relocate MS# 12 off of their property as it was located inside a HONI Transformer Station ("TS"). The new station contributed $2,058,742 to the

increase over 2010. NBHDL also experienced a transformer failure in 2010 and the new substation transformer was put in service in 2011, contributing $262,229 to the variance. Rehabilitation on MS# 14 also occurred in 2011 at a cost of $160,718. Voltage Conversion Plan projects contributed to $1,717,830 to the increase in distribution assets with construction on two major projects, Worthington Street and North Bay TS work accounting for 47% of the costs. Customer demand driven projects such as primary and secondary services, minor betterments, subdivisions and road relocations account for $1,200,693 in increases across the various distribution assets. Major betterment projects, transformer purchases, asset management and switch replacement costs and metering installations increased distribution assets by a further $1,185,098 and contributed capital offset distribution assets by ($464,129). SCADA upgrades and other immaterial projects were offset by disposals related to the scrapping of transformers and other decommissioned equipment for a net increase to gross distribution assets of $11,856.

- General Assets - $497,311

General assets increased over 2010 Actuals by $497,311 in 2011. In 2011, NBHDL renovated the customer service area of its building, which included both the front office staffing area and the customer entrance. This renovation increased general assets, including the building and office furniture/equipment by $154,297. Work equipment purchases in 2011 were $66,985, including $35,076 in test equipment for substation maintenance. Increases in IT related assets of $228,197 were related to a major software upgrade to NBHDL's main platform and various initiatives undertaken for customized applications. NBHDL invested in the replacement of two large bucket trucks and two pick-up trucks in 2011 that were offset by related disposals for a new increase to fleet assets of $31,038. Other individual costs under NBHDL's materiality contribute to the remaining increase on general assets of $16,794.

2012 Actual vs. 2011 Actual:

- Distribution Assets - $3,572,457

Distribution assets are higher than the 2011 Actuals by $3,572,457. In 2012, NBHDL wrapped up final costs on two new substations (constructed in 2008 and 2010), began work on the replacement of MS# 9, completed the rehabilitation on MS# 14 and began rehabilitation on MS# 16. These projects increased substation related assets by $248,164. The final costs for the 2010 transformer failure and another substation transformer failure in 2011 contribute $224,723 in station equipment. 2012 costs were offset by the decommissioning of MS# 12, MS# 5, the write off of failed transformers and the reallocation of new MS# 21 cost to WIP and other immaterial station costs by ($342,472). Voltage Conversion Plan projects contributed to $1,380,014 to the increase in various distribution assets with construction on one major projects, Old Callander Road, accounting for 52% of the costs. Customer demand driven projects such as primary and secondary services, minor betterments, subdivisions and road relocations account for

$1,380,436 in increases across the various distribution assets. Major betterment projects, transformer purchases, asset management and switch replacement costs and metering installations increased distribution assets by a further $1,248,282. Contributed capital offset distribution assets by ($675,928). SCADA upgrades, the increase of WIP by substation gross assets and other immaterial projects increased gross distribution assets by $109,238.

- General Assets - $752,915

General assets increased over 2011 Actuals by $752,912 in 2012. Completion of the customer service area renovations increased general assets, including the building and office furniture/equipment by $149,443. Other building and facility upgrades, including renovations to the men's washroom, security upgrades, and work done on the service yard gate increased general assets by $84,892. Increases in IT related assets of $269,696 were related to a phone system upgrade, network upgrades, various software upgrades and various initiatives undertaken for customized applications and equipment, including a disconnect/reconnect application, automated bill creation and a bill folder/inserter. Final costs related to one of the bucket trucks replaced in 2011, the replacement of two pick-up trucks and an additional truck added to the fleet in 2012 was offset by the related disposals for an increase to fleet assets of $227,459. Other individual costs under NBHDL's materiality contribute to the remaining increase in general assets of $21,425.

2013 Actual vs. 2012 Actual:

- Distribution Assets - $4,889,254

Distribution assets are higher than the 2012 Actuals by $4,889,254. In 2013, NBHDL completed the majority of the rehabilitation on MS# 16 and construction was completed on MS# 21, increasing substation gross assets by $2,083,796. Costs transferred from WIP in 2012, immaterial individual costs and disposal costs amounted to an additional increase of $15,767. Voltage Conversion Plan projects contributed to $1,170,362 to the increase in various distribution assets. Customer demand driven projects such as primary and secondary services, minor betterments, subdivisions and road relocations account for $1,895,767 in increases across the various distribution assets. $459,691 of this increase in demand work is related to the city wide deployment of Bell's Aliant's fibre to the home service. The "Bell FSA" project involves approximately 3,829 new attachments to NBHDL poles and in order to accommodate these attachments NBHDL engineers the attachments and then performs construction activities to make the poles ready for the new attachments. This is the typical process for managing and completing 3rd party attachments. The project has been staged over 2013 and 2014. Major betterment projects, transformer purchases, switch replacement costs and metering installations increased distribution assets by a further $740,210. Contributed capital offset distribution assets by ($1,061,939). NBHDL collects

100% of the costs related to the Bell FSA work through contributed capital; Bell Aliant is billed as individual FSA work orders are closed after review and approval by the Engineering department. SCADA upgrades and other immaterial projects increased gross distribution assets by $45,291.

- General Assets - $389,801

General assets increased over 2012 Actuals by $389,801 in 2012. An upgrade of NBHDL's HVAC system was initiated in 2012 and costs increased $148,769, with ($57,888) being offset to WIP which is included in the distribution assets category. The HVAC project was needed to address issues with the building's heating and cooling system to properly size the unit to meet the demand of the facility, to improve zoning control and allow for consumption efficiencies. This project carried into 2014. Tools and other work equipment increased general assets by $101,630 and included additional substation testing equipment, a new Spider rope system used for stringing conductor, a load analyzer and other individual tools. An increase in IT related assets of $123,898 were related to a phone system upgrade, various software upgrades, the integration of Ontario One Call, web presentment and a new financial reporting package. The replacement of a pick-up truck, the refurbishment of a bucket truck and other fleet work increased gross assets by $58,916. Other building and facility upgrades increased general assets by $14,476.

2014 Actual vs. 2013 Actual:

- Distribution Assets - $5,711,434

Distribution assets are higher than the 2013 Actuals by $5,711,434. In 2014, NBHDL will be replacing the transformer at MS# 1 that is operating at 4kV, as part of the overall Voltage Conversion plan, increasing station assets by $278,506. The disposition of the gross asset value of the transformer currently in place offsets this increase by ($25,000). Final costs related to the 2013 rehabilitation on MS# 16 and the construction of MS# 21 will further increase station assets by $116,282 in 2014 and improvements being completed at MS# 15 contribute an addition $226,416 in gross station asset increases. NBHDL is purchasing two station transformers in 2014 in relation to the 2015 planned construction of MS# 22, the replacement of MS# 9 which is in very poor condition and becoming a safety hazard. The costs of these transformers are included in WIP in 2014, increasing gross assets by $679,396. NBHDL was able to reduce purchase costs by leveraging a larger group purchase with two other LDCs. Significant investment in SCADA is also taking place in 2014; $368,822 is required to replace the obsolete radio that represents the backbone of the SCADA system. The radio is down to one channel with no support available. Other SCADA projects account for increasing gross asset costs of $57,361. Voltage Conversion Plan projects contribute $1,247,452 to the increase in various distribution assets. Customer demand driven projects such as primary and secondary services, minor betterments, subdivisions and road relocations account for $1,790,020 in increases across the various distribution assets; $744,212 of this increase is related to

the Bell FSA project. Major betterment projects, transformer purchases, switch replacement costs and metering installations increased distribution assets by a further $1,412,295. Forecasted contributed capital offsets distribution assets by ($1,128,077). On February 20, 2014 NBHDL received a Decision and Order (*EB-2013-0157*) regarding its 2014 IRM that included a prudence review of smart meter costs and a proposal regarding the disposition and recovery of costs related to the Smart Meter deployment initiated in 2009 by NBHDL. The Board granted its approval of historically incurred costs and the costs projected for 2014 and as such NBHDL recorded these costs in its gross fixed assets in May of 2014. As part of this COS application, NBHDL will be seeking disposition of the NBV of its stranded meters and has adjusted its rate base accordingly in 2014 to recognize the disposition. $3,344,188 in smart meters were added to gross distribution assets, offset by the disposition of stranded meter costs of ($2,283,802) for a net increase to gross distribution assets of $1,060,387. General asset related purchases are included in WIP and account for $22,012 on the increase in distribution assets. In 2014, NBHDL has also estimated disposals related to the retirement of distribution assets which results in a decrease to gross assets of ($394,439).

- General Assets - $697,524

General assets increased over 2013 Actuals by $697,524 in 2014. Several projects are being completed in 2014 in relation to NBHDL's facility which contributed to an increase in the building asset costs. The completion of the HVAC system increased building assets by $207,315. A new generator for the building, which houses all NBHDL operations, increased gross assets by $166,800. The generator that was in place was not capable of running the entire building's systems and power requirements, and as such only a few systems were on emergency power. A significant overhaul of the gate to NBHDL's service yard, which provides access to equipment and materials, is also occurring in 2014 resulting in an increase of $75,000 in gross general assets. The position of the gate is a safety concern for both employees and customers as it is in a high traffic area in front of the customer entrance. Additional projects related to the building increase assets by $123,111 and are related to padmount transformer bunks, safety lighting in the backyard, garage door upgrades, a hoist for the garage, upgrades to the control room and other miscellaneous items. Fleet costs in 2014 relate to the replacement of a pick-up, a utility trailer, a winch upgrade for one of the older bucket trucks and other immaterial costs which increase fleet assets by $72,163. NBHDL is also replacing a 1997 bucket truck that has been taken off the road because of safety concerns. The costs related to the cab and chassis of $83,285 are included in 2014, however, these have been reallocated to WIP for 2014. The work required on the truck in relation to the radial boom device will be completed in 2015, at which point the truck will be put into service. Fleet costs are offset by ($331,838) for the disposal of two pick-up trucks and the bucket truck that has been taken off the road. Fleet purchases are based on a replacement schedule. An increase in IT related assets of $252,811 are related to server requirements, PC related upgrades, software upgrades, customized applications for customer

applications and other technology initiatives for efficiency and process improvements. As part of the disposition of smart meter implementation costs, NBHDL recorded an additional $84,163 to IT related general assets in 2014. Tools, other work equipment and other miscellaneous items increased general assets by an additional $47,999**.**

2015 Actual vs. 2014 Actual:

- Distribution Assets - $5,828,021

Distribution assets are higher than the 2014 Actuals by $5,828,021. In 2015, NBHDL will be replacing the transformer at MS# 13, increasing station equipment costs by $271,740. This transformer has been rated in poor condition and is being replaced to prevent the risks associated with failure. Construction of MS#22 will be completed in 2015 further increasing station assets by $1,781,297. Increased station assets are offset by ($137,479) for disposals related to the decommissioning of MS# 9 and the transformers. Voltage Conversion Plan projects contribute $1,869,726 to the increase in various distribution assets, with three very large jobs in the downtown area accounting for 50% of these costs. Customer demand driven projects such as primary and secondary services, minor betterments, subdivisions and road relocations account for $1,165,030 in increases across the various distribution assets. Major betterment projects, transformer purchases, switch replacement costs and metering installations increased distribution assets by a further $1,883,092. NBHDL's Asset Condition Assessment Report (prepared by METSCO Energy Solutions Inc. ("METSCO") and attached as Appendix B to Appendix 2-A) has identified that a significant amount of underground replacement is required and three major projects are being executed in 2015, these projects contribute $1,279,631 to major betterment work referenced in the amount above. Contributions in aid of capital are forecasted at ($503,987). General asset related purchases related to WIP and miscellaneous SCADA work net to a reduction in gross distribution assets of ($67,817) on the increase in distribution assets. In 2014, NBHDL has estimated disposals related to the retirement of distribution assets which results in a decrease to gross assets of ($433,581).

- General Assets - $771,443

General assets increased over 2014 Actuals by $771,433 in 2015. Costs related to NBHDL's building and contribute to an increase in the building asset costs of $56,652 and include a renovation to the area that houses inventory. Fleet costs increase $598,285 in 2015 related to the scheduled replacement of three pick-up trucks, two utility trailers, and the replacement of a 1997 bucket truck that has been taken off the road. The costs related to the cab and chassis of $83,285 have been reallocated from WIP in 2014 and the work required on the truck in relation to the radial boom device accounts for $315,000. Fleet costs are offset by ($83,455) for the disposal of the three pick-up trucks. An increase in IT related assets of $147,500 are related to server requirements, PC related upgrades, software upgrades, and printers.

Tools, other work equipment and other miscellaneous items increased general assets by an additional $52,451.

SUMMARY OF INCREMENTAL CAPITAL MODULE ADJUSTMENT

NBHDL confirms that it has not applied for nor received any ICM adjustments as part of a previous IRM application.

RECONCILIATION OF CONTINUITY STATEMENTS TO CALCULATED DEPRECIATION EXPENSES

NBHDL confirms that the depreciation expenses in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and are presented by account. As such there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

WORKING CAPITAL CALCULATION

OVERVIEW

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the 13% Allowance Approach or the filing of a lead/lag study. Using the 13% Allowance Approach, the working capital allowance is calculated to be 13% of the sum of Cost of Power ("COP") and controllable expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). NBHDL did not conduct a lead lag study and is using the 13% Allowance Approach in accordance with the Filing Requirements.

The working capital allowance for the 2015 Test Year is based upon 13% of the COP and controllable expenses. In calculating the working capital allowance for 2010 to 2013 actual and for the 2014 Bridge Year, NBHDL used the Board's historical 15% Allowance Approach.

Table 2-25 provides a summary of NBHDL's COP and controllable expenses used to the calculate working capital allowance for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridge Year and the 2015 Test Year.

Table 2-25 - Summary of Working Capital Allowance

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Cost of Power	**44,788,315**	**44,267,559**	**48,303,086**	**50,412,615**	**56,023,658**	**57,307,862**	**61,164,705**
Controllable Expenses:							
Operations	691,316	789,643	942,500	860,402	897,622	960,774	1,088,205
Maintenance	1,270,828	1,146,781	1,126,685	1,270,845	1,397,537	1,536,335	1,721,331
Billing & Collecting	1,144,087	910,353	887,267	1,056,107	1,019,133	1,604,983	1,243,810
Community Relations	112,000	0	(784)	35,050	(6,800)	1,502	2,200
Administration & General Expense	2,462,179	2,158,328	2,407,977	2,309,976	2,397,460	2,704,381	2,949,298
Donations - LEAP	0	0	14,550	14,550	14,550	14,550	16,700
Property Taxes	64,292	60,827	58,586	57,183	62,479	66,004	69,876
Total Controllable Expenses	**5,744,701**	**5,065,932**	**5,436,781**	**5,604,113**	**5,781,981**	**6,888,529**	**7,091,420**
Working Capital	**50,533,016**	**49,333,491**	**53,739,867**	**56,016,728**	**61,805,639**	**64,196,390**	**68,256,125**
Working Capital Allowance Rates	15%	15%	15%	15%	15%	15%	13%
Working Capital Allowance	**7,579,952**	**7,400,024**	**8,060,980**	**8,402,509**	**9,270,846**	**9,629,459**	**8,873,296**

As shown in Table 2-25, the 2015 working capital allowance has increased $1,293,344 or 17% in comparison to the 2010 Board Approved Year. The change between the 2015 Test Year and 2010 Board Approved Year is a result of increased working capital requirements due to increased costs of power and increased controllable expenses, less the decrease in percentage rate applied in the computation of the working capital allowance from 15% to 13%. Table 2-26 provides a summary of the increase between the 2015 Test Year and 2010 Board Approved working capital allowance.

Table 2-26 - Summary of Changes in Working Capital Allowance

Description	2010 OEB Approved	2015 Test Year	Change	Working Capital Allowance Factor	Working Capital Allowance
Cost of Power (COP)	44,788,315	61,164,705	16,376,390	15%	2,456,458
Total Controllable Expenses	5,744,701	7,091,420	1,346,719	15%	202,008
Working Capital	**50,533,016**	**68,256,125**	**17,723,109**		**2,658,466**
COP & Controllable Expenses		68,256,125		13%	8,873,296
		68,256,125		15%	10,238,419
Decrease in Working Capital Allowance					**(1,365,122)**
Net Working Capital Allowance					**1,293,344**

Approximately 92% of the working capital increase of $17,723,109, which translates to an increased working capital allowance for rate base purposes of $1,293,344, is related to cost of power. Controllable OM&A expenses represent 8% of the increase over the 2010 Board-Approved amounts for working capital and details on the expenses can be found in Exhibit 4 – Operating Costs.

COST OF POWER CALCULATIONS

NBHDL has calculated COP for the 2015 Test Year based upon the 2015 load forecast, adjusted for the impact of Conservation and Demand Management activities and in accordance with the Board's filing requirements. A summary of the total COP expenses is provided in Table 2-27.

Table 2-27 - Summary of Total Cost of Power Expenses

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Cost of Power Expenses							
Power Purchased	35,876,792	35,834,623	39,461,790	41,414,241	46,570,209	47,670,501	51,507,689
Wholesale Market Service Charges	2,824,341	2,454,781	2,472,482	2,249,530	2,282,359	2,281,155	2,195,346
Rural Rate Assistance Charges	764,913	744,645	733,516	662,578	664,893	704,022	703,273
Network Charges	2,822,247	2,767,456	3,149,258	3,386,346	3,634,818	3,664,870	3,697,319
Connection Charges	2,478,457	2,448,443	2,465,785	2,681,551	2,702,303	2,744,005	2,816,870
Low Voltage Charges	21,565	17,612	20,254	18,370	20,325	20,614	19,930
Smart Meter Entity Charges	0	0	0	0	148,752	222,694	224,277
Total COP Expenses	**44,788,315**	**44,267,559**	**48,303,086**	**50,412,615**	**56,023,658**	**57,307,862**	**61,164,705**

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate used to calculate COP was determined in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual data and uses the most current RPP price.

The RPP and non-RPP price was obtained from the Regulated Price Plan Price Report for the period of November 1, 2014 through October 31, 2015 published by the BOARD October 16, 2014. For the purposes of calculating the 2015 Test Year, NBHDL has used an estimate of $.09496 per kWh for RPP customers. For non-RPP customers, NBHDL has used $.09552/kWh which includes $.02064 per kWh for the Wholesale Electricity Price and $.07488 per kWh for Global Adjustment charges.

NBHDL understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of its Application.

Regulatory Charges

For the purposes of determining the cost of Wholesale Market Service ("WMS") Charges for the 2015 Test Year, NBHDL reviewed the historical WMS expense incurred from 2011 through 2013 and applied the historical annual WMS expense against the annual power purchased to determine an annual average

cost per kWh. A three (3) year average cost per kWh for WMS of $.0041 was then applied to the forecasted power purchases for the 2015 Test Year.

For the purposes of calculating the Rural Rate Assistance cost, NBHDL based the cost on the current rate of $.0013/kWh applied to the forecasted power purchase for the 2015 Test Year.

Network and Connection Charges

NBHDL incurs Network and Connection charges from both the IESO and Hydro One. For the purposes of determining the cost of each for the 2015 Test Year, NBHDL determined the kW billed by both the IESO and Hydro One for 2013 actual Network and Connection costs. The 2013 kW was then utilized to estimate the monthly Network and Connection costs for the 2015 Test Year by applying the forecasted kW by the January 1, 2014 Uniform Transmission Rates (UTR) as approved by the Board (EB-2012-0031) and Hydro One's 2014 approved rates as invoiced. NBHDL understands that the transmission costs will be updated to reflect any new rates that may become available prior to the approval of its application.

Low Voltage Charges

NBHDL incurs low voltage charges from Hydro One and the 2015 Test Year costs were estimated using a rate of $.682 per kW, Hydro One's 2014 rate.

Smart Meter Entity Charges

The Smart Meter Entity costs are calculated based on the rate of $0.788 per month for each Residential and General Service < 50 kW customer approved by the Board on March 28, 2013. The 2013 customer count has been utilized for the 2015 Test Year calculation.

Table 2-28 provides a summary of the COP calculation for the 2015 Test Year.

Table 2-28 - 2015 Cost of Power Calculation

	Metric	2015 kWh - Jan~Apr	Loss Factor - Current	2015 Uplifted kWh	2015 kWh - May~Dec	Loss Factor - Proposed	2015 Uplifted kWh	2015 kW - UTR	2015 Rates	2015
Electricity - Commodity - RPP										
Class per Load Forecast										
Residential	kWh	78,925,144	1.0480	82,713,551	119,051,130	1.0471	124,658,438		$ 0.09496	$ 19,692,044
GS<50	kWh	27,496,865	1.0480	28,816,715	46,938,725	1.0471	49,149,539		$ 0.09496	$ 7,403,675
GS>50	kWh	4,300,367	1.0480	4,506,784	6,971,910	1.0471	7,300,287		$ 0.09496	$ 1,121,200
Unmetered Scattered Load	kWh	17,658	1.0480	18,505	35,203	1.0471	36,861		$ 0.09496	$ 5,258
Intermediate	kWh		1.0375			1.0366			$ 0.09496	$ -
Sentinel Lighting	kWh	130,376	1.0480	136,634	250,068	1.0471	261,847		$ 0.09496	$ 37,840
Street Lighting	kWh		1.0480			1.0471			$ 0.09496	$ -
TOTAL		**110,870,410**		**116,192,190**	**173,247,036**		**181,406,972**			**$ 28,260,016**
Electricity - Commodity - Non-RPP										
Class per Load Forecast										
Residential	kWh	6,183,479	1.0480	6,480,286	9,327,195	1.0471	9,766,506		$ 0.09552	$ 1,551,894
GS<50	kWh	4,278,650	1.0480	4,484,026	7,317,791	1.0471	7,662,459		$ 0.09552	$ 1,160,232
GS>50	kWh	64,956,600	1.0480	68,074,516	121,882,528	1.0471	127,623,195		$ 0.09552	$ 18,693,045
Unmetered Scattered Load	kWh		1.0480			1.0471			$ 0.09552	$ -
Intermediate	kWh	5,851,245	1.0375	6,070,667	10,683,565	1.0366	11,074,583		$ 0.09552	$ 1,637,714
Sentinel Lighting	kWh	9,610	1.0480	10,072	18,433	1.0471	19,301		$ 0.09552	$ 2,806
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.09552	$ 201,982
TOTAL		**82,058,410**		**85,935,776**	**150,469,449**		**157,444,382**			**$ 23,247,673**
TOTAL POWER PURCHASED - USoA 4705		**192,928,820**		**202,127,966**	**323,716,485**		**338,851,354**			**$ 51,507,689**
Wholesale Market Service										
Class per Load Forecast										
Residential	kWh	85,108,624	1.0480	89,193,838	128,378,325	1.0471	134,424,944		$ 0.0041	$ 907,466
GS<50	kWh	31,775,516	1.0480	33,300,740	54,256,516	1.0471	56,811,998		$ 0.0041	$ 365,686
GS>50	kWh	69,256,966	1.0480	72,581,301	128,854,438	1.0471	134,923,482		$ 0.0041	$ 842,074
Unmetered Scattered Load	kWh	17,658	1.0480	18,505	35,203	1.0471	36,861		$ 0.0041	$ 225
Intermediate	kWh	5,851,245	1.0375	6,070,667	10,683,565	1.0366	11,074,583		$ 0.0041	$ 69,577
Sentinel Lighting	kWh	139,986	1.0480	146,706	268,501	1.0471	281,148		$ 0.0041	$ 1,736
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.0041	$ 8,581
TOTAL WHOLESALE MARKET SERVICE - USoA 4708										**$ 2,195,346**
Rural Rate Assistance										
Class per Load Forecast										
Residential	kWh	85,108,624	1.0480	89,193,838	128,378,325	1.0471	134,424,944		$ 0.0013	$ 290,704
GS<50	kWh	31,775,516	1.0480	33,300,740	54,256,516	1.0471	56,811,998		$ 0.0013	$ 117,147
GS>50	kWh	69,256,966	1.0480	72,581,301	128,854,438	1.0471	134,923,482		$ 0.0013	$ 269,756
Unmetered Scattered Load	kWh	17,658	1.0480	18,505	35,203	1.0471	36,861		$ 0.0013	$ 72
Intermediate	kWh	5,851,245	1.0375	6,070,667	10,683,565	1.0366	11,074,583		$ 0.0013	$ 22,289
Sentinel Lighting	kWh	139,986	1.0480	146,706	268,501	1.0471	281,148		$ 0.0013	$ 556
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.0013	$ 2,749
TOTAL RURAL RATE ASSISTANCE - USoA 4730										**$ 703,273**
Transmission - Network										
Based on 2013 kW for NBHDL										
IESO	kW							1,023,625	$ 3.82000	3,910,248
Hydro One	kW							41,037	$ 3.23000	132,549
RSVA Adjustment										- 345,477
TOTAL NETWORK - USoA 4714										**$ 3,697,319**
Transmission - Connection										
Based on 2013 kW for NBHDL										
IESO	kW							1,075,278	$ 2.80000	3,010,778
Hydro One	kW							41,811	$ 2.27000	94,911
RSVA Adjustment										- 288,820
TOTAL CONNECTION - USoA 4716										**$ 2,816,870**
Low Voltage										
Based on 2013 kW for NBHDL										
Hydro One	kW							40,438	$ 0.68200	27,579
Hydro One - Fixed Charges										7,096
RSVA Adjustment										- 14,745
TOTAL LOW VOLTAGE - USoA 4750										**$ 19,930**
Smart Meter Entity Charges										
Based on 2013 customer count				# of Cust			# of Cust	# of Months		
Residential	CX #			21,064			21,064	12	$ 0.78800	199,181
General Service <50 kW	CX #			2,654			2,654	12	$ 0.78800	25,096
TOTAL SMART METER ENTITY CHARGE - USoA 4751										**$ 224,277**
TOTAL COST OF POWER EXPENSE - 2015										**$ 61,164,705**

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

NBHDL is seeking disposition of the NBV of its stranded meters as at December 31, 2014. In accordance with the Board's *Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), whereby distributors are to be "held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the smart meter initiative)", NBHDL seeks disposition of its stranded meter costs as at December 31, 2014 in the amount of $278,085. This represents the amount of the pooled residual NBV of the meters removed from service, less any net proceeds from sales of the meters and contributed capital attributable to the meters at December 31, 2014.

On August 30, 2013, NBHDL filed its 2014 IRM application (*EB-2013-0157)* which included a request for the disposition and recovery of costs related to smart meter deployment (the "Smart Meter Application"). NBHDL did not seek recovery of its stranded meter costs at that time, but instead proposed to dispose of its stranded meters in its next cost of service application. In the Decision and Order dated February 20, 2014, the Board authorized NBHDL to continue to use the established sub-account Stranded Meter Costs of Account 1555 to record and track remaining costs of the stranded conventional meters replaced by smart meters and indicated that the balance of this sub-account should be brought forward for disposition in NBHDL's next cost of service application.

STRANDED METER CALCULATION AND COST ALLOCATION METHODOLOGY

In accordance with the Board's *Guideline G-2008-0002, Smart Meter Funding and Cost Recovery*, NBHDL transferred the cost of stranded meters from Account 1860 - Meters to Account 1555 - Sub-account Stranded Meter Costs in its 2014 Bridge Year; the NBV of stranded meters is not included in the 2015 Test Year revenue requirement, not as a return on capital or as part of depreciation expenses. Due to limited historical information, the amount recorded in Account 1555 is based on NBHDL's best estimate of stranded meters related to the smart meter deployment. There are 2 components to the determination of the stranded net book value:

1) NBHDL determined the cost of all meters installed as of December 2003 and calculated amortization to December 31, 2014. From there NBHDL estimated the stranded NBV and assigned this amount to the Residential and GS < 50 classes by utilizing the meter capital weighted allocation factors for Residential and GS<50 classes as approved in NBHDL's 2010 COS (EB-2009-0270) Cost Allocation Model.

2) NBHDL isolated costs related to stranded meters from 2004 through 2008 and calculated amortization to December 31, 2014. Costs were allocated by class as either Residential or

GS<50 based on the same 2010 Cost Allocation weighting factors above, however, each of the two classes is determined as a percentage of 100%. NBHDL began its smart meter implementation in 2009 and as such did not include any costs as part of its stranded meter calculation subsequent to December 31, 2009.

Table 2-29 provides a summary of the residual NBV calculation for stranded assets in relation to the smart meter implementation at NBHDL. In accordance with the *Accounting Procedures Handbook*, no carrying charges were recorded for the stranded meter cost balances in the sub-account of Account 1555.

Table 2-29 - Net Book Value Calculation for Stranded Meters

Description		Residential Class	GS<50 Class	Total - Residential & GS<50 Class
2010 Cost Allocation Model - as % of all classes		58%	16%	75%
2010 Cost Allocation Model - as % of Residential and GS<50 only		78%	22%	100%
Meters, cost as of December 31, 2003:				
Cost	2,919,543	1,694,594	480,520	2,175,115
Accumulated Amortization, calculated to December 31, 2014	2,635,492	1,529,723	433,769	1,963,492
Net Book Value, December 31, 2014	284,050	164,872	46,751	211,623
Meter, additional costs from 2004 through 2008:				
Cost	108,687	84,676	24,011	108,687
Accumulated Amortization, calculated to December 31, 2014	42,225	32,897	9,328	42,225
Net Book Value, December 31, 2014	66,462	51,780	14,683	66,462
Meters, Total Cost		1,779,271	504,531	2,283,802
Meters, Total Accumulated Amortization		1,562,619	443,097	2,005,716
Meters, Total Stranded Net Book Value		**216,651**	**61,434**	**278,085**

Table 2-30 is consistent with Board Appendix 2-S, Stranded Meter Treatment and provides the net book value of the stranded meters, reflecting accumulated depreciation to December 31, 2014. These figures reconcile to the amounts reflected in Table 2-18 that was used to determine NBHDL's rate base. NBHDL did not collect contributed capital from customers as part of the smart meter implementation nor were there any proceeds upon disposition.

Table 2-30 – Stranded Meter Treatment

Appendix 2-S Stranded Meter Treatment							
Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 2,267,660	$ 1,535,504	$ -	$ 732,156	$ -	$ 732,156
2007		$ 2,272,167	$ 1,598,898	$ -	$ 673,270	$ -	$ 673,270
2008		$ 2,283,802	$ 1,662,525	$ -	$ 621,277	$ -	$ 621,277
2009		$ 2,283,802	$ 1,726,384	$ -	$ 557,417	$ -	$ 557,417
2010		$ 2,283,802	$ 1,790,244	$ -	$ 493,558	$ -	$ 493,558
2011		$ 2,283,802	$ 1,850,474	$ -	$ 433,328	$ -	$ 433,328
2012		$ 2,283,802	$ 1,906,905	$ -	$ 376,896	$ -	$ 376,896
2013		$ 2,283,802	$ 1,958,816	$ -	$ 324,985	$ -	$ 324,985
2014	(1)	$ 2,283,802	$ 2,005,716	$ -	$ 278,085	$ -	$ 278,085

STRANDED METER RATE RIDERS

NBHDL is requesting the recovery of the NBV of the stranded meters of $278,085 as at December 31, 2014 through separate Stranded Meter Rate Riders for each of the Residential and General Service < 50 kW rate classes over a one-year period. NBHDL proposes to recover the NBV of the stranded meters through a fixed monthly Stranded Meter Rate Rider for the Residential and General Service < 50kW rate classes. The proposed disposition is calculated based upon the NBV of stranded meters by rate class as shown in Table 2-28 and the average number of customers as forecasted for the 2015 Test Year. NBHDL requests approval for a Stranded Meter Rate Rider $0.85 per month for each Residential customer and $1.91 per month for each metered customer in the General Service < 50 kW rate class. Table 2-31 summarizes the calculation of the proposed Stranded Meter Rate Rider.

Table 2-31 – Proposed Stranded Meter Rate Riders

Description	Residential Class	GS<50 Class
Net Book Value, December 31, 2014	216,651	61,434
Recovery Period	1	1
Average Number of Customers, December 31, 2013	21,120	2,675
Proposed Rate Rider by Class	**$ 0.85**	**$ 1.91**

CAPITAL EXPENDITURES

PLANNING OVERVIEW

In accordance with the Filing Requirements, NBHDL is filing its consolidated DSP as a stand-alone document which includes all elements of the DSP as Appendix 2-A of this Exhibit. NBHDL has organized the information contained in the DSP using the headings indicated in Chapter Five of the Board's *Filing Requirements for Electricity Distribution and Transmission Applications*, *Consolidated Distribution System Plan Filing Requirements.* The DSP incorporates matters pertaining to asset management, regional planning, and renewable energy generation.

All categories of system investments, including system renewal, system access, system service, and general plant have been addressed and consolidated in NBHDL's capital expenditure plan. NBHDL has provided historical spending by material capital project in the categories mentioned for 2010 Actual, 2011 Actual, 2012 Actual, 2013 Actual, 2014 Bridget and 2015 Test Year. NBHDL has assigned all historical and future construction projects to the new categories as required by the Board. The DSP provides the suggested spending level, as determined through an asset condition assessment performed by METSCO, for 2016 through 2019; NBHDL has levelized the plan to address pacing and affordability.

NBHDL belongs to the "North/East of Sudbury Region" for which HONI is the lead transmitter. The formal regional planning process with HONI is scheduled to begin in 2016, however, the process is not expected to have material impacts on NBHDL's DSP and the proposed investments as there are no transmission capacity constraints to deter new connection.

Based on the evaluation of the distribution system to accept green energy generation connections NBHDL is not proposing any capital investments for capacity upgrades to accommodate applications for the connection of renewable energy generation plant over the next five years (2015 to 2019) as no constraints have been identified in the system preventing the connection of such installations.

NBHDL assets fall into two broad categories – distribution plant, which includes assets such as wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant which includes assets such as the office building, SCADA, equipment and tools. For internal budgeting purposes, NBHDL has categorized all spending to align with the new DSP categories of system renewal, system access, system service and general plant, however, internal projects are further categorized as follows.

Major Betterments:

These are major line and engineering related projects that NBHDL undertakes and involve the following:

The rehabilitation or expansion of HV lines required to service new large users and GS>1000kW (greater than 5 poles)

These projects involve the rehabilitation or the extension of HV lines to new customers to meet customer service obligations in accordance with the Board's DSC and NBHDL's Conditions of Service.

Large Renewal Projects (greater than 5 poles)

These projects involve the renewal of assets that reach end of life and must be replaced. NBHDL completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

Capacity/Redundancy Projects

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, and feeder ingress and egress for a new substation. These projects are not customer-specific, but rather, they benefit many customers. These projects also consider the probability and impact of asset failure at peak load to determine the risk a possible failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for NBHDL.

Underground Rebuilds

Investments in this category are driven by the requirement to replace end of life assets that are in poor or very poor condition as determined by the Asset Condition Asset Report. Investments in this category are aimed at ensuring reliability is maintained, but more importantly ensuring that O&M costs are controlled. Cable failures, especially cables that are direct buried which are a characteristic of cables in this age demographic, are extremely costly to repair as excavation in built up urban areas is very expensive. The program is aimed to proactively replace cables to avoid the high customer impact that is associated with their failure.

Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its Conditions of Service. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget

Voltage Conversion:

Voltage Conversion projects involve all line construction work relating to the preparation to convert, or actual conversion of, NBHDL's existing 22kV subtransmission system to 44kV and the 4.16/2.4kV system to 12.47/7.2kV. The 22 kV and 4.16kV systems are the oldest in NBHDL's service territory and therefore most plant is at the end of its useful life and must be replaced. Voltage conversion projects not only prepare for or convert the voltage to 12.47/7.2kV but also renew NBHDL's oldest assets to current standards. Voltage conversion projects will lead to the harmonization of the distribution system voltage, lower line losses, eliminate safety hazards to the public and NBHDL employees, and lower future maintenance costs.

Minor Betterments:

These are minor lines and engineering related projects that NBHDL undertakes and involve the following:

The rehabilitation or expansion of HV lines required to service new residential and general service customers (5 or less poles)

These projects involve the rehabilitation or extension of HV lines to new customers to meet customer service obligations in accordance with the Board's DSC and NBHDL's Conditions of Service.

Small Renewal Projects (5 or less poles)

These projects involve the renewal of assets that reach end of life and must be replaced. NBHDL completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In all cases the projects involve spot replacement of assets; new assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its Conditions of Service. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project.

Secondary Services:

This category represents the capital work required to upgrade existing or to install new secondary service wires, overhead and underground, from distribution plant located on the municipal street or in easements on private property to customer's premises. The majority of the work involves the services to the residential class. Costs are recovered as per NBHDL's Conditions of Service.

Subdivisions:

This project represents the capital work required in subdivisions due to developer driven demand. The expenditure represents cost to provide material to developers, and NBHDL labour to install transformers and make primary and secondary connections. Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its Conditions of Service. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.

Transformer Purchases:

This category represents the purchase of new overhead and underground distribution transformers used for the following reasons;

- *Asset Renewal & Rehabilitation*
- *New/Upgraded Services*
- *Special Projects.*

Although NBHDL maintains a small stock due to long lead times, backup, and emergency use, distribution transformers are for the most part ordered as required.

Metering:

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities.

Road Relocations:

This category represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground facilities installed within municipal or provincial owned road allowances. Based on a legislated cost sharing formula, the City of North Bay or MTO, contribute 50% of

all labour, labour saving devices, and equipment costs. In the case where the governing body directs NBHDL to replace overhead plant with underground plant the governing body funds the cost differential between overhead and underground.

Primary Services:

This category represents the capital work necessary to rehabilitate and/or expand plant to service new customers or maintain existing customers, residential and general service, over the 400A threshold. Costs are recovered as per NBHDL's Conditions of Service.

Substations:

This category represents investments that are undertaken to improve or maintain reliability to a large numbers of customers, to maintain security and safety at the substations, and to renew or replace end of life substation equipment. The preparation for the conversion of NBHDL's 4.16 kV system has seen the recent construction of two new 12.47kV stations to replace two existing 4.16kV stations, with the overall conversion goal to reduce the total number of substations, a reduced number of distribution feeders and improved efficiency in the delivery of electricity.

General Plant:

This category represents investments in the NBHDL office building and fixtures, land, office furniture / equipment, computer hardware / software, fleet, stores equipment, tools, shop and garage equipment, communication equipment, SCADA and load management controls.

Budget

The following comments provide an overview of NBHDL's capital budgeting process.

The budget is prepared annually by management and is reviewed and approved by the NBHDL Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

NBHDL has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital budget is a critical component of NBHDL's business plan.

2015 Major Betterments and Voltage Conversion projects were estimated in co-operation with the Engineering, Operations and Finance departments. After field inspection, a high level design of the project is done by the Engineering department. Labour hours and 3rd party contracting costs are then

estimated based on discussions with the Operations department and known civil contractor costs. Anticipated costs, including materials, are then broken down by category or 'job' and applied accordingly within a project estimate. Each job category is linked to a specific GL # within NBHDL's accounting system which is in turn mapped to the appropriate USoA #.

All other categories (Minor Betterments, Primary Services, etc.) within the distribution assets are budgeted based on a 5 year average of historical spending and were mapped to the appropriate USoA category using 2013 historical spending. General Plant assets were mapped according to their nature.

2014 forecasted spending was based on June 2013 YTD actuals and July through December forecasts – with overall spending in line with the approved 2014 capital spending forecast. All spending was allocated to the appropriate USoA category based on 2013 historical coding. Costs for projects were based on the same rationale as described above.

REQUIRED INFORMATION

SUMMARY OF CAPITAL EXPENDITURES

Table 2-32 below provides a summary of historical capital expenditures for the past four historical years, 2010 through 2012, projections for the 2014 Bridge Year and 2015 Test Year, as well as projections for the period 2016 through 2019. This table is consistent with Board Appendix 2-AB. NBHDL has made its best efforts to categorize historical projects into the DSP categories. In 2014, NBHDL received approval for the disposition and recovery of its smart meter costs. As this was a distinct, discrete one-time project, NBHDL has not included these costs in the capital expenditure table. The annual capital expenditures include all new spending in the fiscal period. Costs for projects that are considered WIP at the end of a fiscal year are captured in the year spent, not the year the asset is transferred into service. The variance between the annual capital expenditure totals in the table and the total 'additions' in the continuity schedules are those applicable to WIP, 2014 smart meter costs and contributed capital.

Chart 2-1 shows the percentage of the cumulative gross capital expenditures incurred by NBHDL for the period 2010 through 2014 in each of the investment categories which represents total gross capital spending of $33,355,690. Chart 2-2 shows the percentage of the cumulative gross capital expenditures forecasted by NBHDL for the period 2015 through 2019 in each of the investment categories for a total forecasted amount of $31,784,637.

Table 2-32 – Capital Expenditure Summary – 2010-2019

Appendix 2-AB

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

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	N/A	1,283,260	--	N/A	1,308,483	--	N/A	2,022,775	--	N/A	1,858,535	--	N/A	1,800,867	--	1,143,704	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	N/A	5,164,759	--	N/A	5,055,154	--	N/A	2,313,746	--	N/A	3,997,037	--	N/A	4,168,904	--	5,469,405	4,180,343	4,235,741	4,266,049	4,054,266
System Service	N/A	396,490	--	N/A	289,717	--	N/A	200,907	--	N/A	141,128	--	N/A	206,779	--	373,245	214,743	127,302	89,044	135,918
General Plant	N/A	146,512	--	N/A	829,735	--	N/A	780,227	--	N/A	423,463	--	N/A	967,211	--	771,603	373,400	549,000	350,700	642,000
TOTAL EXPENDITURE	-	6,991,021	--	-	7,483,088	--	-	5,317,656	--	-	6,420,163	--	-	7,143,762	--	7,757,956	5,935,064	6,101,952	5,919,500	6,070,166

Chart 2-1 – Cumulative Gross Capital Expenditures 2010 - 2014

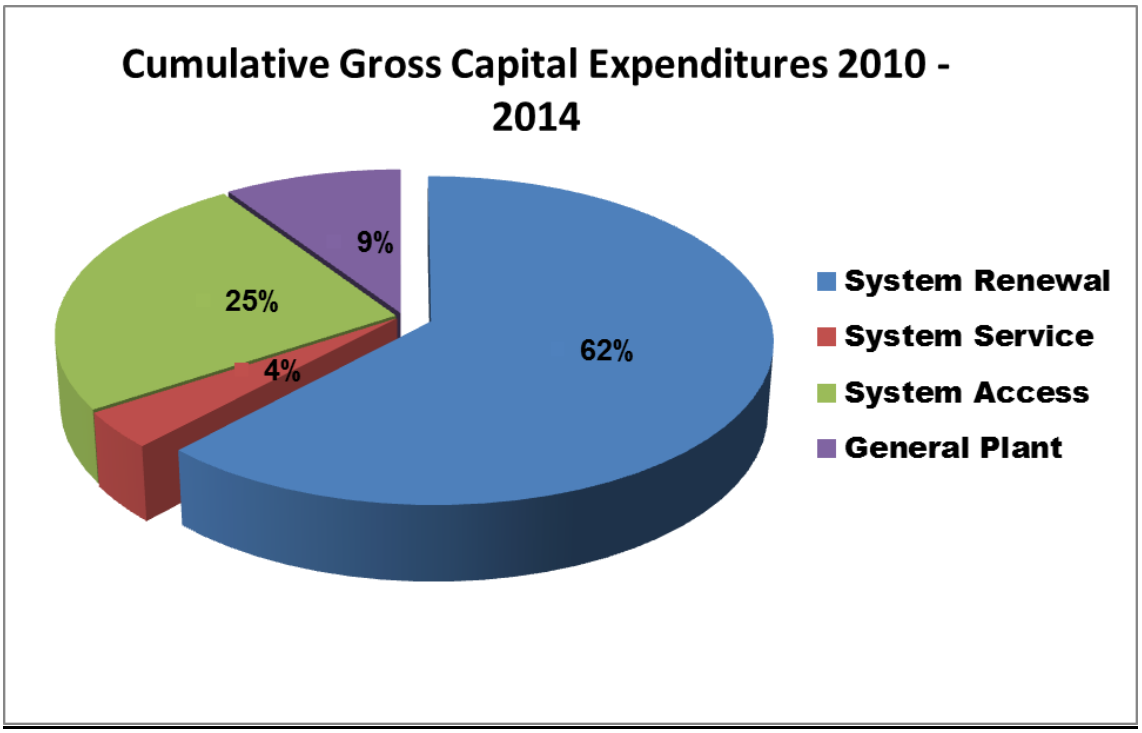
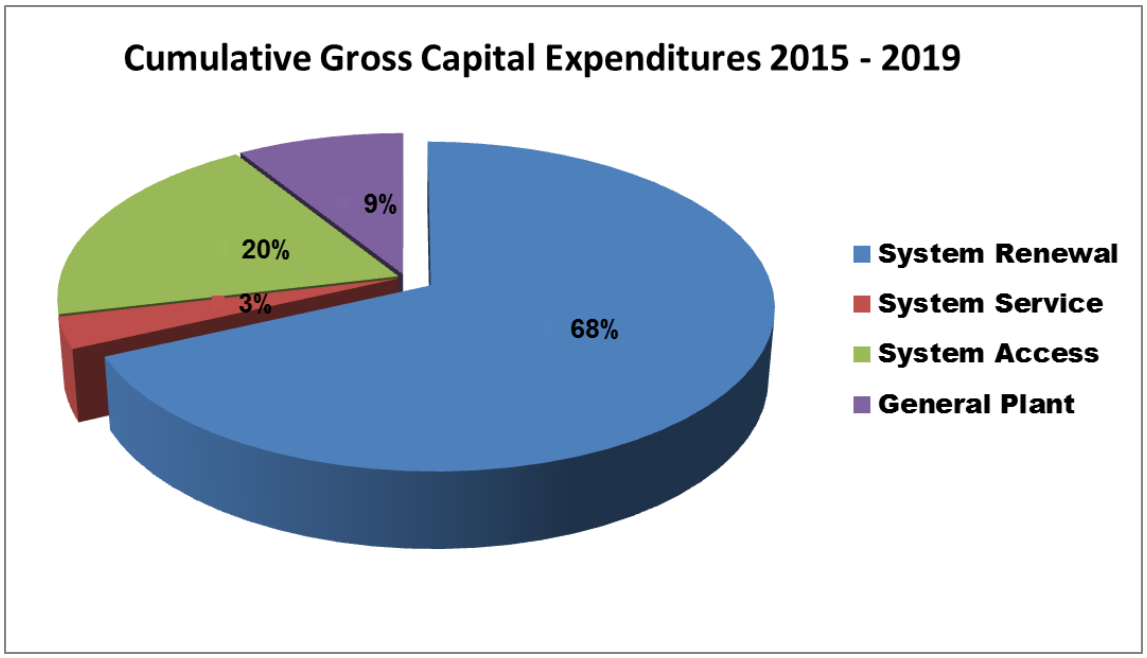


Chart 2-2 – Cumulative Gross Capital Expenditures 2015 - 2019



As shown in the above table and charts, NBHDL's main infrastructure focus is on renewal; this has been the driver of historical spending and is the driver of future spending.

VARIANCE OF YEAR OVER YEAR CATEGORY SPENDING

An analysis of year over year trending for historical costs within the DSP categories is as follows.

- **2011 Actual vs. 2010 Actual**

Table 2-32A – 2011 Actual vs. 2010 Actual

Description	2010 Actual	2011 Actual	Variance from 2010 Actual
System Access	1,283,260	1,308,483	25,223
System Renewal	5,164,759	5,055,154	(109,605)
System Service	396,490	289,717	(106,773)
General Plant	146,512	829,735	683,222
Total Capital Expenditure	**6,991,021**	**7,483,088**	**492,067**

System Access - the variance is below the materiality threshold and therefore deemed immaterial.

System Renewal - although the variance exceeds the materiality threshold, the variance represents a difference of approximately 2% year over year indicating a very consistent expenditure level in this category. There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $109,605.

System Service – this variance is primarily due to the installation of two loadbreak switches on the 44kV system to allow for load balancing in 2010 and higher meter related costs for the installation of new IESO metering points at North Bay T.S. in 2010 over 2011.

General Plant – the variance was primarily driven by the following costs in 2011: a large truck replacement ($289,661), renovations to the customer service department to meet the requirements of Bill 168 ($154,297), increased purchases for work equipment that included substation testing equipment ($39,234), and upgrades of the main software platform, along with the implementation of new customized applications ($189,729).

- **2012 Actual vs. 2011 Actual**

Table 2-32B – 2012 Actual vs. 2011 Actual

Description	2011 Actual	2012 Actual	Variance from 2011 Actual
System Access	1,308,483	2,022,775	714,293
System Renewal	5,055,154	2,313,746	(2,741,407)
System Service	289,717	200,907	(88,810)
General Plant	829,735	780,227	(49,507)
Total Capital Expenditure	**7,483,088**	**5,317,656**	**(2,165,432)**

System Access - the variance relates to spending fluctuations in different types of demand work. Variances are as follows: major betterment projects increased $627,240 from 2011 due to the construction by the City of the Aerospace Industrial Park and the new customers it attracted; road project costs were up $222,091 from 2011 due to increased road projects in 2012; minor betterment projects were up $61,809 relating to demand work in 2012; transformer purchases were higher by $30,625 as a result of the increases in demand work in 2012; subdivision costs were down $37,482 as there were fewer subdivision projects; primary services were lower by $54,570 due to fewer projects; and secondary services were also down $115,961 due to a review of the classification of costs to Secondary Services. The remainder of the variance is attributable to various small projects.

System Renewal - the largest contributor to the variance between 2012 and 2011 was the lack of a substation replacement project in 2012. In 2011, construction of MS20 totaled $2,018,615. Other contributors include: the lack of AM activities in 2012 for a variance of $180,303, reduced spending on voltage conversion projects for a variance of $230,483, less demand based work for a variance of $205,578 and the associated reduction in transformer purchases related to reduced demand work and voltage conversion projects for a variance of $139,239.

System Service – 2012 showed lower costs including $57,506 less in various smart meter installations and upgrades, $21,857 less in 2012 in relation to a number of small miscellaneous projects and with the completion of the 44kV metering upgrade in 2011, a further reduction of $103,671 compared to 2012. Offsetting these reductions was a unique project in 2012 involving the installation of metering and voltage regulation equipment to enable the connection of a renewable generation project in the amount of $90,347.

General Plant - the variance is below the materiality threshold and therefore deemed immaterial.

- **2013 Actual vs. 2012 Actual**

Table 2-32C – 2013 Actual vs. 2012 Actual

Description	2012 Actual	2013 Actual	Variance from 2012 Actual
System Access	2,022,775	1,858,535	(164,241)
System Renewal	2,313,746	3,997,037	1,683,290
System Service	200,907	141,128	(59,779)
General Plant	780,227	423,463	(356,764)
Total Capital Expenditure	**5,317,656**	**6,420,163**	**1,102,507**

System Access - the variance relates to spending fluctuations in different types of demand work. Variances are as follows: major betterment projects down $534,634 as servicing for the Aerospace Industrial Park was substantially completed in 2012 with no additional projects in 2013; 2013 costs were related to the finishing work required on 2012 road projects and as a result, overall road project costs were down $268,181; minor betterment projects up $19,145 relating to demand work in 2013; the Bell FSA Project, a system wide deployment of a fibre network system in the NBHDL service territory, contributed to an increase in demand spending of $459,691 in 2013 as the project was not in place in 2012; transformer purchases were down $72,235 related to the reduced demand work in 2013; subdivision costs were higher than 2012 by $32,781 due to increased subdivision projects; primary services increased $408,966 due to two large 44kV connections and the Aerospace Condo servicing project; and a reduction in secondary services demand work resulted in a decrease of $84,165. The remainder of the variance is attributable to various small projects.

System Renewal - the scheduled replacement of MS6 and the rehabilitation of MS16 in 2013 contributed to the majority of the variance, as substation related expenditures were up $1,663,008 over 2012, a year that involved no large substation projects. Year to year variances between major betterments, voltage conversion projects, minor betterments, porcelain switch and insulator replacements, and AM activities existed, however as whole represented a net of approximately $20,000 in incremental spending in 2013.

System Service - the variance is below the materiality threshold and therefore deemed immaterial.

General Plant - in 2013, only one small vehicle was replaced representing a decrease in spending of approximately $193,000 over 2012 which involved the replacement of a single bucket truck, replacement of two pick-up trucks and the addition of a new pick-up truck. Building related expenditures were down approximately $56,000 and IT related expenditures were down approximately $146,000 in 2013. Tool related purchases increased approximately $53,000 as a result of several higher cost items.

- **2014 Forecast vs. 2013 Actual**

Table 2-32D – 2014 Forecast vs. 2013 Actual

Description	2013 Actual	2014 Forecast	Variance from 2013 Actual
System Access	1,858,535	1,800,867	(57,667)
System Renewal	3,997,037	4,168,904	171,867
System Service	141,128	206,779	65,651
General Plant	423,463	967,211	543,748
Total Capital Expenditure	**6,420,163**	**7,143,762**	**723,599**

System Access - the variance is below the materiality threshold and therefore deemed immaterial.

System Renewal - although 2014 involves the replacement of the MS1 transformer, the replacement of the SCADA radio system, the rehabilitation of MS15 and the procurement of 2 power transformers for MS22, substation spending in 2014 is forecasted to be down $454,930 versus 2013 which saw the full replacement of MS6 and the rehabilitation of MS16. A large forecasted increase to major betterment spending in 2014 of $421,343 is related to the construction of three end of life projects outside the voltage conversion area and the related transformer purchases of $107,818, along with smaller variances in voltage conversion projects, minor betterments, porcelain switch and insulator replacements and AM activities offset the decrease in substation spending to provide an overall increase in spending in 2014 of $171,867.

System Service - the variance in 2014 is primarily driven by the infrastructure modernization project which focuses the metering department on a scheduled replacement program that will transition customers to interval capable SMART meters.

General Plant - the large increase in general plant spending in 2014 over 2013 is attributable to building and general plant upgrades, specifically upgrades to the HVAC system, the replacement of the generator to cover the entire building's load in outage situations, and improvements to the garage and yard representing an increase in spending of $350,092. An increase to fleet replacements of $91,762 and an increase in IT related purchases of $128,913 also contributed to this variance. Small miscellaneous variances in other general plant categories account for the balance of the variance.

- **2015 Forecast vs. 2014 Forecast**

Table 2-32E – 2015 Forecast vs. 2014 Forecast

Description	2014 Forecast	2015 Forecast	Variance from 2014 Actual
System Access	1,800,867	1,143,704	(657,164)
System Renewal	4,168,904	5,469,405	1,300,501
System Service	206,779	373,245	166,466
General Plant	967,211	771,603	(195,609)
Total Capital Expenditure	**7,143,762**	**7,757,956**	**614,194**

System Access - the completion of the Bell FSA Project decreases spending in 2015 by $744,212 over 2014. The remaining variance from 2015 to 2014 can be explained by the year over year fluctuations of the estimated spending in the various demand categories as determined by utilizing a 5 year average cost for the 2015 Test Year.

System Renewal - the largest variance in 2015 is explained by the replacement of MS# 9 by MS# 22 at a cost of $1,781,297, an increase of $1,069,995 over 2014 substation construction expenditures. The remaining variance is represented by an increase in major betterment projects, specifically underground replacement projects to address failing underground secondary servicing of $636,700, and the increase of $493,217 in relation to voltage conversion projects. These increases are offset by a reduction in other substation type expenditures of $686,650, which includes the purchase of the MS# 22 transformers in 2014; this was done in order to obtain discounted pricing and spread the MS# 22 costs over two years to the extent possible, keeping 2015 costs mitigated. The completion of the porcelain switch and insulator replacement project in 2014 results in a decrease over 2014 of $101,671. Reduced costs of various small projects result in a year over year decrease of $128,744.

System Service - the variance can be attributed to the conversion of 5 feeders from 4.16kV to 12.47kV representing an increase of $121,979 and work relating to meter infrastructure modernization and the 2015 replacement schedule which represents an increase of $51,072.

General Plant - although there is one large bucket truck, 3 small trucks, and 2 utility trailers being replaced in 2015 for an increase in fleet spending of $361,937, reduced spending on the building and yard in the amount of $451,386 coupled with reduced spending on IT related activities of $105,311 in 2015 offset the bulk of the increased general plant spending in 2015 compared to 2014.

- **2016 Forecast vs. 2015 Forecast**

Table 2-32F – 2016 Forecast vs. 2015 Forecast

Description	2015 Forecast	2016 Forecast	Variance from 2015 Actual
System Access	1,143,704	1,166,578	22,874
System Renewal	5,469,405	4,180,343	(1,289,062)
System Service	373,245	214,743	(158,502)
General Plant	771,603	373,400	(398,203)
Total Capital Expenditure	**7,757,956**	**5,935,064**	**(1,822,892)**

System Access - forecasted expenditures in the system access category are based strictly on average historical costs, the increase in spending from 2016 to 2015 is based on an inflation factor of 2%.

System Renewal - The main driver of the decreased spending in 2016 compared to 2015 can be explained by the lack of substation related activities in 2016; a decrease in spending of $1,502,768 over 2015. The replacement of MS9 in 2015 represents the last major substation project required over the next 5-10 years. Fluctuations amongst voltage conversion, major betterments and minor betterments projects account for the balance of the variance.

System Service - The majority of the variance can be attributed to a decrease in scheduled meter conversions compared to 2015 of $98,218, and a decrease in feeder conversion costs of $45,170 as the voltage conversion program nears completion.

General Plant - The majority of building, yard, and IT requirements were dealt with in the previous 5 years and as a result, there are minimal costs in 2016 relating to these categories, representing a decrease of $126,203. In addition, there is a reduction of $272,000 in fleet purchases, as only small fleet vehicles will be replaced in 2016 as per the fleet replacement schedule.

- **2016 – 2019 Trending**

Table 2-32G – 2016 – 2019 Trending

Description	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
System Access	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	4,180,343	4,235,741	4,266,049	4,054,266
System Service	214,743	127,302	89,044	135,918
General Plant	373,400	549,000	350,700	642,000
Total Capital Expenditure	**5,935,064**	**6,101,952**	**5,919,500**	**6,070,166**

System Access - forecasted expenditures in the System Access category are based strictly on average historical costs and as such the system access category has been forecasted to increase each year through 2019 by an inflation factor of 2% per year.

System Renewal - the replacement of MS# 9, following the strategy of replacing a station every 2 years since 2009, concluded the replacement of all substations in poor or very poor condition in 2015. As a result of this program, substation spending over the next 4 years is forecasted to be consistent and flat. Both pole renewals and underground replacement projects have been levelized from 2016 to 2019 keeping the System Renewal costs consistent and flat over the rate filing horizon.

System Service - there is not a significant amount of work planned in this category and the majority of the System Service costs are driven by the modernization of meter infrastructure scheduled from 2016 to 2019. This spending follows the plan developed by the Metering Department in line with a 3rd party analysis and recommendation. With the completion of the voltage feeder conversion, projects of this nature will cease to exist in this category and will not have an impact on system service costs after 2016. Minor betterment work relating to system service investments is a very small piece of the costs and is forecasted to stay consistent and flat through to 2019.

General Plant - expenditures over the forecast period will for the most part vary based on the fleet replacement strategy, which is well documented throughout the DSP found in Appendix D of Appendix 2-A. The bulk of the items related to the building, yard and IT department were handled over the previous 5 years and spending in those areas will remain very consistent through to 2019, aside from a larger IT expenditure forecasted in 2019 to handle the required replacement of main servers. Tool expenditures have been levelized over the entire rate filing period at $45,000 per year.

NBHDL's capital expenditures over the Historical Period years vary swing year over year, however, as the variance analysis explains, the major factors affecting the program were:

- fluctuations in demand based work outside of the control of NBHDL;
- adherence to the substation replacement program which has seen the replacement of a substation every 2 years since 2009 which in turn caused peaks in the System Renewal category in 2009, 2011, 2013 and the 2015 Test Year; and
- the replacement of fleet vehicles and upgrades to the building, yard, and IT in accordance to replacement strategies and necessity.

System Service expenditures have made up a very small portion of the historical period expenditures and will continue to make up a very small portion of total capital expenditures over the forecast period. The demand work has been levelized over the forecast period due to the use of a historical average. NBHDL does expect fluctuations year over year in this category, however, the total envelope of dollars is anticipated to be within an acceptable tolerance range for accuracy. Substation expenditures have been reduced as the majority of poor assets will be replaced by the end of 2015. This, in turn, has levelized the System Renewal spend out between 2016 and 2019. This levelized spend occurs despite the introduction of the underground replacement renewal projects starting in 2015. Fleet expenditures going forward will continue to follow a fleet replacement strategy informed by the Fleet Assessment and NBHDL's knowledge of its assets which will cause changes year to year. All other general plant expenditures will remain fairly consistent throughout the filing period. NBHDL is forecasting to spend $1,571,053 less over the forecast period than what was spent during the historical period with respect to capital expenditures.

CAPITAL PROJECT SUMMARY

Table 2-33 provides a summary of all capital projects for the years 2010 through 2013, the 2014 Bridge Year and the 2015 Test Year. All projects above NBHDL's materiality threshold of $65,000 have been listed individually within the DSP categories and all individual projects below the threshold have been grouped together as miscellaneous within the applicable category. NBHDL's DSP, found in Appendix 2-A, provides capital project summaries that provides a full description and justification of all individual material projects listed in the table for the 2015 Test Year. These summaries are found in Appendix Q of Appendix 2-A. Table 2-33 is consistent with the Board's Appendix 2-AA, Capital Projects Table and, when contributed capital is removed, reconciles to Table 2-32 above.

1 **Table 2-33 – Capital Projects Table – 2010 – 2015**

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Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
System Renewal:							
Transformer Purchases - Various Jobs	353,556	306,734	167,495	154,512	262,330	284,135	1,528,761
Major Betterment Projects							
Mercer Drive	293,011	3,255	165	-	-	-	296,431
O'Brien Street - 44kV Line Extension	210,978	-	-	-	-	-	210,978
Norman Avenue	13,779	2,296	-	916	286,402	-	303,393
Birch's Road - move 12kV to new pole line	3,156	232,480	32,287	1,251	-	-	269,175
Bond Street	-	-	-	61	142,287	-	142,348
Giroux Street	-	-	-	198,603	3,631	-	202,234
Turret Complex - Madelena	-	-	-	105	-	529,572	529,678
Turret Complex - Melina Close	-	-	-	105	-	293,306	293,411
Turret Complex - Lake Heights	-	-	-	210	190,380	-	190,590
Turret Complex - Wickstead	-	-	-	105	-	436,521	436,626
Voltage Conversion Projects							
Timmins & Nipissing - Upgrade Polelines for MS19	165,703	-	-	-	-	-	165,703
King Street West	-	-	-	959	167,431	-	168,390
Duke Street	111,138	103,747	-	-	-	-	214,885
Victoria Avenue	12,649	140,365	6,925	-	-	-	159,938
Queen Street, including 3PH	-	1,285	1,870	856	146,132	-	150,143
Sixth Avenue	-	65,079	234	-	-	-	65,312
Old Callander Road	-	34,240	712,070	(2,452)	-	-	743,858
Graham Drive	-	141,589	80,380	12,988	-	-	234,958
Drew Street	-	5,669	133,864	94,589	-	-	234,121
6F4 Area - Preparation for Voltage Conversion	-	-	43,382	56,580	-	-	99,963
Cassells Street	-	-	9,229	141,990	-	-	151,219
MS # 5 - 22kV & Primary Removals	73,519	35,317	37	-	-	-	108,873
Worthington Street	305,617	562,246	93,460	4,606	1,817	-	967,746
NB TS Egress - including Angus	-	245,370	17,324	-	-	-	262,694
Angus Street	-	-	184,627	49,089	-	-	233,716
6F1 - Conversion							
Brookes Street	-	-	-	363	62,811	-	63,174
Hardy Street	-	-	-	251	90,935	-	91,187
Maher Street	-	-	-	242	96,357	-	96,599
Laurier Street	-	-	-	83,311	-	-	83,311
Franklin Street	-	-	-	1,287	223,400	-	224,688
McGaughey Street	-	-	5,350	132,323	365	-	138,039
Hammond Street	-	-	10,544	187,745	52,271	-	250,560
Metcalfe Street	-	-	651	43,373	356,859	-	400,883
Chippewa Street	-	-	-	189,177	-	-	189,177
MS21 Egress Work	-	-	-	112,820	365	-	113,184
Fourth Avenue	-	-	-	1,400	-	147,188	148,588
Fifth Avenue	-	-	-	639	-	154,232	154,871
Fraser South - 12kV	-	-	-	-	-	116,034	116,034
McIntyre Street	-	-	-	1,050	-	452,969	454,019
Ferguson Street	-	-	-	-	636	278,780	279,416
First Avenue	-	-	-	-	814	136,126	136,941
Regina Street	-	-	-	-	785	81,248	82,032
Main Street West	-	-	-	-	422	215,217	215,639
Sherbrooke Street	-	-	-	-	-	112,822	112,822
Second Avenue	77,510	113	126	-	-	-	77,748
Pinewood Voltage Conversion - Civil & Prep	1,571,932	2,913	7,050	-	-	-	1,581,895
Pinewood Voltage Conversion - Electrical	1,140,594	217,726	18,053	-	-	-	1,376,374
Minor Betterment Projects	69,504	89,896	120,395	251,724	86,676	106,591	724,787
Porcelain Switch & Insulator Replacement	65,164	21,694	100,696	8,900	101,671	-	298,125
Asset Management	40,290	182,290	1,986	27,752	24,066	-	276,383

1 **Table 2-33 – Capital Projects Table – 2010 – 2015 – Cont'd**

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Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
System Renewal:							
Distribution Substation Construction							
MS# 19 - Replacement MS# 5	68,468	60	20,191	-	-	-	88,718
MS# 20 - Replacement MS# 12	68,599	2,058,742	40,126	-	-	-	2,167,467
MS# 21 - Replacement MS# 6	-	-	73,962	1,312,184	31,907	-	1,418,052
MS# 22 - Replacement MS# 9	-	-	-	-	679,396	1,781,297	2,460,693
Distribution Substation Improvements & Rehabilitation							
MS# 8	194,134	14,480	-	-	-	-	208,615
MS# 14	7,819	160,718	104,375	-	-	-	272,911
MS# 15	-	-	-	-	226,416	-	226,416
MS# 16	-	-	9,492	798,829	84,376	-	892,696
Distribution Substation Transformers							
8T1 Failure - December 2008 - Insurance Proceeds	(92,392)	-	-	-	-	-	(92,392)
17T1 Failure - October 2010	62,526	262,229	25,727	333	-	-	350,815
13T2 Failure - October 2011	-	-	186,034	11,568	-	-	197,602
MS# 1 - Transformer Replacement - T1	-	-	-	-	278,506	-	278,506
MS# 13 - Transformer Replacement - T1	-	-	-	-	-	271,470	271,470
Distribution Substation SCADA							
SCADA - implementation of new radio system for SCADA	-	-	2,835	1,440	368,822	-	373,097
Misc. Projects <$65k on individual project basis	347,505	164,621	102,806	115,251	200,640	71,897	1,002,721
Sub-Total, System Renewal	**5,164,759**	**5,055,154**	**2,313,746**	**3,997,037**	**4,168,904**	**5,469,405**	**26,169,004**
System Service:							
Highway 11 North - Voltage Regulator Installation & Metering Upgrade	-	-	90,347	-	-	-	90,347
Copeland St. - 44kV Loadbreak Switches	64,600	-	-	-	-	-	64,600
IESO Meter Installations - 44kv Metering							
Bond St., O'Brien St., 15M1/15M2 for NBTS Conversion to 44kV	137,585	103,671	3,344	1,831	-	-	246,432
Meters Installs and Upgrades - Smart Meters	111,423	100,945	43,439	62,040	15,000	15,000	347,848
Capital Infrastructure Modernization	-	-	533	263	148,141	199,213	348,151
Misc. Projects <$65k on individual project basis							
Meters	38,028	33,544	2,760	41,352	10,000	10,000	135,683
Substations, SCADA and Misc. Projects	22,475	51,185	39,757	9,986	22,822	15,735	161,962
Major & Minor Betterment Projects	22,380	371	20,726	25,655	9,349	9,851	88,332
Feeder Conversion Projects - 5 Individual Projects <$65k/project	-	-	-	-	1,467	123,445	124,912
18F1, 18F2, 18F3, 7F2, and 1F1							
Sub-Total, System Service	**396,490**	**289,717**	**200,907**	**141,128**	**206,779**	**373,245**	**1,608,267**
System Access:							
Transformer Purchases - Various Jobs	93,439	156,988	187,612	115,377	106,872	95,113	755,401
Major Betterment Projects							
Aerospace Park - 44kV & 12kV Line Extension	-	-	496,321	9,125	-	-	505,446
Voodoo Cres. - 12.5kV and 44kV Line Extension	-	-	130,919	83,482	-	-	214,401
Minor Betterment Projects	292,314	207,132	268,941	288,086	198,147	230,102	1,484,722
Bell FSA Project	-	-	-	459,691	744,212	-	1,203,903
Primary Services Projects	46,683	121,508	137,329	198,663	135,952	217,820	857,955
Gormanville Rd - OPP 44Kv Service & Other 44Kv Work	-	78,298	74	-	-	-	78,372
Aerospace Park - Condo Development	-	-	7,833	182,307	-	-	190,140
100 Chippewa West - Memorial Gardens	-	-	-	92,019	-	-	92,019
Thompson Park - New Primary Service	-	-	-	81,213	-	-	81,213
Secondary Services	299,563	404,425	288,463	204,301	361,792	249,365	1,807,908
Subdivisions	108,129	109,429	71,948	104,729	110,975	100,973	606,183
Road Relocations Projects					103,218	212,218	315,436
Algonquin Ave. - Cassels x Copeland	246,094	164	-	-	-	-	246,258
Front St. - McLeod x Second	161,830	-	-	-	-	-	161,830
Main St.	-	48,408	184,610	6,307	-	-	239,326
John St.	-	-	90,053	177	-	-	90,230
Misc. <$65k on individual project basis	35,207	182,131	158,671	33,060	39,699	38,112	486,879
Sub-Total, System Access	**1,283,260**	**1,308,483**	**2,022,775**	**1,858,535**	**1,800,867**	**1,143,704**	**9,417,624**

Table 2-33 – Capital Projects Table – 2010 – 2015 – Cont'd

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
General Plant							
Building & General Office Upgrades, including Furniture	12,656	13,858	63,237	11,532	71,116	26,300	198,699
HVAC System	-	-	4,200	148,769	149,427	-	302,396
Generator	-	-	-	-	166,800	-	166,800
Customer Service Entrance & Department Renovation	-	154,297	149,443	-	-	-	303,740
Operations Facility Upgrades - Garage, Yard, Driveway & Warehouse	-	-	17,800	3,945	126,995	36,652	185,392
Fleet Replacement - Bucket Trucks, Radial Boom Devices & Trailers	-	289,661	137,946	12,207	100,063	370,000	909,877
Fleet Replacement - Vehicles < 3 Ton	64,703	73,801	116,478	49,094	53,000	145,000	502,076
Work Equipment	27,751	66,985	21,427	74,019	47,000	46,151	283,332
Servers, PC, Other Hardware	18,783	162,087	181,608	7,832	80,600	126,500	577,409
Software	22,620	69,045	88,089	116,066	172,211	21,000	489,030
Sub-Total	**146,512**	**829,735**	**780,227**	**423,463**	**967,211**	**771,603**	**3,918,751**
Contributed Capital							
Contributed Capital from Customers	(905,001)	(464,129)	(675,928)	(1,061,939)	(1,128,077)	(503,987)	(4,739,061)
Sub-Total	**(905,001)**	**(464,129)**	**(675,928)**	**(1,061,939)**	**(1,128,077)**	**(503,987)**	**(4,739,061)**
Miscellaneous	-	-	-	-	-	-	-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**7,253,969**	**36,374,585**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*	-	-	-	-	-	-	-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**7,253,969**	**36,374,585**

CAPITAL PROJECT VARIANCE – 2010 BOARD APPROVED VS. 2010 ACTUAL

Table 2-34 provides a summary, by material capital project, of 2010 actual project costs compared to 2010 Board-Approved projects. An explanation of the material variances follows.

Table 2-34 – 2010 Capital Projects vs. 2010 Board Approved Projects

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2010 - OEB Approved	2010 - Variance
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**
System Renewal:			
Transformer Purchases - Various Jobs	353,556	577,913	(224,357)
Major Betterment Projects			
Mercer Drive	293,011	274,601	18,411
O'Brien Street - 44kV Line Extension	210,978	139,718	71,260
Voltage Conversion Projects			
Timmins & Nipissing - Upgrade Polelines for MS19	165,703	163,780	1,923
Duke Street	111,138	127,174	(16,036)
Victoria Avenue	12,649	81,095	(68,446)
MS # 5 - 22kV & Primary Removals	73,519	-	73,519
Worthington Street	305,617	579,684	(274,067)
Fraser South - 12kV	-	183,075	(183,075)
McIntyre Street	-	325,601	(325,601)
Ferguson Street	-	179,471	(179,471)
Second Avenue	77,510	92,493	(14,983)
MS#4 Conversion to 12.47kV	40,825	82,976	(42,151)
Wyld Street South	-	87,199	(87,199)
Pinewood Voltage Conversion - Civil & Prep	1,571,932	2,139,648	(567,716)
Pinewood Voltage Conversion - Electrical	1,140,594	759,115	381,479
Porcelain Switch & Insulator Replacement	65,164	-	65,164
Asset Management	40,290	213,239	(172,950)
Distribution Substation Construction			
MS# 19 - Replacement MS# 5	68,468	-	68,468
MS# 20 - Replacement MS# 12	68,599	-	68,599
Distribution Substation Improvements & Rehabilitation			
MS# 8	194,134	-	194,134
MS# 14	7,819	176,981	(169,162)
MS# 16	-	151,531	(151,531)
Distribution Substation Transformers			
8T1 Failure - December 2008 - Insurance Proceeds	(92,392)	-	(92,392)
17T1 Failure - October 2010	62,526	-	62,526
Misc. Projects <$65k on individual project basis	393,120	440,879	(47,759)
Sub-Total, System Renewal	**5,164,759**	**6,776,173**	**(1,611,414)**
System Service:			
Copeland St. - 44kV Loadbreak Switches	64,600	(35,277)	99,876
IESO Meter Installations - 44kv Metering			
Bond St., O'Brien St., 15M1/15M2 for NBTS Conversion to 44kV	137,585	16,062	121,523
Meters Installs and Upgrades - Smart Meters	111,423	-	111,423
Capital Infrastructure Modernization - including >50 conversion to smart meters	38,028	212,242	(174,214)
Misc. Projects <$65k on individual project basis	44,855	151,189	(106,334)
Sub-Total, System Service	**396,490**	**344,216**	**52,274**

Table 2-34 – 2010 Capital Projects vs. 2010 Board Approved Projects Cont'd

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2010 - OEB Approved	2010 - Variance
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**
System Access:			
Transformer Purchases - Various Jobs	93,439	156,298	(62,859)
Major Betterment Projects			
Airport Road - 44kV Line Extension	-	192,005	(192,005)
Minor Betterment Projects	292,314	234,635	57,680
Primary Services Projects	46,683	150,330	(103,647)
Secondary Services	299,563	307,328	(7,766)
Subdivisions	108,129	110,528	(2,399)
Road Relocations Projects	20,755	464,676	(443,921)
Algonquin Ave. - Cassels x Copeland	246,094	-	246,094
Front St. - McLeod x Second	161,830	47,111	114,720
Misc. <$65k on individual project basis	14,452	34,124	(19,673)
Sub-Total, System Access	**1,283,260**	**1,697,037**	**(413,777)**
General Plant			
Building & General Office Upgrades, including Furniture	12,656	57,563	(44,907)
Fleet Replacement - Vehicles < 3 Ton	64,703	51,000	13,703
Work Equipment	27,751	59,715	(31,965)
Servers, PC, Other Hardware	18,783	75,962	(57,179)
Software	22,620	112,975	(90,355)
Sub-Total	**146,512**	**357,216**	**(210,704)**
Contributed Capital			
Contributed Capital from Customers	(905,001)	(594,434)	(310,567)
Sub-Total	**(905,001)**	**(594,434)**	**(310,567)**
Total	**6,086,019**	**8,580,208**	**(2,494,188)**

System Renewal:

Transformer Purchases – ($224,357)

Transformer purchases for any given year are estimated based on two factors; the transformation requirement for the planned capital program and the amount of demand type work that materializes over the year. The projects that were implemented in 2010 differed from the planned 2010 projects and required less transformation. Expenditures on demand projects were also less than approved based a reduction of actual demand type projects compared to that anticipated. The combination of these factors results in the variance of $224,537.

O'Brien Street – 44kV Line Extension - $71,260

The majority of the variance in the O'Brien Street project can be attributed to a change in scope of work from the estimate stage to the full design stage. NBHDL decided at the time of full design to replace the existing 12.47kV circuit conductors with new 336 ASC conductor to bring up to the current NBHDL conductor standards for main feeders, a change from the estimate stage where it was planned to simply transfer the existing conductors. This represented an increase to the project of $44,400. Two other scope changes, the addition of another 300m of 3/0 Al. spun buss to complete the installation of spun buss along the entire length of O'Brien Street and the replacement of existing underground primary cables feeding a hotel that was missed during the estimate stage added approximately $24,400 in additional costs to the project. All changes in scope were approved at the time of design due to the additional benefits.

Victoria Avenue - $($68,446)

The variance for this project is explained by the timing of the project. Due to engineering commitments to the Pinewood project NBHDL attempted to contract out the design of the project in order to have it available to crews prior to year end. The work provided by the consultant did not meet NBHDL's expectations and the job had to be delayed until 2011 so the design work could be finalized internally. The project was completed in 2011.

MS# 5 – 22kV & Primary Removals - $73,519

This project was not budgeted in 2010 but was required and implemented due to the successful progress of the Pinewood project, which allowed the removal of the ingress (1 - 22kV circuit) and egress (3-12.47kV circuits) of the MS#5 substation earlier than anticipated. The work included the removal of a large number of backlot poles, including a pole line running through a school yard. This project replaced one of the four voltage conversion projects eliminated from the 2010 planned capital program.

Worthington Street – ($274,067)

The Worthington project was one of the largest proposed pole line rebuild projects scheduled by NBHDL over the past 10 years and due to the engineering commitments to the Pinewood projects it wasn't issued for construction until September, with crews starting the project late September, early October. Construction was estimated to take 5 straight months, and with the late start, only 3 months of construction were realized in 2010. The project was also hampered by congested traffic conditions, the presence of snow and the limits that imposed on construction in December, and the presence of rock which slowed down pole installations. The project was completed in 2011.

Fraser South – 12kV – ($183,075)

This project was deferred due to the additional workload and resource requirements associated with the Pinewood project in general and other priorities that factored into the deferral of this project including the Pinewood Phase 12 project, Porcelain Switch Replacements, the MS# 5 Removals project, and the increase in work on the O'Brien Street project due to the scope change. The 2010 budget was developed based on a high level plan that did not include a formalized and structured guide to the execution of project sequencing that was required to complete voltage conversion in the 4kV area of town. As such, this project was deferred due to differing priorities without a replacement expenditure related to the Voltage Conversion project. NBHDL improved and refined the Voltage Conversion Plan in 2012.

McIntyre Street – ($325,601)

This project was deferred for the same reasons as the Fraser South 12kV project due to additional workload and resource requirements of the Pinewood project and differing priorities as explained above.

Ferguson Street – ($179,471)

This project was deferred for the same reasons as the Fraser South 12kV project due to additional workload and resource requirements of the Pinewood project and differing priorities as explained above.

Wyld Street South - ($87,199)

This project was deferred for the same reasons as the Fraser South 12kV project due to additional workload and resource requirements of the Pinewood project and differing priorities as explained above.

Pinewood Voltage Conversion – Civil & Prep - ($567,716)

This part of the Pinewood project represented the civil work and costs were based on tendered pricing. The actual costs for the tendered portion of the work came in much less than the estimated amounts, which explains the entire variance between the approved and the actual amounts.

Pinewood Voltage Conversion – Electrical - $381,479

This part of the Pinewood project involved all electrical based work including electrician work to replace meter bases and prepare homes for the new underground servicing, and all NBHDL construction (cable and transformer installation, along with all connections and associated line work). Increased costs were due to higher than forecasted electrician costs ($57k), an additional Phase 12 being added to complete the entire neighbourhood ($80k), 3rd party project management and inspection costs ($228k) and internal engineering department overtime to manage customer requests and issues ($28k).

Porcelain Switch & Insulator Replacement - $65,164

An oversight in the budgeting process resulted in this project being included in the overall capital expenditure budget, however, the work was always planned as NBHDL had suffered numerous switch failures in 2008 and 2009 causing catastrophic pole fires and failures. The work involves proactively replacing a certain type of porcelain cutout switch. The variance over budget is a result of costs spent in 2010 replacing these defective switches.

Asset Management - ($172,950)

This work program was intended to help develop the asset management plan by allowing NBHDL to conduct non-destructive pole testing for the first time in order to assess condition of pole assets. As NBHDL did not have experience in this work, it took longer than expected to develop a specification document so the work could be tendered. The tender went out in late 2010 and therefore was awarded later than anticipate. With the early onset of winter conditions only a small portion of poles were tested and a result only a small fraction of the tender costs were charged in 2010, representing the majority of the variance. Pole testing concluded in 2011.

MS# 19 – Replacement of MS# 5 - $68,468

This work was not forecasted as part of the 2010 Board Approved plan as it was expected that MS19 work would conclude in 2009. Deficiencies and a few civil issues that were missed had to be taken care of in 2010 and explain the variance.

MS# 20 – Replacement of MS# 12 - $68,599

This work was not forecasted as part of the 2010 Board approved plan as NBHDL was not made aware of the need to relocate MS#12 out of HONI's North Bay TS until 2010. The majority of the expenditure in 2010 represents the purchase of a new lot for the relocation ($26k), conceptual design work for the relocation ($20k), and a geotechnical report completed by a 3rd party to identify civil requirements for budgeting purposes and feasibility ($20k). MS# 20 was constructed and MS# 12 was removed from North Bay TS in 2011.

MS# 8 - $194,134

This project was substituted into the 2010 plan as a replacement for the MS# 14 project. The MS# 14 project was determined to be a lower priority than MS# 8 after a more in-depth review of priorities in 2010. The main justification was that the MS# 8 project aided in voltage conversion where MS# 14 did not.

MS# 14 - ($169,162)

The MS# 14 project was substituted for the MS# 8 project in 2010 as it was determined that the work at MS# 8 was a higher priority as explained above. Ground testing and conceptual design work was still completed in 2010 on the MS# 14 project to ensure the work could be started early in 2011. The overall difference in spending between the two projects was an incremental $24,972 over the 2010 Board approved amount.

MS# 16 – Rehabilitation - ($151,531)

The original scope of work for this project involved the installation of new reclosers to allow for SCADA to be equipped at MS# 16, however after a more in-depth look at the station in 2010 it became evident that it would was an appropriate time to address more than just the reclosers as there were a number of deficiencies present within the station. This project was postponed so that all work could be done more efficiently at the same time. Other priorities within substations that were factored into the delay included the requirement to complete work on MS# 19, the initiation of activities related to MS# 20, and the conclusion of the work related to the failure of 17T1.

8T1 Failure – December 2008 – Insurance Proceeds - ($92,392)

This expenditure (credit) represents proceeds received in 2010 from a power transformer (8T1) that failed in 2008. NBHDL did not have confirmation on when the proceeds would be issued and therefore it was not included in the 2010 budget.

System Service:

Copeland Street – 44kV Loadbreak Switches - $99,876

This project involved the installation of three 44kV loadbreak switches required for paralleling the existing 22kV circuits that would operate at 44kV after conversion of North Bay TS. In the 2010 budgeting process, additional costs required to complete the project were omitted from the budget contributing $64,600 to the budget variance. The additional $35,277 was a result of costs that were estimated to transfer from WIP that did not occur.

Bond Street, O'Brien St., 15M1/15M2 for NBTS Conversion to 44kV - $121,523

The 2010 Board approved expenditure involved the replacement of metering PT's at the Woods Junction location, a Hydro One embedded distributor billing point. However, after confirmation of the conversion of North Bay TS to 44kV it was decided that the entire IESO compliant 44kV metering racks (PT's and CT's)

would be ordered for not only the Woods Junction location but the two feeders out of North Bay TS. Spares were also included on this order, as all 3 units would be exactly the same, meaning only one spare PT and CT would be required to cover all 3 units. The costs of the 3 metering racks and the associated spares represent the entire increase in spending from 2010 Board approved.

Meters Installs and Upgrades – Smart Meters - $111,423

Throughout 2009 and 2010, NBHDL was focused on the deployment and operationalization of smart meters for Residential and GS <50 kWh customers. The costs included in 2010 were considered non-incremental and were not included in the smart meter deferral and variance account, but instead PP&E. NBHDL did not engage incremental resources for this work, instead existing staff were re-assigned to complete this work. These costs were not originally included in the 2010 budget, however, they are offset by the reduced spending in relation to the conversion of GS >50 meters for a net variance of ($62,791).

Capital Infrastructure Modernization – ($174,214)

The 2010 budget proposed the conversion of all non-smart GS >50 kW meters to SMART Meters capable of reading at hourly intervals. NBHDL's focus through 2010 and 2011 was on the completion of smart meter deployment for Low Volume customers and correcting operational problems with the AMI system. There were significant challenges for the AMI service provider to overcome radio communication issues in the rugged and remote sections of NBHDL's service territory. There was considerable trial and error to trouble shoot the system and this tied up most of NBHDL's available resources. NBHDL was also concerned about the maturity of the radio communication technology required in the meters for GS>50kw customers and spoke with other LDC's who advised at the time to delay this phase of smart meter deployment. NBHDL has put forward a revised conversion plan for the remaining non-interval capable meters in its system over the 2014 through 2019 period.

System Access:

Airport Road – 44kV Line Extension - ($192,005)

Information provided by the City of North Bay Economic Development office indicated that the development of an industrial park would require servicing in 2010 and as such, the project was included in the 2010 budget. This project did not materialize in 2010 as planned.

Primary Services Projects - ($103,647)

The projects grouped into this category are all demand projects and budget estimates are based on historical costs over the previous 5 years. Actual expenditures follow the demand that is brought forward

to NBHDL in the given year and in 2010 there was very little demand for this type of servicing and as a result there was $103,647 less costs than was included in the 2010 Board approved amount.

Road Relocations – ($83,107)

The projects grouped into this category are all customer demand projects and the 2010 budget estimate was based on historical costs over the previous 5 years that were included as an envelope of dollars in the amount of $464,676, plus $47,111 in specific costs related to the anticipated work on Front Street. Actual expenditures follow the demand that is brought forward to NBHDL in the given year. 2010 total costs for Front Street were $161,830 and another large project was undertaken on Algonquin Avenue for a cost of $246,094. Other road work jobs were immaterial. As a result of the actual construction executed in 2010 there was $83,107 less cost in road relocations than was included in the 2010 Board approved amount.

General Plant:

General Plant – ($210,704)

In the 2010 COS, NBHDL had several individual projects under the materiality threshold, however, three specific projects included under IT related assets did not proceed contributing to the majority of the variance in general plant. In 2010, NBHDL had anticipated implementing the SunGard PS 'Click to Gov" server for $75,317. NBHDL ultimately decided to leverage the work performed with an existing vendor who had already integrated to NBHDL's HTE platform. Throughout 2011 and 2012, the vendor was able to execute a robust e-billing and customer portal platform and renovate the existing bill generation process greatly improving stability and versatility. The integration and platform then allowed the launch of NBHDL's web presentment feature into a browser and mobile friendly format, and further enabled the quick implementation of the "Green Button" initiative in 2013. These were significant savings and achieved far more than what the "Click to Gov" platform would have. NBHDL also included $49,494 in 2010 related to a major upgrade to NBHDL's AS400 server. This upgrade went forward in 2011. During the 2010 COS, LEAP was a new undertaking and NBHDL estimated that $26,899 would be required in customization to the billing system in order to accommodate the new customer service rules. NBHDL has had less than 10 customers declare as low income and as such these accounts are addressed manually.

Contributed Capital – ($310,567):

NBHDL estimated contributed capital based on a high level forecast of transformation needs anticipated for the construction projects in the 2010 Board Approved amount. Actual contributions collected by NBHDL are in accordance with the DSC and the provisions of NBHDL's Conditions of Service and determined through the economic evaluation methodology from the DSC to determine the level of capital contribution for each project. Changes in the actual work performed and the economic evaluation output results in budget variances in any given year. Two significant drivers of the variance over the Board Approved amount are $94,270 in contributed capital related to road work and $197,669 related to Services work.

Summary

Variances from the 2010 Board approved expenditures to 2010 actual expenditures exist, and in some cases they are significant, however NBHDL has identified the following main drivers to the overall variance in 2010 and due to lessons learned and improvements made over the historical period fully expect to spend to the proposed 2015 capital plan:

- ✓ The Pinewood Project

  This project was the first of its kind for NBHDL and took significantly more work, specifically in labour and project oversight requirements, than originally anticipated which was offset by the civil contractor portion of the project being awarded for much less than estimated. The cascading effect of the extra labour requirement resulted in the delay of 2010 projects and in some instances the total postponement of others. The delay in the Worthington and Victoria projects are examples of the effect of the Pinewood Project.

- ✓ Reduction in Demand Work

  Almost all demand categories were down in 2010 compared to prior years, a variable that is outside NBHDL's control, but one that can have a dramatic effect on expenditures. 2010 was a prime example of that.

- ✓ Voltage Conversion and Substation Rehabilitation Plan

  The first three months of 2010 required NBHDL to commit the majority of management resources to completing the 2010 Cost of Service Application process. Once this process concluded NBHDL made a decision to develop a more thorough planning framework to guide the voltage conversion and substation rehabilitation projects. Although the number of large projects undertaken in 2010 was similar, the spending on the substituted projects represented a much lower expenditure in total. NBHDL made significant improvements in planning over the historical period, which included the

formulation of a voltage conversion plan in 2010 that was later refined in 2012, as detailed in within NBHDL's DSP, which is included in Exhibit 2 as Appendix 2-A, Section 1.2.2. Improvements in planning continue to be a focal point in 2015 and beyond as it is vital to the execution of the capital plan, the importance of which can be found in the planning metrics that have been included within the DSP in Section 2.3.1.2. Improvements in planning are evident from 2010 to 2014; the majority of planned projects were completed in 2013 and all planned projects are forecasted to be completed in 2014.

✓ Project Scope Changes

Even with the best planning processes there are a number of variables that can change the scope or cost of a project. Weather can be a major factor, as well as encountering rock hidden just below soil surface. The development of detailed work orders or job specifications can sometimes identify new problems or opportunities not previously identified. In some situations, it becomes apparent that it is more efficient to complete additional work activities on a job when all resources are mobilized. When this does occur there can be a cascading effect that impacts the timing of other planned projects. Changes in scope are an inevitable part of design process and something that is difficult to avoid. NBHDL is making every effort to review projects thoroughly at the budgetary level to ensure that changes in scope are minimized at time of final design.

TREATMENT OF PROJECTS

Life Cycle Greater than One Year

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

Treatment of Cost of Funds

NBHDL's accounting policy is to expense borrowing costs. It does not capitalize interest on capital projects.

COMPONENTS OF OTHER CAPITAL EXPENDITURES

NBHDL does not have other capital expenditures, such as non-distribution activities, for which it needs to provide components.

CAPITALIZATION POLICY

CAPITALIZATION POLICY OVERVIEW

NBHDLs current capitalization policies and principles are based on CGAAP, and guidelines set out by the Ontario Energy Board, where applicable. NBHDL will be converting to IFRS January 1, 2015 and as such the capitalization policy in effect for the 2014 Bridge Year and 2015 Test Year is compliant with MIFRS.

In 2012, NBHDL reviewed its capitalization policy in anticipation of transitioning to IFRS; componentization of assets, depreciation changes and overheads were the focus of the review. In parallel with this analysis, the capitalization policy was also reviewed in light of the July 17, 2012 Board letter indicating that changes to depreciation expense and capitalization policies were permitted in 2012. NBHDL elected to make these changes in 2012 as a substantial amount of work had gone into the analysis for componentization and depreciation changes. NBHDL confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the APH, effective January 1, 2012. NBHDL's external auditors have also deemed NBHDL's capitalization policy, including the overhead policy, to align with IFRS standards.

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 and other costs directly attributable to bringing the asset to a working condition for its intended use.

Assets with a cost in excess of $500 expected to provide future economic benefit greater than one year will be capitalized. 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 goodwill, patents, copyrights and 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.

NBHDL has used the Typical Useful Life provided in the Kinectrics Report as its basis for assigning the estimated service life to assets. 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. For rate setting purposes, 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. Changes to NBHDL's depreciation policy are explained below under Changes to Capitalization Policy and in Exhibit 4 – Operating Costs.

Overhead Policy

NBHDL's overhead policy has been reviewed by both its external auditors and the consulting services branch of the firm's Risk Advisory Services and has been deemed IFRS compliant.

In 2009, NBHDL reviewed and changed its overhead policy, including the capitalization component, to follow a more direct allocation of costs. At the time, this review was unrelated to the potential transition to IFRS and was instead initiated in an effort to more appropriately allocate costs to departments within the organization and the capital program. NBHDL does not capitalize general administrative costs related to Administration, HR or Finance.

Included in NBHDL's labour costs are those costs that are generally considered labour 'burden'. NBHDL's burden costs include vacation, statutory holidays, sick time, CPP, EI, OMERS contributions, health care and other employee benefits. Burden rates are forecasted by individual employee and are set-up in NBHDL's payroll system accordingly. Through the timesheet process, employees track their hours by work order which designates whether the work is expensed or capitalized. Labour costs, including burden, are then directly charged to specific project by employee based on the work executed in the field.

The overhead policy addresses what NBHDL considers as five service departments; the Stores department (which includes facility costs, inventory and purchasing costs, and fleet costs), the Engineering department, and the Operations Administration department. Costs of these departments are allocated to the departments that are served – Lines, Substations, Metering, and Customer Service – and directly impact construction activities.

Facility - the costs to operate the building are charged out to the various functional departments based on the square footage of each department. Costs are allocated to Administration, IT, HR, Finance, Engineering and Operations Administration.

Inventory and Purchasing – the costs of this function are related to the labour associated with employee managing the warehouse and all inventory processing. As part of the budget process, NBHDL determines the material that is forecasted to flow through the warehouse and a rate is determined as a % of total costs. Material anticipated to be issued out to O&M is based on the previous historical year and capital is based on individual project estimates that include inventory as well has a historical average for customer demand jobs. The inventory overhead is assigned directly to the materials signed out of the warehouse by employees against specific work orders through the automated inventory and work order system.

Fleet Costs - these costs include the costs associated with maintaining NBHDL's fleet of pick-up trucks, bucket trucks with aerial devices, and trailers. These costs include fuel costs, repairs, parts, insurance,

depreciation and all other items of expense necessary to keep the fleet in service. A fleet rate is determined on an annual basis for each vehicle group by estimating the run time of each category of vehicle and allocating the costs accordingly. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle. These costs are expensed or capitalized directly to the specific project through the timesheet process by work order.

Engineering and Operations Administration - the Engineering and Operations Administration departments follow a similar methodology for the calculation of overheads and the determination of what can be directly attributable to capital and therefore included in the capital costs of a project. There are two steps involved in the calculation of the overhead rate for each department, noting that in the determination of the overhead rate for Engineering, Operations Administration is considered a department supported by Engineering:

1) Employees in both departments allocate their time directly to O&M and capital through the timesheet process by work order. Based on this forecast, all other costs in the departments are determined to be in support of capital or O&M work based on the actual allocation of labour.

2) The labour costs for the departments that Engineering and Operations Administration support - Lines, Substations, Metering and Customer Service - are forecasted by capital and O&M. Capital labour hours are based on individual project estimates. This calculation forms the base of the hourly overhead rate as the overhead rate is expressed as a % of labour hours for the departments that are served. For example, if it is determined that there is $50,000 in Engineering costs that are related to the support of the capital program, and the forecast of direct capital labour for Operations Administration, Lines, Substations, and Metering is $740,000, the hourly Engineering overhead rate for capital would be 7.8%.

Once the overhead rates are determined, the costs are charged to the capital and O&M projects directly through the timesheet process by work order. Using the example above, for every labour dollar allocated to a capital or O&M project by an employee through the timesheet process, 7.8 cents for every dollar is also directly attributed to the specific project. For example, when a line crew is working on a specific job, the hours worked on the job are processed through payroll and the automated work order system then multiplies those hours by the overhead rate to attach the cost directly to the job.

CHANGES TO CAPITALIZATION POLICY

Two changes have been made to NBHDL's capitalization policy since the last rebasing application in 2010. The first change is related to the overhead policy that was further refined during the 2009 year end audit process. The second change was a result of the Board's letter dated July 17, 2012 and impacted componentization, depreciation and contributed capital. Changes made as a result of the direction provided by the Board in this letter have been tracked in Account 1576 and are explained in further detail in Exhibit 9 – Deferral and Variance Accounts.

Overhead Policy Changes

In the 2010 rebasing application, NBHDL handled the forecasted treatment of the calculation for facility costs and the determination of the capitalized component for Engineering and Operations Department slightly different than the actual calculation used in the audited financial statements. Facility costs were not segregated from the costs related to managing the warehouse and inventory. Instead, in the forecast, these costs were determined as the total costs of the Stores department and allocated to capital and O&M based on the forecasted material purchases. For the determination of Engineering and Operations Administration costs the amounts were forecasted between capital and OM&A based on the labour split for the departments served as opposed to the actual time directed to capital and OM&A by the Engineering and Operation Administration staff itself. During the 2009 year end audit process, the overhead calculation was reviewed in detail and changes were made to reflect the revised policy as explained in the above section 'Capitalization Policy Overview'. The changes were made in order for a more direct and appropriate allocation of costs between capital and OM&A for the service departments.

With the exception of more closely aligning the capitalization component of the three service departments in 2009, there were no changes to the NBHDL's overhead policy with regards to the transition to MIFRS or the July 17, 2012 Board letter. NBHDL's capitalization policy has been reviewed and approved as IFRS compliant by NBHDL's external auditors and as such no costs have been recorded in Account 1576 for CGAAP changes with regards to capitalization policy changes.

Componentization and Depreciation Changes

In 2010, NBHDL retained the services of BDO Canada LLP's ("BDO") Risk Advisory Services group to assist with determining the level of PP&E componentization required under IFRS, establishing updated useful lives based on the Kinetrics report and examining whether any changes to overhead capitalization were required as part of the planned conversion to MIFRS. As discussed above, no changes were deemed necessary in relation to the overhead policy; however, a significant amount of analysis was done

with regards to asset componentization and the related impacts on depreciation. At that point in time, NBHDL was anticipating conversion to MIFRS for 2011 with a 2010 transition year.

BDO and NBHDL worked together to determine an appropriate level of componentization on historical assets and an assessment of remaining useful lives was undertaken in preparation of the conversion in order to establish a revised January 1st opening value for the transition year. In October 2010, the conversion to MIFRS was subsequently deferred to 2012. In 2011, NBHDL engaged BDO to update the PP&E analysis to reflect the deferral period and update opening values and revised useful lives for depreciation purposes with the anticipation of moving forward with MIFRS. In March 2012, another IFRS deferral was granted to 2013 and on July 17, 2012 the Board issued a letter advising LDCs that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP (i.e. effective January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the AcSB permits further deferrals for the changeover to IFRS.

As part of work involved in the transition to IFRS, NBHDL determined that there was a module within its main software platform that would allow for the componentization of assets at the capital project level through a feature that enabled Engineering Technicians to create project estimates that linked all significant asset components to a fixed asset sub-ledger. Upon completion of a project, the estimate would be 'unitized' which would create asset records by component. A considerable amount of resources and time were required to design the estimate templates that would be used – balancing the needs of Finance for componentization and the ability for Engineering to still efficiently and effectively design jobs. With this in mind, and leveraging the work already completed for the componentization analysis in 2010 and 2011, NBHDL engaged BDO's services to update the componentization analysis to reflect an updated January 1st, 2012 opening balance that incorporated all material components of historical costs, adjusted the service lives to reflect the typical useful life identified in the Kinetrics report and provided an assessment of remaining service lives for which to calculate depreciation expense for 2012 forward. NBHDL proceeded to incorporate historical assets from the analysis into its fixed asset sub ledger with depreciation calculating automatically by asset component within the sub ledger on a go-forward basis. The adjustments made to NBHDL's service lives had a significant impact on NBHDL's depreciation expense and NBHDL has a substantial refund owing to customers because of this change which is recorded in Account 1576 as explained in detail in Exhibit 9 – Deferral and Variance Accounts. The changes in depreciation and the reassessment of remaining useful lives based on the componentization analysis are the only changes that occurred to NBHDL's capitalization policy in anticipation of the transition to MIFRS.

NBHDL's depreciation expense continues to be based on a straight line basis. As part of the analysis done for PP&E componentization, NBHDL distribution assets were assigned the typical useful life (TUL) service life as provided in the Kinetrics report. General assets were also reviewed to ensure that the useful lives were in line with the ranges provided in Table F-2 – Summary Useful Life of Minor Assets as provided within the report. For both financial statement reporting and rate setting purposes, NBHDL has utilized the commonly used ½ year rule for the calculation of depreciation on capital asset based on the year that the asset is deemed in-service. Under this rule, capital assets additions are assumed to be put into service equally throughout the year, therefore, on average depreciation starts at the midpoint of the acquisition, or in-service, year.

Customer Contributions Changes

Under CGAAP, NBHDL recorded customer contributions as an offset to the cost of capital assets and amortized accordingly. Under MIFRS, NBHDL cannot capitalize these customer contributions as part of its net capital assets, but instead will classify the contributions as a deferred revenue liability and amortize the costs to revenue over the life of the asset the contribution relates to. For financial reporting purposes, NBHDL has classified forecasted customer contributions for the 2014 Bridge Year and 2015 Test Year as deferred revenue and amortized the contribution to revenue over the life of the related asset. For rate setting purposes, these costs are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense. For financial statement purposes, historical contributed capital has been reallocated and netted against the specific PP&E asset they relate to, however, for continuity and rate setting purposes, these costs are included in Account 1995. Please see Table 2-20 - Account 1995 Breakdown for the reconciliation between financial statement reporting and rate setting classification.

CAPITALIZATION OF OVERHEAD

OVERVIEW

NBHDL, along with its consultant BDO, performed an analysis of all costs that were being capitalized under CGAAP in order to determine whether these costs were eligible for capitalization under IFRS. As discussed above in the "Capitalization Policy Overview" section, it was determined that no changes were required to the capitalization of overhead as a result of the transition to IFRS and that the policy as explained above is compliant with IFRS requirements.

Table 2-35 provided below, which is consistent with Board Appendix 2-D, has been completed to show NBHDL's OM&A costs prior to the allocation of costs for the Engineering and Operations Administration departments, fleet and inventory (Stores) to capital construction projects.

BURDEN RATES

Table 2-36 below summarizes the historical and forecasted overhead rates related to the capitalization of costs on self-constructed assets. The rates are changed and updated periodically to reflect actual costs or changed circumstances. NBDHL has also included the 2010 Board Approved rates as the overhead process was refined as described in the "Overhead Policy Changes" section above.

NBHDL has four types of overhead costs that are capitalized; (i) Engineering; (iii) Operations Administration; (iv) Fleet; and (v) Stores. NBHDL also capitalizes payroll benefits for applicable employees in the Engineering and Operations department (consisting of Operations Administration, Lines, Substations, and Metering), however, these costs are directly allocated to capital through a burden rate in the payroll system. NBHDL has refined its burden calculation by budgeting payroll benefits by individual employee and attaching an individual burden rate by employee within the payroll system.

As described previously, NBHDL does not allocate any indirect costs associated with Finance, Human Resources, Information Systems Technology, or the Administration department.

1

Table 2-35 – Summary of Capitalized

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	2010 Historical Year	2011 Historical Year	2012 Historical Year	2013 Historical Year	2014 Bridge Year	2015 Test Year
Administration	$ 813,436	$ 791,094	$ 983,065	$ 1,123,969	$ 1,568,577	$ 1,474,728
Finance	$ 1,387,537	$ 1,553,947	$ 1,495,971	$ 1,407,660	$ 1,876,173	$ 1,933,801
HR	$ 382,487	$ 569,105	$ 566,269	$ 495,688	$ 456,328	$ 391,108
Engineering Costs	$ 238,502	$ 286,970	$ 337,890	$ 339,211	$ 435,627	$ 494,908
Operations Administration Costs	$ 474,708	$ 372,136	$ 386,916	$ 419,367	$ 430,499	$ 483,885
Operations - Lines, Substations, Metering, Customer Service, Fleet, Stores	$ 2,052,443	$ 2,144,955	$ 2,113,171	$ 2,262,319	$ 2,417,986	$ 2,615,623
Total OM&A Before Capitalization (B)	$ 5,349,112	$ 5,718,207	$ 5,883,281	$ 6,048,214	$ 7,185,190	$ 7,394,054

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	2010 Historical Year	2011 Historical Year	2012 Historical Year	2013 Historical Year	2014 Bridge Year	2015 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
Administration	$ -	$ -	$ -	$ -	$ -	$ -		
Finance	$ -	$ -	$ -	$ -	$ -	$ -		
HR	$ -	$ -	$ -	$ -	$ -	$ -		
Engineering	$ 53,085	$ 50,836	$ 35,115	$ 35,137	$ 52,510	$ 54,607	Y	Changes based on required labour to complete annual capital program
Operations Administration	$ 31,615	$ 45,861	$ 55,573	$ 51,418	$ 54,153	$ 52,011	Y	Changes based on required labour to complete annual capital program
Operations - Fleet	$ 157,442	$ 144,122	$ 178,788	$ 164,038	$ 174,708	$ 181,232	Y	Changes based on required labour to complete annual capital program and changes in annual fleet costs
Operations - Stores	$ 101,867	$ 113,742	$ 81,426	$ 92,669	$ 95,844	$ 101,360	Y	Changes based on material requirements of capital projects each year
Total Capitalized OM&A (A)	$ 344,007	$ 354,561	$ 350,902	$ 343,263	$ 377,215	$ 389,210		
% of Capitalized OM&A (=A/B)	6.4%	6.2%	6.0%	5.7%	5.2%	5.3%		

Total Costs - OM&A	2010 Historical Year	2011 Historical Year	2012 Historical Year	2013 Historical Year	2014 Bridge Year	2015 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
Administration	$ 813,436	$ 791,094	$ 983,065	$ 1,123,969	$ 1,568,577	$ 1,474,728		
Finance	$ 1,387,537	$ 1,553,947	$ 1,495,971	$ 1,407,660	$ 1,876,173	$ 1,933,801		
HR	$ 382,487	$ 569,105	$ 566,269	$ 495,688	$ 456,328	$ 391,108		
Engineering Costs	$ 185,417	$ 236,134	$ 302,775	$ 304,073	$ 383,117	$ 440,301	Y	
Operations Administration Costs	$ 443,093	$ 326,275	$ 331,343	$ 367,949	$ 376,345	$ 431,874	Y	
Operations - Lines, Substations, Metering, Customer Service, Fleet, Stores	$ 1,793,134	$ 1,887,091	$ 1,852,957	$ 2,005,612	$ 2,147,435	$ 2,333,031	Y	
Total Capitalized OM&A (A)	$ 5,005,105	$ 5,363,646	$ 5,532,379	$ 5,704,951	$ 6,807,975	$ 7,004,844		

Table 2-36 – Overhead Rates

Description	Unit	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Burden Rates:								
Payroll Benefits	Direct Labour	50.9%	52.6%	49.5%	51.0%	51.4%	48.1%	45.5%
Overhead Rates:								
Engineering	Direct Labour	15.6%	8.1%	8.2%	5.4%	5.5%	7.7%	7.8%
Operations Administration	Direct Labour	26.3%	5.1%	8.1%	9.6%	9.1%	8.9%	8.3%
Stores Costs	Material $	7.6%	9.9%	16.0%	10.7%	9.5%	13.7%	11.9%
Small Truck	Direct Labour	$8	$7	$7	$8	$7	$7	$7
Large Truck	Direct Labour	$34	$33	$27	$37	$34	$35	$39

COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

NBHDL has not incurred any costs for the connection of qualifying generation facilities.

NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* and in it the Board has established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

> The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").
>
> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

NBHDL does not have any discrete capital projects within the five-year horizon that it believes would require this new policy option. The capital investment required by NBHDL from 2016 through 2019 is relatively flat and NBHDL believes it can be managed through the rates proposed within this application.

ADDITION OF ICM ASSETS TO RATE BASE

NBHDL has not applied for approval of ICM Assets and therefore has no such assets added to its rate base.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

NBHDL follows the Board's Reporting and Record Keeping Requirements Guideline to report its service quality indicators annually. In accordance with the Filing Requirements, Table 2-37 is provided below and is consistent with Board Appendix 2-S, Service Quality Indicators. The table provides the performance measurements for the last five (5) historical years – 2009 through 2010.

With the exception of the Telephone Accessibility metric in 2009 that is addressed below, NBHDL's performance results over the 2009 to 2013 period meet or exceed the Board's approved standards. NBHDL's performance is within the range of acceptable performance over the previous five years and no corrective action is required. NBHDL will be transitioning to an automated system for the tracking of reliability metrics, including the analysis of worst performing feeder information; NBHDL does not calculate this statistic formally and is implementing this project in a further effort to improve reliability.

In 2009, there was a re-structuring and turnover in NBHDL's front office which temporarily resulted in calls answered on time falling below the threshold target. Since then, NBHDL has introduced changes which allowed improvements in performance in 2012 and 2013. Between 2010 and 2013 total call volume increased by 66% with no increase in staffing levels within the Customer Accounts group and no decrease in service level. Efficiency improvements and process standardization has assisted in this improvement in service level despite the increased workload.

Table 2-37 – Service Quality and Reliability Performance

Appendix 2-G
Service Reliability Indicators
2009 - 2013

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
SAIDI	1.93	2.76	2.91	2.04	2.81	1.56	2.72	2.87	1.60	2.32
SAIFI	1.63	2.86	2.37	2.68	3.07	1.48	2.75	2.16	2.29	1.89

5 Year Historical Average				
SAIDI		2.49		2.21
SAIFI		2.52		2.11

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013
Low Voltage Connections	90.0%	100.0%	100.0%	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%	53.2%	76.5%	71.6%	77.2%	78.2%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	9.0%	2.4%	2.8%	2.4%	6.1%
Appointment Scheduling	90.0%	100.0%	100.0%	99.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	N/A	N/A	100.0%	N/A	N/A
Reconnection Performance Standard	85.0%	N/A	N/A	100.0%	100.0%	100.0%

Appendix 2-A: Distribution System Plan

Distribution System Plan

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- Project Reference: Turret Complex - Madelena
- Project Reference: Turret Complex – Wickstead
- Project Reference: Fourth Avenue Rebuild – Ferguson x Fisher
- Project Reference: Fifth Avenue Rebuild – Cassells x Wyld
- Project Reference: McIntyre Street Rebuild – Cassells x Wyld
- Project Reference: Ferguson Street Rebuild – Princess x First

1 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)(“Filing Requirements”). The Filing Requirements implement 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.

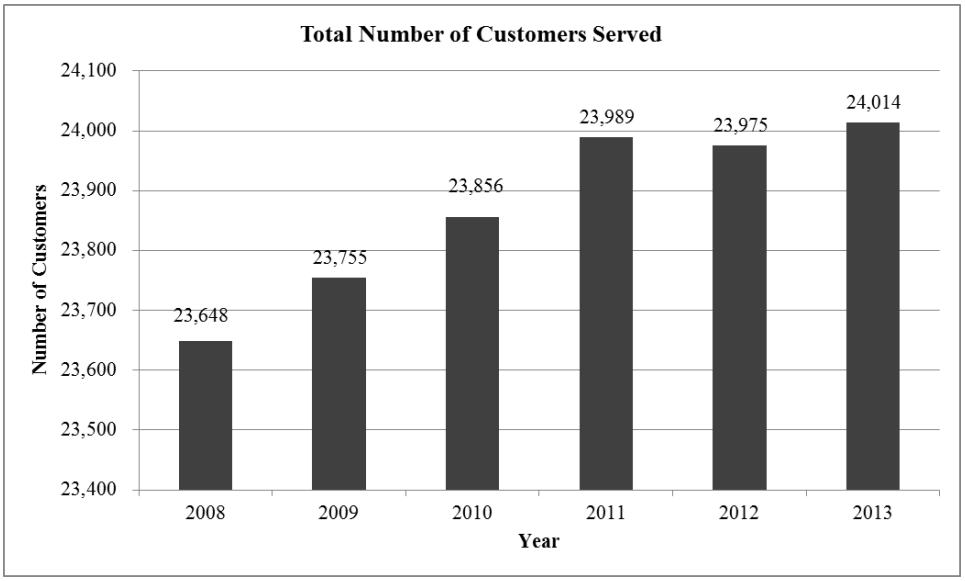
North Bay Hydro Distribution Limited (“NBHDL”) produced this Distribution System Plan (“DSP”) in accordance with the Filing Requirements.

1.1 Description of the Utility Company

NBHDL is the local distribution company (“LDC”), responsible for electricity distribution in the City of North Bay (the ”City”). NBHDL is responsible for operating and maintaining the distribution network serving a population of approximately 54,000 and approximately 23,740 customers as of 2014. The service area served by NBHDL covers approximately 312.28 square kilometers, of which 270 square kilometers is rural. Figure 1-1 shows the map of NBHDL’s distribution service territory. The NBHDL distribution network consists of 16 municipal substations, approximately 488km of overhead distribution lines and approximately 110 km of underground distribution lines.

Figure 1-1: Map of Distribution Service Territory

As evident in Table 1-1 below, the size of NBHDL's customer base has experienced minor fluctuations but there is no significant growth or decline since 2008. The same trend has been observed for population in the City.



	2008	2009	2010	2011	2012	2013
Residential	20,757	20,850	20,952	21,096	21,074	21,108
GS<50	2,616	2,629	2,633	2,623	2,645	2,649
GS>50	273	274	269	268	254	255
Intermediate	2	2	2	2	2	2

Table 1-1: Customer Count

NBHDL receives power from Hydro One at the following Hydro-One-owned Transformer Stations ("TS"):

- North Bay TS ("NBTS"); and
- Trout Lake TS ("TLTS").

Power is stepped down from 115kV and 230kV, respectively, at these transformer stations and NBHDL receives power from Hydro One at 44 kV. There are 8 sub-transmission feeders operating at 44 kV that supply a total of 16 Municipal Distribution Stations ("MS"), where it is stepped down to 4.16kV or 12.47kV.

Approximately 25 years ago NBHDL embarked upon a voltage conversion project ("Initial VC Plan"), upgrading the distribution system voltage from 4.16 kV to 12.47kV. As of the date of this DSP, the Initial VC Plan is now 74.2 percent complete. NBHDL has since formalized its plans for voltage conversion, but this original goal of upgrading from 4.16kV to 12.47kV service remains the same.

Currently, there are two substations (MS1 and MS7) that step down power from 44 kV to 4.16 kV and there is one substation (MS18) that is equipped with dual winding transformers. The dual winding transformers at MS18 are capable of supplying both 4.16 kV and 12.47 kV, but presently supply at 4.16 kV. All of the remaining substations in the NBHDL service area step down electricity from 44 kV to 12.47 kV. Locations of the Distribution Stations are shown in Figure 1-2 below:

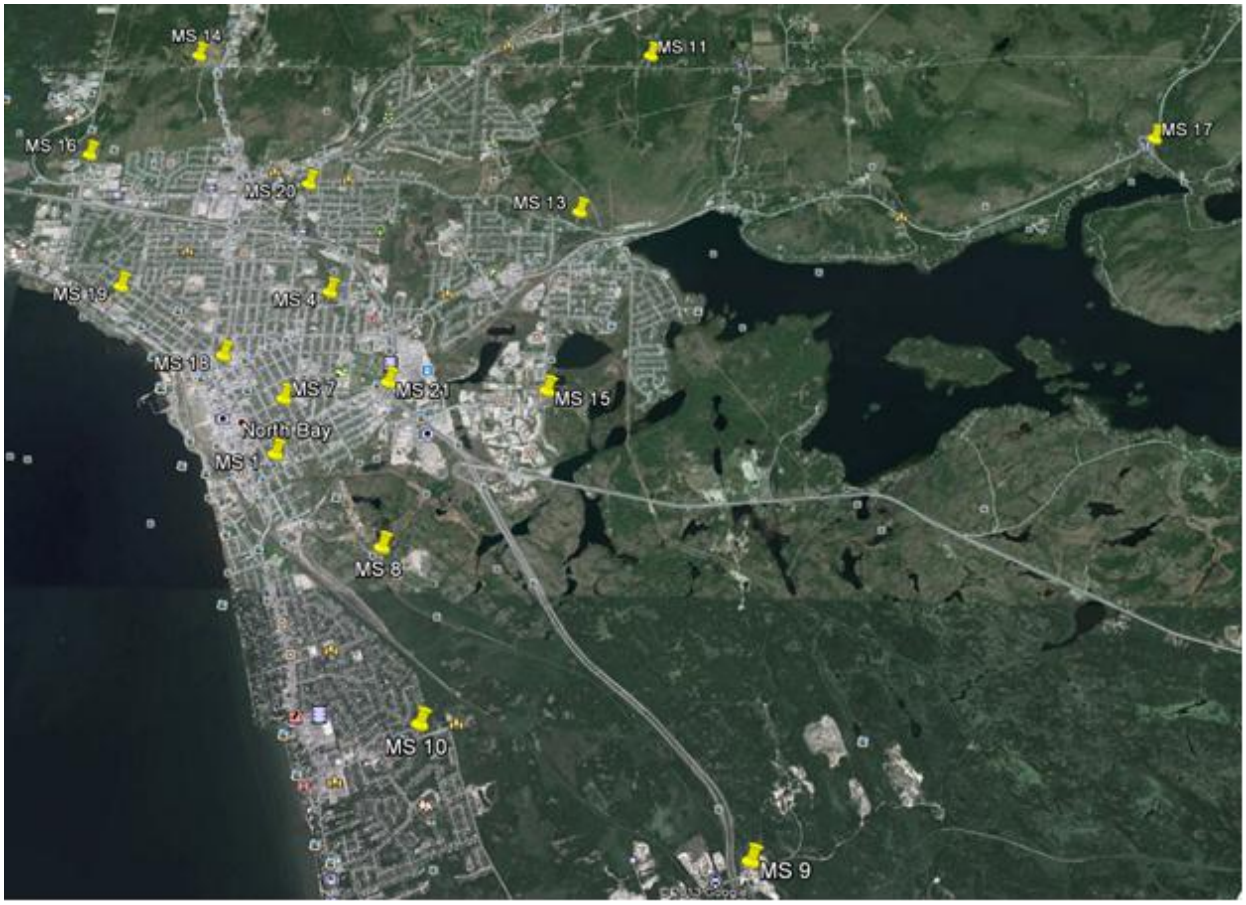


Figure 1-2: NBHDL Distribution Station Locations

Electricity is then distributed in the service territory through a total of 54 distribution feeders. Forty (40) of these feeders are currently operating at 12.47 kV with the remaining fourteen (14) feeders operating at 4.16 kV. The large industrial customers are supplied directly from the 44 kV feeders. This includes twenty four (24) customer owned stations representing large connection customers with over 1MW of transformation. Figure 1-3 below shows the peak demand on NBHDL's distribution system. As shown, the demand peaks in winter and over the recent years maximum demand of 120 MW was recorded in 2009.

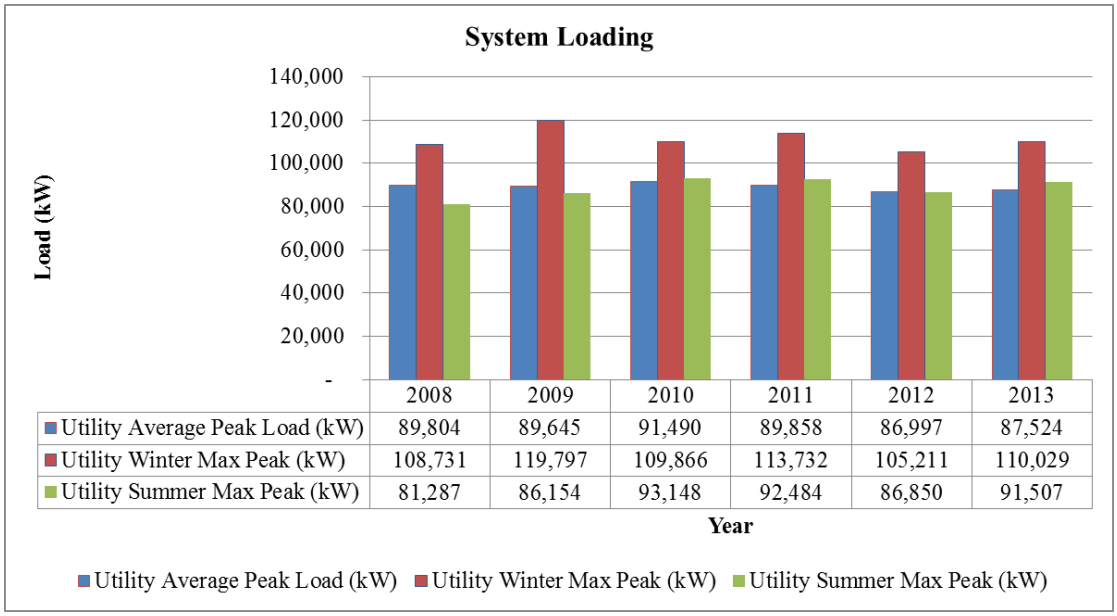


Figure 1-3: System Loading

There are currently thirty four (34) distributed generation installations connected to NBHDL's distribution system under the Feed-in-Tariff ("FIT") and micro FIT programs, as indicated below:

- Three (3) FIT installations with generating capacity of 1.88 MW, as listed in Table 1-2.
- Thirty One (31) micro-FIT installations with 259.84 kW installed capacity, as shown in Table 1-3

In addition to the above, there are seventeen (17) micro-FIT installations that are currently registered with Ontario Power Authority ("OPA"), but have not yet proceeded to the development stage. There are currently no constraints in the distribution system preventing connection of additional distributed generation from renewable sources to the distribution system.

Table 1-2: FIT Generation Facilities

S. No.	Fuel Source	kW Rating
1	Solar Power	30
2	Landfill Site	1600
3	Solar Power	250

Micro-FIT Reference #	Meter Install Date	Rating (kW)
M398BVN	18/01/2010	10.00
M3ERPKX	28/10/2010	2.70
MHT2DVF	13/05/2010	8.00
MRTCG3X	25/06/2010	10.00
MXTD9JV	13/08/2010	10.00
MP422N8	03/12/2010	4.14
MB8I8C2	18/11/2010	10.00
MBEZI3Q	10/02/2011	4.14
MU6YEEB	13/06/2011	8.46
MJT2MR2	09/09/2011	10.00
M31YDMU	09/01/2012	10.00
M9M6FT9	20/03/2012	2.60
M2EB668	28/02/2012	10.00
M3NMX47	12/01/2012	10.00
MJDDAKJ	13/12/2011	10.00
MQF4F2F	04/07/2012	10.00
MPZMKKT	20/03/2012	10.00
MYU6YJC	27/02/2013	10.00
MQCN8YN	27/04/2012	10.00
MJIWG4D	30/10/2012	10.00
MM39FQM	05/07/2012	10.00
MB8JUWN	23/01/2013	10.00
MXTPJQI	27/11/2012	8.30
M2ZPA6G	29/05/2013	10.00
MKD2AV8	01/11/2013	5.00
M3MKIDY	12/06/2013	10.00
MBMFAQN	13/09/2013	10.00
MDTPJ2C	11/12/2013	5.50
M84JXDZ	28/06/2013	10.00
MJ8V8CI	20/09/2013	5.00
MXA97NF	25/10/2013	6.00
Total		259.84

Table 1-3: Micro FIT Generation Facilities

1.2 Background & Drivers

The background and drivers for the proposed capital investments over the next five year period are discussed below under following investment categories identified in the Filing Requirements:

- System Access;
- System Renewal;
- System Service; and
- General Plant.

1.2.1 System Access

For the proposed investments under the System Access category, the key drivers for NBHDL include:

- Customer service requests for new customer connections, requests for service modifications and load expansion at existing commercial and industrial customers, or at existing commercial and industrial locations; and
- Third party infrastructure developments requiring system plant relocates.

As identified in Table 1-1 above, NBHDL has not seen a significant change in the number of customers served during the past several years. NBHDL receives a modest number of requests each year for newly constructed homes. In spite of these new connections, there has not been any increase in the number of overall customers. This discrepancy can be attributed to the fact that a proportionate number of existing customers in multi-family dwellings relocate or move out of town.

Currently there is no backlog at NBHDL for customers requiring new services and no significant change is anticipated in the number of new services required from NBHDL from those experienced in recent years.

In addition, road widening projects undertaken by the City require relocation of some power distribution lines each year. Such relocation projects are anticipated to continue throughout the next five years.

1.2.2 System Renewal

A significantly large percentage of the assets employed on NBHDL's distribution system, particularly the assets employed on 4.16 kV overhead lines, have been in service for much longer than their typical useful life ("TUL"). Most of the 4.16 kV distribution lines have reached a service life ranging from fifty (50) years to 70 years. NBHDL has been renewing the assets at the end of their useful service life by reconstructing the lines and upgrading the system voltage to 12.47 kV. Specific outputs of the asset management process relating to TUL will be discussed further in Section 4.

The current NBHDL distribution system was created from the amalgamation of three (3) different power companies in 1968; Widdifield Hydro, West Ferris Hydro, and North Bay Hydro, each of which had their own distribution system operating voltages. At that time, the amalgamated North Bay Hydro had three (3) different distribution voltages; 12.47/7.2kV, 8.32/4.8kV, and 4.16/2.4kV. Due to the inefficiencies and inflexibility of operating such a system, an engineering study was undertaken by F.D. Ball and Associates Limited on behalf of North Bay Hydro to determine the benefits associated with the implementation of a voltage conversion project in the West Ferris system. The decision derived from the study's conclusions was to convert the system from 8.32/4.8kV to 12.47kV/7.2kV as doing so would improve voltage

regulation, decrease pole line congestion by minimizing number of feeders, lower line loss, improve system security, reliability and operational flexibility through ties to the existing 12.47/7.2kV system. From a long-term perspective, the number of required substations would be minimized. This project became a reality in 1977/78 and the entire West Ferris area was converted from 8.32/4.8kV to 12.47/7.2kV. Following the West Ferris area conversion, NBHDL made the decision to convert the 4.16kV/2.4kV system to 12.47/7.2kV and harmonize the entire system to one distribution voltage for optimal efficiency. However, the 4.16/2.4kV system is the oldest, largest, and most dense system of the three, and NBHDL recognized this would not be a simple task. It was decided at the time, that upon rehabilitation and renewal of any plant in the 4.16kV area, dual rated equipment would be installed to ease conversion at a later date.

Rehabilitation and renewal of plant with the dual rated equipment design concept has been the main driver behind all capital expenditures above and beyond system access for the past twenty five (25) years. Although the conversion goals conceptualized and implemented from the Initial VC Plan remained incomplete, prior to the 2010 Cost of Service (COS) application (EB-2009-0270) there was not a formalized plan, nor direction in the projects selected, to achieve the actual conversion to 12.47kV and therefore the remaining capital program projects were scattered throughout the 4.16kV area.

In 2009, as part of the 2010 COS application, a plan using the approach of converting the old, end of life 4.16kV system from the outside in was devised and put into action with a target end date for completion between 2015 and 2017 ("Voltage Conversion Plan").This plan was further refined in 2012 with a strategy sequencing the order of jobs required for completion to ensure the lowest amount of risk with respect to 'islanded' or isolated 4.16kV areas.

Since the 2010 COS Application, all discretionary dollars, substantiated by the Asset Management ("AM") plan of the time, have been directed towards renewal of infrastructure in the 4.16kV area to allow for the methodical conversion to 12.47kV. NBHDL has used these discretionary dollars and followed the Voltage Conversion Plan to complete the following renewal projects:

- MS19 rebuild (replacement of MS#5 station operating at 22/4.16kV);
- Pinewood Area Conversion to accept 12.47kV supply from MS16 and MS19;
- MS4 feeder rebuilds and conversion to 12.47kV – 4F11, 4F12, 4F13;
- MS5 feeders converted to accept supply from MS19 12.47kV feeders;
- MS21 rebuild (replacement of MS#6 station operating at 44/4.16kV); and
- MS6 feeder rebuilds and conversion to accept supply from MS21 12.47kV feeders.

Contemporaneously with the projects listed above, NBHDL converted two subtransmission circuits operating at 22kV to 44kV. The conversion of the subtransmission circuits was a great achievement for NBHDL for the same reasons mentioned above as it facilitated the rehabilitation of NBTS, one of the two Hydro One Networks Inc. ("HONI") stations supplying the NBHDL service territory, to 44kV. NBTS was placed back into service in late 2012 and allowed for voltage harmonization of the subtransmission grid, leading to increased operational flexibility and reliability as the bulk supply system could not be tied together between NBTS and TLTS. In 2013 alone two separate loss of supply outage events, affecting more than 2500 customers each time, were minimized to one hour instead of four hours because of the ability to pick the NBTS 44kV feeders up out of TLTS.

In continuing the implementation of the Voltage Conversion Plan, in 2013 NBHDL engaged METSCO Energy Solutions Inc. ("METSCO"), an independent power sector consulting firm, to conduct a comprehensive condition assessment of the distribution system assets. The goal of this assessment was to determine not only the condition of the assets, but also affirm NBHDL's decision to continue with the Voltage Conversion Plan. This assessment resulted in the stand-alone Asset Condition Assessment ("ACA") report attached in **Appendix B** (the "ACA Report").

The ACA Report evaluated the risk of asset failure in service by taking into account all available information, including age, operating conditions, results of visual inspections and non-destructive testing and identifies the assets in very poor and poor condition that present unacceptably high risk of failure in service. By comparing the value of risk against the risk mitigation cost, the report also identifies the level of investments considered economically efficient.

A majority of the assets determined to be in poor condition are employed on the 4.16 kV distribution lines. METSCO concluded that NBHDL's lower voltage assets presented a greater risk of failure and specifically stated the following: "Since voltage upgrade of lines offers other economic benefits in addition to reducing the risk of asset failures, poles in "very poor" and "poor" condition employed on the 4 kV lines are recommended to be given priority in conjunction with the implementation of line voltage upgrades." In addition, assets found in poor condition not only present greater risk of asset failures in service, which would degrade system reliability, but they also pose potential safety hazards to NBHDL employees and the public. As part of its capital investment plan for the next five years, NBHDL is proposing to replace the assets found in poor condition and rebuild those lines to mitigate the risk of in-service failures.

As is the case with the 2010 COS Application, the Voltage Conversion Plan is a major driver behind the prioritization of System Renewal projects in this Application. To accomplish this goal, NBHDL intends to maintain the 'outward in' Voltage Conversion Plan methodology it has employed over the last 4 years. This methodology is illustrated below by Figure 1-4 through Figure 1-7. Specifically, looking from Figure 1-4 to Figure 1-6, it can be seen that the area designated for voltage conversion is decreasing from the outer limits inward. In each figure, a smaller area of the NBHDL service area remains, culminating in the proposed remaining area as of Q4 2014 as indicated in Figure 1-6. Figure 1-7 shows the progress that NBHDL has made in completing the Voltage Conversion Plan from 2010 to 2014.

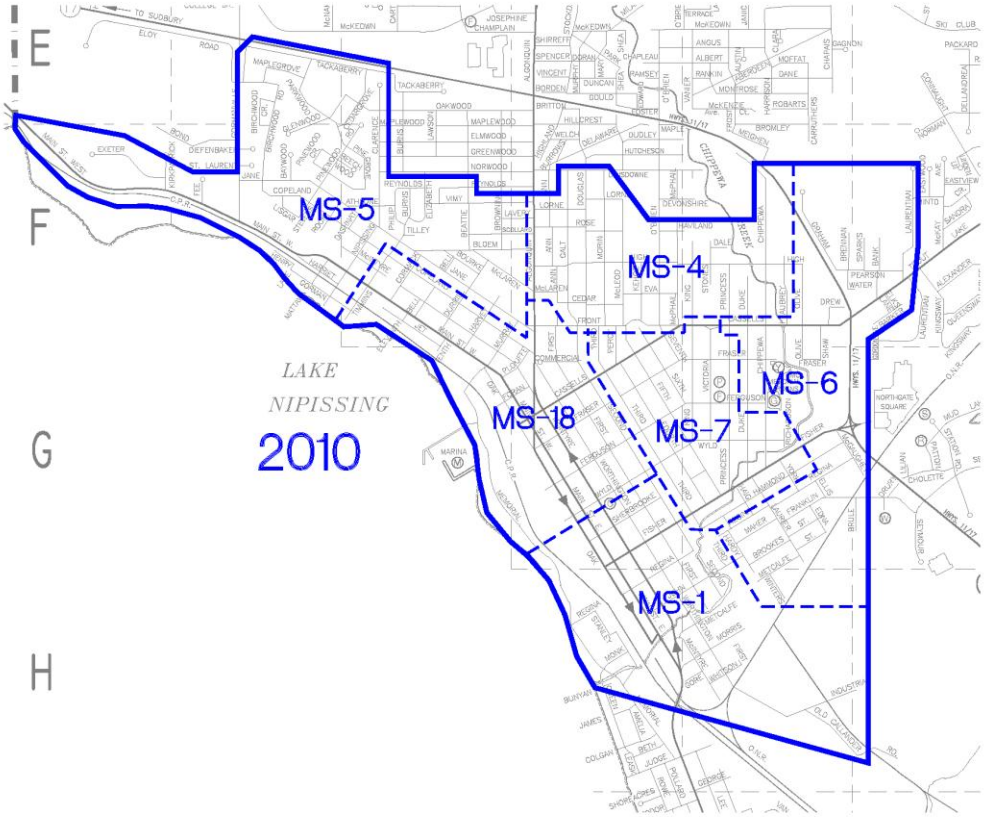


Figure 1-4: Voltage Conversion Map 2010

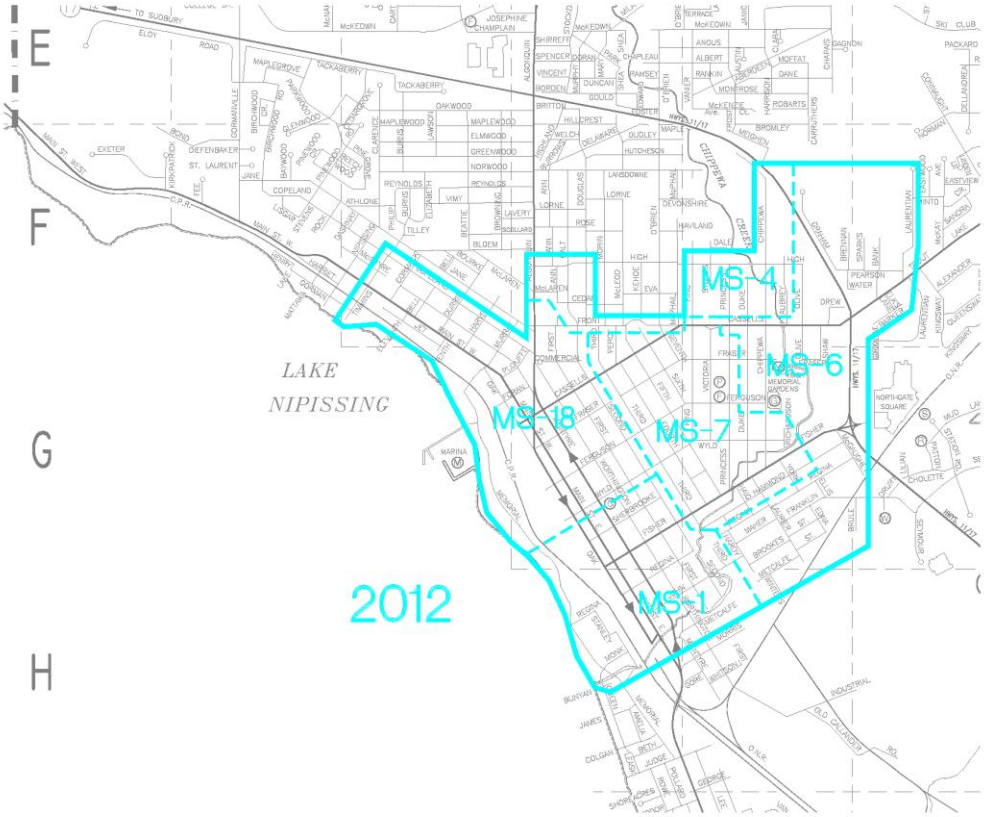


Figure 1-5: Voltage Conversion Map 2012

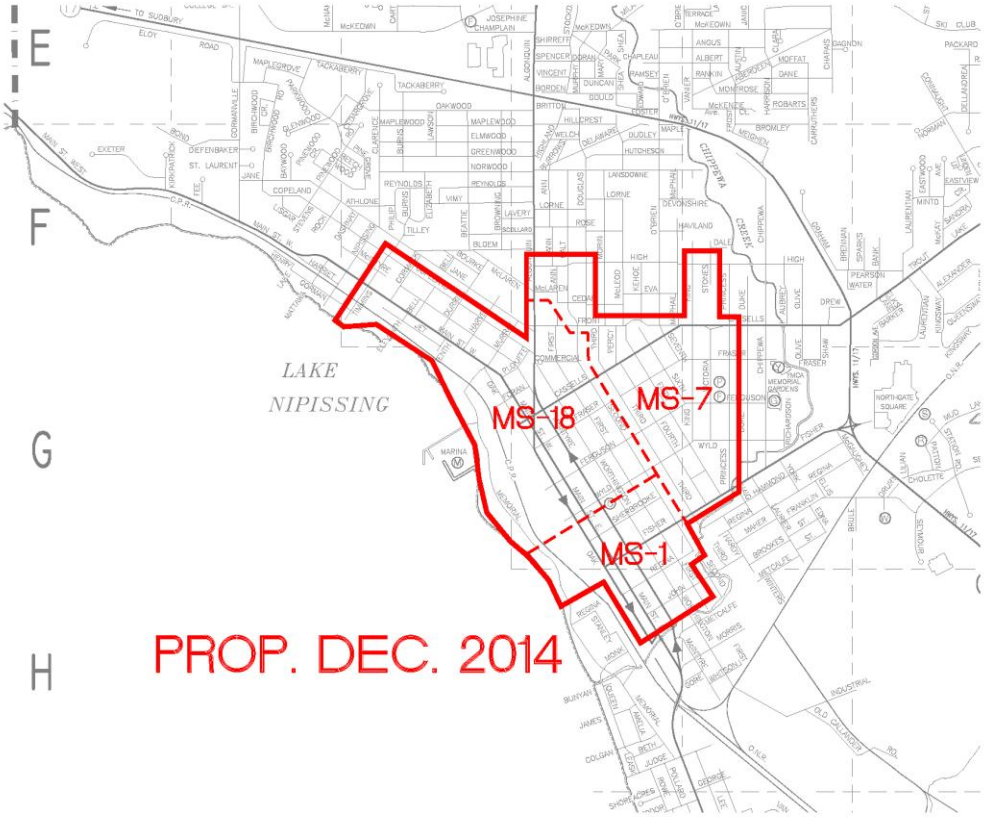


Figure 1-6: Voltage Conversion Map – Proposed for December 2014

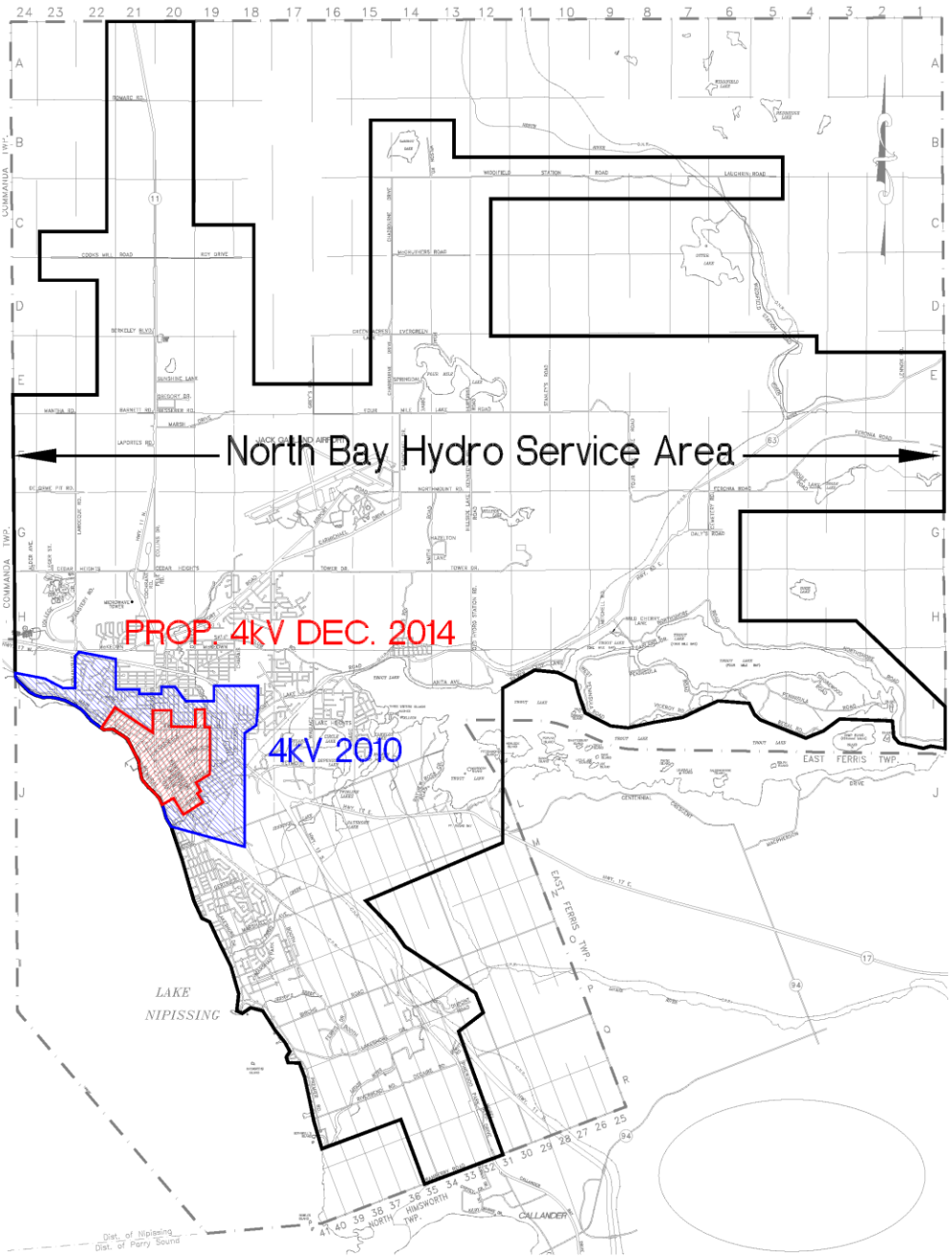


Figure 1-7: Voltage Conversion Map 2010 vs. Proposed 2014

In order to accomplish the Voltage Conversion Plan goal of having the 4.16kV system fully converted to 12.47kV by the target year set forth in EB-2009-0270, the projects for which "system renewal" is the primary driver have been further prioritized for implementation, using benefits of voltage upgrade as a secondary driver, among other drivers such as safety and reliability concerns. The asset renewal projects proposed for implementation during 2015, 2016 and 2017 will allow complete elimination and removal from service of all the 4.16 kV lines and substations. These projects, in addition to risk mitigation against in service asset failures, provide the added benefits associated with voltage upgrade, i.e. increased operational flexibility, increased reliability in the form of reducing outage length by increasing redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs. The conversion to 12kV will eliminate the need for all dual wound transformers in inventory. The current inventory levels of dual wound transformers fluctuate between 80 and 90, totaling approximately $400k worth of inventory. The completion of the Voltage Conversion Plan will also allow elimination of MS#7, one of the sixteen (16) NBHDL substations and one of the original six (6) 4.16kV substations.

1.2.3 System Service

Projects in the System Service category are driven by the need to alleviate capacity constraints due to load growth. The projects in this category also include capital investments aimed at improving system operations, reliability and efficiencies through voltage upgrades, distribution automation, intelligent devices or equipment, all aimed at enhancing customer value and operational effectiveness.

During the next five years, no capacity constraints are anticipated on the distribution system requiring investments into capacity upgrades. NBHDL's Smart Grid development initiative ("SMART GRID Initiative") involves equipping all the distribution stations with a supervisory control and data acquisition ("SCADA") system. The reconstruction of MS9 with a new substation MS22, scheduled in 2015, will complete this initiative.

A number of NBHDL's feeders that have been upgraded or will be upgraded to the 12.47 kV construction standards continue to operate at 4.16kV after upgrading due to system configuration. When a 12.47kV supply becomes available to said upgraded feeders a modest level of capital investment is required to change taps of the dual rated transformers to the higher voltage setting and replace fusing to match the lower current requirements, all of which are captured in this category. Table 1-4 below shows a list of all the feeders that will be converted from 4.16 kV to 12.47 kV operations, during the 2015-2019 time-periods.

Year	Feeder Planned for Upgrade
2014	7F1, 7F3
2015	1F1, 7F2, 18F1, 18F2, 18F3
2016	1F3, 1F4, 7F4, 18F4, 18F5, 18F6

Table 1-4: 4.16kV NBHDL Feeders to be converted to 12.47kV by 2019

Finally, all residential customers have been equipped with smart meters and NBHDL is currently changing over the revenue meters for >50 kW general service customers and investments into revenue meter upgrades are planned over the next five years.

1.2.4 General Plant

The capital investments under this category include investments into motor vehicle fleet, equipment and tools, buildings and facilities, computer hardware and software systems. These investments are driven by the objectives to improve employee safety, worker productivity and operating efficiency.

In 2013, NBHDL engaged an independent third party – Piotrowski Consultants Ltd., to conduct inspections and perform a condition assessment of its building and facilities. This included an Architectural Building Condition Assessment and a Mechanical and Electrical Building Condition Assessment (the "Building Assessment"). The Building Assessment is attached in **Appendix C**. As described in detail in Section 4, based on the deficiencies identified in the buildings and facilities in this report, NBHDL has planned investments for repairs and building upgrades, most of which will have been carried out in 2014.

NBHDL also engaged an external service provider – John Saunders Utility Services, to perform a condition assessment of the motor vehicle fleet ("Fleet Assessment"). The motor vehicle Fleet Assessment report is attached in **Appendix D**. Based on the recommendations of the report, a fleet replacement plan has been adopted by NBHDL and the scope of investments for fleet replacement is described in detail in Section 4.

NBHDL engaged an external service provider – BDO Canada LLP, in 2013 to perform an information technology ("IT") assessment to identify potential areas of risk so that risk mitigation measures can be proactively developed to reduce or eliminate the likelihood of the risk occurring ("IT Assessment"). The detailed IT Assessment report is attached as part of Appendix 4-B. The risks identified in the assessment and the key areas for improvement, as recommended in this report, are listed below:

- Improve TOU billing process;
- Enhance NaviLine utilization;
- Establish a robust demand management program;
- Develop "Business Continuity" & execution of smart meter operations;
- Improvement of IT general controls & IT infrastructure;
- Further utilize SunGard testing environment for regulatory changes;
- Reassess advanced metering infrastructure operations;
- Improve vendor management / communication with SunGard & Sensus; and
- Develop policies & processes for "Disaster Recovery Planning."

The investment plan described in Section 4 includes initiatives to address the critical deficiencies and risks in the IT system.

1.3 Objectives & Scope of Work

The key objectives of the capital investment program proposed to be implemented during the next five years include:

- ✓ Meeting NBHDL's regulatory obligations, including the obligation to serve customers within the service territory and the obligation to relocate lines when requested by the Regional and Municipal Governments, in conjunction with road widening programs.

- ✓ Ensuring supply system reliability is maintained at optimal levels by mitigating the risk of in-service equipment failures, through economically efficient investments, i.e. implementing reliability improvement projects when the value of risk is greater than the risk mitigation cost.

- ✓ Delivering good value service for money while providing a fair rate of return to the City of North Bay.

- ✓ Mitigating public safety risks from distribution system operations.

- ✓ Harmonization of the distribution system operating voltage to 12.47/7.2kV to improve operation flexibility and reliability and to reduce inventory levels and line losses.

- ✓ Smart grid development initiatives, improving protection, controls and monitoring of distribution stations.

- ✓ Improving worker safety and productivity and enhancing operating efficiency.

- ✓ Proactively monitoring and removing constraints in the distribution system that prevents connection of small scale generation from renewable sources to the distribution system.

The requests for new customer connections, for load increase from existing customers and for line relocations from the municipal government are commonly received at a relatively short notice throughout the year. Therefore, the proposed investments into the "System Access" category, to meet NBHDL's regulatory obligations are based on the historic investment levels. The level of investments and prioritization of the investments into system renewal, aimed at improving supply system reliability and public safety have been determined through an evaluation of the risk as described in detail in the stand-alone report ACA Report attached in **Appendix B**.

As described in detail in the "Green Energy Plan" (**Appendix F**), supported by the comment letter from Ontario Power Authority (**Appendix G**), no constraints have been identified in the distribution system and no REG investments are required. Similarly, the SMART GRID Initiative involves provision of SCADA system at MS-9 and this investment has been captured under the station renewal program. Therefore, under the System Service category, only a modest level of capital investments is required to implement voltage upgrade for distribution transformers.

A number of investments aimed at meeting the regulatory compliance, improving worker safety and productivity and enhancing operating efficiency are proposed under General Plant category and these investments are supported by stand-alone reports included in **Appendix C**, **Appendix D** and **Appendix E**.

1.4 Outline of Report

The report is organized based on the Filing Requirements and is divided into four sections, including this introductory section. Section 2 provides an overview of the Distribution System Plan and describes the process employed in its development, i.e. stakeholder consultations, collaboration with municipal/regional governments and transmitters, performance measurements and monitoring metrics. Section 3 describes in detail the asset management process employed by NBHDL to determine the scope of capital investments into asset sustainment and to assist in the prioritization of investments. Section 4 documents the overall capital expenditure plan covering system access, system renewal, system service, as well as capital investments into general plant upkeep and investments into provincially mandated programs to facilitate smart grid, CDM and Green energy connections during the next five years. Cross references to

the Filing Requirements are included in brackets () at all headings/subheadings within this report for ease of reference.

2 Distribution System Plan (5.2)

2.1 Distribution System Plan Overview (5.2.1)

2.1.1 (5.2.1a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives:

As described previously in Section 1, the capital investments proposed in this distribution plan involve investments into each of the four categories: (1) System Access; (2) System Renewal; (3) System Service; and (4) General Plant. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan. Table 2-1 below provides a summary of the total capital spending planned for the forecast period broken up into the four categories identified above. This will be further discussed in Section 4 below.

		2015	2016	2017	2018	2019	TOTAL	AVERAGE
SR	System Renewal	$ 5,469,405	$ 4,180,343	$ 4,235,741	$ 4,266,049	$ 4,054,266	$ 22,205,804	$ 4,441,161
SS	System Service	$ 373,245	$ 214,743	$ 127,302	$ 89,044	$ 135,918	$ 940,251	$ 188,050
SA	System Access	$ 1,143,704	$ 1,166,578	$ 1,189,909	$ 1,213,707	$ 1,237,982	$ 5,951,880	$ 1,190,376
GP	General Plant	$ 771,603	$ 373,400	$ 549,000	$ 350,700	$ 642,000	$ 2,686,703	$ 537,341
	Total Capital Spending	**$ 7,757,956**	**$ 5,935,064**	**$ 6,101,952**	**$ 5,919,500**	**$ 6,070,166**	**$ 31,784,637**	**$ 6,356,927**

Table 2-1: **Summary of Capital Spending for Forecast Period**

In addition to the total capital spending table above, Table 4-9 (Appendix 2-AB) in Section 4 provides year-over-year spending for System Access, System Renewal, System Service and General Plant.

The proposed investments in the System Access category include non-discretionary expenditure, required by NBHDL to meet its regulatory obligations. These investments consist of three components:

i. all work to accomodate new customer connections;

ii. line relocations required in conjunction with municipal road widening programs; and

iii. investments to maintain revenue meters compliant with regulations.

Although it is not easy to accurately estimate in advance the level of investments needed over the next five years in this category, NBHDL has used all available information obtained through consultations with the municipal government, local developers and major customers to estimate the required expenditure as accurately as possible. As was the case during the last five years, NBHDL currently knows of no major load growth or road development projects that are planned in the City during the next five years. The capital investment level for this category has been estimated based on the average expenditure in this category during the last five (5) years, with an adjustment for inflation. Investments into revenue metering infrastructure are needed to equip >50 kW general service customers with smart meters.

The scope of capital investments proposed in the System Renewal category has been determined with the objective of keeping power supply reliability from deteriorating from its existing level. As previously

described in Section 1.2.2, there are assets employed on NBHDL's overhead distribution system that have been in service for much longer than their TUL. Many of the 4.16 kV overhead lines, in particular, have reached the end of service life. These assets currently range from 50 years to 70 years. The level of investments and prioritization of investments into specific projects has been established based on the risk based approach, by taking into account the probability of assets failing in service, valuation of the consequences of such failures and comparing the risk costs with the risk mitigation costs. The methodology is described in greater detail in 4.3. The average level of capital investments proposed during the next five (5) years into the asset renewal category is approximately of the same order as the average capital expenditure during the last five (5) years.

No capacity constraints are anticipated in the distribution system during the next five years and no investments are required into capacity upgrades. The capital investments in the System Service category are aimed at improving system operations, reliability and efficiencies through distribution automation, as well as enhancing customer value and operational effectiveness. To complete the implementation of NBHDL's SMART GRID Initiative vision of equipping all distribution stations with SCADA system, capital investment is proposed to install SCADA system at MS9, when it is reconstructed in 2015. A small amount of capital investment is also proposed for voltage upgrade of a small number of distribution transformers, after the lines have been upgraded from 4.16 kV to 12.47 kV.

The capital investments under the General Plant category include investments into:

i. buildings and facilities;

ii. motor vehicle fleet; and

iii. IT system, PC upgrades and other efficiency programs such as laptops in trucks for locates, etc.

These investments are aimed at improving worker productivity, operating efficiency and employee safety. The average level of investments proposed for the next five years in this category are of the same order of magnitude as the previous five years.

The capital investments proposed for the 2015 to 2019 period, as briefly identified above, are expected to yield the following benefits:

- The investments into System Access category will allow NBHDL to meet its obligations to serve new customers and relocate lines in public right-of-ways upon receipt of requests for such services.

- The change-over of revenue meters to smart meters for general service customers will improve operating efficiency, permit control of peak demand and enable hourly pricing for customers as the transition is completed. The conversion period is aligned with the Ontario Energy Board's amendments as set out in *EB-2013-0311.*

- The investments into System Renewal will reduce the risk of critical asset failures in service and help sustain the reliability and safety at acceptable levels. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures.

- Since the majority of the investments into System Renewal projects are aimed at the 4 kV distribution systems as part of the Voltage Conversion Plan, reconstruction of the lines with upgraded voltage will also reduce line losses, eliminate the need for stocking duplicate spare parts and reduce the number of substations by one (1).

- The proposed investments into System Service category will permit equipping the remaining one (1) substation with SCADA system (after reconstruction) and complete implementation of the current SMART GRID vision.

- Investments into General Plant are aimed at improving employee safety and worker productivity by providing safe work environment and modern tools and equipment, as well improvement in customers services through increased productivity and efficiency.

These capital investment strategies and their associated benefits will be fully discussed below in Section 4.

2.1.2 (5.2.1b) sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution:

The sources of costs savings expected to be achieved over the forecast period by NBHDL through good planning and DS Plan execution include the following:

- Improvements in the overall planning process is anticipated to lead to lower variances in project costs to budget and will also help with the completion of planned capital projects in the given fiscal year.

- Specifically, implementation of a formalized asset management prioritization protocol (to be initialized in 2016) through consultation with METSCO is anticipated to allow NBHDL to have stronger and more efficient practices in determining asset health and coordinating repair and replacement efforts.

- The focus on the renewal of the system, specifically the replacement of assets past their useful life, is anticipated to result in less reactive based maintenance (trouble calls). The benefit may not be realized immediately, and is anticipated to help mitigate the effect of other O&M cost increases in the longer term. Less trouble calls also have the potential to result in higher reliability.

- The reestablishment of 4.5m (15') of clearance of all high voltage lines from trees is anticipated to reduce tree related outages, in turn increasing reliability and decreasing truck rolls, overtime labour costs, and preventing damage to NBHDL assets. Upon completion of the reestablishment of said clearance the annual tree trimming budget will be reduced.

- The installation of SCADA in the last non-automated substation is anticipated to reduce man hours and truck rolls required to deal with breaker operations and also reduce restoration times in outages specific to that system due to the ease of operation from the control room.

- The completion of the Voltage Conversion Plan for the 4kV system to 12.47kV is anticipated to continue to lower line loss.

- The decommissioning of MS7 is anticipated to provide cost benefits as it will free staff from current tasks such as: Monthly station inspections, preventative maintenance at the station every 4 years, annual infrared scanning at the station, annual oil sampling, and the small items needed to keep the station running (changing of batteries, cleaning of the yard, minor repairs). Time saved at this substation could be applied elsewhere in the system adding to productivity. NBHDL estimates cost savings as follows: Oil sampling is about $200/station/year, minor repairs when averaged are probably close to $1000/station/year, station snow plowing averages $513/station/year, and herbicide application at this station is $411/year, and consumption of electrical energy for station purposes would be close to $200/year. The loss through the power transformer is also eliminated from the system.

- The proactive replacement or rejuvenation of underground cabling is anticipated to help reduce expensive reactionary O&M costs and reduce outages relating to underground cable failure in turn improving reliability. This focus also allows NBHDL to rebuild the area with today's underground construction designs that have evolved significantly since the 1970's and is anticipated to eliminate a number of inaccessible backlot poles in the 2015-2016 projects.

2.1.3 (5.2.1c) period covered by the DS Plan (historical and forecast):

This DSP covers the historical period of 2010 to 2013, the current year of 2014 and future investment period from 2015 to 2019. The 2014 year includes six (6) months of actual costs and six (6) months of forecasted spending.

2.1.4 (5.2.1d) vintage of information on investment drivers used to justify investments identified in the application:

The DSP employs data as of December 31, 2013 to support the proposed investment decisions. A representative sample of the station assets was visually inspected by METSCO staff on September 18th and 19th of 2013.

2.1.5 (5.2.1e) where applicable, indication of important changes to the distributor's asset management processes (e.g. enhanced asset data quality or scope; improved analytic tools, process refinements; etc.) since the last DS Plan filing:

This is NBHDL's first DSP under the new Filing Requirements and as such, it is difficult to compare it to past submissions. The methodology employed to support the level of investments and prioritize the investments into specific project categories represents an improvement from the methodology used in NBHDL's 2010 COS in the following ways:

- The model employs updated data related to health and condition of assets as of the end of 2013, including asset age, results of testing and visual inspections (much of this data can be attributed to the implementation of the ACA Report);

- NBHDL has implemented a prioritization matrix with weighted scoring to assist in asset management and prioritized investments for 2015 ("Prioritization Matrix") until it can implement the 2016 prioritization protocol designed by METSCO;

- NBHDL engaged third party consultants to investigate the asset conditions of General Plant which resulted in the formation of the Architectural Building Condition Assessment and a Mechanical and Electrical Building Condition Assessment (leading to the Building Assessment report), as well as the Fleet Assessment and IT Assessment; and

- A risk model for quantitative valuation of the risk of assets' failure in service has been used, as opposed to the qualitative model used in 2010 submission.

2.1.6 (5.2.1f) aspects of the DS Plan 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, LTLT) and the expected dates by which such outcomes are expected or will be known:

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 for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of customer requests for new services and line relocates. NBHDL expects such deviations to be minor and the overall expenditure level during the next five (5) years is not expected to be significantly different from the previous five (5) years,

when adjusted for inflation. These coordinated efforts are ongoing and the DSP is contingent on them with respect to allocating part of the budget envelope only. The formal regional planning process ("RPP") with the transmitter is scheduled to begin in late 2015, but since there are no capacity constraints the plan process is not expected to have material impacts on this distribution plan and proposed investments.

Given this information, aside from the deviation in System Access projects, NBHDL anticipates no future events that the DSP is contingent on.

2.2 Coordinated Planning with Third Parties (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 OPA or other third parties, a distributor must provide:

2.2.1 (5.2.2a) a description of consultations:

The results of coordinated planning with third parties are documented in this section by addressing the following questions for each consultation:

- the purpose of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process;
- the nature and prospective timing of the final deliverables, that are expected to result from or otherwise be informed by the consultation; and
- an indication of whether the consultation has or is expected to affect this DSP as filed and if so, a brief explanation as to how.

Stakeholders Involved

This DSP has been prepared through a coordinated planning process with all major stakeholders. Input from the following stakeholders has been considered by NBHDL during preparation of the DSP:

- customers;
- the regional and municipal governments;
- CDM program partners (including the Ontario Power Authority);
- the transmission company – HONI; and
- the Embedded distributor – HONI.

The following section addresses the specific questions under the Filing Requirements for each of the specific stakeholders identified above.

2.2.1.1 Customer Engagement

NBHDL has provided a summary of its customer engagement activities in Exhibit 1 of this Application, The following description is specific to the customer engagement that is directly relevant to matters addressed by this DSP. Customer engagement has always been important to the success of NBHDL.

The purpose of these engagement processes has always been to focus on addressing issues of concern raised directly by customers. The issues are addressed according to NBHDL customer preference on how they wish to be served and engaged. For example:

- In 2013, 27,446 inbound phone calls were answered by NBHDL customer service staff on 22 different topics of concern to customers including account information, services such as eBilling, TOU rates, outages, conservation programs, payment, bill components, etc;
- 12,359 outbound calls were made on various issues with the majority on collection issues;
- 3,678 locates were completed to allow customers to safely build on their property without danger of electrical contact;
- Many customers have requested paperless electricity bills and in 2013 4,562 customers had signed up for eBilling;
- Many customers have expressed an interest in reviewing their electricity consumption and 5,395 have signed up to use a web portal to look at TOU data;
- Customers are very interested in conservation and over 950 small businesses out of a population of approximately 2,600 have participated - over 137 projects have been completed with larger businesses out of a population of over 250;
- Bill inserts and on-bill messaging is included monthly in/on the bill according to topics of interest and relevance to customers; and
- Thousands of customers are contacted each year to discuss vegetation management activities that will be performed on their property.

As can be seen above, NBHDL is both proactive and reactive in its customer engagement consultations. The majority of these exercises and discussions provide helpful insight in to the day to day operations of NBHDL. These examples demonstrate that customer engagement and communication is a priority for the NBHDL and ties directly to NBHDL's core objectives of community and customer focus, and community and customer safety.

NBHDL has also made significant efforts to engage the largest energy consumers in the City to work on issues of importance to them. These engagement issues include electricity rates and pricing, billing inquiries, electrical supply concerns, demand response, energy conservation, metering and sub-metering, monitoring and changing electricity demands. NBHDL's experience with this approach is that larger electricity consumers are very busy with their core responsibilities and they have a tolerance for the right amount of engagement that benefits their business.

Historically, NBHDL has relied on direct, day-to-day, real time interactions with customers to inform decision making, to advise of issues important to customers and to address communication and customer service needs. The Board's Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach ("RRFE") policy objective of increased customer engagement and focus resulted in NBHDL initiating a more formalized engagement process with residential and small business customers through a series of telephone surveys and focus groups that began in the late summer of 2013. The purpose of these activities was to gauge the level of customer satisfaction throughout all aspects of the

organization, to determine a benchmark for customer service and reliability for which NBHDL could strive for continuous improvement and to assist in determining customer preferences. These consultations were used as a way of determining what NBHDL was doing well, how it could improve and what customers wanted to see from the organization. NBHDL sought direct input from customers to determine if NBHDL's operational and capital plans aligned with customer preferences and whether customers would ultimately support the decisions that NBHDL is making in order to run an efficient and effective distribution company.

The engagement process for this 2015 Application occurred in three phases as follows:

- Phase 1 - Clark Marketing and the North Bay Chamber of Commerce were engaged to provide initial local feedback through surveys and focus groups.

- Phase 2 - Simul Corporation was contracted to conduct its UtilityPULSE customer survey in May 2014. This is a widely used survey within the Ontario distribution sector that provides NBHDL with comparable statistics from both a provincial and national perspective.

- Phase 3 - Innovative Research Group ("Innovative") was retained to obtain customer feedback on NBHDL's proposed 2015 capital investment and operational plans and the expected distribution rate impact as proposed in the 2015 rebasing application. Two focus groups and a telephone survey were conducted.

Phase 1

NBHDL retained the services of a local marketing firm, Clark Marketing Communications ("Clark"), to begin the initial survey work and subsequently run two focus group sessions for additional customer feedback.

Residential Customers

Between August and September 2013, 876 residential customers (4% of NBHDL's customer base) were invited by NBHDL to participate in a fourteen (14) question survey to establish residential customer opinions on reliability, electricity costs, customer service levels, service preferences (underground versus overhead), green electricity, bill format and how NBHDL might better serve these customers. This survey is attached as Appendix 1-2 to Exhibit 1.

To get customers to participate in the survey, NBHDL included a bill insert in customer bills, added a link to the NBHDL website, advertised in the local paper (the Nugget) and on the local radio stations (the Moose FM and Rogers Radio), and made direct calls to customers. In addition, a $500 credit (for use against a future bill) was offered as an incentive to get customers to fill out the survey.

The survey identified some useful information for NBHDL review purposes. Lower costs continue to be a key concern as identified by residential customers. Overall the feedback on reliability was positive with 93.3% of participants having no complaints about reliability and 97% believing that responding to outages within 30 minutes was a reasonable service level. The survey also indicated that nearly 66% of customers were not aware that 75% of the bill was from sources other than NBHDL.

On June 10, 2014, NBHDL held a customer engagement session with residential customers. Twenty five (25) participants attended. The session was hosted by Clark on behalf of NBHDL and no representatives of NBHDL were in attendance. The purpose of the residential engagement session was to generate feedback from residential ratepayers and learn what NBHDL can do to improve its services and

communications. Customers were asked to review the results of the customer surveys and were asked for their comments on each question/response. Customers were also asked to respond to 3 questions: (1) How can we serve you better?; (2) What do you want to know about North Bay Hydro?; and (3) What is the best way to communicate with you?

To these questions, customers provided numerous different answers. A few of which are provided, as example, below.

1) How can we serve you better:

    - Reduce the cost of energy and the cost of delivery
    - Adjust the peak times for the common residential ie: Laundry-Monday obsolete doing it on weekends or until midnight.
    - Debt retirement charge (When will this end?)
    - Communication with residents was horrible for the tree removal-messes left
    - Provide better legibility on bills
    - Provide more knowledge about why rates have been increased twice a year during the past several years
    - Do not cancel energy saving programs
    - Changing billing time frames (monthly/quarterly)
    - More consumer choice
    - Start operating on cost-recovery basis
    - Website overhaul (Online help)
    - Put forth incentive programs (not only for low income)
    - Creative billing options
    - Partner with other utilities
    - Gages to measure consumption
    - Respect intelligence of consumers

2) What do you want to know about North Bay Hydro?

    - Poor service issues with contacted service arranged contractors
    - Need promises that no more arbitrary removal of trees
    - Relationship with other hydro providers in the province and country
    - Why and when is North Bay Hydro borrowing money for the city?
    - How much are your executive salaries?
    - Where is the cost savings?
    - Is North Bay Hydro purchasing off Ontario Hydro at peak time?

3) What is the best way to communicate with you?

    - Email
    - Phone
    - Depends on purpose
    - Put on bill in large font
    - TV and radio ads
    - Incentives
    - Mail outs
    - Text message

Business Customers

In November 2013, NBHDL initiated a survey of 105 business customers to further assist with development of the 2015 plans in a manner that is inclusive of customer issues. Customers had a high opinion of NBHDL and 77% had no complaints about reliability and system performance. This Business Customers Survey is attached as part of Appendix 1-2 to Exhibit 1.

As with the residential survey, 68% of participants were not aware that the majority of their bill was from sources other than NBHDL.

In summary business customers most important issues were:

- Better prices/lower rates 77.2%
- Educate customers on how to reduce costs 41.6%
- Make consumption data available on a real time basis 40.6%

On May 8, 2014, NBHDL held a customer engagement session with business and institutional customers at the Hampton Inn in North Bay, Ontario. Eleven (11) business owners and managers were randomly assembled. There were no incentives offered, other than light beverages and snacks. The session was hosted by Clark, on behalf of NBHDL, and no representatives from NBHDL were present in the room for the session. The purpose of the business engagement session was to generate feedback from local businesses and learn what NBHDL can do to improve its services and communications.

NBHDL also worked on a joint survey with the local Chamber of Commerce to further explore business customer issues. This was an on-line survey with questions on forecasted changes in electricity use by customers, conservation opportunities and programs, customer satisfaction, communication preferences and reliability. A total of 74 business customers responded to the online survey as of May 22, 2014.

Phase 2

NBHDL engaged Simul Corporation to conduct the UtilityPULSE customer survey that is widely utilized among LDCs in Ontario. The results of the survey contribute to the annual Electric Utility Customer Satisfaction Survey that reports on benchmark scores from electric utility customers across Canada. The survey covers a wide range of issues relating to customer satisfaction, service levels, business operations, reliability, conservation, smart meters and smart grid. UtilityPULSE contacted 1,110 customers. Of these 1,110 customers, 412 completed the survey.

The survey provides information that supports improving customer care at every level of the business utility. In addition to providing NBHDL customer responses to a variety of questions, both provincial and national results are provided to provide NBHDL with a sense of not only where the company stands in terms of customer perception, but how NBHDL fares across other LDCs in Ontario and across the board in Canada. The results of the survey have been gathered and a UtilityPULSE Report Card was provided with a snapshot of performance based on customer responses on 6 categories of attributes that research has shown are important to customers for influencing satisfaction and affinity levels with their utility. As an example, in the category of demonstrating credibility and trust, NBHDL scored 82% (above the Ontario average of 77% and National average of 80%). This statistic, among others, cumulatively shows that NBHDL scored very well on this survey. At the survey conclusion, NBHDL received the UtilityPULSE scorecard provided in Figure 2-1 below:

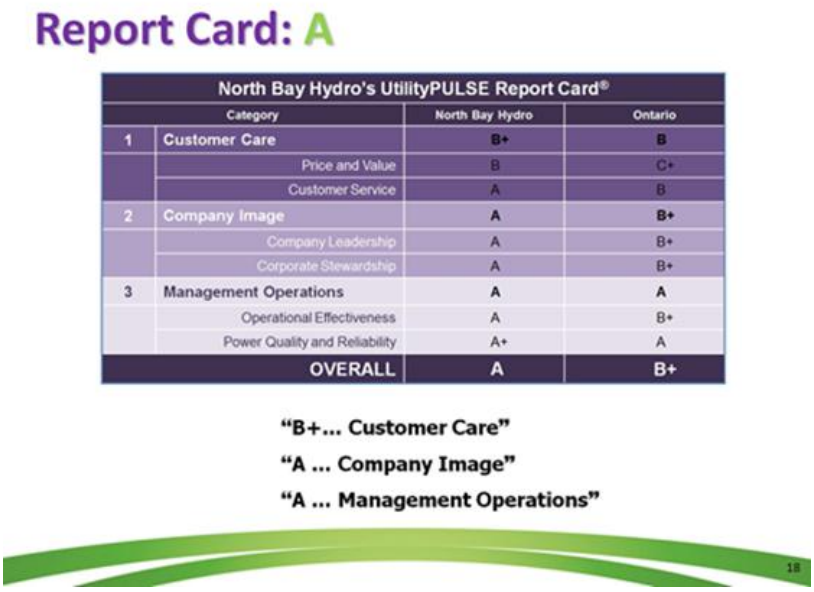


Figure 2-1: UtilityPULSE Report Card

Customer engagement is an evolving and iterative process; there are no 'final' deliverables. Based on the survey work completed in Phase 1 and 2, NBHDL customers want:

1. Affordable electricity costs
2. Reliability of service with rapid response to un-planned outages
3. Information supporting the value of services provided
4. Assistance to reduce consumption and thereby costs
5. Professional interactions with highly skilled and experienced personnel
6. Communications through a variety of media including phone, internet, social media, in-person mail and email
7. Proactive communications when there are un-planned outages
8. Business to be customer centric including timely service that solves their problems
9. Continued delivery of high quality services

In order to address these customer expectations, improve customer service and support provincial policy initiatives, customer communication and engagement activities must be robust and an incremental level of work must be done on a go-forward basis. The results of these surveys have informed NBHDL's O&M costs related to customer engagement and communication, including the implementation of a multi-media program to begin to address issues raised by customers. Customer engagement and communication costs are discussed in Exhibit 4 – Operating Costs of the Application.

A consistent theme in both the survey and focus group work in Phase 1 and 2 was that overall customers are highly satisfied with the reliability of NBHDL's system. Within the UtilityPULSE survey, NBHDL customers indicated that their top 3 priority investments are maintaining and upgrading equipment,

reducing the time needed to restore power and investing more in the electricity grid to reduce the number of outages, priorities that are in-line with all Ontario LDCs surveyed. Of all the important attributes of operational effectiveness listed in a survey question asking customers to describe what they feel are important, the top two responses from both residential and commercial customers were providing consistent, reliable electricity (90%R; 91%GS) and making electrical safety a top priority (88%R; 90%GS). Customers gave NBHDL an overall A in Management Operations; Operational Effectiveness rated an A and Power Quality and Reliability an A+.

While there is no significantly direct integration of these results into the DSP, the responses validate the direction and focus of NBHDL's capital program. Seventy percent (70%) of NBHDL's 2015 capital plan is focused on system renewal which concentrates on replacing NBHDL's oldest assets. NBHDL's 2015 Prioritization Matrix does however reflect these customer preferences - safety, reliability, asset condition and operational efficiency. Each of these preferences carries considerable weighting in the prioritization of work for the 2015 projects. NBHDL anticipates these preferences will also factor into the formalized prioritization protocol to be implemented in Q2, 2015.

Phase 3

NBHDL retained Innovative for the final phase (Phase 3) of the engagement process for the rate application. Unlike prior engagement efforts, Phase 3 engagement was specific to the proposals outlined in this rate application. This process included two separate focus groups for residential and small business customers that included a detailed workbook that outlined the cost pressures NBHDL faces, the 2015 capital and O&M plan, efficiency initiatives and the impact of the 2015 plan on customer rates. From that input, Innovative worked with NBHDL to refine a series of telephone survey questions to provide a quantitative assessment of key aspects of the plan. These efforts culminated in a report that is available as part of Exhibit 4 – Appendix 1-A.7.

For both aspects of this engagement process customers were provided with a high level picture of the 2015 capital and O&MA budgets along with the proposed 2015 distribution rate impact and the resulting 5 year impact on distribution rates. A projection of the required capital investment over the next 5 years was also provided.

The purpose of this consultation was to provide customers with the context of the proposed rate impact of 2015 capital investment and O&M spending and to determine if they would support the resulting rate increase. NBHDL attempted to outline for customers the major reasons for the spending and why it was necessary, to demonstrate that infrastructure needs to be replaced at a pace that is affordable but does not compromise reliability. 73% of residential customers surveyed support the proposed rate increase. A very important component of that acceptance rate is that almost half (48%) of those customers don't like the increase, but understand why it's necessary.

Customers are starting to recognize that there is a cost to being able to turn on their lights without a moment of consideration and NBHDL has recognized a level of social acceptance among customers for the notion that in order to have a reliable and safe system, investments must be made into the infrastructure.

NBHDL does not have a reliability issue, but in order to maintain that status, a structured approach to capital spending must take place. About three-quarters of residential (76%) and GS respondents (74%) think NBHDL should either spend what is needed to reduce the number of power outages (23% RS; 29% GS) or to maintain the current level (53% RS; 45% GS). On infrastructure investment, six-in-ten (59%) residential respondents and nearly four-in-ten (37%) of General Service respondents believe that NBHDL should invest in its aging infrastructure to reduce future outages, even if it means higher bills. Two-thirds

(63%) of residential customers and half (52%) of General Service customers believe that NBHDL should be wise with its spending on equipment and tools, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

While not directly incorporated into the DSP, the results of this consultation work indicate to NBHDL that the pacing, prioritization and focus of the 2015 capital spending and the projected infrastructure spending levels out to 2019 are aligned with customer preferences and expectations. The importance of maintaining the high level of reliability was identified by customers and is inherently reflected in the capital expenditure plan through a focus on the planned completion of the Voltage Conversion Plan and the annual replacement targets set in the system renewal forecast.

2.2.1.2 Municipal Government Consultations

NBHDL interacts with the City in a number of different ways and each interaction helps in the coordination of infrastructure planning and the connection of customers in a timely fashion.

City Engineering Department

The first form of consultation is the annual utilities meeting held by the City's engineering department in late January/early February. All utilities that provide service in the City are invited to the meeting where the City reviews their updated ten (10) year capital plan with emphasis on what projects are scheduled for the current year. The utilities that participate are also invited to share their capital plans again with emphasis on the current year, an opportunity NBHDL takes advantage of and will continue to take advantage of.

Although specific details about the City projects are rarely available at the time of the annual meeting and therefore scheduling and/or budgeting the projects is not a feasible deliverable from the meeting, the awareness of what projects are on the horizon provides the opportunity to familiarize with and prepare for the projects. It also provides the NBHDL engineering department with a list of projects to monitor, and allows for coordination of any infrastructure plans NBHDL has to be integrated into the City plans. The meeting doesn't have a direct effect on the DSP investment level as a historical average is used to calculate the spend for system access which is where road relocations and City required infrastructure investments are quantified, but it aids in the coordination of NBHDL's infrastructure planning.

Development and Review Team

The second consultation process is the involvement of NBHDL on the City Development and Review Team ("DART") where representatives from all utilities, City departments (Public Works, Parks and Rec, Economic Development, Fire, etc.) and local agencies (MTO, North Bay and Mattawa Conservation Authority, etc.) review applications put forth to the City that involve new development/servicing, zoning changes, and site plan and control. NBHDL was invited by the City back in 2006 to join the process. The main goal of the team is to identify and communicate to potential developers, property owners, local design firms, any show stoppers that may be present with what is being proposed before substantial time and money is invested. This is an extremely helpful process as it provides the end user with issues that must be addressed upfront and at the same time provides NBHDL with advanced notice of upcoming developments and proposals allowing for the better planning of work and the timely connection of new customers. This interaction doesn't affect the DSP investment level, but contributes to successfully meeting the required Distribution System Code ("DSC") connection timelines and enhances customer communications and interactions.

City Economic Development Office

The last form of consultation is with the City Economic Development Office ("EDO"). This interaction is not formal, but is very important. A strong relationship exists between NBHDL and the EDO and provides the City with the ability to easily obtain information that helps in attracting new development into the NBHDL service territory. The communication is typically initiated by the City and doesn't have an impact on the DSP investment levels, but represents a communication path that promotes the connection of customers and provides valuable insight into projects that may be on the horizon, all which leads to better planning and execution of system access related projects for NBHDL.

2.2.1.3 CDM Program Partner Consultations (OPA)

NBHDL has been offering OPA prescribed save-ON-energy Conservation and Demand Management (CDM") programs from 2011-2014, that have extended partly into 2015 as LDC's in the province prepare to transition to a new six (6) year framework. As per the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, NBHDL will work together with its regional LDCs to develop a refined delivery model that best suits regional needs.

Stakeholder consultation will be a key component to the new conservation delivery model and the first stage of this will include consultation with the OPA alongside member LDC's to identify programs best suited to be delivered at a provincial scale versus programs that are specific to meeting regional needs.

Member LDC's will evaluate their conservation delivery experience, impact of anticipated load growth, benefits of collaboration with regional LDCs, and carry out market research with all customer classes. A higher emphasis on residential conservation programs will be placed in the new delivery model as the previous framework provided limited opportunity to provide services to the residential customer class.

NBHDL does not anticipate that CDM consultation will affect the DSP.

2.2.1.4 Transmitter (Hydro One) Consultations

NBHDL belongs to the "North/East of Sudbury Region", for which HONI is the lead transmitter. HONI is primarily responsible for steering the regional planning in this region and NBHDL has requested HONI for the regional planning status. A letter from HONI was received on April 2, 2014 confirming that the RPP has not been initiated nor has a Regional Infrastructure Plan ("RIP") been developed for the sub-region within the North/East of Sudbury Region affecting NBHDL. HONI also stated in the letter that the RPP for the North/East of Sudbury Region is expected to be initiated in fourth quarter of 2015. The letter from HONI is attached in **Appendix I**.

As there are no transmission capacity constraints to deter new connection, including micro-FIT and FIT connections, there are no adverse impacts of the regional planning process being put off until 2015 on NBHDL's distribution system operations.

2.2.1.5 Embedded Distributor (Hydro One) Consultations

Due to the fact that HONI has embedded assets within the NBHDL system, NBHDL initiated consultation with HONI to determine if any investments would be required on the NBHDL system over the 5 year rate filing period by asking the following:

1. Can HONI confirm that NBHDL has consulted HONI regarding its needs with respect to capacity and REG projects on the two embedded locations within the NBHDL distribution system;

2. Is there anything HONI requires from NBHDL with respect to capacity or providing the ability to connect REG's; and

3. Does HONI have any projected new load projects or REG connections that NBHDL needs to plan for in the next 5 years.

To these questions, HONI provided the following responses:

1. "Yes, via this e-mail, NBH has asked HON to identify any needs with respect to capacity and renewable generation at our two embedded supply points."

2. "HON does not require any information from NBH at this time."

3. "There are currently no significant new load requirements on HON's embedded supply points. Also, there are no REG requests active or pending on the two embedded supply points."

As can be seen from the answers provided by HONI, there are no final deliverables that are expected from the consultation and therefore the consultation does not affect the NBHDL DSP.

2.2.2 (5.2.2 b) Regional Planning Process:

As noted above, NBHDL relies on the letter from HONI in **Appendix I** for the fact that the RPP will not be initiated until late 2015. Therefore comments cannot be made with respect to the role of NBHDL in the consultation, the status of the consultation, or anything with respect to the final deliverables.

Upon the initiation of a RIP or RPP however, NBHDL anticipates it will incorporate such consultation processes in future capital expenditure planning processes and future rate applications as necessary.

2.2.3 (5.2.2 c) OPA Comment Letter:

A Green Energy Plan, identifying the investment requirements for accommodating Renewable Energy Generation connections for its service territory for the five year period 2015-2019, has been prepared by NBHDL and submitted to the OPA. Based on the evaluation of the distribution system to accept green energy generation connections, no constraints have been identified in the system, preventing the connection of renewable energy generation installations. Therefore, NBHDL is not proposing any capital investments for capacity upgrades on the distribution system to accommodate the applications for the connection of renewable energy generation plant, over the next five years from 2015 to 2019. Approximately $16,000 of capital investments are proposed for installation of the SCADA systems at MS-9, in 2015. Funds have also been budgeted to connect one or two FIT projects per year to the distribution grid. The Green Energy Plan and OPA's comment letter are included in **Appendix F** and **Appendix G**. NBHDL did not provide a written response to the OPA's comment letter.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

2.3.1 (5.2.3 a) identify and define the methods and measures used to monitor distribution system planning process performance

In order to continually improve its operating performance, NBHDL measures and monitors its performance through the following performance indicators:

Customer Oriented Performance

- Supply system reliability indicators;
- Bill impacts;
- Voltage; and
- Power Quality

Cost Efficiency and Effectiveness with respect to Planning Quality and DSP Implementation

- Planning quality indicators;
- Operating efficiency indicators;

Asset and/or System Operations Performance

- Supply system reliability indicators; and
- Asset health index information ("Health Index").

The metrics and methods for measurement of each of the above indicated performance indicators are described below.

2.3.1.1 Customer Oriented Performance

Supply System Reliability Indicators

Maintaining distribution system reliability and quality is a core objective of NBHDL; for supply system reliability, the key performance indicators include System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI").

i. SAIDI

SAIDI is an index of system reliability that expresses the average duration, per reporting period, over which supply to a customer is interrupted. It is determined by dividing the total customer hours of interruptions into average number of customers served.

NBHDL's target for average number of hours that power to a customer is interrupted is within the range of 1.56 – 2.87 hours.

ii. SAIFI

SAIFI is an index of the distribution system reliability that expresses the number of times per reporting period that the supply to an average customer is interrupted. It is determined by dividing the total number of customer interruptions over a year into the average number of customers served.

NBHDL's target for average number of times that power to a customer is interrupted is within the range of 1.48 – 2.75 times per year.

iii. CAIDI

CAIDI measures the average annual outage duration that customers experience and is calculated by dividing SAIDI into SAIFI and provides an indication of the typical response time to restore power following an outage.

Bill Impacts

As part of the Application process, NBHDL 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.

Voltage

As per NBHDL's Conditions of Service ("COS"), NBHDL COS-230-05 (attached as **Appendix J**, NBHDL endeavours to supply a constant, stable supply voltage from its distribution system. NBHDL does so by supplying voltage at the Consumer's service entrance within the guidelines of CSA Standard CAN3-C235-83 (latest edition) Table 2-2 (shown as Table 2-2 below), which allows variations from nominal voltage of:

Nominal Voltage	**Voltage Variation Limits**			
	Extreme Conditions			**Extreme Conditions**
		Normal Conditions	**Normal Conditions**	
SINGLE PHASE				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
THREE PHASE 4W				
120/208	110/190	112/194	125/216	127/220
240/416	220/380	224/388	250/432	254/440
277/480	245/424	254/440	288/500	293/508
347/600	306/530	318/550	360/625	367/635
THREE PHASE 3W				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Table 2-2: CSA Standard CAN3-C235-83

Where supply voltages lie outside the indicated limits for normal operating conditions but within the indicated limits for extreme operating conditions, improvement or corrective action should be taken on a planned and programmed basis. Where supply voltages lie outside the indicated limits for extreme operating conditions, improvement or corrective action should be taken as soon as practical. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to supply voltage levels and duration, etc.

NBHDL shall practice reasonable diligence in maintaining supply voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter. NBHDL shall not be liable for any delay or failure in the performance of any of its obligations under this COS document due to any events or causes beyond the

reasonable control of NBHDL, including, without limitation, items indicated in the Force Majeure defined in NBHDLCOS-230-03, Electrical Disturbances.

NBHDL targets to have zero (0) voltage issues outside of the extreme conditions and less than five (5) voltage issues outside of the normal conditions but within the extreme conditions annually. Note that a voltage complaint does not constitute a voltage issue until proven to be within one of the two limits indicated above.

Power Quality

As per the NBHDL COS, specifically NBHDLCOS-230-02 (attached as **Appendix K**), NBHDL endeavours to supply continuous energy with no power quality problems. NBHDLCOS-230-02 details the steps to be taken and the policies and processes with respect to power quality issues. The limit on individual harmonic distortion is 3% and the limit on total harmonic distortion is 5%. NBHDL targets to have one or less power quality issues annually.

2.3.1.2 Cost Efficiency and Effectiveness with Respect to Planning Quality and DSP Implementation

Planning Quality Indicators

NBHDL is committed to continuously improving efficiency and productivity performance to provide better value service for ratepayer money. In order to work towards the achievement of this objective, NBHDL seeks to identify and implement measures that will lead to sustainable long-term efficiencies that utilize resources more effectively. Ensuring the successful implementation of the DSP and as well as continuously improving the planning process is critical to the improvement of efficiency and productivity performance.

Since the last NBHDL Cost of Service submission to the OEB in 2009, considerable work has been done to improve the quality of planning, both at the program and project stage. In 2011/2012, NBHDL conducted field surveys of all field mounted fixed assets to prepare accurate lists of the age, type and ratings of assets employed on each of the distribution feeders and entered this information into the GIS system. This information now serves as an effective tool for asset management and investment planning but also improves the quality and accuracy of work orders for repair, refurbishment and replacement of assets and enhances cost controls at the project level as well as program level. It is anticipated the above described improvements in the asset related data base will result in less variance in the program investments proposed in the current DSP in relation to the historical cost of service submission. NBHDL is also in the process of implementing new initiatives that will allow for more effective planning and continuous improvement on all construction jobs in relation to the creation of detailed budgets by the Engineering department and line crew productivity in the execution of work in the field. These initiatives are as follows:

1. Updating and review of the DSP expenditure levels with specific attention to forecast vs. actual expenditures; and,

2. Review of actual vs. budgeted costs >10% for all individual construction jobs over a $50,000 threshold.

The first initiative will be undertaken to ensure that the committed spending levels are being met throughout the rate filing period. During the development of the annual budget, the target for this planning metric will be the approved DSP investment levels by system renewal, system service, system access and general plant. The development of the construction budget requires individual project-specific

budgets that will be prioritized based on the methodology described in Section 4.2.3. As these projects are rolled up into the overall capital spending forecast for the period any variances +/- 10%, at the DSP category level, will require an analysis of the drivers causing the variance including the quantitative and qualitative factors affecting prioritization and pacing if applicable to the variance explanation. Once approved through the budget process, forecasted vs. actual spending will be monitored on a regular basis by management.

The second initiative taking place will require detailed review at both the estimate and work execution levels of capital projects, including sign-off by the Operations Manager and Manager, Engineering. The exception to this target will be costs in the System Access category. System Access costs are budgeted based on the approved DSP level, but actual costs will vary throughout any given year based on customer demand work. For specific projects that are budgeted, a refined estimate will be created prior to the project being issued for construction and compared against the estimate approved as part of the budget process explained above. Variances will be examined and approved or declined accordingly. Upon construction completion, a second variance analysis will be conducted to compare the budget against actual costs including labour hours, materials and contracted services used. This step will serve two purposes 1) improve on estimate accuracy and/or 2) call attention to productivity issues in the field.

The variance analysis process will have the Engineering Technician that designed the job and created the budget estimate work directly with the Chargehand leading the crew in the field to provide management with explanations of any variances over 10% in all categories of the estimate; Senior Management approval prior to the project being closed will be required. For projects that are not budgeted, the process will remain the same but will lack the first variance as a budgeted amount will not exist.

Planning quality indicators will have the following targets:

- <10% variance between actual and budgeted DSP expenditure level;
- <10% variance between actual and budgeted project costs; and
- 100% of budgeted projects completed in the year budgeted.

Operating Efficiency Indicators

Planning quality indicators such as the targets set out above lend themselves inherently to operating efficiency, however, NBHDL also intends to begin recording the following metrics to measure and monitor the efficiency of its operations.

i. Efficiency Assessment

A total cost benchmarking analysis is used by the OEB to produce a single efficiency ranking of Ontario's distributors; the ranking is based on the size of the difference between a distributor's actual costs and those predicted in the benchmarking analysis conducted by Pacific Economics Group Research, LLC (PEG) on behalf of the OEB.

NBHDL will monitor the annual efficiency assessment to maintain or improve 2013 Group 3 ranking.

ii. Operational staffing levels

An effective utilization of resources allows NBHDL to operate efficiently and as such consistent staffing levels are maintained with a target of 50 full-time employees or less within the organization. Capital work is planned and executed based on the available hours of NBHDL's line department and overtime hours on a project specific basis are minimized to the extent possible through prudent planning of work,

engagement with customers and required shut-downs. NBHDL has established that to adequately service its system 35 to 40% of hours for the line department must be allocated to operations and the balance is available for the execution of capital construction programs identified through the DSP. Adequate staffing of the Engineering department ensures that projects are designed on an on-going basis to ensure capital work is continually flowing to the field and front-line staff are focused on the construction that needs to take place.

Aligned with the new initiatives discussed within the planning quality indicators, NBHDL intends to review the variance between the labour hours included within the project estimates against the actual hours worked with variances >10% explained by the Chargehand. The new detailed review will allow for continuous improvement of planning estimates and allow for productivity issues and opportunities in the field to be flagged.

NBHDL intends to implement the following targets with regards to the resources required to effectively plan and execute the DSP:

- 60% of line crew time is spent in the execution of capital infrastructure projects; and
- <10% variance between budgeted labour hours and actual hours.

2.3.1.3 Asset And/Or System Operations Performance

Supply system reliability indicators

Supply system reliability indicators, as identified above under customer oriented preference, provide NBHDL with a metric for its operations performance. These indicators are used to determine the history and trending information that NBHDL uses to monitor its assets performance over the historical period and future years.

Health Index

NBHDL developed asset Health Index as part of the ACA Report compiled by METSCO in 2014. The health index for substations, and poles, 44kV switches, and underground cable provides a snapshot of their respective health as of 2014. The assets are ranked either, very good, good, average, poor or very poor and it is the intention of the asset renewal program to maintain the asset health at or above the 2014 levels over the 5 year filing period. In future versions of the DSP, asset health will be benchmarked against the 2014 ACA results.

2.3.2 (5.2.3 b) provide a summary of performance and performance trends over the historical period

The following tables provide historical performance and performance trends over the historical period for the performance metrics identified in (5.2.3 a).

2.3.2.1 Customer Oriented Performance

Supply system reliability indicators

i. SAIDI

In Figure 2-2 below, SAIDI values are shown, by including and excluding the interruptions caused by the loss of incoming power supply from Hydro One transmission system, during the past four years. The chart shows improvements in SAIDI values during the past two year period (2012-2013) in relation to the

previous two year period (2010-2011). Some the variations in SAIDI are caused by variations in the number and severity of storms from one year to the next. For example the high number of storms in 2013 caused the SAIDI to increase in 2013 in relation to 2012, in spite of the investments aimed at asset renewal during last rate filing period.

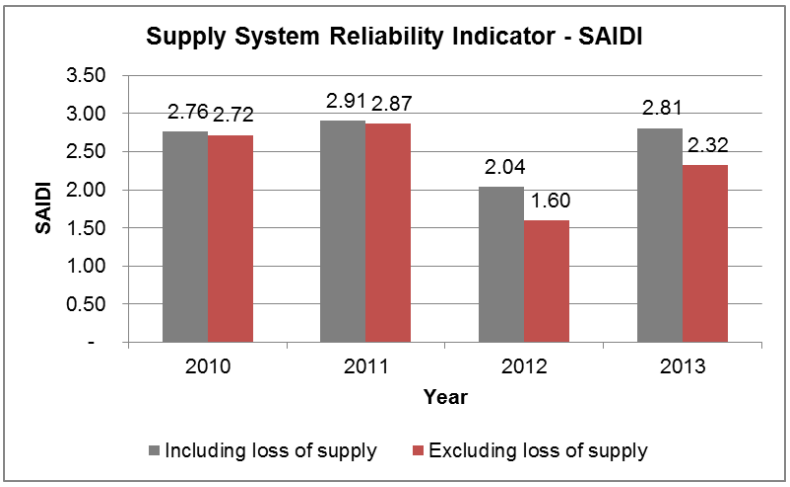


Figure 2-2: Historic SAIDI Performance

ii. SAIFI

Figure 2-3 shows the SAIFI performance for NBHDL during the past four years, by including and excluding the power interruptions caused by the loss of incoming power supply from Hydro One transmission system.

The chart also shows the improving time trend in SAIFI, but once again there are significant year to year variations caused by variations in number and severity of storms in the service territory.

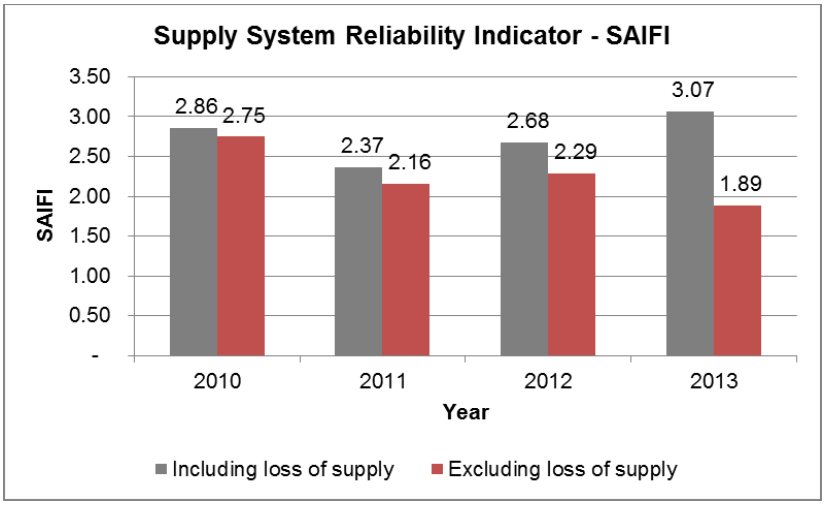


Figure 2-3: Historic SAIFI Performance

iii. CAIDI

Figure 2-4 shows the CAIDI performance for NBHDL during the past four years. The chart shows CAIDI values by including and excluding the interruptions caused due to loss of incoming power supply.

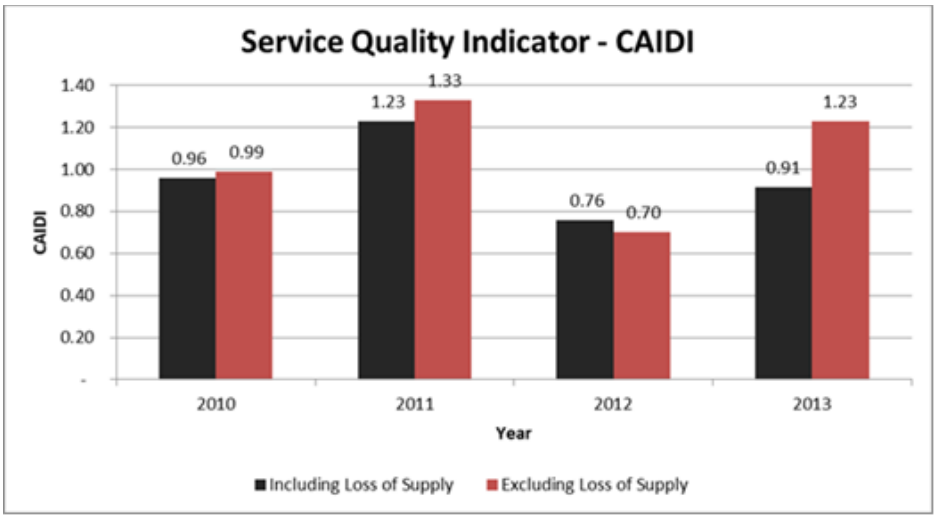


Figure 2-4: Historic CAIDI Performance

Bill Impacts

Although NBHDL has used bill impact feedback to inform part of its planning processes for this Application, over the course of the Historical Period a metric was not established and monitored formally. Going forward, NBHDL will continue to include bill impact considerations in the rate application process and will undertake to minimize and mitigate to the greatest extent possible when balancing against the needs of the business.

Voltage

Although NBHDL has followed the COS section, NBHDLCOS-230-05, since 2006 in maintaining voltage and addressing issues, a metric was not established and the issues were not tracked and therefore historical information does not exist. Going forward, voltage issues will be recorded so they can be monitored and the metric reported. It can be noted that the amount of complaints over the past 5 years have been minimal, with the majority of the complaints falling within the Normal operating range and therefore not posing an actual issue.

Power Quality

Although NBHDL has followed the COS section, NBHDLCOS-230-02, since 2006 in relation to power quality issues, a metric was not established and the issues were not tracked and therefore historical information on the metric does not exist. Going forward, power quality issues will be recorded so they can be monitored and the metric reported. It can be noted that in the last 5 years only one power quality issue has been reported (August 2014) and it is still under investigation.

2.3.2.2 Cost Efficiency And Effectiveness With Respect To Planning Quality

Planning Quality Indicators

The targets set are to be monitored beginning in 2015. A previously approved distribution system plan has not been filed with the OEB and as such historical performance is not available.

Operating Efficiency Indicators

i. Efficiency Assessment

NBHDL has been ranked in Group 3 for efficiency in 2012 and 2013. The ranking is a new metric that has been put in place in 2013 and will be reported on a go-forward basis.

ii. Operational staffing levels

Cost Effectiveness - Resource Efficiency				
Metric	2010	2011	2012	2013
Staffing Level	46	47	47	47

Table 2-3 - Operational Staffing

Table 2-2 shows the consistent NBHDL total staffing level for each of the years in the historical period. A 60% target of line staff resources executing construction work has been established for the 2014 fiscal period and is a new target set by NBHDL. Through an iterative learning process that included detailed reviews of variances in the capital budget vs. actual costs, as well as a review of labour allocation, it has been determined that this is the balance required to ensure both the operating and capital needs of the business are met.

Productivity is managed on a real time basis and a bi-weekly review of labour is undertaken to ensure resource planning and performance is on track.

2.3.2.3 Asset and/or System Operations Performance

Supply system reliability indicators

See Section 2.3.2.1 above under customer oriented performance.

Health Index

As the ACA Report, attached as **Appendix B**, was finalized in 2014, there is no historical information to reference and therefore no trending data available. Trending will begin in 2015 and be available for any future asset management or capital expenditure planning purposes.

2.3.3 (5.2.3 c) explain how this information has affected the DS Plan and has been used to continuously improve the asset management and capital expenditure planning process

2.3.3.1 Customer Oriented Performance

Supply System Reliability Indicators

The supply system reliability indicators have had a major impact on the DSP from an O&M perspective. Figure 2-5 below provides a summary of the system outages, sorted by cause that occurred between 2011 and 2013.

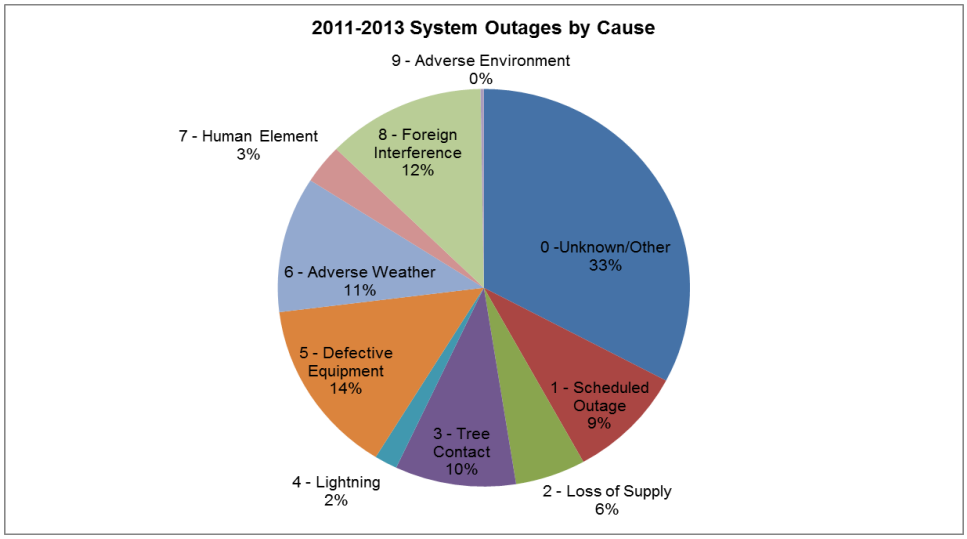


Figure 2-5: Outage Cause Summary

As can be seen, the majority of outages in the NBHDL system can be attributed to 4 OEB codes: Unknown/Other, Tree Contact, Adverse Weather, and Foreign Interference. It is also believed the Unknown/Other code is typically related to tree contact or animal contact that cannot be verified. The NBHDL system is predominantly overhead, and therefore trend data will always correlate with the number and severity of storms that roll through the service territory on an annual basis, however the outages that are caused by trees can be mitigated and therefore NBHDL evaluated the approach to tree trimming in 2012 and came to the following conclusions:

- High amount of large mature trees located too close to high voltage lines throughout city;
- Trees located directly under high voltage lines were being topped and not removed, creating perpetual maintenance costs and recurring safety hazards; and
- Right of ways not cleared back enough at time of trimming to allow for 4 or 5 years of growth

Due to the observations it was decided on a go forward basis that 4.57m (15') of clearance would be required on each side of all high voltage lines, large mature trees would be removed within this area, and topping would no longer be permitted.

NBHDL employed a local utility arborist (ArborWorks Tree Service) in 2013 to provide sound arboricultural advice and provide an assessment on the required dollars to implement the above recommendations.

The report, North Bay Hydro Tree Trimming Consultation, dated February, 2014 is included in Appendix 4-E to Exhibit 4**.** The recommendations have a cost impact to implement, as shown in Table 2-4 below.

Year	2010	2011	2012	2013	2014	2015
Tree Costs	$279,036	$411,366	$187,121	$350,991	$415,831	$656,194

Table 2-4: Tree Costs

Once all cycles are completed to the new standard, it is NBHDL's understanding and belief that the number of tree related outages will be reduced and in turn there will be a reduction in the potential of animal contact situations as trees will be at a much greater separation from all high voltage lines. In addition, the new standards will help reduce tree related damage in storm situations. The overall tree trimming maintenance costs should be reduced in the next iterations of all cycles once the new standards have been established.

NBHDL will be transitioning to an automated system for the tracking of reliability metrics, including the analysis of worst performing feeder information; NBHDL does not calculate this statistic formally and is implementing this project in a further effort to improve reliability. NBHDL anticipates implementing a formal worst performing feeder analysis by the end of Q2, 2015.

Although the CAPEX investments during the last rate filing period have resulted in newer, more reliable equipment as indicated in the ACA Report (**Appendix B**), there are still significant quantities of old vintage assets in poor health and condition still in service. To mitigate the risk of the reliability worsening in the coming years, investments are proposed in this DSP to replace and refurbish the assets in poor condition, where the risks associated with asset failures exceed the cost of risk mitigation.

Bill Impacts

Customers have indicated that they do not want prices to rise, however, they reluctantly accept the in reality there are requisite costs involved in the operation of a successful and reliable LDC. With that in mind, NBHDL has given consideration to the justification of costs that drive the bill impacts and ways that NBHDL can mitigate such impacts where possible. NBHDL will continue to look into meaningful ways to incorporate bill impact considerations into its capital expenditure and O&M planning processes.

Voltage

As voltage complaints are not common, and the majority of the complaints put forward are actually within the normal conditions, voltage issues have not affected the DSP and have not been used to continuously improve the asset management and capital expenditure planning process.

Power Quality

As power quality issues are not common, power quality issues have not affected the DSP and have not been used to continuously improve the asset management and capital expenditure planning process.

2.3.3.2 Cost Efficiency and Effectiveness With Respect to Planning Quality

Planning Quality Indicators

Financial analysis has always been a fundamental process of the capital planning process, but the analysis around the DSP will be a new initiative. The refined financial analysis around projects over the defined threshold will also be a new initiative. These new initiatives will help with the execution of work at NBHDL and ensure that the DSP is executed as planned.

Operating Efficiency Indicators

The operating efficiency indicators will be used as benchmarks to help guide decision making processes and ensure cost control.

2.3.3.3 Asset and/or System Operations Performance

Supply system reliability indicators

See Section 2.3.3.1 above under customer oriented performance.

Health Index

The asset condition assessment is one of the main inputs into the asset management process and therefore drives the investment spending over the filing period. Because the NBHDL system is older and has a significant amount of assets in poor or very poor condition the majority of NBHDL's capital plan is renewal based and therefore the health index has had a major impact on the DSP. As the health index information was finalized in 2014 continuous improvement in asset management and the capital expenditure planning cannot be tied to it yet. However, moving forward, the health indices will help push forward renewal in NBHDL's system to minimize risk of asset failure.

A tool now exists to ensure the overall asset NBHDL manages does not slip to a point where associated risk increases over time (in this case the rate filing period), but is maintained if not decreased. If the desired outcomes are achieved it will illustrate continuous improvement in both asset management and capital expenditure planning.

3 Asset Management Process (5.3)

This section describes in detail NBHDL's asset management process and strategy ("Asset Management Strategy") and the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan covered by this DSP.

3.1 Asset Management Process Overview (5.3.1)

3.1.1 (5.3.1 a) description of asset management objectives, relationship to corporate goals and how distributor ranks asset management objectives for the purpose of prioritizing investments:

In developing and implementing the asset management plan, NBHDL's overarching corporate goal is to distribute electricity safely and reliably with highest operating efficiency to provide good value service (in accordance with the goals and objectives stated in Exhibit 1) and provide the shareholder the full regulated return on equity. To achieve this corporate goal in asset management planning, NBHDL adheres to the following key asset management objectives (with associated corporate objectives found in Exhibit 1):

- Public and Employee Safety (NBHDL Corporate Objective 2)
- Reliability and Supply System Security (NBHDL Corporate Objective 3)
- Customer Service Quality (NBHDL Corporate Objectives 1 and 4)
- Minimizing Asset Life Cycle Costs (NBHDL Corporate Objective 4)

- Minimizing Risk of Premature Failures (NBHDL Corporate Objectives 1, 2, and 4)
- Getting Full Life out of Assets (NBHDL Corporate Objective 4)
- Operating Efficiency (NBHDL Corporate Objective 4)
- Minimizing Environmental Risks (NBHDL Corporate Objectives 1,2 and 5), and
- Regulatory Compliance (NBHDL Corporate Objective 5).

NBHDL acknowledges that these objectives must be weighted differently depending on various situations in order to provide the optimal prioritization of asset investments. As such, decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

3.1.2 (5.3.1 b) information regarding the components of the asset management process used to prepare a capital expenditure plan, data sets, primary process steps, and information flows used to identify, select, prioritize and/or pace investments:

The risk based Asset Management Strategy, used by NBHDL in preparation of the asset management plan, determines the risk of asset failure based on the condition of the asset, which is commonly measured with the help of a yard stick of "Asset Health Indices", and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs.

PAS-55, a specification for asset management, was developed by the British Standards Institute ("BSI") and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. NBHDL's asset management plan is compliant with the BSI developed PAS-55 asset management standard and incorporates all the essential elements documented in Figure 3-1.

Figure 3-1: Essentials of PAS-55 Compliant Asset Management Strategy

NBHDL employed techniques leveraged from PAS-55 to ensure optimal asset planning. While not directly following the strategy, this information was informative in NBHDL's plan. In preparing the consolidated DSP, NBHDL's overarching objective was to develop capital and preventative maintenance investment plans, which could be effectively implemented to achieve optimal system performance by focusing on stakeholder needs. Figure 3-2, as shown below, illustrates the necessary decision framework inputs that were required to develop the optimal CAPEX and O&M investment plans.

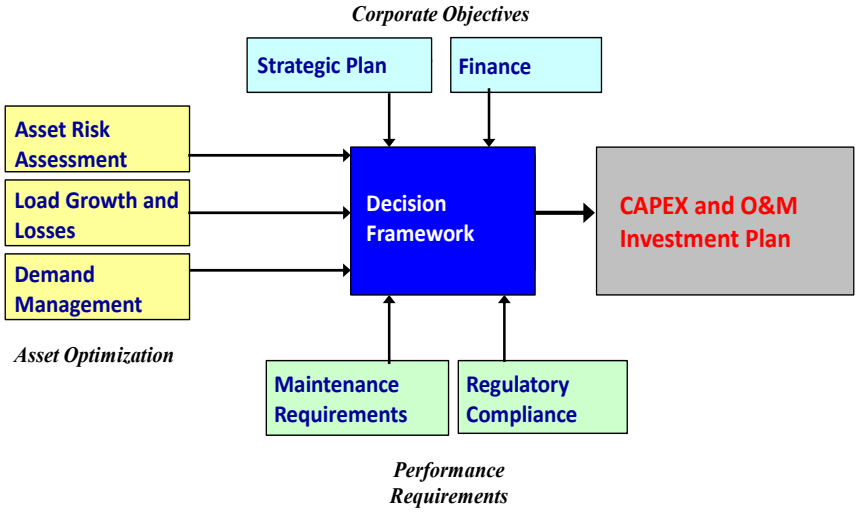


Figure 3-2: Multi-Prong Decision Framework

Figure 3-3 shows the basic decision support model employed by NBHDL in preparing this DSP, determining the scope and timing of the investments and prioritizing the investments into specific projects. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

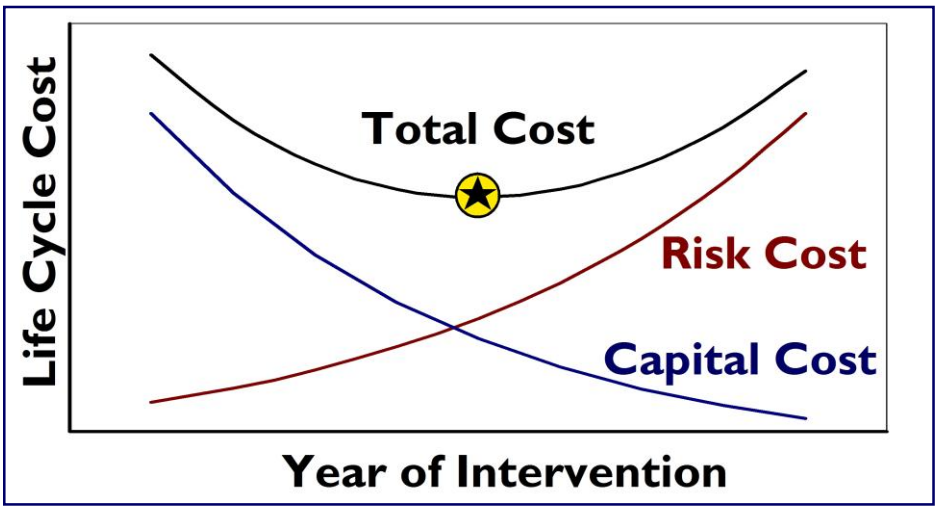


Figure 3-3: Risk Based Decision Support System

Figure 3-4 below summarizes the risk matrix and decision process used to sift through the large number of assets and objectively identify the assets that present the highest risk of in-service failures so that the investments could be targeted into assets exhibiting the highest risk levels.

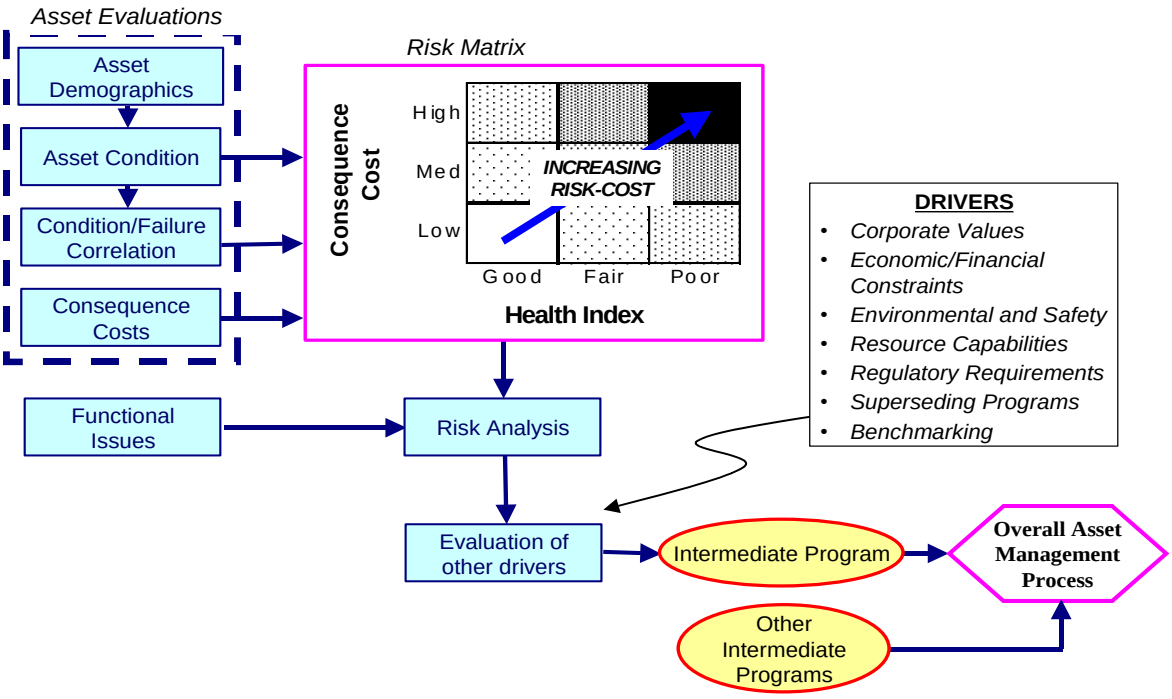


Figure 3-4: Model to Identify Assets with Highest Risks

Numeric health indices, normalized to a scale of 100, have been used to express the health and condition of assets, as shown in Figure 3-5 below. This procedure allowed separation of the assets in "very good", "good" and "fair" condition that require minimal risk mitigation from those in "poor" and "very poor" condition, requiring a higher level of investments. By following this process, the investment plan was prepared which is proposed to be implemented in this DSP for implementation during the next five (5) year period.

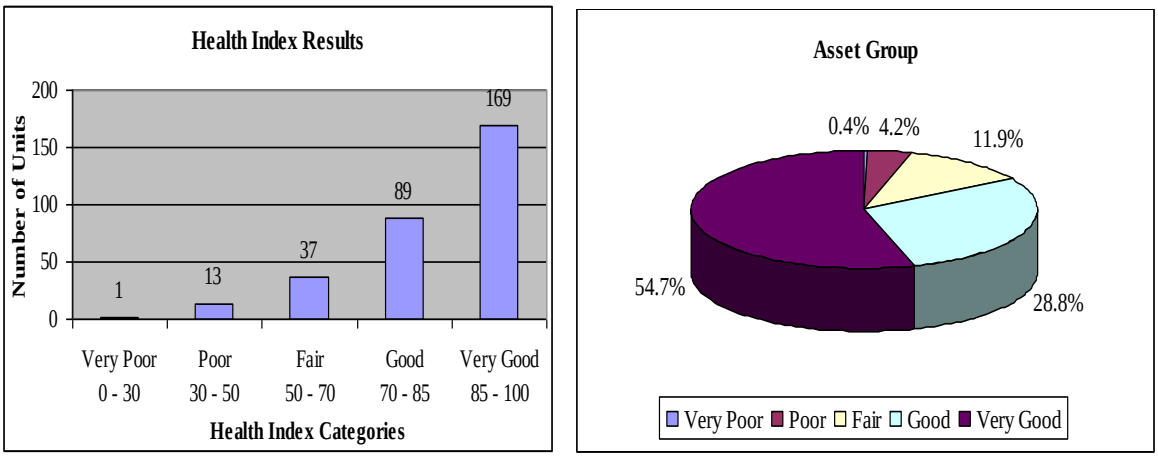


Figure 3-5: Identification of Assets with Higher Risk of Failure

Asset Register

To ensure efficiency in asset management, NBHDL maintains an asset register of all of its equipment and structures. This register system tracks assets using ESRI, NBHDL's GIS software.

After the health and condition of all assets was determined through the above method, by taking into account the consequences of asset failure risk while still in service, NBHDL has determined the scope of investments needed to refurbish or replace assets and also prioritized the investments to mitigate the risks. Prioritization of the System Renewal projects has been established using the Asset Investment Planning ("AIP") Software Tool, with appropriate weights assigned to various risk consequences; i.e. public and worker safety, power supply reliability, environmental impacts, economic efficiency of investments and regulatory compliance etc.

Capacity Constraints

Due to the excess capacity available in the NBHDL system, NBHDL has not previously had cause to employ any asset capacity utilization or constraint assessments. As such, these metrics are not informative of this DSP.

Worst Performing Feeder

As identified earlier, NBHDL does not currently apply a reliability-based 'worst performing feeder' analysis in its asset management process. This analysis will be implemented by Q2, 2015 and inform future DSPs, asset management and capital expenditure planning.

Asset Condition Assessment

METSCO performed an asset condition assessment and provided the ACA Report attached as **Appendix B**. This report has been informative for the NBHDL asset management process. Details of the ACA Report are provided below in Section 3.2.3.1.

Asset Components and Prioritization

Using the information NBHDL has on the condition of its assets (provided by METSCO and through its daily operational procedures), NBHDL has created an in depth Prioritization Matrix for capital expenditure prioritization for 2015. This matrix uses weighted scoring based on a variety of factors (including *inter alia*, reliability, safety, condition and aesthetics) to determine which project to complete at what time during 2015. The weighted scores determine the prioritized order of projects. If the scores were tied, NBHDL used discretion based on the outward in strategy of the Voltage Conversion Plan.

This Prioritization Matrix is a temporary measure as NBHDL moves towards the implementation of a formalized priority structure with the assistance of METSCO to be implemented in 2016. In future years NBHDL will rely on this prioritization methodology and protocol to select which projects to initiate and when. Currently, the approach for the 2015 period takes into account all of the objectives and goals stated in this DSP and provides a systematic solution to ensure optimal efficiency in NBHDL's capital planning process.

3.2 Overview of Assets Managed (5.3.2)

3.2.1 (5.3.2 a) description/explanation of features of the distribution service area pertinent for asset management purposes:

NBHDL's distribution system area can be considered predominantly sub urban, mostly overhead and the economic growth in the region is slow. The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40˚C during winter. The presence of a number of different soil types, the Canadian Shield, numerous clays, and muskeg make all excavation activities a challenge. The region is vulnerable to tornados and strong wind storms are common occurrence. While potentially vulnerable, NBHDL's service area has not experienced any major storm event since 2006 and typically the storms have not caused any significant impact on the NBHDL distribution system. As such, none of the above mentioned features are expected to change over the forecast period and should not impact the DSP.

3.2.2 (5.3.2 b) description of system configuration:

NBHDL owns and operates sixteen (16) municipal stations. The single line diagrams complete with the power transformer ratings for each of the substations are documented in **Appendix M**. Two (2) of the substations, MS1 and MS7, step down power from 44 kV to 4.16kV. One substation (1), MS18, has dual winding transformers capable of supplying both 4.16 kV and 12.47 kV, but is presently supplying at 4.16 kV. The remaining substations step down from 44 kV to 12.47 kV.

Table 3-1 shows the length of overhead lines and underground cable circuits employed on 44kV, 12.47 kV and 4.16 kV distribution systems. There are fifty-four (54) distribution feeders, fourteen (14) operating at 4.16kV, and forty (40) operating at 12.47kV and eight (8) subtransmission feeders all operating at 44kV. There are a total of 3,147 distribution transformers.

Overhead Line Lengths (m)				Underground Cable Lengths (m)	
	4.16kV	12.47kV	44kV	4.16kV	12.47kV
1-ph	10,414	151,542	-	2,648	88,371
3-ph	30,922	205,986	88,792	5,375	13,987

Table 3-1: Length of Overhead Lines and Underground Cable Circuits

NBHDL is bounded by Hydro One Networks Inc. on all service territory boundaries. NBHDL is embedded in Hydro One's 44 kV sub transmission system at the City's water treatment plant located at 248 Lakeside Dr. and at substation #17, which is located in North Bay's rural area at 20 Peninsula Road. Hydro One is embedded in NBHDL's 44kV sub transmission system at Bond St., also known as Wood's Junction. Hydro One is also embedded in NBHDL's 12kV distribution system at the northern city limits of North Bay on Highway 11 North.

The substation ratings and maximum peak load reached at each of the substations during the past five years is indicated in Table 3-2 below.

12.47 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS4	7.5	10	7.19
MS8	7.5	10	5.9
MS9	T1 - 7.5, T2-7.5	No fans	T1 - 5.00, T2 -4.00
MS10	T1-7.5, T2 - 7.5	T1-10, T2-10	T1-5.94, T2-6.54
MS11	7.5	10	7.21
MS13	T1-6, T2-7.5	T1-No fans, T2-10	T1-6.32, T2-6.46
MS14	7.5	10	5.93
MS15	7.5	10	6.55
MS16	7.5	No fan rating	5.42
MS17	7.5	10	5.36
MS19	7.5	10	7.21
MS20	7.5	10	8.5
MS21	7.5	10	**

4.16 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS1	5	No fans	3.93
MS7	5	6	5.24
*MS18	T1 - 7.5, T2-7.5	T1-10, T2-10	T1-5.24, T2-6.34

* MS18 is a dual voltage station on the LV side, however at this time it is operating at 4.16kV

** just put into operation, peak load not known at this time

Table 3-2: Station Ratings and Load Levels

As can be seen, there are no capacity constraints at any of the substations.

3.2.3 (5.3.2 c) information by asset type on quantity/years in service profile and condition, including the date the data was compiled:

The demographic information on NBHDL's distribution system is included in full detail in **Appendix B**. The health and condition of the assets are summarized in Section 3.2.3.1, based on the data obtained in the last quarter of 2013.

3.2.3.1 Results of 2013 Asset Condition Assessment

The stand-alone ACA Report attached in **Appendix B** provides complete demographic and asset condition information on material fixed assets employed in substations, overhead distribution system and the underground distribution system. The ACA Report documents the condition of all major assets in units of health indices on a scale of 1 to 100. In determining the health indices of assets, all available

information relevant to the assets' health, including age, results of visual inspections and diagnostic testing has been utilized. The ACA Report was compiled in May 2014 by METSCO.

The health and age indices for major assets are summarized in Figure 3-6 through Figure 3-40 below. Conclusions of METSCO are provided from the ACA Report for assets in need of action within the forecast period.

Substation Transformers

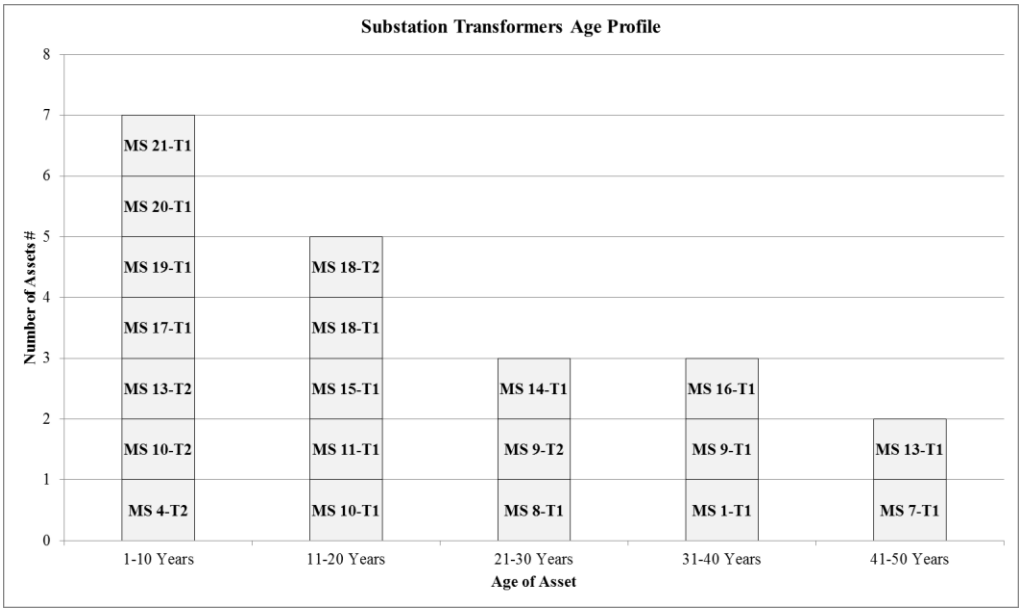


Figure 3-6: Substation Transformers Age Profile

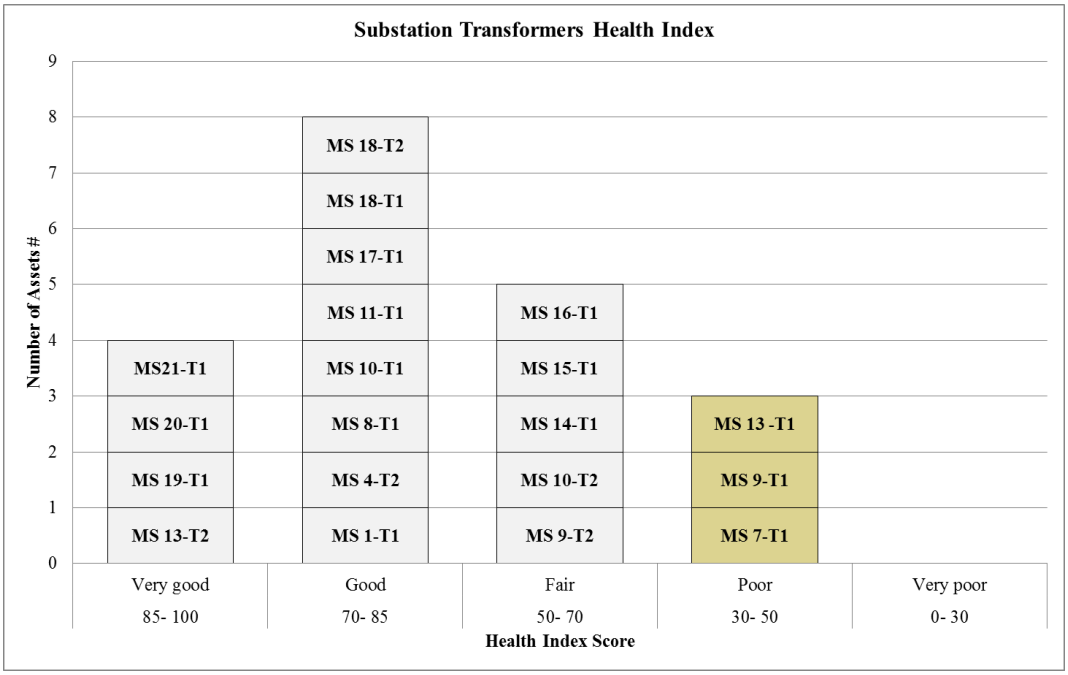
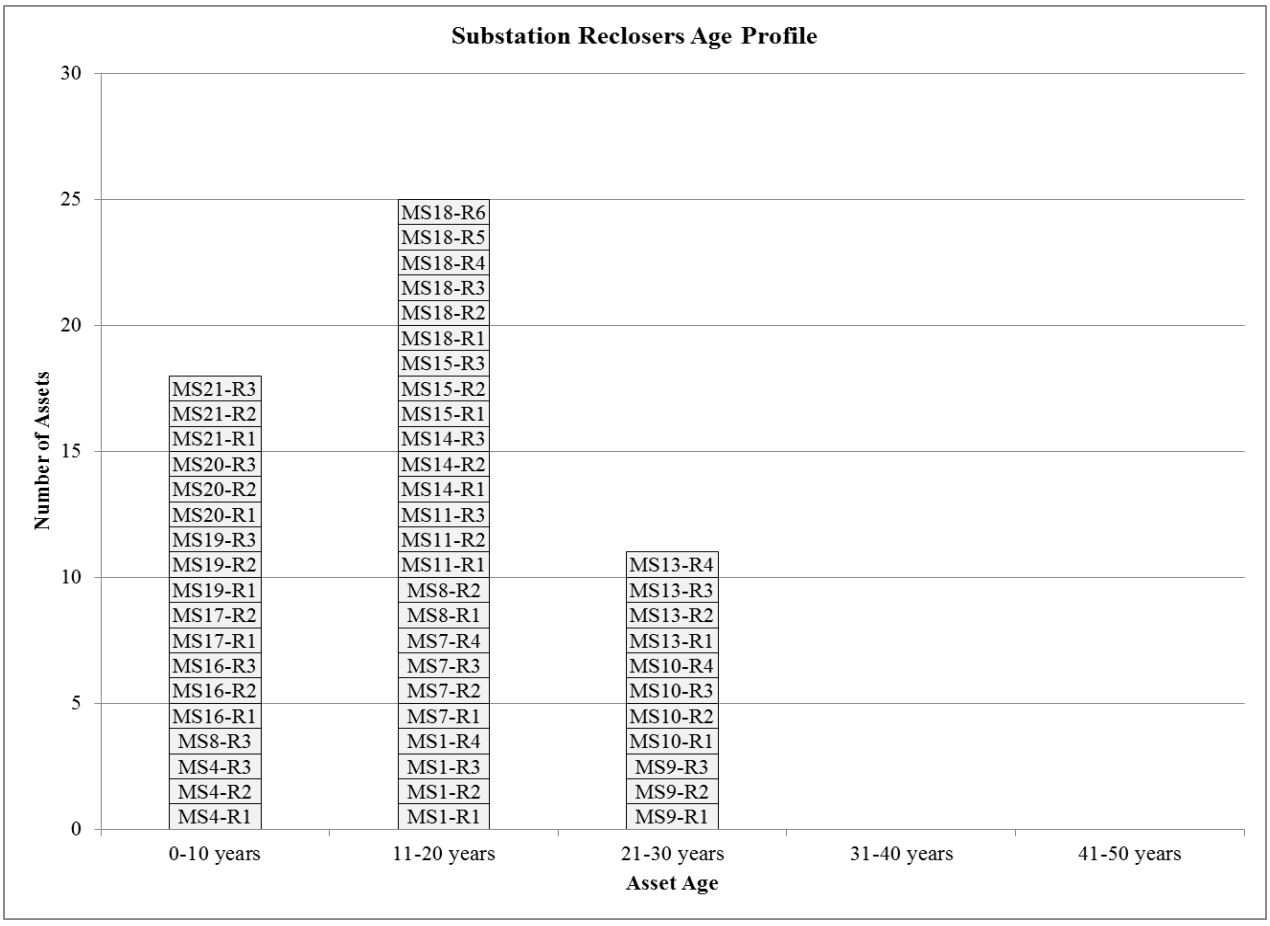


Figure 3-7: Substation Transformers Health Index

As seen above in Figure 3-7, three power transformers – MS-7-T1, MS-9-T1 and MS-13-T1 transformers have determined to be in “poor” condition, while the remaining transformers are ranked to be in “fair”, “good” or “very good” condition. The transformers determined to be in poor condition present high risk of failure in service and are recommended to be replaced during the next five years.



*Age information of substation reclosers has been updated after the ACA study was completed

Figure 3-8: Substation Reclosers Age Profile

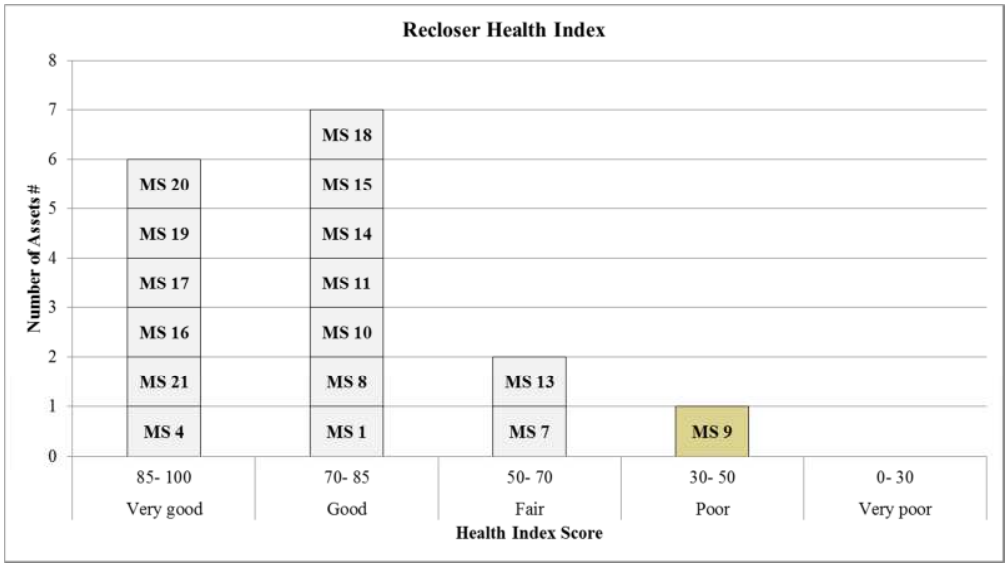


Figure 3-9: Substation Reclosers Health Index

Substation Circuit Breakers and Reclosers

As seen above in Figure 3-9, the reclosers at MS-9 have been determined to be in "poor" health and recommended to be replaced during the next five years. By taking into account the high probability of failure of the assets found in poor and very poor condition and the consequence of the assets' failure in service, Section 5 [of the ACA Report] documents additional analysis supporting replacement of the assets found in poor and very condition.

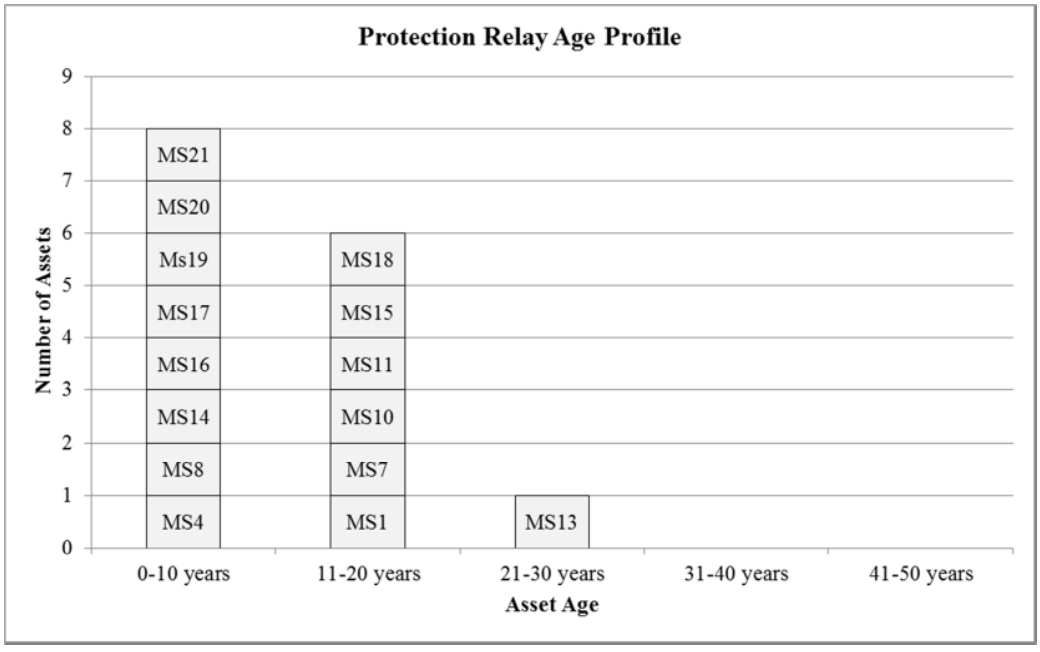


Figure 3-10: Substation Protection and Control Relays Age Profile

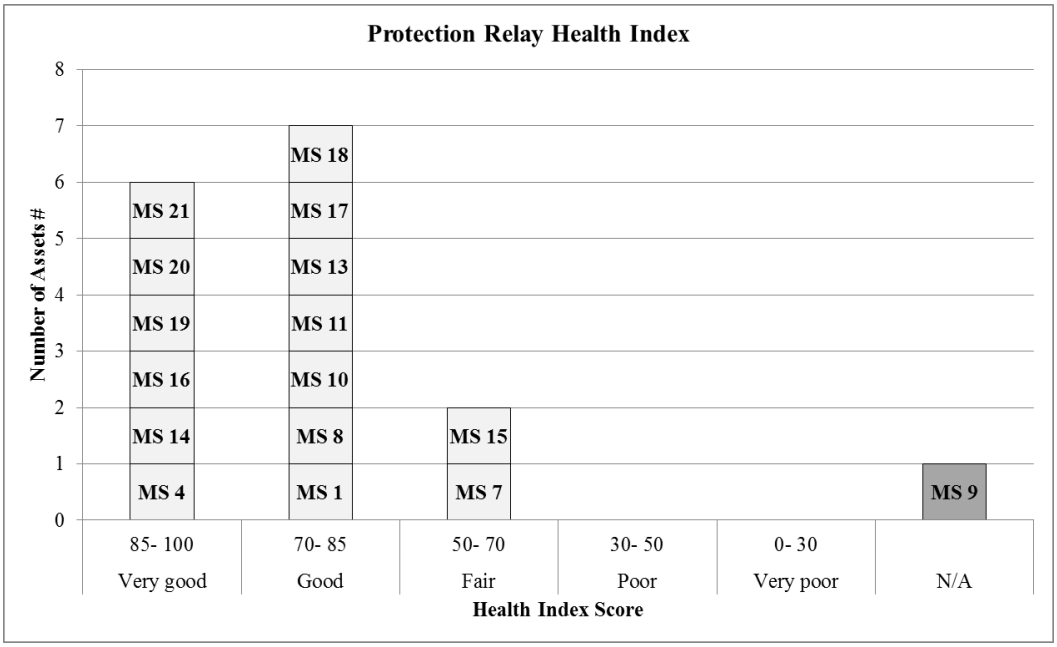


Figure 3-11: Substation Protection and Control Relays Health Index

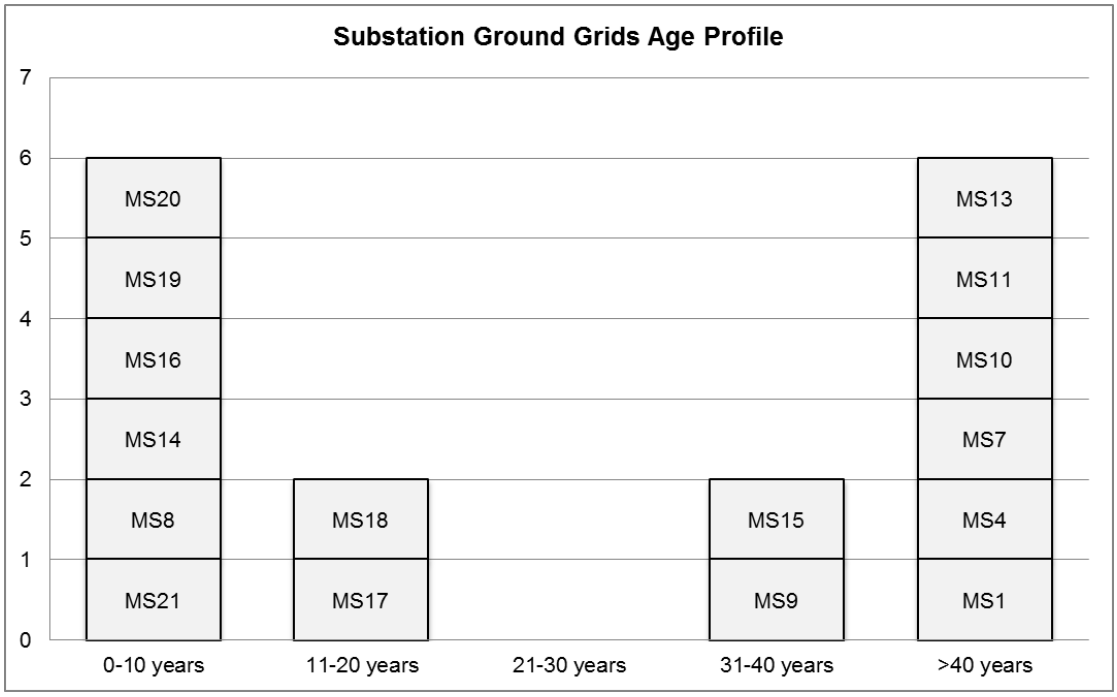


Figure 3-12: Substation Ground Grids Age Profile

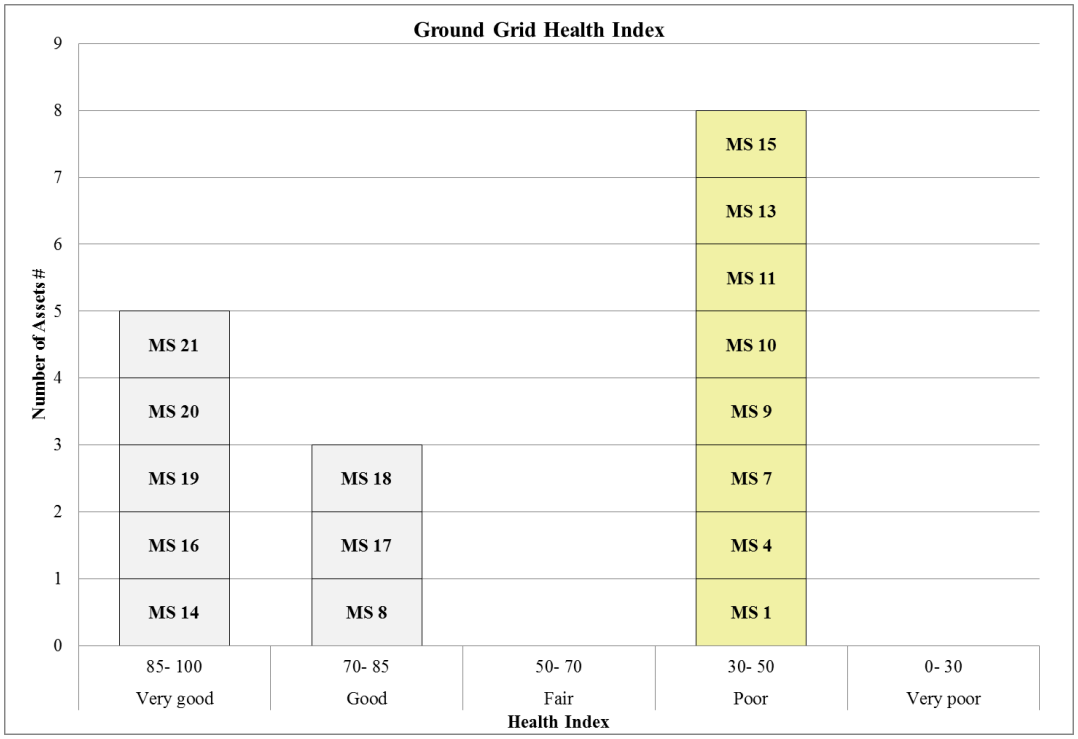


Figure 3-13: Substation Ground Grids Health Index

Substation Ground Grids

As indicated in Figure 3-13, the ground grids at MS1, MS4, MS7, MS9, MS10, MS11, MS13, MS15 and MS16 are determined to be in poor condition, mostly due to the poor condition of the surface stone and the rest are in good and very good condition. It is recommended the surface stone found in poor condition be replaced during the next five years.

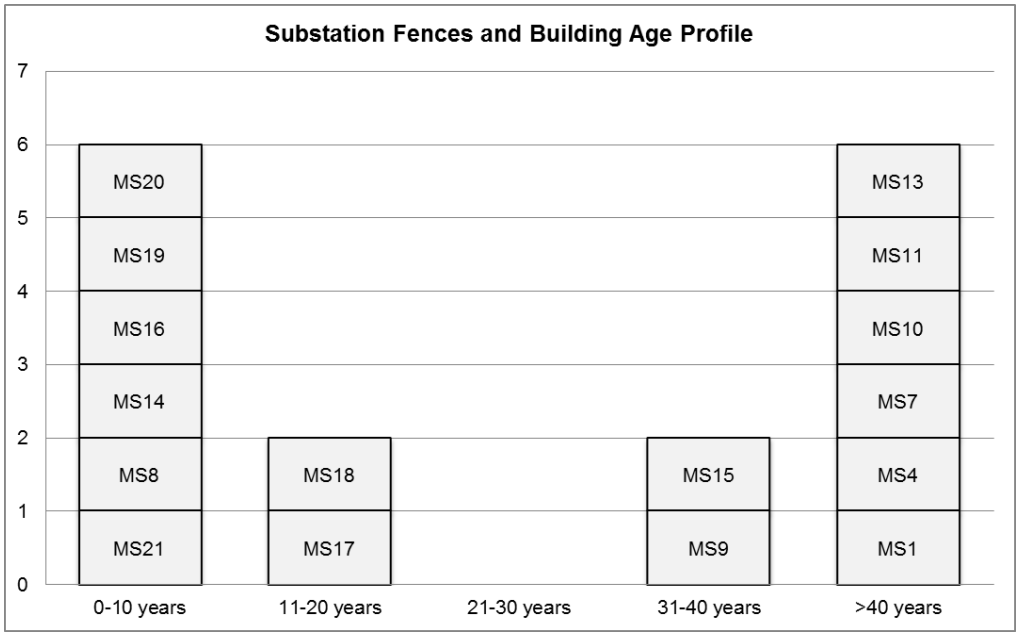


Table 3-3: Substation Buildings and Fences Age Profile

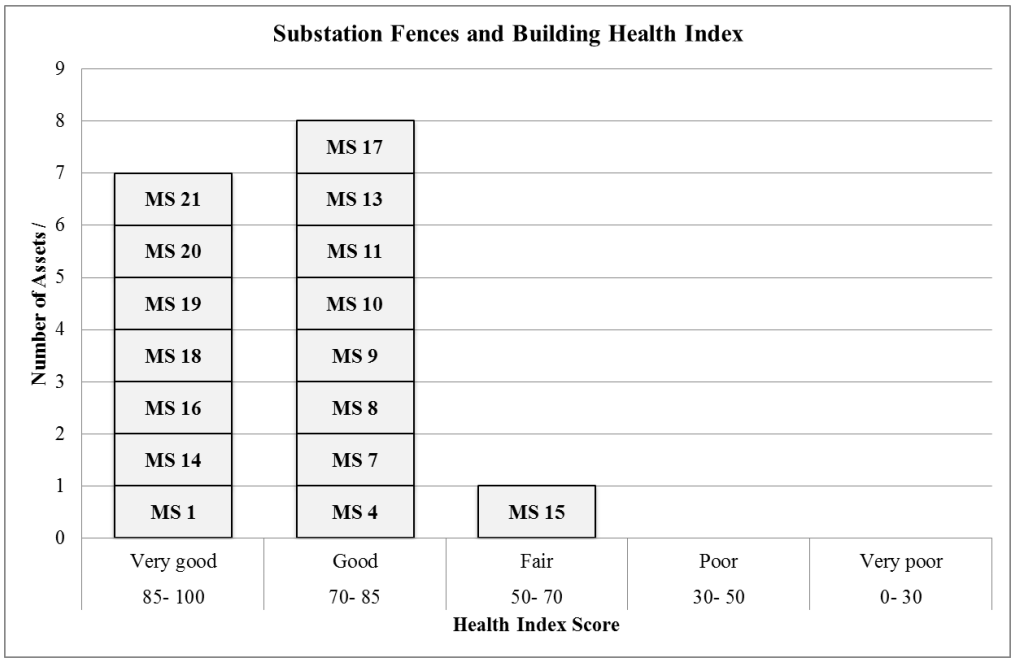


Figure 3-14: Substation Fences and Buildings Health Index

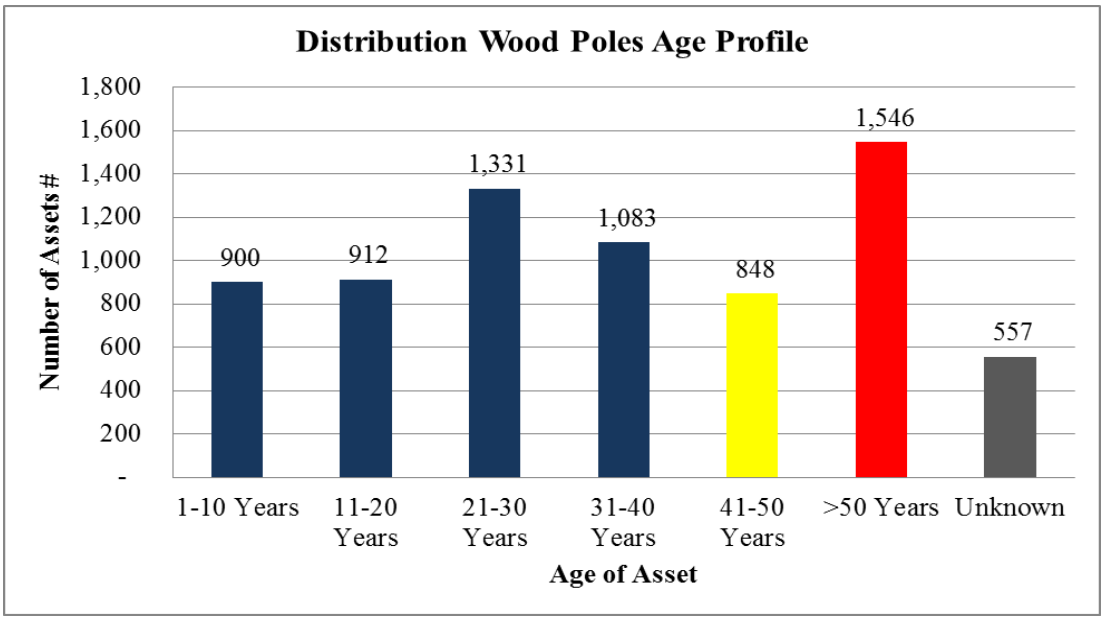


Figure 3-15: Age Demographics of Wood Poles

Figure 3-15 above, displays the age profile of wood poles employed on NBHDL's distribution system.

	41-50 years	>50 years	Unknown
MS1	21	28	13
MS7	23	26	49
MS18	11	32	21
MS19	26	26	24
MS4	8	14	9
TOTAL	89	126	116

Figure 3-16: Wood Poles Age Profile for 4kV lines

Figure 3-16 displays the number of poles in service age categories of “41-50 year”, “>50 years” and “unknown age” employed on 4 kV lines.

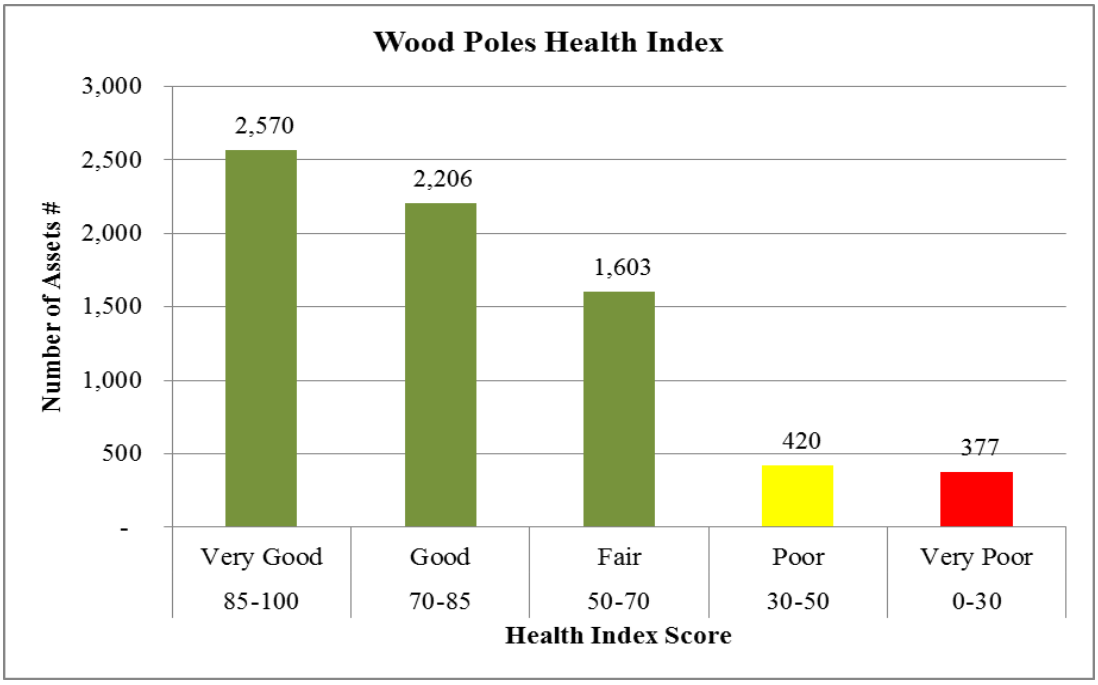


Figure 3-17: Wood Poles Health Index

In this Figure 3-17, poles with a health index of 50 or less (labeled in yellow as poor and red as very poor), present a high risk of failure, and are recommended to be replaced during the next five years, with higher priority being assigned to poles in “very poor” condition. Since voltage upgrade of lines offers other economic benefits in addition to reducing the risk of asset failures, poles in “very poor” and “poor” condition employed on the 4 kV lines are recommended to be given priority in conjunction with the implementation of line voltage upgrades.

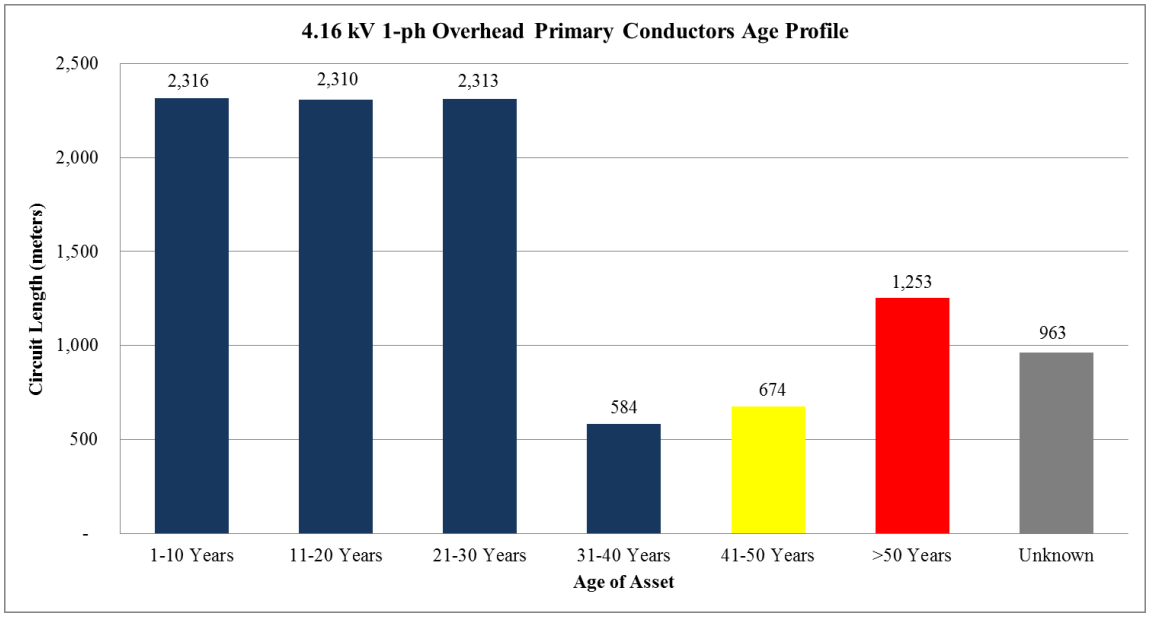


Figure 3-18: 4.16kV 1-ph Overhead Primary Conductors Age Profile

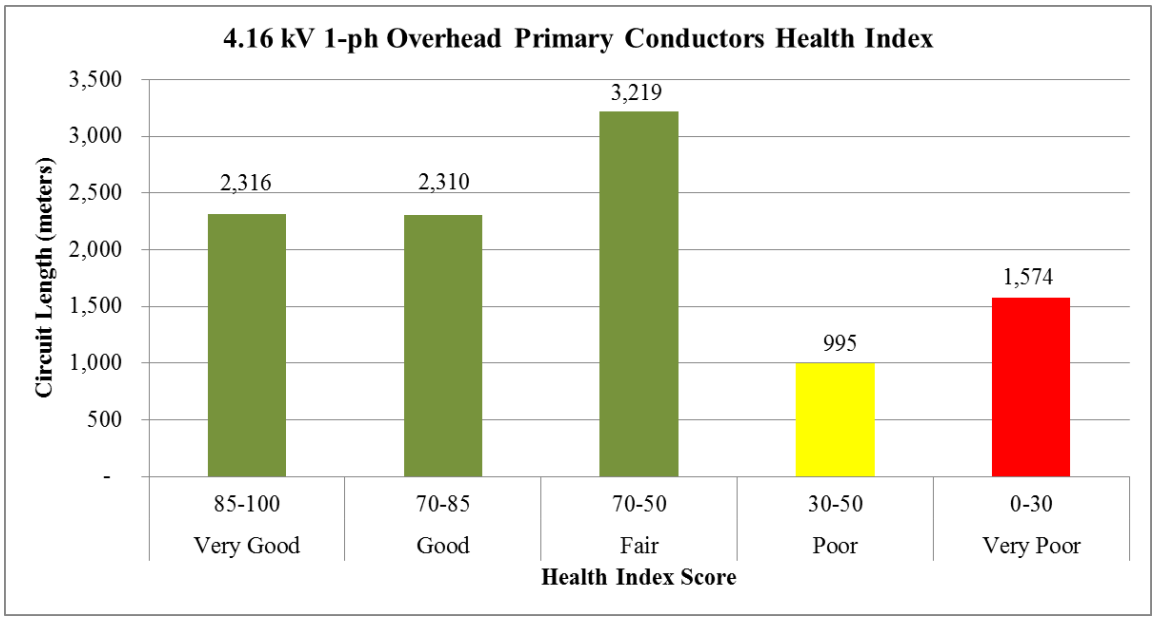


Figure 3-19: 4.16kV 1-ph Overhead Primary Conductors Health Index

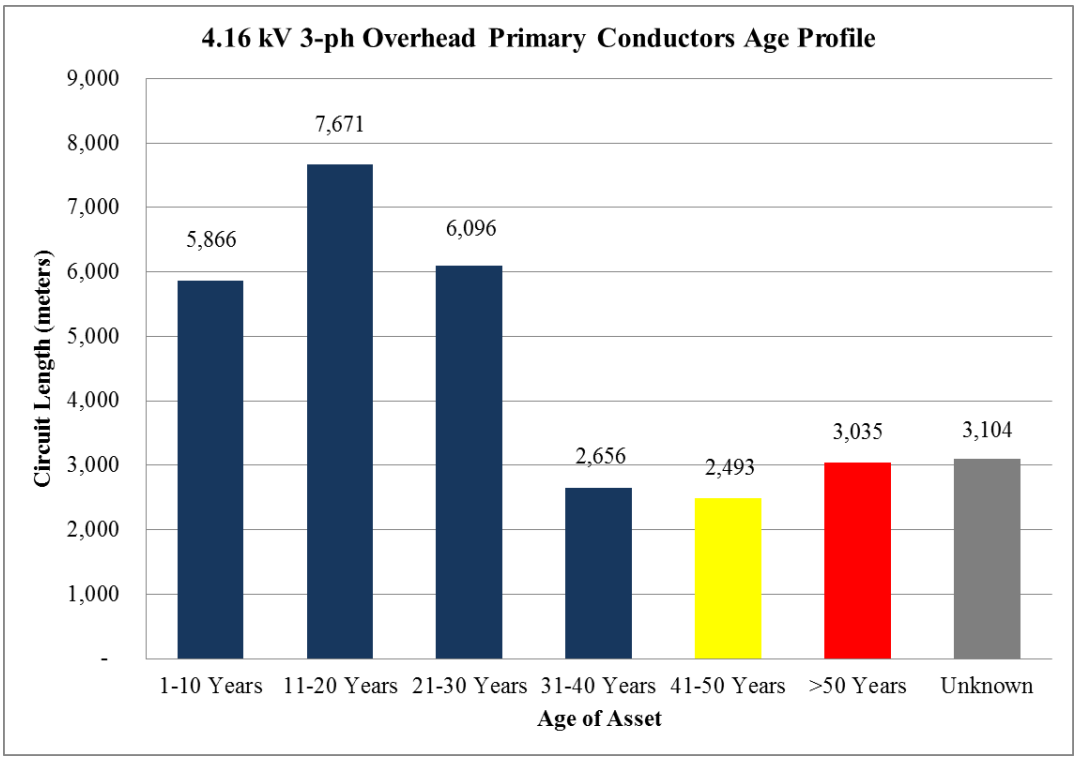


Figure 3-20: 4.16kV 3-ph Overhead Primary Conductors Age Profile

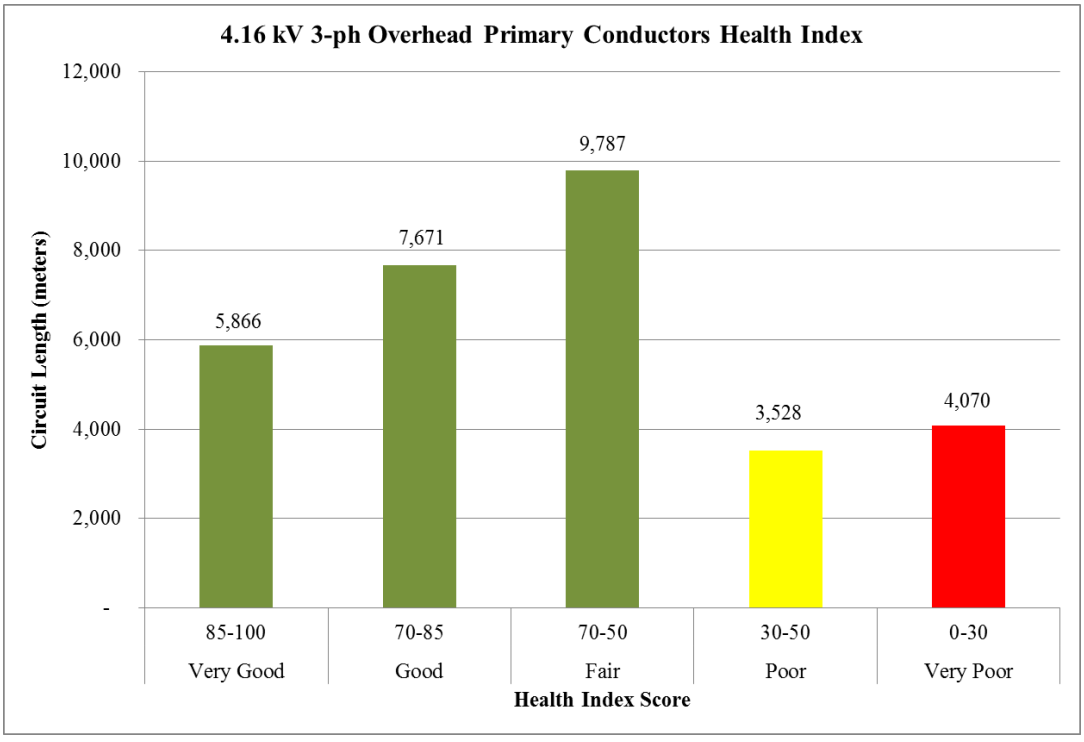


Figure 3-21: 4.16kV 3-ph Overhead Primary Conductors Health Index

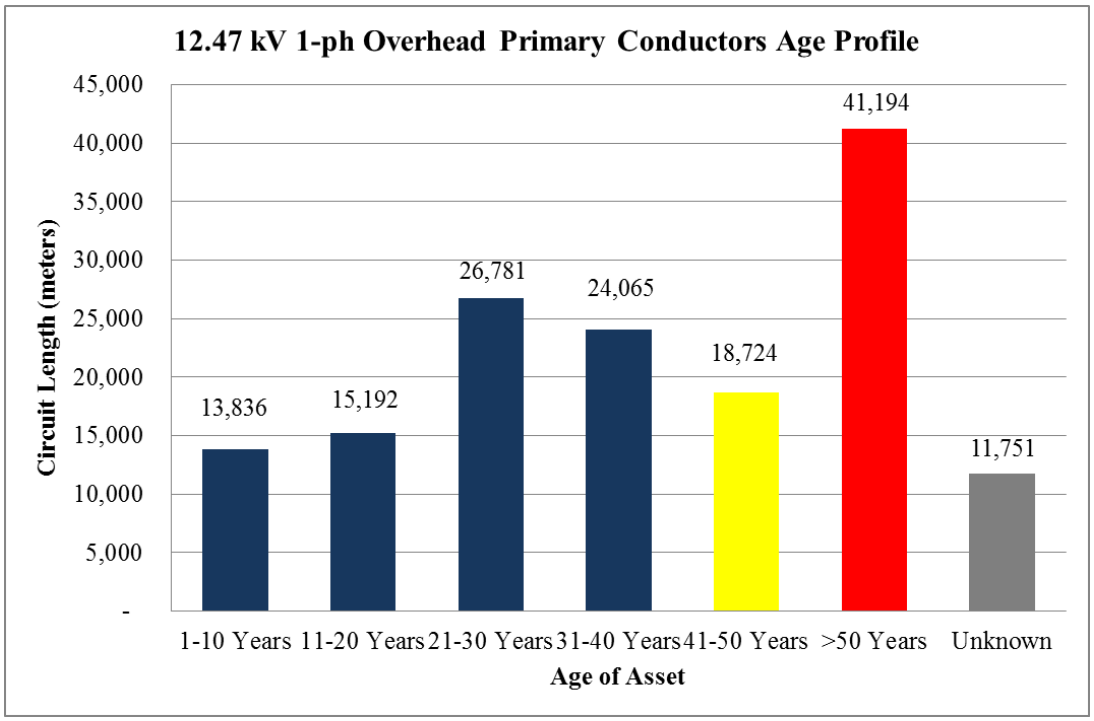


Figure 3-22: 12.47kV 1-ph Overhead Primary Conductors Age Profile

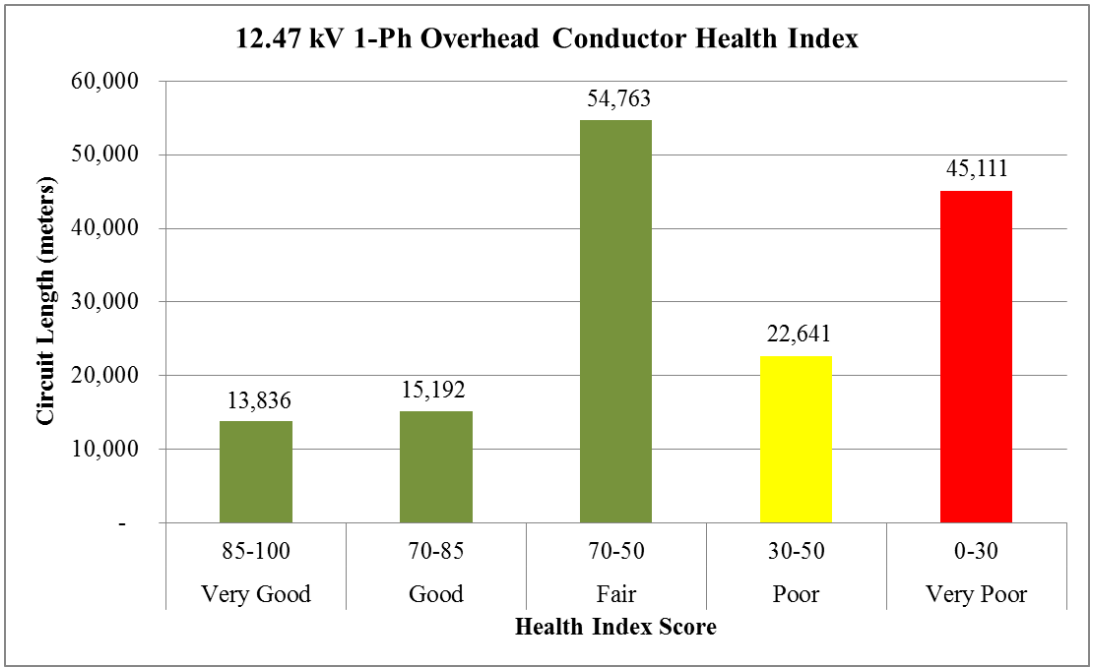


Figure 3-23: 12.47kV 1-ph Overhead Primary Conductors Health Index

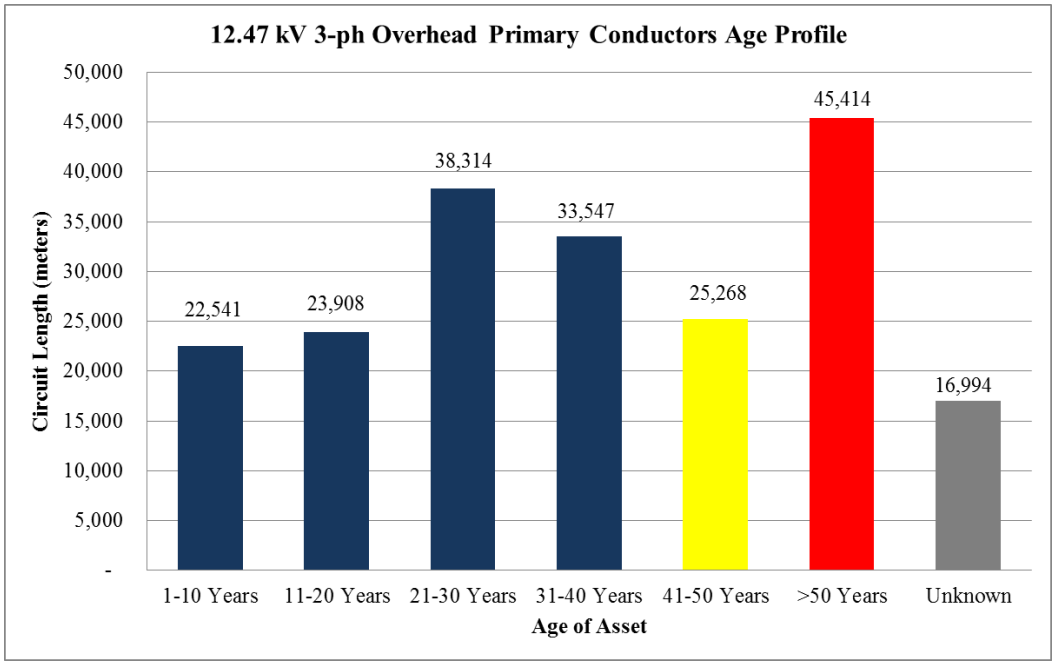


Figure 3-24: 12.47kV 3-ph Overhead Primary Conductors Age Profile

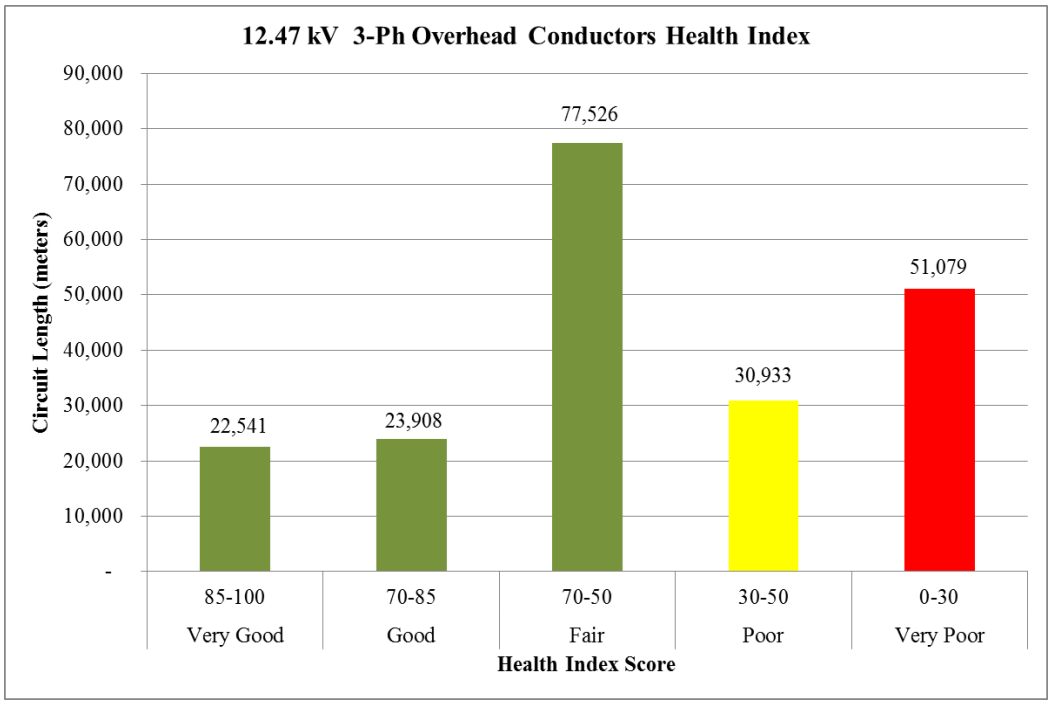


Figure 3-25: 12.47kV 3-ph Overhead Primary Conductors Health Index

Figure 3-18 to Figure 3-25 above indicate the health indices for different categories of overhead line conductors. The conductors determined to be in “poor” and “very poor” condition are recommended to be replaced during the next five years.

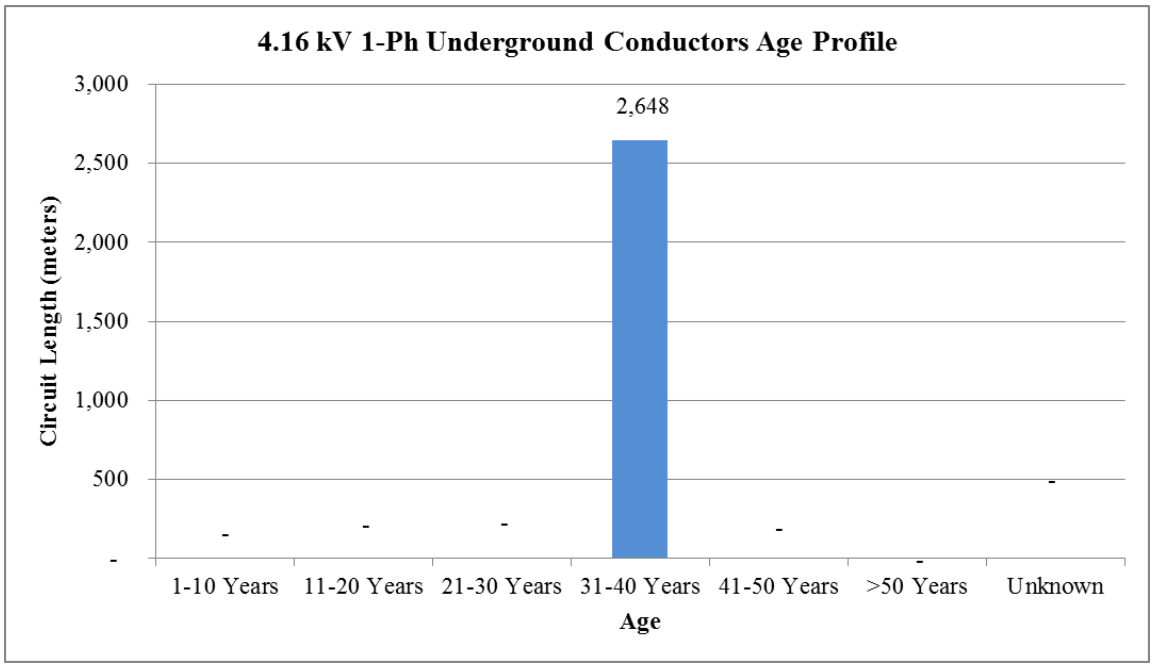


Figure 3-26: 4.16kV 1-ph Underground Primary Conductors Age Profile

Health indices for different voltage distribution cables, derived from available health indicators, are presented in Figure 3-27 to Figure 3-33 below. Cables determined to be in poor and very condition present a high risk of failure in service and are recommended to be replaced during the next five years.

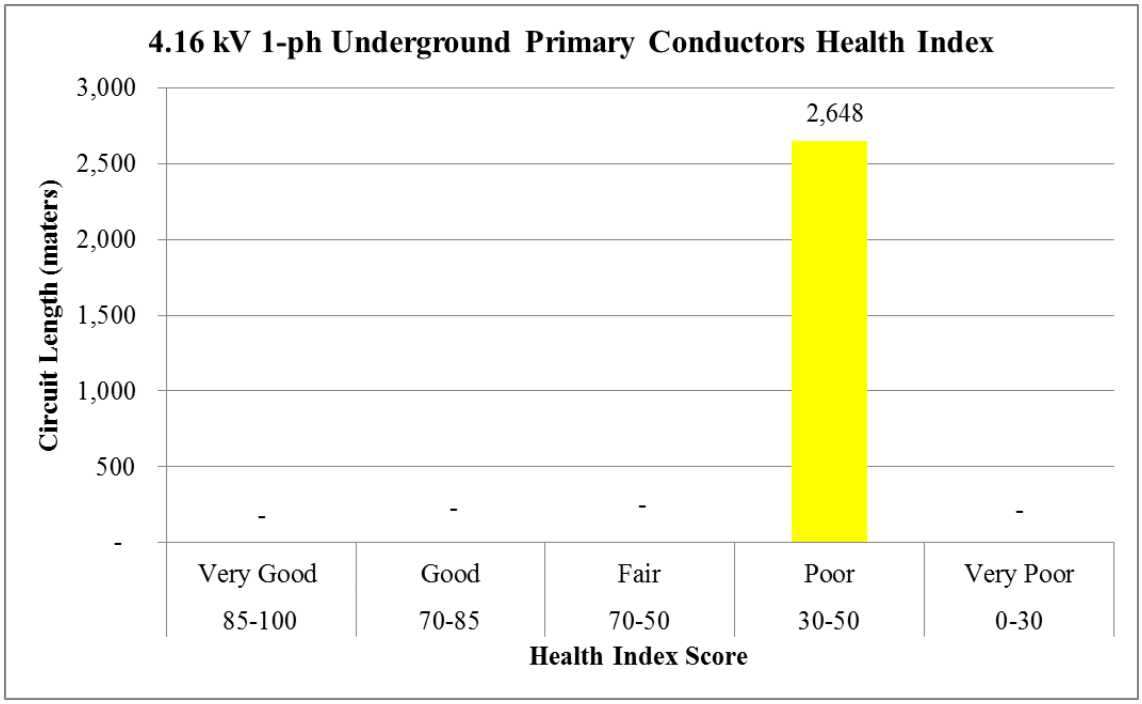


Figure 3-27: 4.16kV 1-ph Underground Primary Conductors Health Index

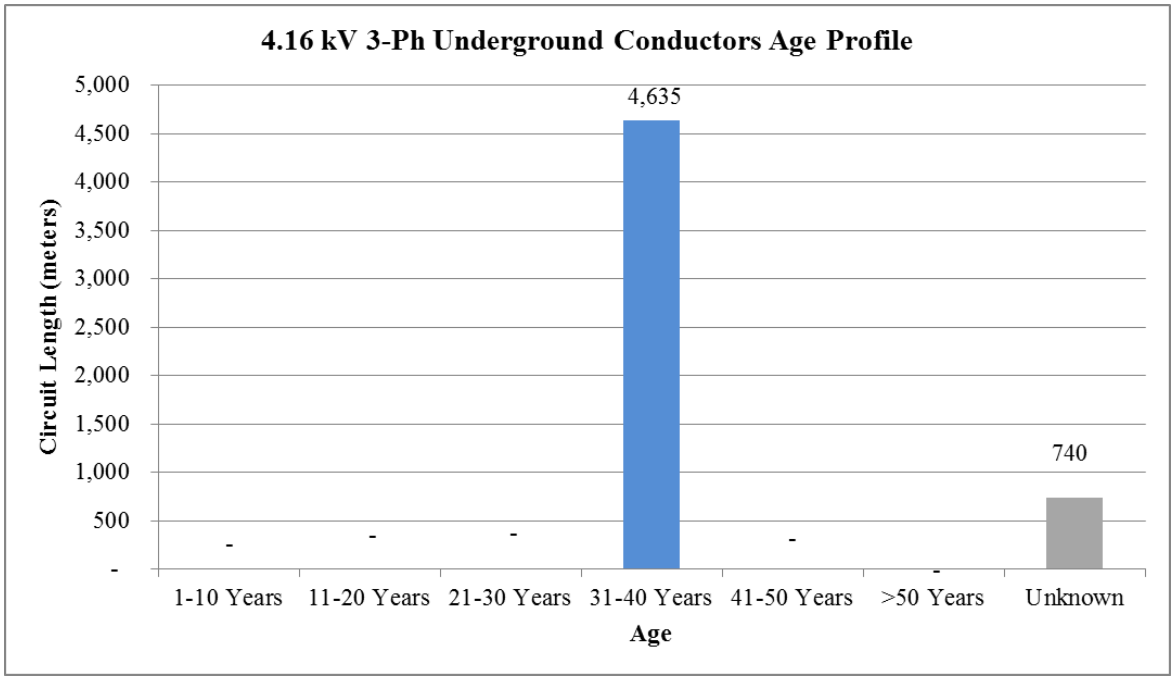


Figure 3-28: 4.16kV 3-ph Underground Primary Conductors Age Profile

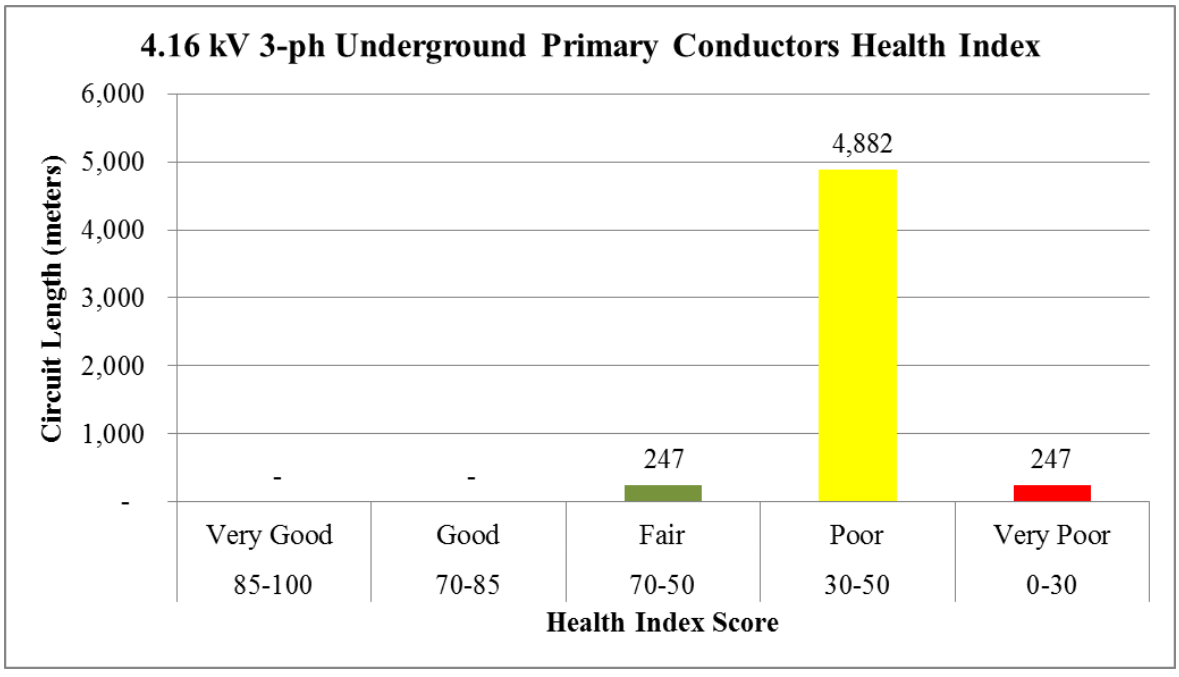


Figure 3-29: 4.16kV 3-ph Underground Primary Conductors Health Index

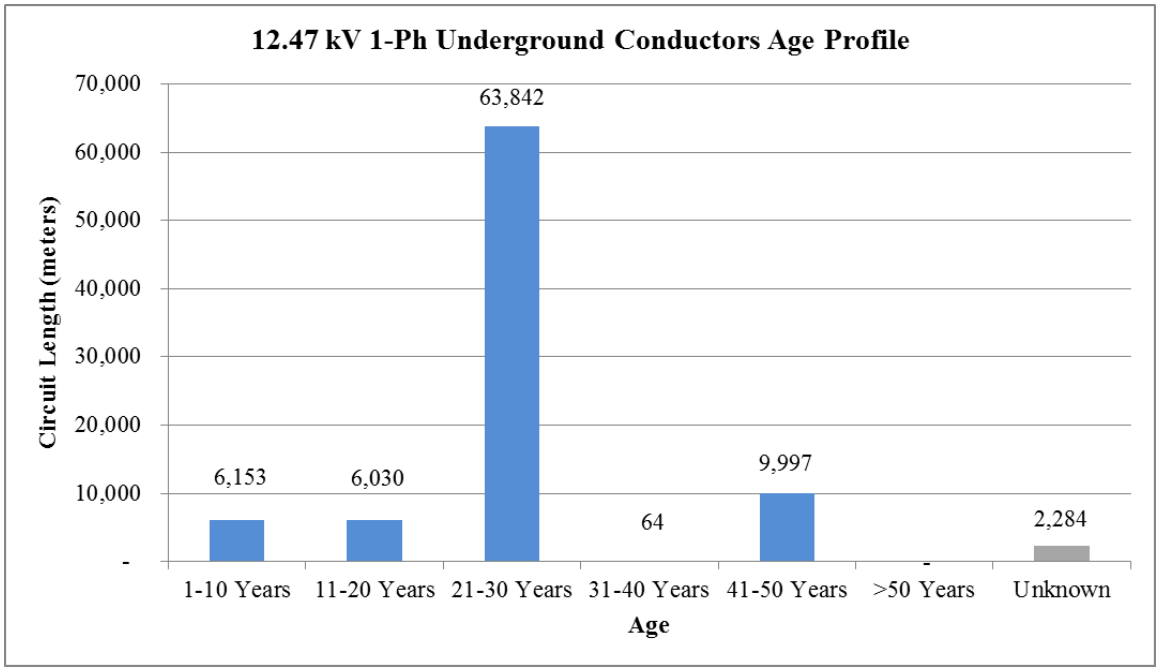


Figure 3-30: 12.47kV 1-ph Underground Primary Conductors Age Profile

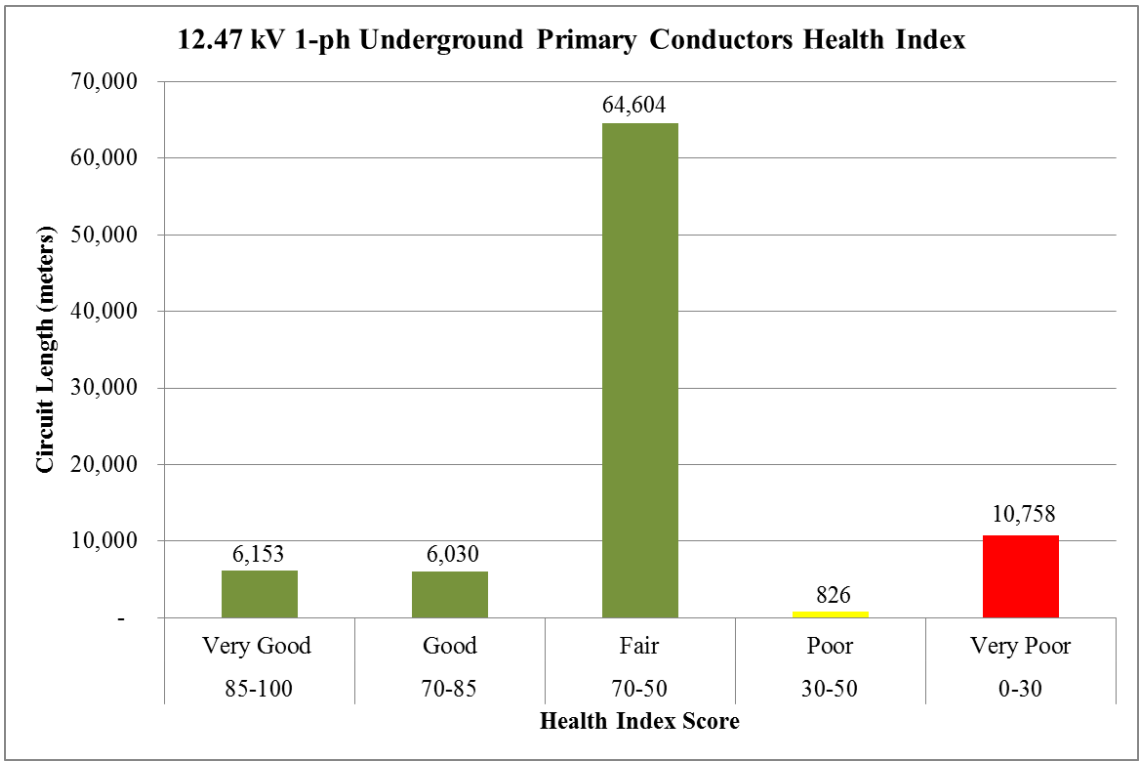


Figure 3-31: 12.47kV 1-ph Underground Primary Conductors Health Index

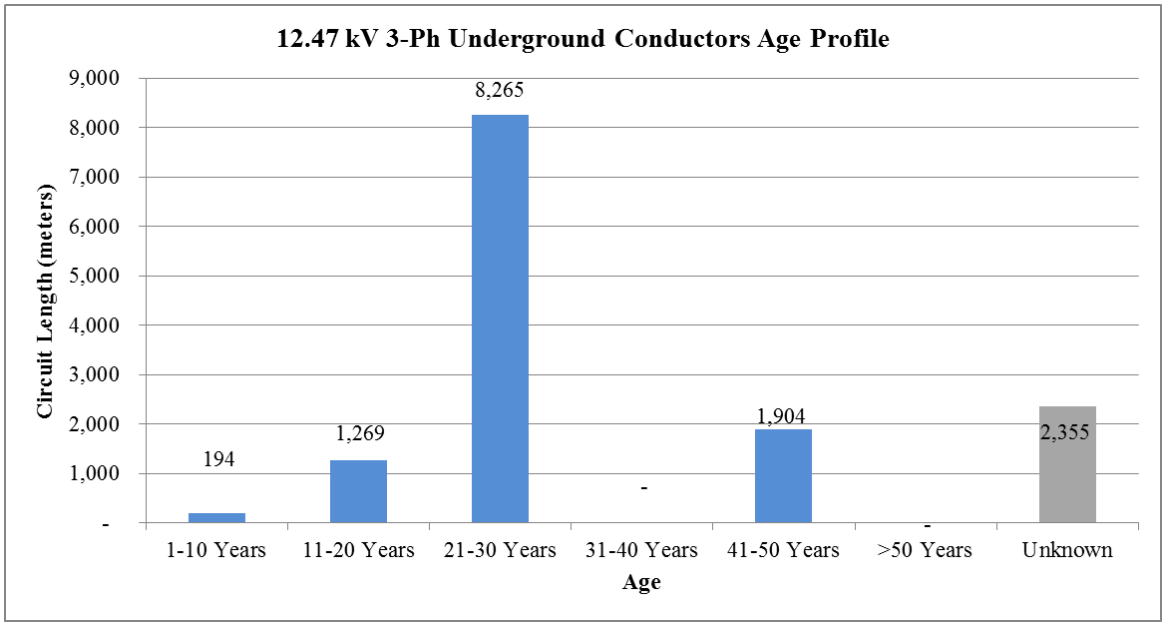


Figure 3-32: 12.47kV 3-ph Underground Primary Conductors Age Profile

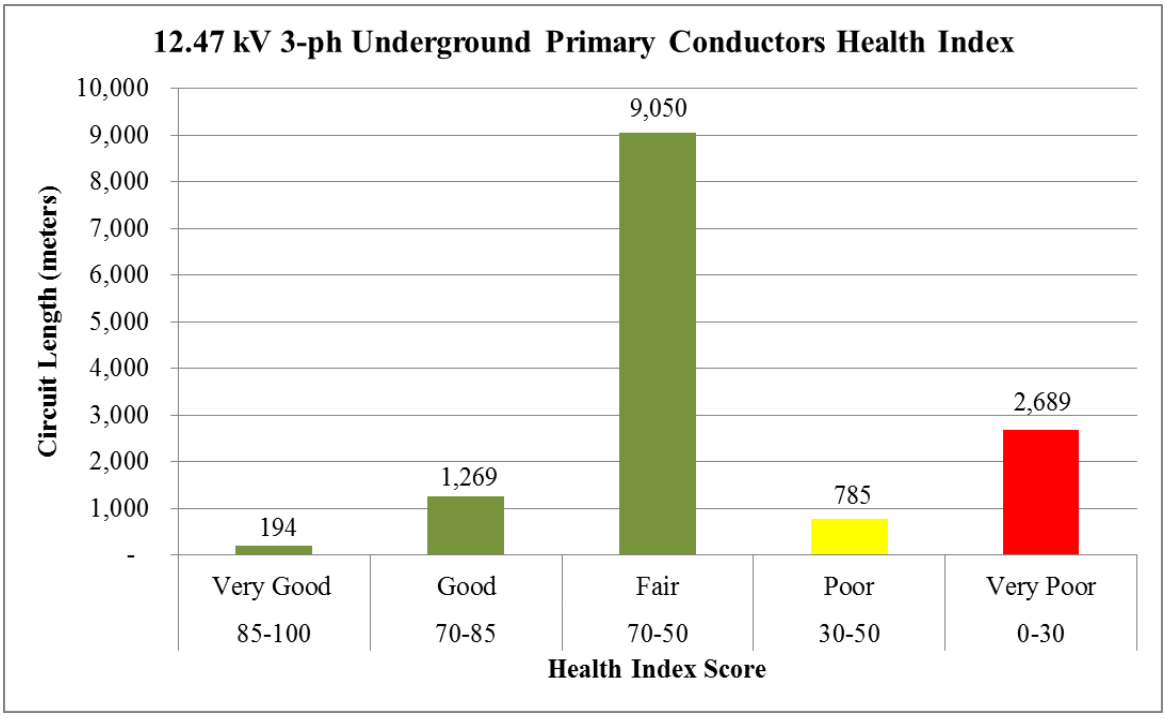
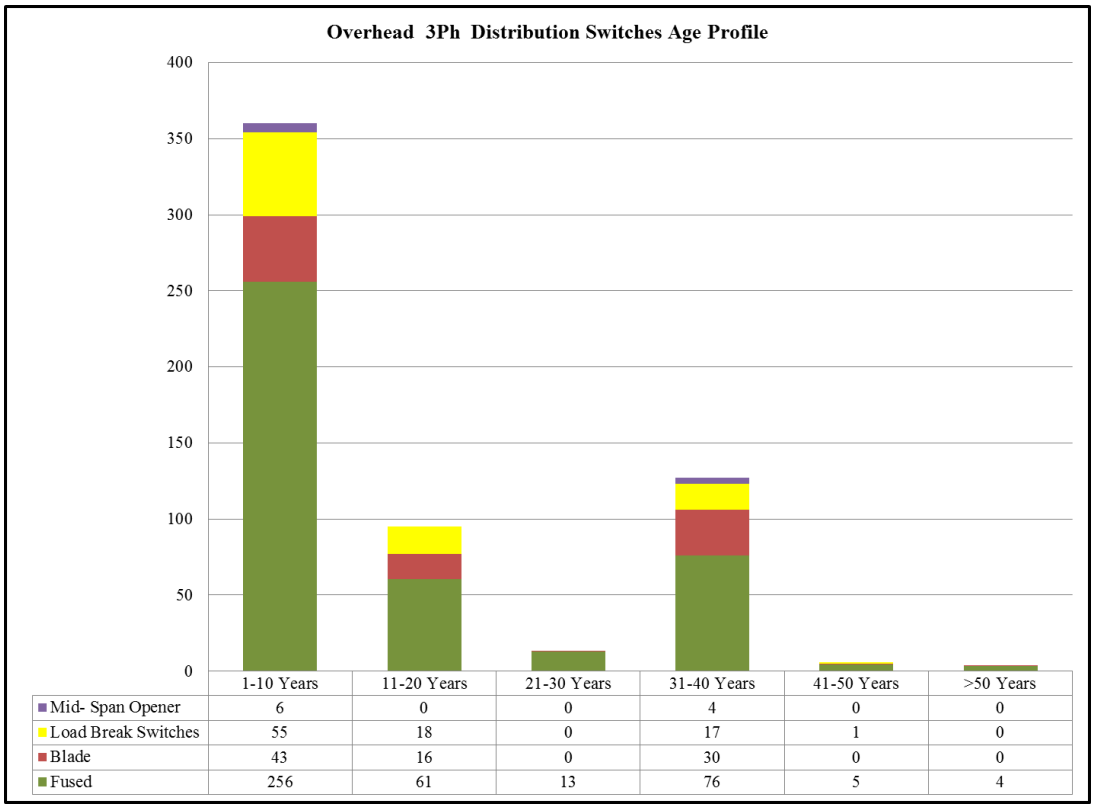
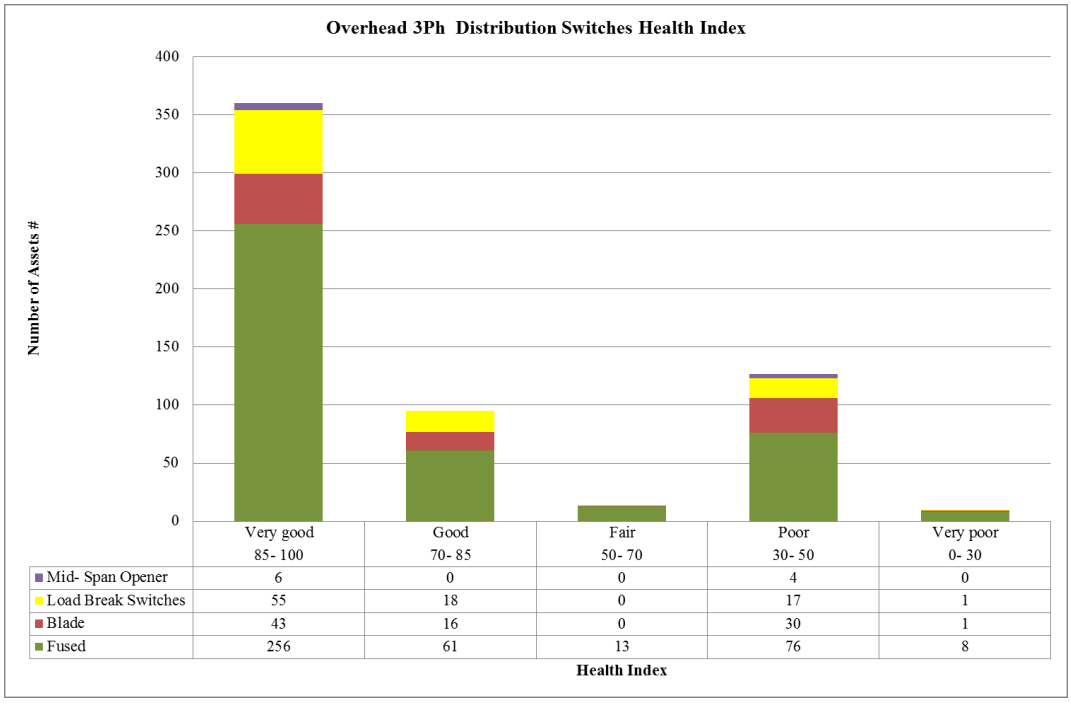


Figure 3-33: 12.47kV 3-ph Underground Primary Conductors Health Index



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Mid- Span Opener	6	0	0	4	0	0
Load Break Switches	55	18	0	17	1	0
Blade	43	16	0	30	0	0
Fused	256	61	13	76	5	4

Figure 3-34: 3-ph Overhead Distribution Switches Age Profile



	Very good 85- 100	Good 70- 85	Fair 50- 70	Poor 30- 50	Very poor 0- 30
Mid- Span Opener	6	0	0	4	0
Load Break Switches	55	18	0	17	1
Blade	43	16	0	30	1
Fused	256	61	13	76	8

Figure 3-35: 3-ph Overhead Distribution Switches Health Index

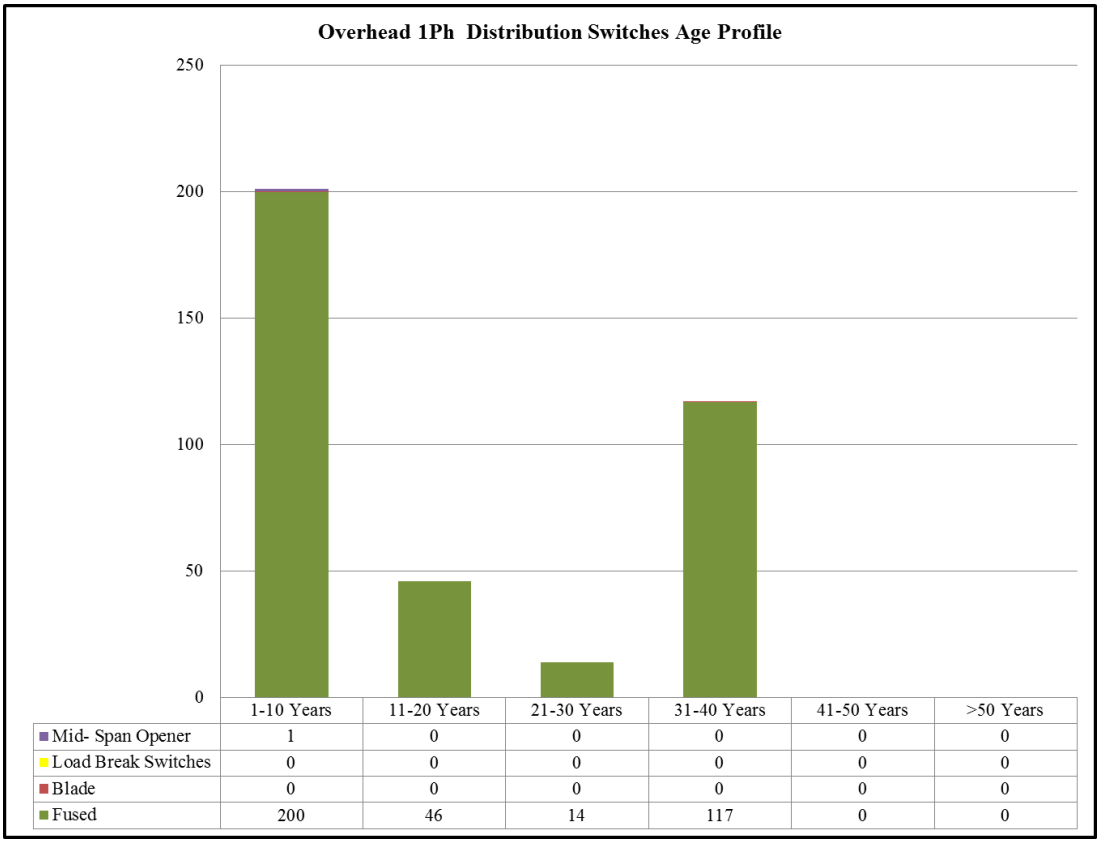


Figure 3-36: 1-ph Overhead Distribution Switches Age Profile

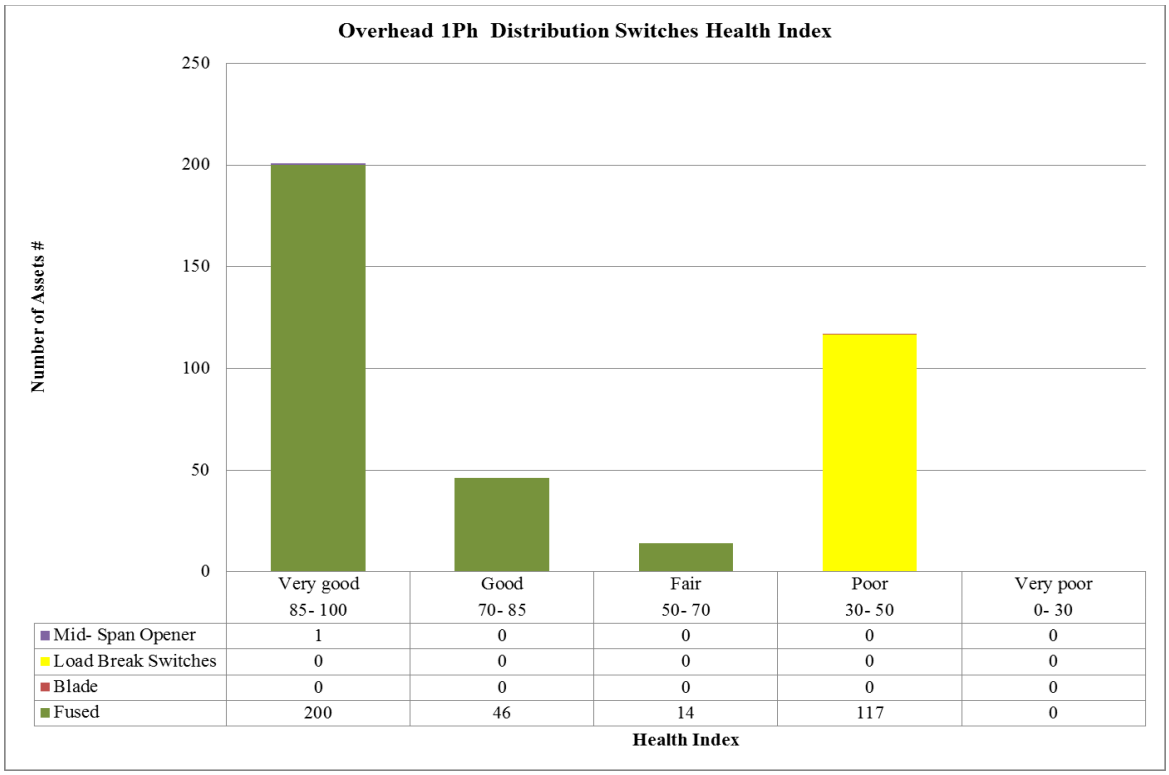


Figure 3-37: 1-ph Overhead Distribution Switches Health Index

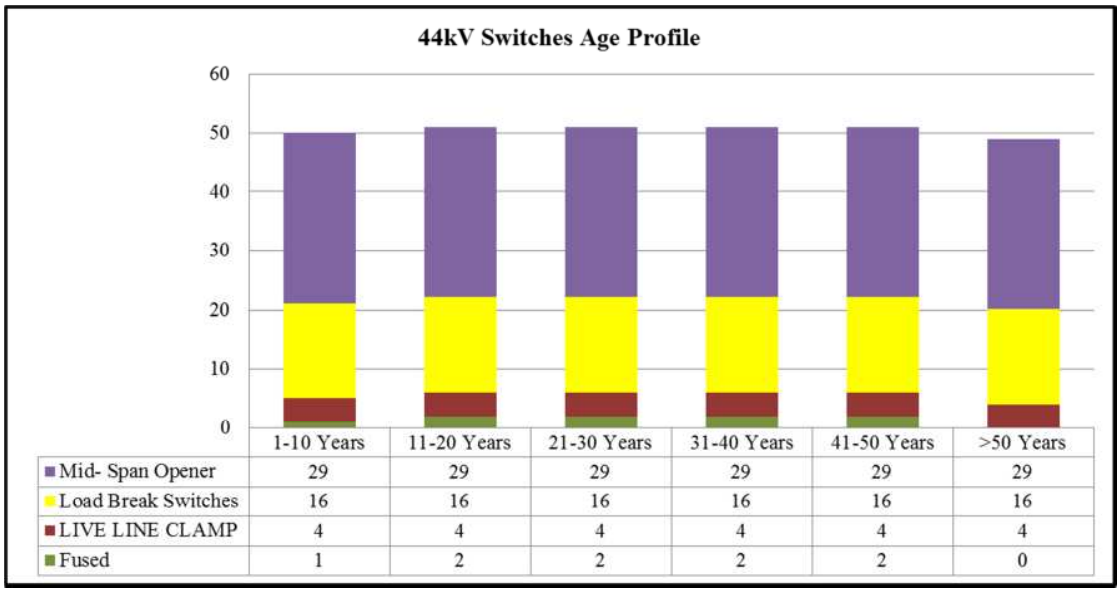


Figure 3-38: 44kV Switches Age Profile

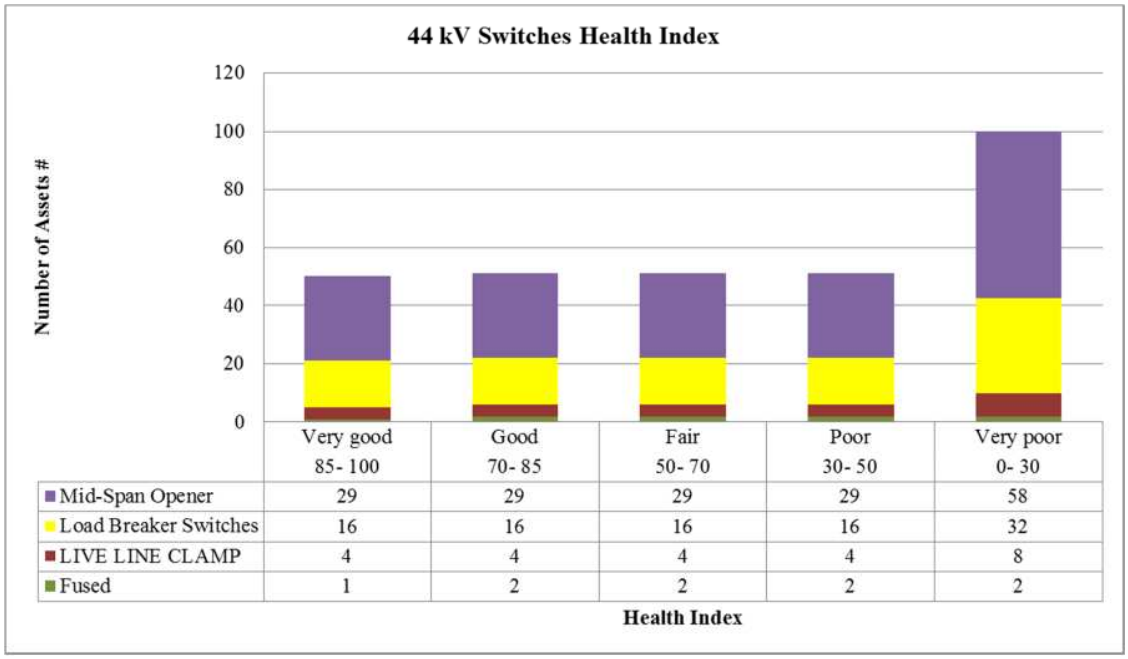


Figure 3-39: 44kV Switches Health Index

Based on the condition assessment criteria described in Section 3 of the ACA Report, the Health Index score is calculated for the 3-phase and 1-phase distribution switches and the 44 kV line switches and the results are presented above in Figure 3-34 to Figure 3-38 above. The assumed age profile for the 44 kV line switches and the health indices for 44 kV disconnect switches are indicated in Exhibit 4.42. Cutouts and disconnects determined to be in poor and very poor condition are recommended to be replaced during the next five years.

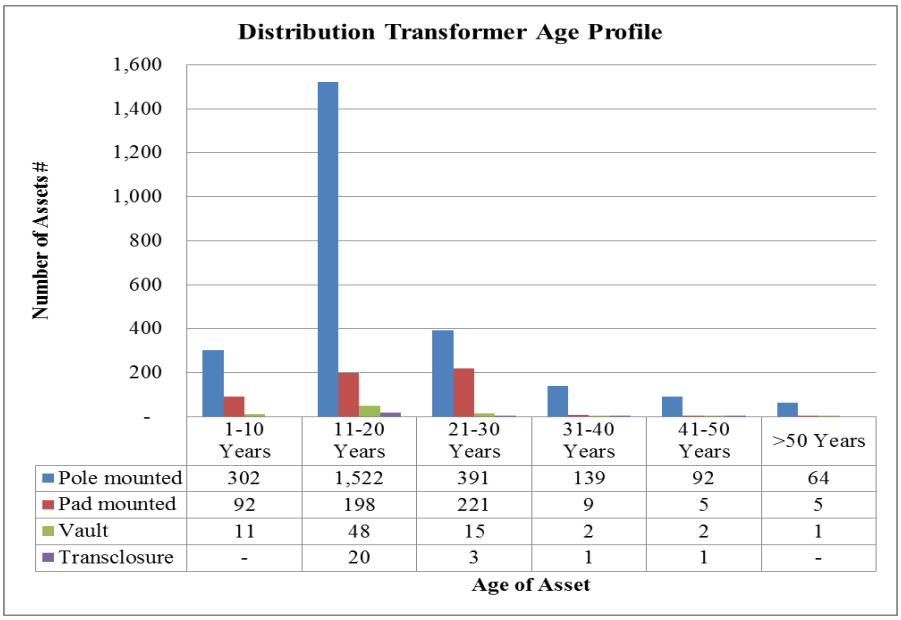


Figure 3-40: Distribution Transformers Age Profile

The health indices for distribution transformers are presented in Figure 3-40 above. The distribution transformers are recommended to be run to failure, i.e. replace a transformer only after failure. The budgets for renewal of this asset can be based on anticipated failure and replacement of the transformers found in poor and very poor condition.

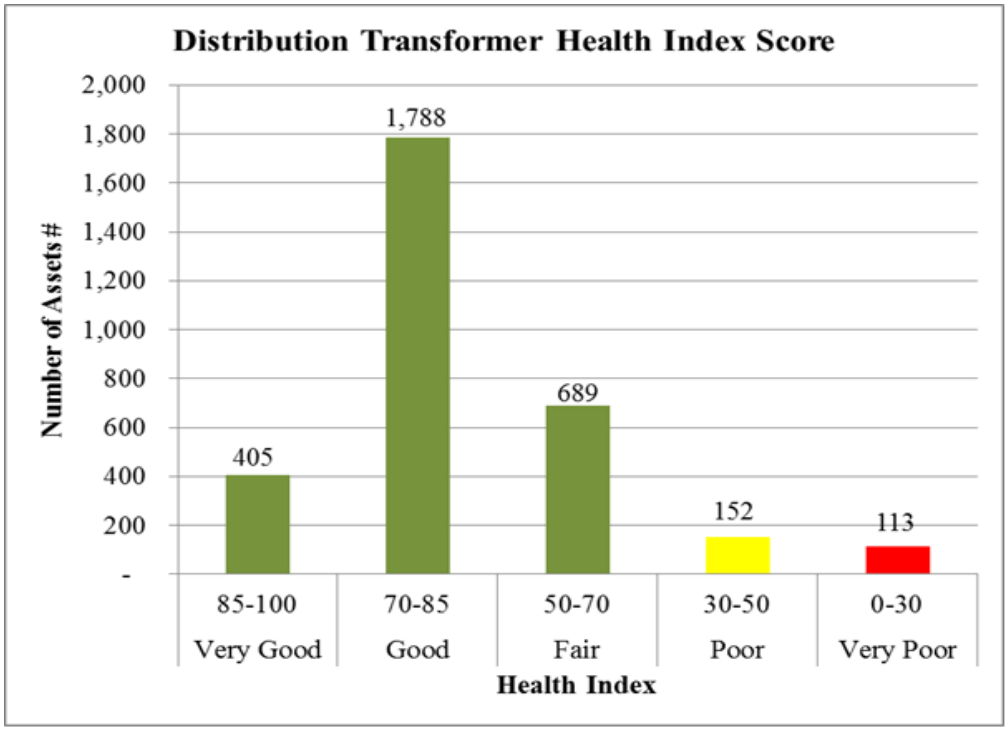


Figure 3-41: Distribution Transformers Health Index

3.2.4 (5.3.2 d) assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria:

The two HONI owned TS's that supply the NBHDL system (NBTS, FZ15 and TLTS, FZ18) provide more than enough capacity to serve the area, now and over the entire planning horizon, while accounting for redundancy and future growth. TS transformer capacity constraints are therefore not identified as being an investment driver over the 2015-2019 filing.

NBHDL's distribution stations also have sufficient capacity to serve current and future load while still maintaining a high degree of redundancy. Distribution station transformer capacity constraints are therefore not identified as being an investment drive over the 2015 – 2019 period and NBHDL will reduce the number of distribution stations by one (1) over the filing period.

Table 3-4 below shows distribution station transformer utilization.

12.47 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS4	7.5	10	7.19
MS8	7.5	10	5.9
MS9	T1 - 7.5, T2-7.5	No fans	T1 - 5.00, T2 -4.00
MS10	T1-7.5, T2 - 7.5	T1-10, T2-10	T1-5.94, T2-6.54
MS11	7.5	10	7.21
MS13	T1-6, T2-7.5	T1-No fans, T2-10	T1-6.32, T2-6.46
MS14	7.5	10	5.93
MS15	7.5	10	6.55
MS16	7.5	No fan rating	5.42
MS17	7.5	10	5.36
MS19	7.5	10	7.21
MS20	7.5	10	8.5
MS21	7.5	10	**

4.16 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS1	5	No fans	3.93
MS7	5	6	5.24
*MS18	T1 - 7.5, T2-7.5	T1-10, T2-10	T1-5.24, T2-6.34

* MS18 is a dual voltage station on the LV side, however at this time it is operating at 4.16kV

** just put into operation, peak load not known at this time

Table 3-4: Distribution Station Transformer Utilization

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

The life cycle optimization policies and procedures employed for preparation of this DSP, including the optimization of the capital investment plan as well as optimization of the preventative maintenance practices is described below:

3.3.1 (5.3.3 a) a description of asset lifecycle optimization policies and practices:

3.3.1.1 Asset Replacement Policies and Prioritization of Capital Investments

An overview of the asset management principles employed to achieve economic efficiency of the investments is provided in Section 3.1. Detailed methodologies employed in assessing the health and condition of assets, determining the probability of the risk of assets' failure in service and valuation of the consequences of asset failure are described in **Appendix B**. The methodology for optimization of the capital investments into fixed assets is summarized below:

The methodology applied to determine the scope and timing of investments into asset renewal is the same as the "Feeder Investment Model", used by many North American utilities, including Toronto Hydro, which has been previously considered by OEB in the context of a utility rate application. The objective is to identify the assets that have reached the end of their economic life, and are due for replacement or refurbishment. The basic concept is that when deciding whether to replace an aging asset, a utility faces two competing objectives. On one hand, you would like to wait as long as possible to replace in order to minimize the capital spending. On the other hand, as you wait longer you will face higher risk due to possible in-service failures as the asset ages and its health deteriorates and it becomes more likely to fail. The strategy that optimizes this trade-off is to minimize life-cycle cost.

The full range of relevant technical and economic considerations is integrated into this approach. Asset age and condition (i.e., health index) are used to estimate failure probability; criticality (i.e., customer effects) is used to define consequence of failure; and direct costs such as maintenance and capital replacement cost are integrated as well. All costs are defined from the perspective of the customer, which supports rate-making and budgeting with the regulator. In particular, the risk of failures captures the estimated customers' cost due to lost service.

Figure 3-42 shows graphically how the optimization is performed; using an example of a station transformer. The horizontal blue-dashed line is the leveled life-cycle cost of a new asset. The orange upward-sloping curve is the risk plus maintenance cost of the existing asset as it ages; this is known as the marginal cost. Risk is defined as probability of failure (which increases as an asset ages) times consequence cost of failure. As long as the marginal cost of the existing asset is lower than the leveled cost of the new one, it is cheaper to leave the existing asset in operation. When the curves cross, the marginal cost of the existing asset is higher than the cost of a new one, and the asset is at the end of its economic life. In the example below, the transformer would be replaced at about age 44.

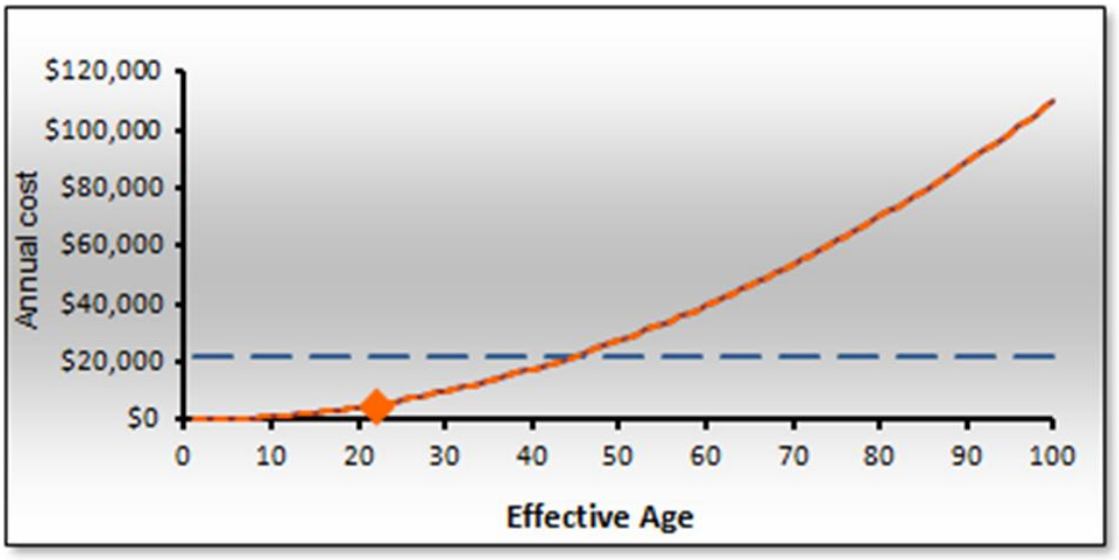


Figure 3-42: Station Transformer Optimization

Using this methodology, NBHDL determines how spending is optimized, prioritized and scheduled to align with budget envelops in accordance with the processes described in Sections [3.3.2 and 3.4] below.

3.3.1.2 Maintenance Planning Criteria and Assumptions

NBHDL's approach to maintenance planning is asset specific and location specific. It does not assign a constant economic life to all assets, but determines the economic life of each asset based on its unique role in the operation of distribution system. For example it is not possible to say that all station reclosers have an economic service life of thirty (30) years. Rather, NBHDL must say that this recloser has a 30-year life, but that one over there, which has different consequences of failure and different test results, has a different life. This analysis looks at each asset individually, and builds recommended spending plans from the bottom up.

The Feeder Investment Model (Section 5 of the ACA Report) also allows determination of which assets should be actively replaced when the risk of in service failure becomes unacceptable, i.e. power transformers in substations; and which assets are low risk and can be replaced after they have failed in service, i.e. small distribution transformers supplying non-critical loads.

Generally maintenance is not performed in a similar way to the capital program. The majority of the budget envelope allocated for line crews (approximately 60%) typically goes towards the execution of capital investments with the remainder being available for O&M. These remaining dollars are applied on an as needed basis to perform O&M. This value is subdivided among resourcing of employees and equipment, costs of disconnects/reconnects, locates, and reactionary maintenance (such as trouble calls).

NBHDL projects its maintenance program, discussed below, to exist under similar conditions in the forecast period that it has experienced in the historical period.

Changes to O&M costs associated with new NBHDL initiatives include: more aggressive tree trimming protocols, operational review and customer engagement. While there may be associated costs with these initiatives, NBHDL anticipates that the O&M work will be completed with the same level of staffing.

NBHDL further assumes that the preventative and reactionary maintenance protocols it has engaged through the historical period will continue to meet optimal efficiency for the forecast period given that it does not anticipate any capacity constraints or significant O&M changes due to capital investment.

3.3.1.3 Preventative Maintenance and Safety Inspections

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. NBHDL's maintenance program employs equipment manufacturer's recommendations as well as best industry practices in determining the scope and frequency of maintenance on power equipment. Maintenance programs also comply with the regulated requirements for maintenance established by the Distribution System Code.

NBHDL maintenance activities are divided into two categories: reactive maintenance and preventative maintenance.

Reactive Maintenance

This type of maintenance consists of activities that involve addressing infrastructure that is operating outside of normal specifications, in a state that will lead to imminent danger, is inoperable and/or has totally failed. Reactive maintenance is not planned and therefore is budgeted for with the use of historical trending and costing, whereas preventative maintenance is planned, and for the most part addressed cyclically.

Preventative Maintenance

This type of maintenance consists of planned activities that address assets on a cyclical basis to ensure continued reliable operation while preventing premature failure.

The following are preventative maintenance activities employed by NBHDL:

- Substation Monthly Inspections
- Substation Preventative Maintenance – 4 year cycle
- Pole Inspections – 1/3 each year
- Feeder Inspections – 1/3 each year
- Padmount and Vault Inspections – 1/3 each year
- Thermographic Infrared Inspection
- Power Transformer Oil Testing
- Vegetation Management
- 44kV Load Break Switch Preventative Maintenance

i. Substation Monthly Inspections

Each month, typically the first day of the month, every substation is visited by NBHDL substation personnel and a visual inspection on all major assets as well as the fencing, grounding and control building is conducted. The inspection is documented on a form and filed for future reference. Deficiencies are noted and addressed based on severity.

ii. Substation Preventative Maintenance

Preventative maintenance activities conducted on substations was a new initiative for NBHDL in 2010. A plan was developed on the basis of a 4 year cycle. As it was new to NBHDL the work was planned to be contracted out, however, NBHDL decided to bring the work in house, increasing substation worker productivity and reducing high contractor costs. In 2011 the substation staff received training on preventative maintenance activities and test equipment was procured. The internal program started slowly in 2012 but now involves the substation staff tackling 4 stations per year.

The work starts by totally de-energizing and isolating the station from the grid and the following activities are performed:

- power transformer testing
- leakage testing of all underground cables
- resistance testing of all connections
- cleaning of all major equipment, with attention to contact areas
- thorough visual inspection of all major assets, with attention to insulators and busswork
- torquing of all required connections
- lubrication of moving parts
- repair or replacement of items found to be in poor condition

Below is the current 4 year cycle substation preventative maintenance plan:

Station	2014	2015	2016	2017
MS1	X			
MS4	X			
MS7			*DC	
MS8		X		
MS9		*DC		
MS10	X			
MS11			X	
MS13			X	
MS14		X		
MS15	X			
MS16			X	
MS17				X
MS18		X		
MS19		X		
MS20				X
MS21				X

*DC = Decommissioning station

Table 3-5: Station PM Schedule 2014-2017

iii. Pole Inspections

As prescribed by the DSC, NBHDL conducts visual pole inspections on 1/3 of the poles within the system each year, allowing for all poles to be visited every 3 years. The visual inspection includes an assessment of the pole condition and provides the opportunity to also assess all attachments (dips, crossarms, guys, insulators, etc.). The results are contained within a database and deficiencies are addressed based on severity.

iv. Feeder Inspections

As prescribed by the DSC, NBHDL conducts a patrol on 1/3 of the feeders within the system each year, allowing for all feeders to be visited every 3 years. The patrol of each feeder starts at the substation and involves driving, or walking when required, the path of the entire feeder until all sections of the circuit are covered. The inspection is documented on a form and filed for future reference. All deficiencies are addressed based on severity.

v. Padmount and Vault Inspections

As prescribed by the DSC, NBHDL conducts visual inspections on 1/3 of the padmount transformers and vault locations within the system allowing all padmount/vault assets to be inspected every 3 years. Each inspection involves a site visit where all aspects are visually inspected, both externally and under the lid of the transformer (bushings, elbows, secondary connections, etc.). A checklist type form is used to document the inspection and all deficiencies are addressed based on severity. In vault scenarios, the room and access to the room is also assessed.

vi. Thermographic Infrared Inspection

NBHDL carries out thermographic infrared inspection every year on the overhead system. The entire subtransmission system is scanned, all substations are covered, and 1/3 of the distribution system is covered, including overhead transformers and switches. The oldest operating padmount transformers are also scanned when time permits. The work is done by a contractor each year who is accompanied by NBHDL staff and the work spans 4 business days.

A report is provided by the contractor upon completion of the work, identifying all the areas that require attention. The issues are categorized into the following categories, minor (addressed within 3 months), intermediate (addressed within 1 month), major (addressed within 1 week), and critical (addressed immediately). NBHDL corrects all issues within the recommended timelines.

vii. Power Transformer Oil Testing

The oil of all power transformers is sampled by NBHDL substation personnel every spring and sent away to a laboratory for analysis.

The following analysis is performed:

- Dissolved Gas Analysis (DGA)
- Oil Analysis
    - Dielectric Breakdown (ASTM No. D877)
    - Neutralization Number (ASTM No. D974)
    - Interfacial Tension (ASTM No. D971)
    - Specific Gravity (ASTM No. D1298)
    - Colour (ASTM No. D1500)
    - Visual Condition (ASTM No. D1524)
    - Water Content (ASTM No. D1533)

- Power Factor - 25 deg. C (ASTM No. D924)

A report is provided from the laboratory summarizing the results and recommending course of action with respect to the oil of each transformer. NBHDL has used the same laboratory for the last 10 years and therefore trending data is also provided with the report. In cases where the oil is unsatisfactory the transformer is removed from service and more thorough testing is performed.

Furan Analysis is also performed from time to time when there are signs of insulation stress. For NBHDL's Furan Analysis, NBHDL gets a recommendation from the sampling company. When the results of the analysis indicate no signs of paper stress, is the transformer is acceptable for continued use until a resampling is undertaken in approximately 3 years. Should the analysis indicate marginal or bad results, NBHDL would be required to remove the transformer from service. NBHDL then consults a transformer expert to ensure the transformer did not reach failure and cause any outages or damage or safety.

viii. Vegetation Management

This is the largest preventative maintenance activity NBHDL undertakes on a yearly basis. The City is divided into 4 sections with a total of 16 subsections (as can be seen in **Appendix N**) and NBHDL endeavours to complete tree trimming activities in one section each year, creating a 4 year tree trimming cycle. The work is contracted out each year via a competitive tendering process.

As referenced in Section 2.3.3.1 and in Appendix 4-E to Exhibit 4 (report from ArborWorks), NBHDL made drastic changes to the approach around tree trimming in 2012 in efforts to re-establish the power space by obtaining 4.5m (15') of clearance from the centreline of all polelines to vegetation on either side. The topping of trees is no longer an acceptable arboricultural practice and therefore NBHDL made the decision in 2012 to stop topping trees, causing a major change to the vegetation management program. This has led to the removal of a large number of trees over the past 3 years and an increase to program costs but will improve safety, reliability and reduce program costs in the future.

Some negative customer feedback has been a consequence of the change to the tree trimming approach, and NBHDL is considering a number of new initiatives going forward with respect to the vegetation management program, some of which are as follows:

- Education on planting trees around powerlines – "Right Tree, Right Place" campaign
- Initiatives that involve helping grow back tree canopy in the community (a number of ideas are being considered)
- Working with the City on ways to help promote trees
- Vegetation management program information to customers via bill inserts and/or messaging on the bill
- Consultation with the public on the program via focus groups or open houses

NBHDL is committed to providing safe, reliable operation of the distribution system, and this maintenance activity is one of most critical to achieving that.

ix. 44kV Load Break Switch Preventative Maintenance

The 44kV system directly services all of NBHDL's substations and all customers over 1MW in size and therefore the reliable operation of it is crucial to the overall performance of the grid. Due to the critical nature of the asset, NBHDL performs preventative maintenance on all 44kV load break switches. The goal is to address 1/3 of the 44kV load break switches each year, so that all 44kV load break switches are visited within 3 years. The maintenance involves isolating the switch, exercising the closing mechanism, realignment if necessary, cleaning all contact areas, visually inspecting the arc chutes and snuffers, ensuring all grounding is adequate, making any necessary repairs, and lubricating all moving parts. The work is documented on a form for future reference. There are times where the maintenance activity leads to the replacement of the switch.

3.3.2 (5.3.3 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 projects

Assessment Methods

A risk-based Asset Management Strategy was deployed as described in Section 3 of this report. The risk-based strategy assumes that the optimal time to replace an asset is at the minimum total cost when considering both the asset capital cost and the risk of failure of the asset.

For each asset, a risk cost is calculated and compared with the minimum total cost, and the asset is recommended for replacement when the costs are equivalent as is demonstrated in the following Figure 3-43 as was further explained in Section 3.1 above.

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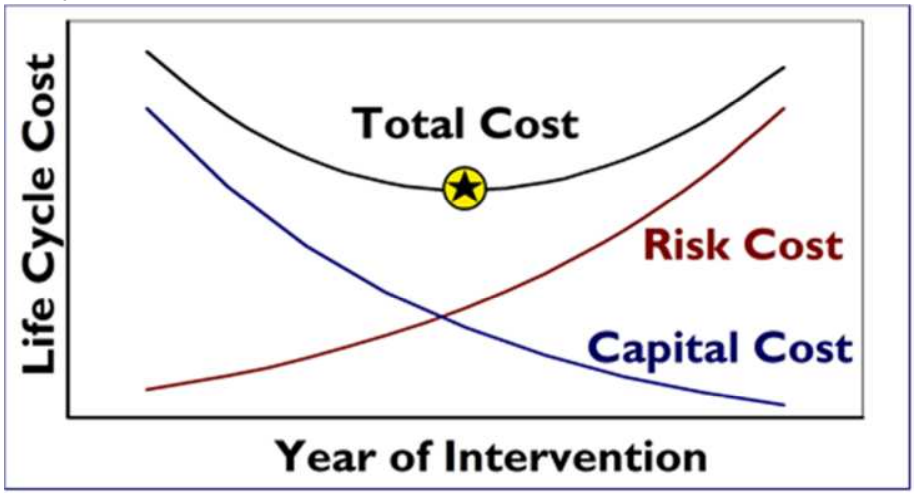

Figure 3-43: Risk Based Decision Support System

The risk costs are based on the consequence costs of a failure and the probability of that failure. The consequence costs are built up from a combination of the asset replacement costs, plus any additional costs likely to be incurred due to emergency asset replacement requirements, potential collateral damage due to catastrophic failure and the customer costs associated with a unplanned outage.

The current condition as per the asset condition assessment study, modifies the demographic age of the asset to arrive at an "effective age". The probability of failure is determined by plotting the "effective age" against the typical asset aging characteristics for that asset.

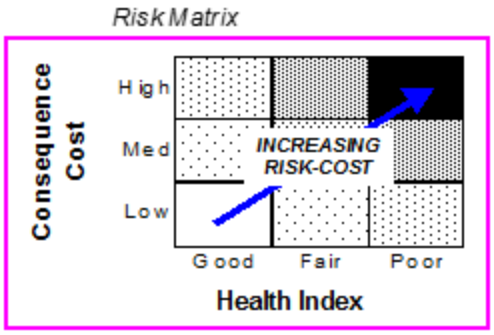

Figure 3-44: Risk Matrix

This assessment methodology, with effective age and appropriate risk scheduling, factors into NBHDL's condition based prioritization of projects. These inputs, as well as the other inputs in the Prioritization Matrix have allowed NBHDL to prioritize projects up to and including projects for the year 2015. This is further described below.

Specifically, the substation assets were prioritized based on a risk based assessment, poles, and conductors based on mean life expectancy age and the risk associated with decreasing health after mean life expectancy is passed and for distribution transformers and underground cable, risk to run to failure is acceptable.

The Voltage Conversion Plan prioritized the work from 2010 to 2014 and a Prioritization Matrix was developed to prioritize the 2015 projects and will be further refined with the tool being implemented through METSCO in 2015 for 2016 projects.

Assessment over the Historical Period

With respect to policies and practices in 2010 to 2014, NBHDL followed the AM plan prepared by METSCO in 2009 for the 2010 rate filing application. The main driver for replacement in that plan for poleline assets (pole, conductors) was mean life expectancy and it indicated the replacement of 4000 poles in a 10 year period. NBHDL made the decision to push for 150 poles per year and based expenditure amounts on that, which represented a major increase from years prior. The substation replacement program was based on a risk assessment done by Costello Associates and provided an overall score for each station. Any asset with a score under 55 was scheduled to be addressed within the rate filing period and all stations under that score were either totally rebuilt or decommissioned between 2010 and 2014.

With respect to underground servicing, NBHDL has made its decisions based on its inherent knowledge of the distribution system, age information of the assets and the limited underground survey information. Using this information, NBHDL made the decision to replace the assets upon failure. During this time, very few of these assets were deemed to require replacement as historically NBHDL has experienced very few failures with the bulk of primary underground serving. Therefore, based on this process, a very small amount of dollars were required for the renewal of these assets.

With respect to some other assets, distribution transformers for example, have always been a run to failure asset, as maintaining them or performing preventative maintenance is not economical. With that said, all transformers that are involved with rebuild projects are brought back in for testing and if deemed acceptable are placed back in inventory to be re-used.

Mitigation

Approaches to mitigation involve all maintenance activities defined in Section 3.3.1.2 & section 3.3.1.3 above.

4 Detailed Capital Investment Plan (5.4)

4.1 Summary (5.4.1)

4.1.1 (5.4.1 a) information on the capability of the distributor's system to connect new load or generation customers

NBHDL's system services the City, a city that has seen very flat growth over the past 20 years. There is very limited development in the City, however NBHDL is capable of handling all new or upgraded connections quickly. NBHDL is able to do this through implementation of efficient internal processes, appropriate resourcing requirements, and a system that has excess capacity and is in a state, for the most part, that does not inhibit service requests.

Due to the flat growth trend and excess capacity in the system (as seen in Table 3-2 in Section 3.2.2), very minimal expenditures have been planned over the 5 year horizon to address the capability to connect new load. The costs that are included are based on historical information. In the same vein, and as shown in Appendix F, the system is also able to allow easy connection of generator customers. The number of generator connections to the system has been minimal and therefore excess capacity remains throughout the entire system to allow connection of any prospective generation projects. As with the connection of new load, very limited expenditures have been planned to address the ability to connect generation customers.

4.1.2 (5.4.1b) Total annual capital expenditures over the forecast period, by investment category.

Table 4-1 below illustrates total annual capital expenditures NBHDL has planned for the forecast period:

		2015	2016	2017	2018	2019	TOTAL	AVERAGE
SR	System Renewal	$ 5,469,405	$ 4,180,343	$ 4,235,741	$ 4,266,049	$ 4,054,266	$ 22,205,804	$ 4,441,161
SS	System Service	$ 373,245	$ 214,743	$ 127,302	$ 89,044	$ 135,918	$ 940,251	$ 188,050
SA	System Access	$ 1,143,704	$ 1,166,578	$ 1,189,909	$ 1,213,707	$ 1,237,982	$ 5,951,880	$ 1,190,376
GP	General Plant	$ 771,603	$ 373,400	$ 549,000	$ 350,700	$ 642,000	$ 2,686,703	$ 537,341
	Total Capital Spending	**$ 7,757,956**	**$ 5,935,064**	**$ 6,101,952**	**$ 5,919,500**	**$ 6,070,166**	**$ 31,784,637**	**$ 6,356,927**

Table 4-1: Total Capital Expenditures

Importantly, these amounts are indicative of gross spending, not capital contributions.

4.1.3 (5.4.1c) 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 briefly describes the outputs of the asset management and capital expenditure planning processes for each of the 4 categories of investment as they have been described in this DSP.

Note that the outputs from condition assessment and asset management planning has the largest influence on the overall investment plan, which is evident by the spending associated with the system renewal category. This is to be expected as NBHDL's system is of an older vintage with a number of assets at or approaching end of life and therefore requiring renewal.

4.1.3.1 System Access

As mentioned in Section 1.2.1, System Access projects have not been a significant concern for the purposes of this DSP as NBHDL is currently experiencing no constraints on capacity and customer connections are done on an as requested basis. With the limited growth in customer base that NBHDL has experienced and expects to experience in upcoming years, limited capital expenditures are anticipated for the forecast period.

Further, capital contributions relating to road relocates and other municipally driven projects are expected to remain stable for the forecast period. As these asset projects are expected to remain stable and be reactive, the output of NBHDL's asset management and capital planning processes is expected to have a minimal effect on System Access investments.

That being said, NBHDL (with the assistance of METSCO) tabulated anticipated System Access investment requirements for 2015 that was inclusive of outputs from Customer Service Requests and Road Relocations for the forecast period.

To reach an informed start point for the forecast period, NBHDL used the 5 year historical averages of customer service requests and road relocations and formulated the 2015 capital expenditure estimate. Customer Service Requests was based on the following subcategories: transformer purchases, primary services, secondary services, subdivisions and minor betterment projects. These categories as well as road relocations are described below.

<u>Transformer Purchases</u>

This category represents the purchase of new overhead and underground distribution transformers used for the following reasons;

- *Asset Renewal & Rehabilitation*
- *New/Upgraded Services*
- *Special Projects.*

Although NBHDL maintains a small stock due to long lead times, backup, and emergency use, distribution transformers are for the most part ordered as required.

<u>Primary Services</u>

This category represents the capital work necessary to rehabilitate and/or expand plant to service new customers or maintain existing customers, residential and general service, over the 400A threshold.

Secondary Sources

This category represents the capital work required to upgrade existing or to install new secondary service wires, overhead and underground, from distribution plant located on the municipal street or in easements on private property to customer's premises. The majority of the work involves the services to the residential class.

Subdivisions

This subcategory represents the capital work required in subdivisions due to developer driven demand. The expenditure represents cost to provide material to developers, and NBHDL labour to install transformers and make primary and secondary connections. Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.

Road Relocations

This category represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground facilities installed within municipal or provincial owned road allowances. Based on a legislated cost sharing formula, the City or MTO, contribute 50% of all labour, labour saving devices, and equipment costs. In the case where the governing body directs NBHDL to replace overhead plant with underground plant the governing body funds the cost differential between overhead and underground.

Minor Betterment

Minor Betterment projects ("MINBET") are minor lines and engineering related projects that NBHDL undertakes and involve the following:

- *The rehabilitation or expansion of HV lines required to service new residential and general service customers (5 or less poles*)

These projects involve the rehabilitation or extension of HV lines to new customers to meet customer service obligations in accordance with the OEB's DSC and NBHDL's COS. These projects are often unplanned when NBHDL discovers that a new user is not in a position to receive service and the nearby assets are required to be renewed or reconditioned.

- *Small Renewal Projects (5 or less poles)*

These projects involve the renewal of assets that reach end of life and must be replaced. NBHDL completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In all cases the projects involve spot replacement of assets; new assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project.

NBHDL tabulated anticipated MINBET projects for 2015 to inform the capital expenditures for the forecast period. Within the forecast period, approximately 31% of the total capital expenditure for projects fall underneath the umbrella of System Renewals and System Service accounts for 2.8% of the expenditure for these projects. The bulk of the expenditure (the remaining 66.4%) is accounted for underneath System Access. NBHDL took 2015 total MINBET costs (based on a 5 year historical average) and applied the historical average % of MINBET jobs that were related to each of these categories (from the historical period 2010 through 2013) – costs are then escalated by inflation each year.

Forecast years

For the forecast years that follow the output of the System Access baseline described above, an inflation rate of 2% per year has been applied.

4.1.3.2 System Renewal

As described in this DSP, NBHDL's System Renewal projects and related capital expenditures are driven by a series of factors, metrics and methods including the AM Strategy, Prioritization Matrix and ACA Report.

These renewal projects are directly linked with the asset management and capital expenditure planning processes and the allocation of budget is dependent on the outcomes derived from them.

As will be seen below in Section 4.1.8, NBHDL has categorized its investment in System Renewal by the following subcategories: transformer purchases, major betterments, voltage conversion projects, MINBET, distribution substation construction, distribution substation transformers and miscellaneous projects. NBHDL has further provided its justifications under Section 4.5 to each of these subcategories. For the purpose of this Section 4.1.3.2 however, the outputs are determined by the ACA Report.

The ACA Report provided NBHDL with a model output for capital investments in the System Renewal categories of: substations, wood poles and underground cable replacements. These outputs are relied upon to justify the capital expenditure and inform the asset management process. The following subsections discuss these outputs.

Substations

Investments in the substation category are driven mainly by the requirement to replace end of life assets that are in poor or very poor condition as determined by the ACA report. Substation assets affect the greatest number of customers upon failure, and therefore NBHDL takes seriously the requirement to address assets that have fallen past their useful life and pose a threat to reliability, safety and cost control. Figure 4-1, reproduced below from the ACA Report, indicates the overall health of NBHDL`s substations.

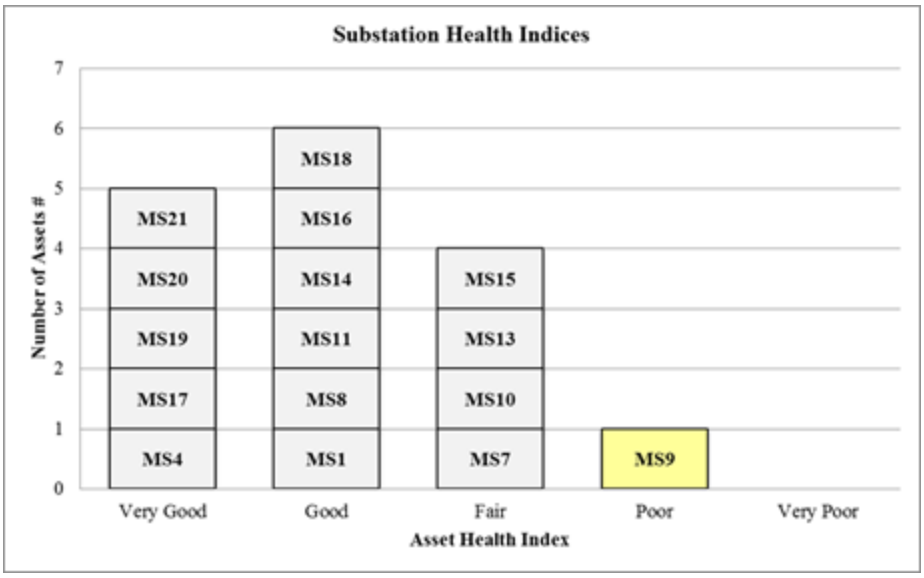

Figure 4-1: Substation Health Indices

Investments in 2015 will include the replacement of a substation (MS9) that is in poor condition with a state of art station (MS22) that will ensure continued reliability for the service area and eliminate current safety hazards. This will be the last of the 4 substations in poor condition to be replaced and will continue on the 2 year replacement strategy of stations, based on affordability, started back in 2009. The large investment in 2015 will be the last full replacement project needed for the next 10 years, as the investments will have addressed all the poor substations operating at the end of their useful lives. Over the rate period, there will be equipment replacements in this category to address parts of substations, but the expenditures will be substantially less than when compared to the previous 5 years as no further full replacements are required. Over the 5 year period, and currently scheduled for 2016, one substation, MS7, will be eliminated as a result of the completion of the voltage conversion plan.

Wood Poles

The ACA Report identified pole line assets that are currently past their TUL, but still in service on NBHDL's overhead distribution system. Figure 4-2, reproduced below from the ACA Report, indicates the health index of wood poles employed on the distribution system.

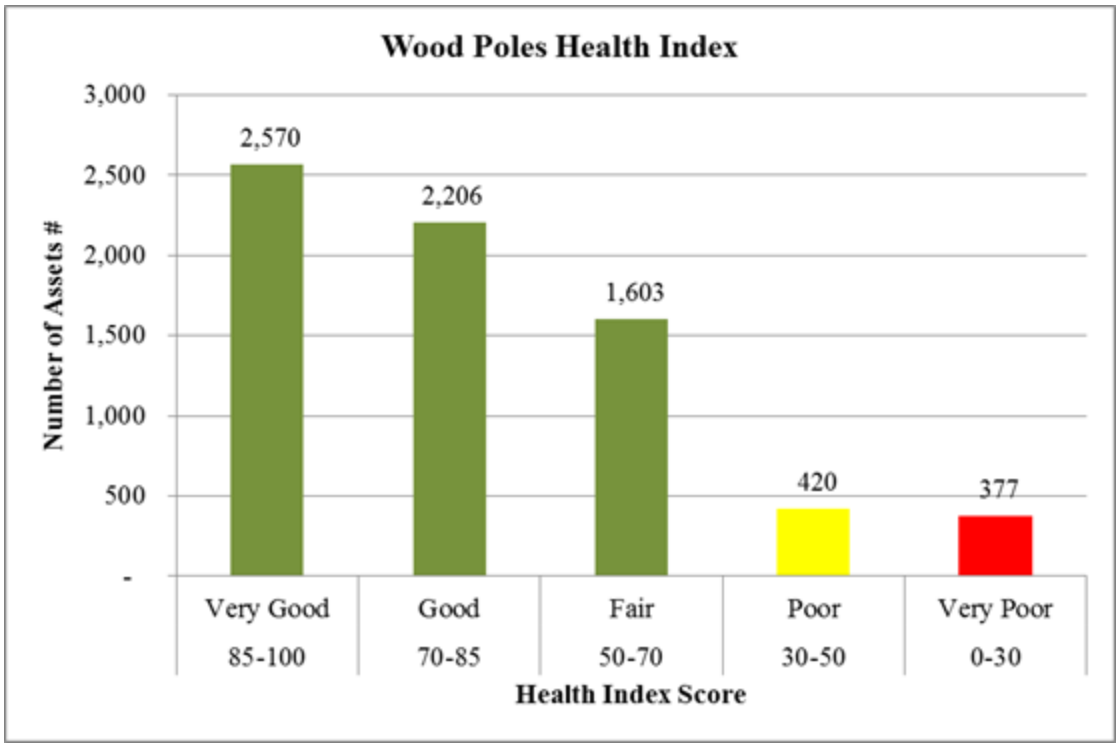

Figure 4-2: Wood Pole Health Index

METSCO recommended approximately 1598 wood poles for replacement during the next five years: 377 shown in "very poor" condition, 420 shown in "poor" condition and 801 shown in "fair" condition. Since voltage upgrade of lines offers other economic benefits in addition to reducing the risk of asset failures, poles in "very poor" and "poor" condition employed on the 4 kV lines are recommended to be given priority in conjunction with the implementation of line voltage upgrades.

i. Model Output

Following the completion of this plan, the ACA Report model output informed the process of determining capital expenditure for the forecast period. METSCO identified an output based on an ideal rate of pole completion of 319 poles per year. At this rate of renewal, METSCO provided NBHDL with the capital expenditures required for 2016 to 2019.

The number of poles proposed in the DSP to be replaced in the forecast period is much less than the number of poles recommended to be replaced in the ACA Report. NBHDL determined that the rate of renewal determined by METSCO was untenable given such factors as equipment & worker availability and level of investment given budget considerations. In addition, NBHDL made the decision to pace its program to mitigate the rate impacts that would occur if all of the high risk assets were replaced during the next five years, as recommended in the ACA Report.

NBHDL reached a compromise in electing to renew the wood poles at 200 per year. This value provides the optimal or "levelized" plan for 2016 through 2019. The outputs provided in Section 4.5 below are informed by this levelized plan implemented by NBHDL with the support of METSCO.

Underground Cable Replacements

Investments in this category are driven, like both the categories above, by the requirement to replace end of life underground cable assets that are in poor or very poor condition as determined by the ACA

report. Investments in this category are aimed at ensuring reliability is maintained, but more importantly ensuring that O&M costs are controlled. Cable failures, especially cables that are direct buried, a characteristic of cables in this age demographic, are extremely costly to repair, as excavation in built up urban areas is very expensive. The program is aimed to proactively replace cables to avoid the high customer impact that is associated with their failure.

Figure 4-3 & Figure 4-4, reproduced below from the ACA Report, indicate the overall health of NBHDL`s underground cabling, split by voltage class.

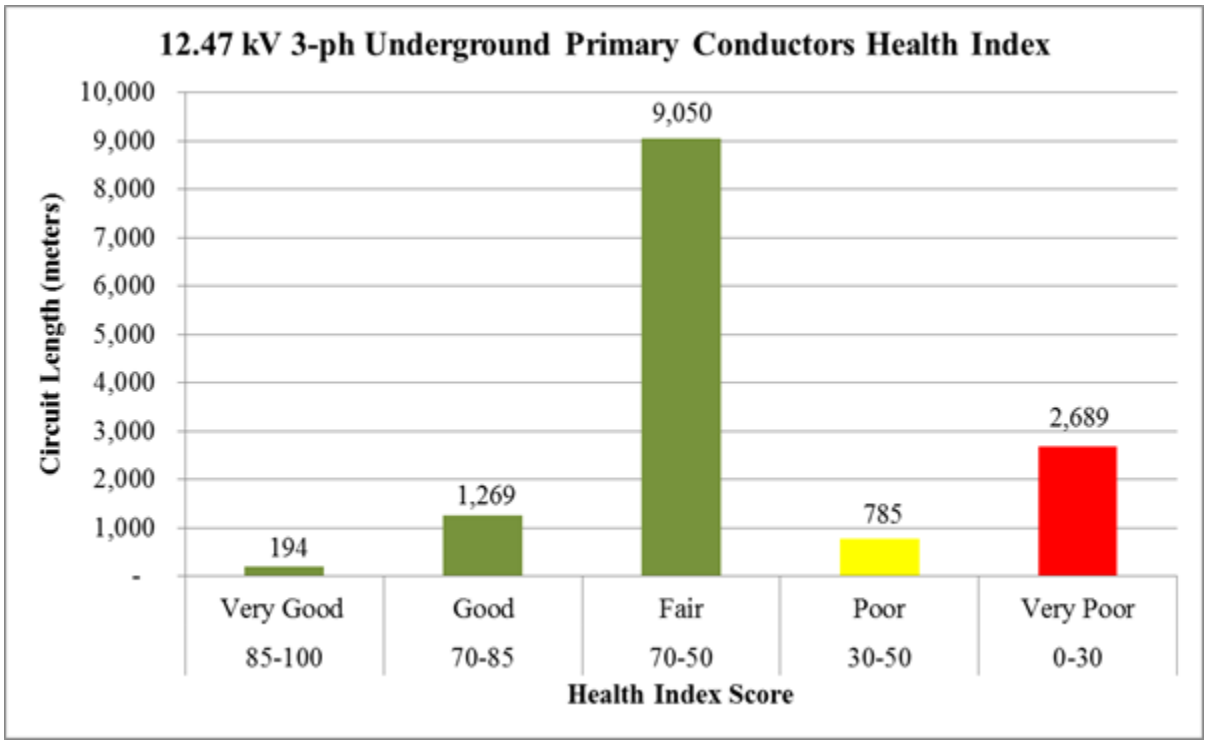

Figure 4-3: 12.47 kV - Underground Primary Conductors Health Index

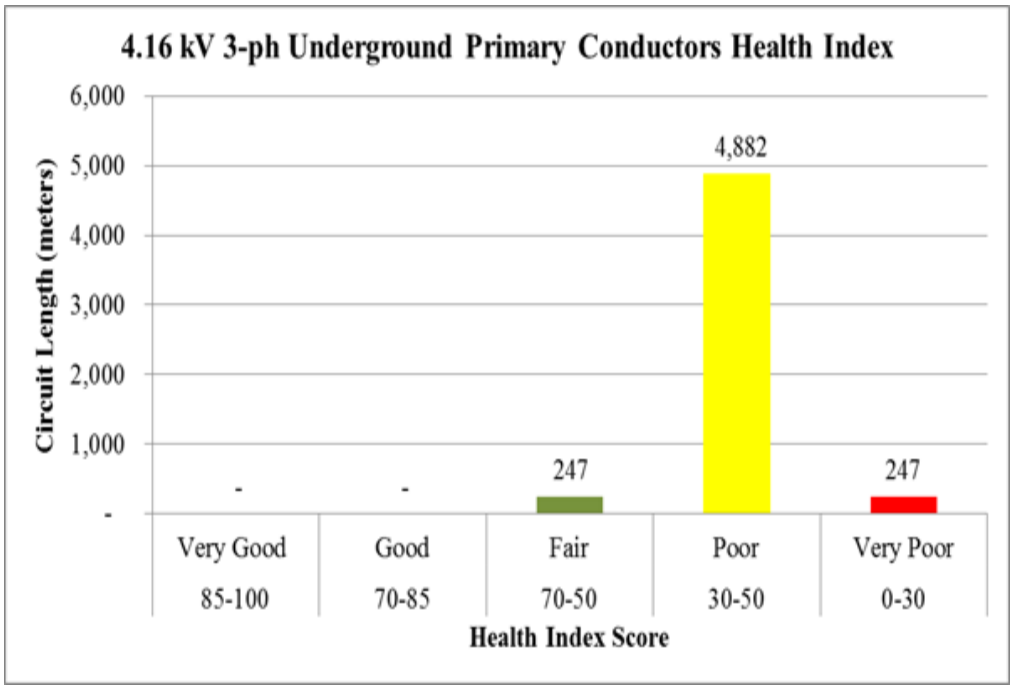

Figure 4-4: 4.16 V - Underground Primary Conductors Health Index

The ACA Report states that the replacement of cables determined to be in poor and/or very poor condition present a high risk of failure in service and are recommended to be replaced during the next five years. In relation to high voltage cabling, five large townhouse developments that have outdated design direct buried secondary underground systems which contribute significant costs to the annual O&M envelope in the form of cable failure and the resulting repairs have been identified in the ACA Report as requiring immediate replacement. Three (3) of the five (5) projects have been scheduled for renewal in 2015 and the other 2 will be tackled in 2016. The plan from 2016 and out is levelized and will involve tackling underground primary cables with the highest risk of failure to the lowest. Cable injection is being considered as an alternative to full out replacement, and a pilot project will be attempted in 2016 to assess the feasibility of that technology.

4.1.3.3 System Service

As identified in Section 1.2.3 above, projects in the System Service category are typically driven by capacity constraints. These projects can include capital investments aimed at improving system operations, reliability and efficiencies through voltage upgrades, distribution automation, intelligent devices or equipment, all aimed at enhancing customer value and operational effectiveness. NBHDL has not identified any anticipated capacity constraints for the duration of the forecast period but does perform other asset management projects under this category. These projects have been categorized as: metering, SCADA, feeder conversion and minor betterment projects.

Metering

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities.

To meet the Filing Requirements and objectives of the Board's RRFE, NBHDL contracted Util-Assist to document a Metering Capital Plan. NBHDL further considered the Board's Notice of Amendment to A Code for EB-2013-0311 for this process. As part of this planning process, regulatory requirements were

considered, including the proposed amendments to the DSC which will have an impact of all Ontario LDCs and the manner in which General Service ("GS") customers are metered and billed. While these proposed amendments do not include reclassification of customers, there are possible impacts to the metering strategy and the business processes associated with the billing of customers currently residing in the GS>50 kW through GS<500 kW rate classification.

The proposed strategy transitions NBHDL from the traditional – and manual – metering and billing process, to one that embraces technology and leverages existing infrastructure for a more automated process that is expected to result in process efficiencies and increased data being available for analysis. This will lead to other business process improvements commonly realized through Smart Meter – and indeed Smart Grid – installations.

The plan accounts for capital and operating costs over the period of 2014 to 2019, which will result in the replacement of more than 300 meters. The outputs of the Util-Assist Metering Capital Plan (Util-Assist Report attached as **Appendix O**) informed the capital expenditures for metering that are presented in Section 4.5 below.

SCADA

NBHDL's SMART GRID Initiative involves equipping all the distribution stations SCADA. This initiative has provided output for 2015 only as part of the substation MS9 reconstruction. Once MS9 is reconstructed the initiative goal will be complete. There are no outputs for 2016-2019 in this category.

Feeder Conversion

A number of NBHDL's feeders that have been upgraded or will be upgraded to the 12.47 kV construction standards are currently operating at 4.16kV due to the NBHDL system configuration. Upon upgrade, a modest capital expenditure will be required to change taps of the dual rated transformers to the higher voltage setting and replace fusing to match the lower current requirements. Table 1-4 in Section 1.2.3 shows a list of all the feeders that will be converted from 4.16 kV to 12.47 kV operations, during the forecast period.

Minor Betterments

As identified above, and can be seen in Appendix 2-AA of this Application, the System Service segment of minor betterments project falls below the materiality threshold. Therefore this bucket of project dollars has been deemed immaterial.

4.1.3.4 General Plant

General Plant outputs differ from the outputs of the above categories. The ACA Report has no bearing on the capital investments projected for the General Plant category. As discussed in Section 1.2.4, NBHDL retained several third party consultants to prepare assessments of the individual asset categories of General Plant that NBHDL considered for capital investment. These categories were:

- Motor fleet;
- Office/Building/Furniture;
- Tools; and
- IT.

Motor Fleet

The Fleet Assessment, attached as **Appendix D**, provided output requirements for the entire forecast period. The assessment report prepared for NBHDL identified which fleet assets required replacement and for what reasons. Typically the assets were identified based on age and condition. The Fleet Assessment provided output specifications such as replacement schedules, duty cycles and priority of assets.

Building/Office Upgrades

NBHDL retained consultants to provide the Building Assessment, attached as **Appendix C**, to identify whether there was any major work required during the five (5) year forecast period of the DSP. The purpose of this official determination was to adequately identify whether there was sufficient capital for any required works in the budget envelope or through the DSP process. This report provided NBHDL with high level outputs on all maintenance required at its headquarters as well as major concerns to be addressed. The Building Assessment identified that the HVAC system was in poor condition and the generator was undersized for the facility. These findings were the two initial major outputs of the Building Assessment and supported NBHDL's capital spending in 2014.

NBHDL started work on the HVAC system in 2013 and it is nearing completion as of the date of this DSP. This represented $150,000 of capital that is not represented in the capital expenditure forecast projections. NBHDL will similarly have completed the resizing of the generator ($160,000) prior to 2015 and the forecast period.

Another key output of the Building Assessment was the safety concerns represented by the asphalt driveway at headquarters. Currently, all of the NBHDL operational vehicles exit the facilities in the same location as customers enter. NBHDL has undertaken to move its gates and redesign its driveway to prevent this issue. This project will should also be completed by the end of 2014, but may be shifted into 2015 depending on practicality and other construction requirements.

Given that the majority of the capital outputs presented by the Building Assessment will likely be completed by 2014, NBHDL will have minimal capital requirements for the forecast period. The remaining outputs for Building/Office Upgrades represent minor capital expenditure in the order of $25,000 per year.

Tools

This category includes such items as: Live line tools, chainsaws, drills and other operational equipment. The tools category in General Plant is typically informed by on the ground information and direct feedback from employees. These requirements tend to fluctuate and the cost has been significantly higher in recent years than historically due to varied requirements. That said, NBHDL has made efforts to optimize tool requirements and anticipates no major capital expenses for the forecast period.

IT System

The IT Assessment, attached as Appendix 4-B to Exhibit 4, identified risks and key areas for improvement as follows:

(i) Improve TOU billing process;

(ii) Enhance NaviLine utilization;

(iii) Establish a robust demand management program;

(iv) Develop "Business Continuity" & execution of smart meter operations;

(v) Improvement of IT general controls & IT infrastructure;

(vi) Further utilize SunGard testing environment for regulatory changes;

(vii) Reassess advanced metering infrastructure operations;

(viii) Improve vendor management / communication with SunGard & Sensus; and

(ix) Develop policies & processes for "Disaster Recovery Planning."

NBHDL has reviewed these identified risks and has begun strategically planning for its IT service requirements through to 2020 ("IT Strategy"). The IT Strategy is provided as Appendix 4-C to Exhibit 4.

Generally, the IT Assessment indicated that NBHDL needed to ensure adequate investment in hardware, hardware replacement and server backups. The projected data from the IT Assessment required that the hardware should be replaced on an as required basis with the risk assessment being a major upfront cost. Some key output elements were ensuring improvement in the customer billing process and utilization of systems to find efficiencies and streamline the process. All of these outputs factor into NBHDL's IT strategies but do not reflect significant capital costs.

In addition, NBHDL intends to stay with its current Customer Information System provider and therefore anticipates no significant software requirements for the forecast period.

4.1.4 (5.4.1d) A list and brief description including total capital cost of material capital expenditure projects/activities, sorted by category

NBHDL has prepared a list of expenditure projects/activities as part of Table 2-AA of the Application for the historical period up to and including 2015. This list of projects and descriptions for the historical period (with total capital cost of material capital expenditures) as well as the 2015 year is attached as Appendix P. NBHDL does not have a specific list of projects and descriptions for beyond 2015 in the remainder of the forecast period.

Starred items in Appendix P (for the 2015 Test Year) are not justified through a capital project summary. Despite the fact that these line items exceed the materiality threshold, they are comprised of a series of individual items that do not exceed the materiality threshold. Each of these items are reviewed and approved or denied on an individual item by item basis during the annual budgeting process with the exception of projects driven by customer demand (for example minor betterment projects). As such, NBHDL has not prepared bucket sum capital summaries for any of these grouped capital expenditures as the individual items in each bucket are immaterial.

4.1.5 (5.4.1e) 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

NBHDL has fulfilled its obligations with respect to the RPP, but at this time, neither a RIP, nor an Integrated Regional Resource Plan ("IRRP") has been completed for NBHDL's service territory.

As stated in Section 2.2.1, NBHDL received a letter (attached as **Appendix I**) from HONI on April 2, 2014 confirming that the RPP has not been initiated nor has a RIP been developed for the sub-region within the North/East of Sudbury Region affecting NBHDL. HONI also stated in the letter that the RPP for the

North/East of Sudbury Region is expected to be initiated in fourth quarter of 2015. Given this information, the RPP has had no material impact on the expenditure plan in 2015. NBHDL is committed to the process and will continue to participate as the process evolves.

4.1.6 (5.4.1f) 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

Formal Process

NBHDL began a more formal process of engaging customers in an attempt to gather information on preferences and customer satisfaction throughout 2013 and 2014. As discussed in Section 2.2.1.1, NBHDL has undertaken a series of customer service initiatives to obtain more formalized input of customer preferences. Several customer surveys focusing on both residential and business customers were completed at a local level to garner feedback on overall satisfaction and preferences. From those surveys, engagement sessions were hosted to garner additional information on how customers wanted to be engaged and what NBHDL could do to improve communications, education, and service. These activities took place throughout NBHDL's budget and planning process. NBHDL engaged Simul Corporation to provide a UtilityPULSE survey for a more in-depth survey on a wide range of topics, including: overall satisfaction, reliability, trust, customer care, outages, billing, management operations and corporate image. This survey provided NBHDL will additional insight as to where the company stood in comparison to others surveyed both provincially and nationally. NBHDL retained the services of Innovative in mid-2014 to specifically talk to customers about NBHDL's 2015 proposed capital and operating plans and the proposed rate increases to customers that are a result of the 2015 Cost of Service application.

Throughout this process, the constant message NBHDL has heard is that customers are satisfied with the reliability of the system and the service that NBHDL provides and they want NBHDL to maintain those levels. Customers, for the most part, understand that it costs money to invest in infrastructure in order to maintain reliability and that to postpone that spending causes problems down the road for future rate payers. NBHDL's DSP is a reflection of that; the primary focus of NBHDL's discretionary capital spending is on infrastructure renewal that addresses assets in need of replacement. Annual planning of projects is based on affordability; the consideration of NBHDL's resourcing capabilities and the prioritization of projects. Non-discretionary capital spending in the DSP is related to customer demand and NBHDL must meet the regulatory obligations of this spending.

Informal Process

Informally, NBHDL responds to a variety of calls on a daily basis from customers in relation to events taking place in the field. Calls regarding all types of issues - power outages, car accidents, fires, equipment issues, traffic lights not working, lines down on a roof, objects touching power lines, etc. are received on a daily basis. Calls are transferred to NBHDL's Operations Dispatcher and the service truck is dispatched within 30 minutes of the call to address the issue. If the service truck is unavailable to respond to the customer within a relatively short amount of time, the Operations Supervisor will dispatch another truck to the site. During evenings and weekends, an answering service will contact a single operations staff on duty – who would typically be arrive at the location within an hour. That person assesses the situation before making a decision on what, if any, incremental resources are required to quickly and safely respond to the situation. If incremental resources are required the person on call consults first with the supervisor on duty.

NBHDL also receives a significant amount of calls related to tree trimming which are transferred directly to the individual responsible for the program in the Engineering department, who contacts the customer and then determines next steps in terms of resolving the issue.

These informal measures allow NBHDL to engage customers on a case-by-case basis and respond as necessary. Whether responding to an acute residential concern, or a meeting with a larger commercial customer, NBHDL is able to ascertain the needs of the customer and leverage that information against its O&M procedures and future decisions as warranted. This information and feedback does not directly impact the DSP but does provide opportunity for NBHDL to ensure its goals are aligned with customers' needs on a more granular level.

4.1.7 (5.4.1g) 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

NBHDL expects growth of the system over the next five years, both from a number of customers and load perspective, to follow a flat trend, which is consistent with the previous 5 years.

With respect to smart grid development, aside from the implementation of SCADA at the new station planned in 2015, very few smart grid initiatives are planned over the five year horizon. Projects that are tackled will centre on enabling an easier exchange of data to and from the customer, and leveraging information gathered via smart meters and SCADA, or will involve very small, low cost ideas that will help improve efficiencies with respect to grid operation (i.e. installation of fault indicators, and/or voltage and line current sensors). The cost benefit to customers to automate high voltage switches cannot be justified currently in the NBHDL system.

NBHDL 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 system. The expectation is that the amount of connections over the next five years will be less than or equal to the amount of connections from the previous 5 years.

The biggest change to NBHDL's system over the next 5 years will be the elimination of the 4.16kV system which has been a 25 year goal for NBHDL. The Voltage Conversion Plan to eliminate the lower voltage system took strong shape in 2010 and was refined further in 2012 to ensure completion of the voltage conversion by 2017. Completion of the Voltage Conversion Plan will represent a substantial achievement for NBHDL that has a number of significant benefits to the operation of system.

4.1.8 (5.4.1h) A list and brief description including where applicable total capital cost of projects/activities planned

NBHDL's plan includes the projects/activities listed below in Table 4-2:

2015 Capital Projects Table		
Projects	**(1) - Customer Preference (2) - Technology (3) - Innovation**	**2015 - Total Forecast**
Reporting Basis		**MIFRS**
System Renewal:		
Transformer Purchases - Various Jobs	2	284,135
Major Betterment Projects		
Turret Complex - Madelena	1	529,572
Turret Complex - Melina Close	1	293,306
Turret Complex - Wickstead	1	436,521
Voltage Conversion Projects		
Fourth Avenue	1	147,188
Fifth Avenue	1	154,232
Fraser South - 12kV	1	116,034
McIntyre Street	1	452,969
Ferguson Street	1	278,780
First Avenue	1	136,126
Regina Street	1	81,248
Main Street West	1	215,217
Sherbrooke Street	1	112,822
Minor Betterment Projects	1	106,591
Distribution Substation Construction		
MS# 22 - Replacement of MS# 9	2	1,781,297
Distribution Substation Transformers		
MS# 13 - Transformer Replacement - T1	2	271,470
Misc. Projects <$65k on individual project basis*	1	71,897
Sub-Total, System Renewal		**5,469,405**
System Service:		
Capital Infrastructure Modernization	1, 2	199,213
Misc. Projects <$65k on individual project basis*		
Meters	1, 2	25,000
Substations, SCADA and Misc. Projects	2	15,735
Major & Minor Betterment Projects	1	9,851
Feeder Conversion Projects - 5 Individual Projects <$65k/project*	1	123,445
18F1, 18F2, 18F3, 7F2, and 1F1		
Sub-Total, System Service		**373,245**
System Access:		
Transformer Purchases - Various Jobs	2	95,113
Minor Betterment Projects	1	230,102
Primary Services Projects	1	217,820
Secondary Services	1	249,365
Subdivisions	1	100,973
Road Relocations Projects	1	212,218
Misc. <$65k on individual project basis	1	38,112
Sub-Total, System Access		**1,143,704**

2015 Capital Projects Table		
Projects	**(1) - Customer Preference (2) - Technology (3) - Innovation**	**2015 - Total Forecast**
Reporting Basis		**MIFRS**
System Access:		
Transformer Purchases - Various Jobs	2	95,113
Minor Betterment Projects	1	230,102
Primary Services Projects	1	217,820
Secondary Services	1	249,365
Subdivisions	1	100,973
Road Relocations Projects	1	212,218
Misc. <$65k on individual project basis	1	38,112
Sub-Total, System Access		**1,143,704**
General Plant		
Building & General Office Upgrades, including Furniture		26,300
Operations Facility Upgrades - Garage, Yard, Driveway & Warehouse		36,652
Fleet Replacement - Bucket Trucks, Radial Boom Devices & Trailers		370,000
Fleet Replacement - Vehicles < 3 Ton, <$65k on individual project basis		145,000
Work Equipment		46,151
Servers, PC, Other Hardware, <$65k on individual project basis	2, 3	126,500
Software	2, 3	21,000
Sub-Total		**771,603**
Contributed Capital		
Contributed Capital from Customers		(503,987)
Sub-Total		**(503,987)**
Miscellaneous		-
Total		**7,253,969**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*		-
Total		**7,253,969**

Table 4-2: 2015 Capital Projects Table

Table 4-2 above is indicative of NBHDL's planned projects and activities for 2015 forecast. These projects are divided up by the 4 asset categories and labelled with one of three identifiers: 1) Customer Preference, 2) Technology; and 3) Innovation.

4.1.8.1 Customer Preference

Through NBHDL's customer engagement, certain factors such safety, reliability and cost have all been identified as concerns at a residential and business level. Customers have indicated that they would like reliability maintained and have an obvious and demonstrated preference towards safety. NBHDL's infrastructure System Renewal projects address these at a broad level. Through the DSP however, there are no projects that address specific customer preferences in relation to capital spending and the costs included in the DSP. NBHDL uses the information derived from customer engagement pieces to ensure

its decisions are aligned with customer preference and that its decisions are valid based on the customer feedback generally, but no projects are implemented as a direct and/or sole result of any particular feedback or customer engagement as of this DSP. The projects indicated above as being related to customer preference therefore are projects that align with customer preference as opposed to projects solely driven by such preference. This makes up a majority of projects identified by NBHDL for 2015 capital expenditures.

NBHDL will continue to ensure that its prioritization of capital expenditure projects is aligned with customer preference for the forecast period and anticipates that its goal of maintaining reliability within the system will achieve that alignment.

4.1.8.2 Technology Based Opportunities

In taking advantage of technology-based opportunities to improve operational efficiency NBHDL will continue to evaluate options with respect to technology as it becomes available throughout the filing horizon. The rollout of the SCADA system to all municipal substations will be completed in 2015 and in 2014 the backbone of the SCADA system, the communication medium, was upgraded to a WIMAX based system operating on the 1.8GHZ spectrum gifted to utilities for the "operation, maintenance, and management of electric supply" by Industry Canada. At this time plans do not exist for the implementation of any other communication based projects in the rate period, but the WIMAX system will easily allow for the following systems to be implemented in the future:

- Fleet Management
- Distribution Automation
- Integration of Distributed Generation
- Outage Management System

NBHDL will also continue to populate and update the AM model implemented in 2013/2014 over the rate period.

The technology currently in place easily allows the integration of distributed generation and complex loads, but NBHDL will continue to evaluate new technologies as they are presented. At this time no material projects are scheduled over the rate period.

4.1.8.3 Innovative Processes, Services, Business Models or Technologies

To demonstrate innovative processes are of continuing importance, NBHDL is completing the automation of additional daily business activities including payroll and the transformer inventory. Both projects will eliminate paper, allow for analytics reporting, and provide efficiencies over the current processes. While these activities see the bulk of investment as part of 2014, implementation and transition will be part of 2015.

NBHDL is also considering the use of cable injection to address the aging underground primary cabling in the system. As trenching in built up urban areas can be extremely costly, injection will extend the life of the cables while providing significant cost savings. NBHDL will try this innovative technology as a pilot and evaluate it to see if it is a viable option for the entire underground system in need of replacement.

In addition to the innovations that were initiated in 2014, NBHDL has been planning innovation for 2015 and the rest of the Forecast Period. Some specific examples of innovative efforts of NBHDL include, *inter alia*, Mobile Notebooks for use in fleet vehicles, the purchase of an 'initializer' for Smart meters which allows for GPS coordination, upgrades to system PCs and server upgrades.

As indicated in Exhibit 1, NBHDL will also continue to utilize 'just in time' delivery to manage stores and material levels. NBHDL intends to continue to purchase materials through the Northern LDC Buying Consortium which is forecasted to save $115,000 in 2015 versus buying outside the Consortium (which savings are built into the forecasted costs of this Application). NBHDL has also made improvements in its systems control room such as a newly integrated mapping/distribution layout.

NBHDL's Engineering and Operations departments are closely integrated to increase efficiency and productivity. Every capital project designed by Engineering is reviewed or co-designed with Operations to make sure the required work can be completed quickly and safely. Often real-time adjustments are made to designs as crews send in pictures via mobile communications for review by Engineering. In 2015, NBHDL is planning to review these functions, how they design, hand-off, execute and report on projects with the objective of formalizing processes, implementing measures to manage to, and increasing efficiency where possible. Technology is evolving and there could be opportunities for greater application on the front line.

4.2 Capital Expenditure Planning Process Overview (5.4.2)

4.2.1 (5.4.2 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 capital expenditure planning process employed by NBHDL consists of the following steps:

- Determination of investment level needed for NBHDL to meet its regulatory obligations (i.e. the level of investments required for System Access projects);
- Determination of investment level needed to maintain adequate capacity margins to supply system security and to improve operation efficiency,(i.e. investments required for System Service projects);
- Determination of investments required to maintain general plant operating safely, reliably and efficiently to support services;
- Determination of economically efficient investments into the system to maintain safety, and reliability while minimizing O&M costs i.e. the level of investment required for System Renewal, as described in detail in Section 3;
- Summation of all of the investment components to determine the overall investment needed;
- Assessment of capacity to complete all planned investment and adjusting investment levels if needed; and
- Evaluation of capital investment impacts on rates and scaling back of the investment levels if needed.

The level of non-discretionary investments required for System Access projects is determined through consultations with the municipal government and major residential and commercial developers in the region, and the use of a 5 year rolling historical average. The level of investments needed for System Service projects is determined through load forecasts and identification of capacity constraints and operating inefficiencies in the power supply system. The investments into System Renewal are determined through condition assessment of assets and identification of economically efficient investments, which is further assisted through the Prioritization Matrix and future prioritization protocols

being developed by METSCO. Investment requirements into General Plant are determined through condition assessment of motor vehicles, building facilities and IT systems.

Due to the system's capacity to easily allow connection of renewable generation facilities, there are currently no specific objectives set to address the accommodation of new REG projects.

4.2.2 (5.4.2 b) 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 RPP in identifying and assessing alternatives

As previously mentioned the RPP has not yet been commenced in NBHDL's region of the province. NBHDL's implementation of CDM projects is an example of a non-distribution system alternative to scaling the system to meet new system demand. However, as mentioned previously, NBHDL does not have capacity related constraints and therefore currently does not have a formal policy to relieving system capacity constraints with distribution system alternatives.

NBHDL will continue to support CDM initiatives in accordance with regulatory requirements, monitor results of CDM projects and accommodate renewable energy connections because of the inherent benefits to both NBHDL and its partners. That being said, at this time no CDM initiatives are relied upon to address system capacity, as there are no system capacity limitations. In addition, the RPP has not yet been implemented in the NBHDL service area (as mentioned in Section 2.2.2) and therefore has not been considered as an alternative to relieving system capacity or operational constraints, were there any.

Should any unanticipated system capacity issues arise beyond the forecast period, NBHDL will actively address these constraints and work with partners through CDM or RPP to ensure continued reliability in the system.

4.2.3 (5.4.2 c) Tools and methods (including where relevant, linkages to the distributor's asset management process) used to identify, select, prioritize and pace the execution of projects in each investment category

The following tools and methods were used to identify, select, prioritise and pace execution of projects in each investment category:

4.2.3.1 System Access

System Access projects are all non-discretionary and must be completed as required in order to comply with the DSC and NBHDL's conditions of service. These projects are prioritized based on DSC requirements and with all things equal on a queue basis, first in, first out.

4.2.3.2 System Renewal

System Renewal projects are discretionary but are determined through ACA and the asset management process both of which are defined in Section 3 of the DSP. Substation assets have been identified directly from the ACA and are scheduled as per the asset management plan.

The asset management plan, using the levelized plan informed by the ACA Report, requires that 200 plus poles be replaced every year for the next 5 years. For the past six (6) years, the 4.16kV system Voltage Conversion Plan has been used to identify projects to address pole replacements, as much of the 4.16kV system is end of life and in need of replacement. NBHDL has been working towards the elimination of the 4.16kV system for over 25 years, with very concentrated focus on doing so since 2009 when the Voltage

Conversion Plan was formally initiated. The methodology of the Voltage Conversion Plan, refined in 2012, was to work from the geographic exterior of the service area towards the interior converting voltage from 4.16kV to 12.47kV. This outside in methodology allowed NBHDL to effectively identify the poleline replacement projects required in any given year.

Since voltage upgrade of lines from 4.16 kV to 12.47 kV offers other economic benefits in addition to reducing the risk of asset failures, poles in "very poor" and "poor" condition employed on the 4 kV lines have been given a priority for replacement. The number poles in poor and very poor condition employed on the 4 kV lines is indicated in Table 4-3.

Substation	41-50 years	>50 years	Unknown
MS1	21	28	13
MS7	23	26	49
MS18	11	32	21
MS19	26	26	24
MS4	8	14	9
TOTAL	89	126	116

Table 4-3: Number and age of 4kV Poles by Substation

Prioritization for 2015

In 2015, the voltage conversion projects identified by that process were then ranked via the Prioritization Matrix. This method allows for the optimal sequence of jobs, and the removal of jobs from the yearly budget if affordability or scheduling becomes an issue. The Prioritization Matrix provides a weighted score (based on Weight factor x Score) to individual decision criteria that contribute to a cumulative tally. The System Renewal project that receives the highest weighted score, is ranked the highest in terms of need for renewal and pacing for investment. Table 4-4 below provides the categories and their associated weights:

Decision Criteria	Weight	Score
Safety	5	0-4
Condition	3	0-4
O&M Costs	4	0-4
Technology Enablement	2	0-3
Reliability	4	0-4
Environmental	4	0-3
Operational Efficiency	3	0-3
Improvement Aesthetics	1	0-3

Table 4-4: Prioritization Matrix Weighting System

The following tables provide the detailed scoring system for each the categories listed in Table 4-4. Each category provides a brief explanation of how the judgment is made to reach a certain score.

Safety	Score
Imminent danger to public or workers	4
Elimination of substandard conditions (more than 3 conditions)	3
Elimination of substandard conditions (3 or less conditions)	2
Very minor safety issues (easily managed by process)	1
No safety issues	0

The safety indicators are as described in the above table.

Condition	
Very poor	4
Poor	3
Average	2
Good	1
Very good	0

Condition – based on age unless otherwise confirmed by visual inspection and any other available information (more than 75% poles greater than 50 years = very poor unless otherwise confirmed by visual condition, more than 75% older than 40 years than poor, 20 to 40 than average, 10 – 20 good, 0-10 very good. Substations are based on actual inspection information, and the underground replacement is based on known failures – More than 3 failures - very poor, more than 1 failure - poor, average – 1 failure or less, good and very good is simply no failures and age, good = no failures and between 15 and 30 years, very good = no failures and 15 years and less.

O&M Costs	
Immediate impact on O&M costs (greater than $15k/year)	4
Immediate impact on O&M costs (greater than $5k/year and equal to or less than $15k/year)	3
Immediate impact on O&M costs (Between $1k and $5k)	2
Impact/avoidance of future O&M costs	1
No impact on O&M	0

The O&M costs indicators are as described in the above table.

Technology Enablement	
Includes implementation of new technology	3
Allows for immediate enablement of new technology	2
Prerequisite to enabling new technology in the future	1
No impact to enabling new technology	0

The technology enablement indicators are as described in the above table.

Reliability	
Addresses and improves current reliability issues substantially	3
Addresses and improves current reliability issues moderately	2
Will ensure current reliability is maintained for the long term	1
Does not impact reliability	0

Reliability – substantial improvement – more than 100 customers, and would actually influence metric by 0.5%, moderately – more than 100 customers, and would actually influence metric by 0.1%; current reliability is maintained – actions don't improve but ensure metrics don't move, and no impact is no impact.

Environmental	
Addresses current environmental issues	3
Adopts environmental friendly alternatives	2
Aids in the prevention of future environmental issues	1
No impact on environmental issues	0

The Environmental indicators are as described in the above table.

Operational Efficiency	
Significant increase in operational efficiency	3
Moderate increase in operational efficiency	2
Marginal increase in operational efficiency	1
No impact on operational efficiency	0

Operation Efficiency – Significant – more than 3 efficiencies gained, i.e. voltage conversion, moderate – 2 efficiencies gained, marginal – 1 efficiency gained, no impact is no impact.

Aesthetics	Score
Significant improvement in aesthetics	3
Moderate improvement in aesthetics	2
Marginal improvement in aesthetics	1
No impact on aesthetics	0

Aesthetics – Significant – more than 3 impacts to aesthetics, moderate 2 or 3 impacts to aesthetics, marginal – 1 impact, no impact is no impact.

Using the above tables, NBHDL was able to calculate a priority score which was then used to prioritize all of its System Renewal projects for 2015 and provide the optimal structure for capital investment. In addition to these 2015 System Renewal projects determined by the Prioritization Matrix, 3 underground replacement projects have been scheduled due to their significant contribution to annual O&M costs.

These projects will be completed in 2015 as they have been designated as having high weight due to their O&M costs as well as the condition.

Prioritization for 2016-2019

As the conclusion of the Voltage Conversion Plan nears, a new process for identifying, selecting, prioritising, pacing the execution of projects was determined to be necessary. For the years, 2016 to 2019, a new prioritization process will be implemented and as of the date hereof is as follows:

1) Discretionary Projects are identified from the Asset Condition Assessment (System Renewal)

2) Projects are identified as a form of system upgrade (System Service) such background growth requirements, reliability improvements, operating efficiency, safety and other performance metrics or other investment under the General Plant category.

3) Non-discretionary projects are entered as planned projects and discretionary projects are given scores in various categories each weighted as below in Table 4-5:

Assigned Weights to Decision Criteria		
MIRR ranking	25	3.5%
NPV ranking	25	3.5%
Reliability Impacts	70	9.9%
Momentary Interruptions	30	4.2%
Corporate Image	50	7.0%
Regulatory Compliance	90	12.7%
Environmental Impacts	90	12.7%
Public Safety	100	14.1%
Employee Safety	100	14.1%
Operational Efficiency	70	9.9%
Asset Health Impacts	60	8.5%

Table 4-5: Project Prioritization Criteria and Weightings

4) The result of this system is a ranked project priority listing which is compared to the available budget as determined by the planning process to determine the remainder of the planned projects for that year.

Figure 4-5 below illustrates NBH's optimized project prioritization methodology that will be reflected by the future prioritization protocols to be implemented as described above. As noted elsewhere in this DSP, implementation of a new asset management prioritization protocol (to be initialized in 2016) through consultation with METSCO will allow NBHDL to have stronger and more efficient practices in determining asset health and coordinating repair and replacement efforts.

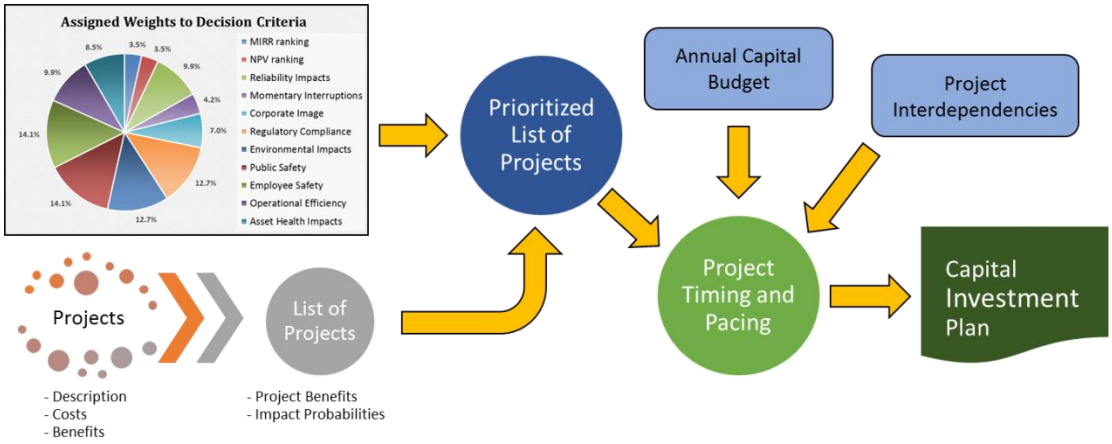

Figure 4-5: Project Prioritization Criteria and Weightings

4.2.3.3 System Service

Due to the excess capacity of the system, very little expenditures will be made into System Service over the forecast period. However, projects that are considered will follow the same process that System Renewal projects are subject to; specifically, NBHDL will ascertain the appropriate project priority and pace by subjecting them to a modified version of the Prioritization Matrix.

As these projects are not driven from assessment, they will also be tested economically to ensure they provide benefit and or savings to the customer.

4.2.3.4 *General Plant*

Historical spending has been based on NBHDL firsthand knowledge of the vehicles and buildings – the Fleet Assessment and Building Assessment were done for the DSP, but NBHDL has undertaken a similar process before. In the past, if NBHDL was of the opinion that a specific aspect of General Plant was required, it would seek out a 3rd party consultant to assess, but the initiation of the project has been in house.

For the DSP, the General Plant assessments validated NBHDL's firsthand knowledge of the problems and assisted in prioritization.

Motor Fleet

Currently, NBHDL is in the midst of completing its fleet replacement schedule based on the Fleet Assessment completed in 2013. The external consultant hired by NBHDL provided distinct schedule regimes for the assets as well as detailed reasons for the schedule (including information on reliability, condition, age, safety, among other things).
The Fleet Assessment identified several priority objectives for NBHDL to complete in the forecast period as follows:

- NBHDL's largest vehicle was in need of replacement as it was over 15 years old and would cost more to repair than to be replaced. Currently the vehicle is tagged and not designated as road worthy. NBHDL, as informed by the Fleet Assessment, considers this project a top priority under General Plant and has undertaken to complete the purchase by 2015. Currently, the purchase of the cab and chassis is a 2014 project and the boom/bucket is scheduled for 2015. Overall this

purchase is approximately $450,000 for 2015 and takes up the majority of the value identified in the table in Section 4.5.1 below.

- NBHDL pickup trucks are to be replaced on a 7 year schedule.
- Large NBHDL vehicles are to be placed on a 12 year replacement schedule.
- Radial Boom Devices ("RBD") can be placed on a 15 year replacement schedule as they do not maintain a similar duty cycle as other large vehicles.

NBHDL retains discretion in its decisions to implement these schedules based on its own industry know how and knowledge of budgetary concerns and pacing with other investments. However, NBHDL acknowledges that in many cases, the schedule is set based on an imminent need to replace or renew an asset and follows it as necessary.

Building/Office Upgrades

In the Building Assessment, the consultant determined that there was an imminent need to replace the HVAC system at NBHDL headquarters. Given the condition of the HVAC system, the project became non-discretionary and was undertaken to be completed by the end of 2014. This project is nearly complete and does not factor into the capital investment projections for General Plant. The Building Assessment schedules only maintenance investment levels for the HVAC system from 2015 to 2019, greatly reducing the need for capital investment under this Application.

In addition to the HVAC, the Building Assessment informed NBHDL that the generator for back-up supply power at NBHDL headquarters required re-sizing on an as soon as possible basis to prevent safety issues in any unplanned outages. NBHDL undertook this projects and will have them completed it the end of 2014 as well.

These two projects represented the main building requirements identified in the Building Assessment in the immediate future and, as demonstrated in Section 4.5.1 below, the bulk of the necessary capital investment. They were prioritized first due to the necessary, if not non-discretionary, nature of the systems in relation to employees of NBHDL.

The remaining investment levels identified in the Building Assessment are for typical building maintenance costs for such issues as: exterior lighting, emergency systems, HVAC, parking lot asphalt, doors, roof and interior. NBHDL prioritizes such tasks on an as required basis and anticipates no major variation over the forecast period.

As with the Motor Fleet, NBHDL's prioritization and pacing of Building / Office Upgrade investments are informed by its consultation with a third party. The schedules and maintenance requirements set out in the Building Assessment provide a solid foundation on which NBHDL has been able to make its capital investment decisions.

Tools

Tool expenditures are prioritized and paced on an as needed basis. The General Plant budget typically affords extra capacity for such projects and when they are required, based on end of life or poor condition of the equipment, NBHDL ensures the expenditure is properly allocated.

IT System

As discussed in Section 4.1.3.4, the IT Assessment provided outputs to inform NBHDL's decisions regarding IT investments. The NBHDL IT Strategy was developed in response to this assessment and provides general prioritization decision structures to assist NBHDL with its future investments in this General Plant subcategory.

Specific justifications for yearly IT expenses and responses to the IT Assessment are discussed below in Section 4.5.1.3.

4.2.4 (5.4.2 d) Details of mechanisms used to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analysis – 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 affected by consideration of this information

As mentioned above in Section 2.2.1.1 and Section 4.1.6, NBHDL began a more formal process of engaging customers in an attempt to gather information on preferences and customer satisfaction throughout 2013 and 2014. This process included customer engagement initiatives, performed through three phases as follows:

- Phase 1 - Clark Marketing and the North Bay Chamber of Commerce were engaged to provide initial local feedback through surveys and focus groups.
- Phase 2 - Simul Corporation was contracted to conduct its UtilityPULSE customer survey in May 2014. This is a widely used survey within the Ontario distribution sector that provides NBHDL with comparable statistics from both a provincial and national perspective.
- Phase 3 - Innovative was retained to obtain customer feedback on NBHDL's proposed 2015 capital investment and operational plans and the expected distribution rate impact as proposed in the 2015 rebasing application. Two focus groups and a telephone survey were conducted.

As discussed in Section 2.2.1.1, this detailed survey information was used to ensure that the DSP was aligned with customer preference and validate decision making protocols of NBHDL. Further, the areas of customer concern also align with the Prioritization Matrix for projects in 2015. NBHDL anticipates these categories will be further used in the prioritization protocols to be implemented in Q2, 2015.

Given that the customer areas of concern formed part of the prioritization of projects, the element of the DSP that was affected by customer feedback was the ranking of projects and justification of capital expenditures.

4.2.5 (5.4.2 e) If different than above, the method and criteria used to prioritize 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 projects.

NBHDL does not use a separate prioritization for REG investments. In addition, due to sufficient capacity in the system and minimal forecasted connections, the analysis does not indicate a requirement for material capital expenditures over the rate filing period. NBHDL does not have plans over the 5 year horizon to connect distributor-owned renewable generation projects. A more complete analysis of NBHDL's capability to connect renewable generation facilities is included Section 4.3 below.

4.3 System Capability Assessment for Renewable Energy Generation (5.4.3)

NBHDL's distribution system is fully capable of accommodating REG, as evident Table 4-5 and Table 4-6 below. This is further provided for in **Appendix F**. At this time there are no specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected REG capacity.

Under conservative assumptions of the maximum permissible generation capacity at a distribution station being equal to 60% of the power transformer nameplate rating plus the minimum station load (equal to 15% of station rating) and 90% power factor, the approximate available capacities for connecting renewable energy generation to various municipal stations is indicated in Table 4-6 and Table 4-7.

As shown, based on the applications currently in hand or anticipated to be received during the next five years, no system constraints exist, preventing the connection of green energy generation developments, within NBHDL's service territory. Therefore, no capital investments are needed for capacity upgrades to facilitate the connection of renewable energy generation plant.

Distribution Station	MVA rating		Approximate Available Capacity (MW) for Generation Connections	System Constraints for Connection of Generation
	ONAN	ONAF		
MS4	7.5	10	6.75	No Constraints
MS8	7.5	10	6.75	No Constraints
MS9	T1 - 7.5, T2-7.5	No fans	10.13	No Constraints
MS10	T1-7.5, T2 - 7.5	T1-10, T2-10	10.13	No Constraints
MS11	7.5	10	6.75	No Constraints
MS13	T1-6, T2-7.5	T1-No fans, T2-10	9.11	No Constraints
MS14	7.5	10	6.75	No Constraints
MS15	7.5	10	6.75	No Constraints
MS16	7.5	No fan rating	5.06	No Constraints
MS17	7.5	10	6.75	No Constraints
MS19	7.5	10	6.75	No Constraints
MS20	7.5	10	6.75	No Constraints
MS21	7.5	10	6.75	No Constraints

Table 4-6:12.47 kV Stations Distributed Generation Connection Capacity

Distribution Station	MVA rating		Approximate Available Capacity (MW) for Generation Connections	System Constraints for Connection of Generation
	ONAN	ONAF		
MS1	5	No fans	3.38	No Constraints
MS7	5	6	4.05	No Constraints
MS18	T1 - 7.5, T2-7.5	T1-10, T2-10	13.50	No Constraints

Table 4-7: 4.16 kV Stations Distributed Generation Connection Capacity

4.3.1 Applications from renewable generators over 10kW for connection in NBHDL's service area

As of August 1, 2014 there were no current applications from renewable generators over 10kW for connection in the NBHDL's service area.

4.3.2 The number and 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)

There are a total of 34 renewable energy generation installations presently connected to NBHDL's distribution system under the province's FIT and micro FIT programs, as summarized below and detailed in Table 4-7 and Table 4-9: MicroFIT Generation Facilities respectively.

- Three (3) FIT installations with generating capacity of 1.88 MW, as listed in Table 4-8.
- Thirty One (31) micro-FIT installations with 259.84 kW installed capacity, as shown in Table 4-9.

In addition to the above, there are seventeen (17) micro-FIT installations that are currently registered with OPA, but have not yet proceeded to the development stage. There are currently no applications in queue, under the FIT program waiting for connection.

S. No.	Fuel Source	kW Rating
1	Solar Power	30
2	Landfill Site	1600
3	Solar Power	250

Table 4-8: FIT Generation Facilities

Micro-FIT Reference #	Meter Install Date	Rating (kW)
M398BVN	18/01/2010	10.00
M3ERPKX	28/10/2010	2.70
MHT2DVF	13/05/2010	8.00
MRTCG3X	25/06/2010	10.00
MXTD9JV	13/08/2010	10.00
MP422N8	03/12/2010	4.14
MB8I8C2	18/11/2010	10.00
MBEZI3Q	10/02/2011	4.14
MU6YEEB	13/06/2011	8.46
MJT2MR2	09/09/2011	10.00
M31YDMU	09/01/2012	10.00
M9M6FT9	20/03/2012	2.60
M2EB668	28/02/2012	10.00
M3NMX47	12/01/2012	10.00
MJDDAKJ	13/12/2011	10.00
MQF4F2F	04/07/2012	10.00
MPZMKKT	20/03/2012	10.00
MYU6YJC	27/02/2013	10.00
MQCN8YN	27/04/2012	10.00
MJIWG4D	30/10/2012	10.00
MM39FQM	05/07/2012	10.00
MB8JUWN	23/01/2013	10.00
MXTPJQI	27/11/2012	8.30
M2ZPA6G	29/05/2013	10.00
MKD2AV8	01/11/2013	5.00
M3MKIDY	12/06/2013	10.00
MBMFAQN	13/09/2013	10.00
MDTPJ2C	11/12/2013	5.50
M84JXDZ	28/06/2013	10.00
MJ8V8CI	20/09/2013	5.00
MXA97NF	25/10/2013	6.00
Total		259.84

Table 4-9: MicroFIT Generation Facilities

NBHDL expects an equal or less amount of applications from REG's over the rate filing period to what has been connected to date (17 micro-FIT – 259.84kW, 3 FIT – 1.88MW), due to the reduced incentives and the very limited participation to date. NBHDL's service territory has a high rural component and a lot of open land space for potential solar farm developments, however at this time, there have not been any large solar farm applications or proposed solar farm developments.

4.3.3 The capacity (MW) of the distributor's distribution network to connect renewable energy generation located within the distributor's service area

NBHDL has the ability to connect at least 5MW of individually connected REG project to every station, with the exclusion of MS1 and MS7, at the distribution system level. (MS1 will be able to connect up to 5MW after 2014, and MS7 will be decommissioned in 2016) On the subtransmission system (44kV), up to 20MW of individually connected REG projects would be permitted per feeder at this time. Of course upstream coordination and approvals with HONI would be required.

4.3.4 Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter)

There are no constraints on the NBHDL system related to the connection of renewable generation. The two Hydro One T.S's that supply the NBHDL system are also not constrained. Figure 4-6 below is a chart that shows TLTS and NBTS capacities. As there are very limited connections to either station at this time, there is ample room to connect new projects to either station.

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)
TRENTON OAK DS	Total	F1,F2	27.6	0.2	TC	3.1
TRENTON PELHAM DS	Total	F1,F2,F3,F4	4.16	0.9	TC	3.3
TROUT CREEK DS	Total	F1,F2	25	2.0	N/A	4.9
TROUT LAKE TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	39.2	376.8	99.2
Station Name	**Bus Name**	**Feeder Name**	**Voltage (kV)**	**Minimum Load (MW)**	**Short Circuit Capacity (MVA)**	**Thermal Capacity (MW)**
NEWINGTON DS	Total	F1, F2	27.6	0.4	133.3	TC
NEWPORT DS	Total	F1	8.32	0.4	N/A	1.3
NEWTON TS	B	M1,M3,M6,M8,M10	13.8	8.5	2.0	8.5
NEWTON TS	Y	M2,M4,M5,M7,M9	13.8	5.7	2.9	5.7
NEWTON TS	Total	M1,M2,M3,M4,M5,M6,M7,M8,M9,M10	13.8	14.4	N/A	Sum of Buses
NEWTONVILLE DS	Total	F1,F2	8.32	0.8	N/A	3.2
NIPIGON DS	Total	F1, F2	4.16	0.8	9.1	2.3
NOBLETON DS	Total	F4,F5,F6	8.32	0.9	N/A	3.3
NOELVILLE DS	Total	F1,F2	12.47	1.1	N/A	2.6
NORFOLK TS	BY	M1, M2, M3, M4, M5, M6	27.6	15.9	74.8	55.9
NORTH AUGUSTA DS	Total	F2,F3	8.32	0.8	N/A	2.3
NORTH AUGUSTA DS #2	T1	F51,F52,F53	8.32	1.4	N/A	5.0
NORTH AUGUSTA DS #2	T2	F56,F57	8.32	1.0	N/A	4.6
NORTH BAY TS	Y	M1, M3	44	5.7	13.1	25.7

Figure 4-6: Capacity by Feeder / Station

4.3.5 Constraints for an embedded distributor that may result from the connections

Currently within NBHDL's distribution system there are no constraints for an embedded distributor that may result from connections of REG's.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-10 below provides a 'snapshot' of NBHDL's capital expenditures over a 10 year period and is consistent with Board Appendix, 2-AB – *Table 2 – Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements*. NBHDL does not have previously filed or approved DSP and as such a variance explanation of actual capital expenditures compared to planned expenditures is not provided.

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

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	N/A	1,283,260	--	N/A	1,308,483	--	N/A	2,022,775	--	N/A	1,858,535	--	N/A	1,800,867	--	1,143,704	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	N/A	5,164,759	--	N/A	5,055,154	--	N/A	2,313,746	--	N/A	3,997,037	--	N/A	4,168,904	--	5,469,405	4,180,343	4,235,741	4,266,049	4,054,266
System Service	N/A	396,490	--	N/A	289,717	--	N/A	200,907	--	N/A	141,128	--	N/A	206,779	--	373,245	214,743	127,302	89,044	135,918
General Plant	N/A	146,512	--	N/A	829,735	--	N/A	780,227	--	N/A	423,463	--	N/A	967,211	--	771,603	373,400	549,000	350,700	642,000
TOTAL EXPENDITURE	-	6,991,021	--	-	7,483,088	--	-	5,317,656	--	-	6,420,163	--	-	7,143,762	--	7,757,956	5,935,064	6,101,952	5,919,500	6,070,166
System O&M		$1,936,424	--		$2,069,185	--		$2,131,247	--		$2,295,159	--		$2,497,109	--	$2,809,536				

Table 4-10: Capital Expenditure Summary Appendix 2-AB

4.4.1 Historical Period – Yearly Variation in Capital Expenditures

4.4.1.1 Variation in Capital Expenditures between 2010-2011

System Renewal

2010: $5,164,759 2011: $5,055,154 Variance: ($109,605)

Although the variance exceeds the materiality threshold, the variance represents a difference of approximately 2% year over year indicating a very consistent expenditure level in this category. There isn't one particular aspect that drives the variance, but instead a difference in the types of projects resulting in the small variance of $109,605.

System Access

2010: $1,283,260 2011: $1,308,483 Variance: $25,223

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

System Service

2010: $396,490 2011: $289,717 Variance: ($106,773)

The variance is mainly due to the installation of two loadbreak switches on the 44kV system to allow for load balancing in 2010 and higher meter related costs for the installation of new IESO metering points at North Bay T.S. in 2010 over 2011.

General Plant

2010: $146,512 2011: $829,735 Variance: $683,222

The variance was primarily driven by the following costs in 2011: a large truck replacement ($289,661), renovations to the customer service department to meet the requirements of Bill 168 ($154,297), increased purchases for work equipment (net $39,234) that included substation testing equipment, and upgrades of the main software platform, along with the implementation of new customized applications ($189,729).

4.4.1.2 Variation in Capital Expenditures between 2011-2012

System Renewal

2011: $5,055,154 2012: $2,313,746 Variance: ($2,741,407)

The largest contributor to the variance was the lack of a substation replacement project in 2012; in 2011, construction of MS20 totalled $2,018,615. Other contributors include: the lack of AM activities in 2012 for a variance of $180,303, reduced spending on voltage conversion projects for a variance of $230,483, less demand based work for a variance of $205,578 and the associated reduction in transformer purchases related to less spending on demand and voltage conversion projects for a variance of $139,239.

System Access

2011: $1,308,483 2012: $2,022,775 Variance: $714,293

The variance relates to the spending fluctuations in different types of demand work as follows:

- Major betterment projects increased $627,240 from 2011 due to the construction by the City of the Aerospace Industrial Park and the new customers it attracted;
- Road projects up $222,091 from 2011 due to increased road projects in 2012;
- Minor betterment projects up $61,809 relating to demand work in 2012;
- Transformer purchases up $30,625 related to the increases in demand work in 2012;
- Subdivisions down $37,482 as there were fewer subdivision projects;
- Primary Services down $54,570 due to fewer projects; and
- Secondary Services down $115,961 due to a review of the classification of costs to Secondary Services.

The remainder of the variance is attributable to various small projects.

System Service

2011: $289,717 2012: $200,907 Variance: ($88,810)

The variance is due to the following: $57,506 less spending in 2012 relating to various smart meter installations and upgrades, $21,857 less in 2012 in relation to a number of small miscellaneous projects and the with the completion of the 44kV metering upgrade in 2011, a further reduction of $103,671 compared to 2012. Offsetting these reductions was a unique project to 2012 involving the installation of metering and voltage regulation equipment to enable the connection of a renewable generation project in the amount of $90,347.

General Plant

2011: $829,735 2012: $780,227 Variance: ($49,507)

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

4.4.1.3 Variation in Capital Expenditures between 2012-2013

System Renewal

2012: $2,313,746 2013: $3,997,037 Variance: $1,683,290

The scheduled replacement of MS6 and the rehabilitation of MS16 in 2013 contributed the majority of the variance, as substation related expenditures were up $1,663,008 over 2012, a year that involved no large substation projects. Year to year variances between major betterments, voltage conversion projects, minor betterments, porcelain switch and insulator replacements, and AM activities existed, however as whole represented a net of approximately $20,000 in incremental spending in 2013.

System Access

2012: $2,022,775 2013: $ 1,858,535 Variance: ($164,241)

The variance relates to the spending fluctuations in different types of demand work as follows:

- Major betterment projects down $534,634 as servicing for the Aerospace Industrial Park was substantially completed in 2012 with no additional projects in 2013;
- Road projects down $268,181, 2013 costs were related to the finishing work required on 2012 projects;
- Minor betterment projects up $19,145 relating to demand work in 2013;
- The Bell FSA Project, a system wide deployment of a fibre network system in the NBHDL service territory, caused an increase in demand spending of $459,691 in 2013. The project did not exist in 2012 as work began in 2013;

- Transformer purchases down $72,235 related to the decreases in demand work in 2013;
- Subdivisions up $32,781 due to increased subdivision projects;
- Primary Services up $408,966 due to two large 44kV connections and the Aerospace Condo servicing project; and
- Secondary Services down $84,165 due to a reduction in secondary service demand work.

The remainder of the variance is attributable to various small projects.

System Service

2012: $200,907 2013: $ 141,128 Variance: ($59,779)

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

General Plant

2012: $780,227 2013: $423,463 Variance: ($356,764)

In 2013, only one small vehicle was replaced representing a decrease in spending of approximately $193,000 over 2012 which involved the replacement of a single bucket truck, replacement of two pick-up trucks and the addition of a new pick-up truck. Building related expenditures were down approximately $56,000 and IT related expenditures were down approximately $146,000 in 2013. Tool related purchases increased approximately $53,000 as a result of several higher cost items.

4.4.1.4 Variation in Capital Expenditures between 2013-2014

System Renewal

2013: $3,997,037 2014: $4,168,904 Variance: $171,867

Although 2014 involves the replacement of the MS1 transformer, the replacement of the SCADA radio system, the rehabilitation of MS15 and the procurement of 2 power transformers for MS22, substation spending in 2014 is forecasted to be down $454,930 versus 2013 which saw the full replacement of MS6 and the rehabilitation of MS16. A large forecasted increase to major betterment spending in 2014 of $421,343 is related to the construction of three end of life projects outside the voltage conversion area and the related transformer purchases of $107,818, along with smaller variances in voltage conversion projects, minor betterments, porcelain switch and insulator replacements, and AM activities offset the decrease in substation spending to provide an overall increase in spending in 2014 of $171,867.

System Access

2013: $1,858,535 2014: $1,800,867 Variance: ($57,667)

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

System Service

2013: $141,128 2014: $206,779 Variance: $65,651

The variance in 2014 is primarily driven by the infrastructure modernization project which focuses the metering department on a scheduled replacement program that will transition customers to interval capable SMART meters.

General Plant

2013: $423,463 2014: $967,211 Variance: $543,748

The large increase in general plant spending in 2014 over 2013 is attributable to building and general plant upgrades, specifically upgrades to the HVAC system, the replacement of the generator to cover the entire building's load in outage situations, and improvements to the garage and yard representing an increase in spending of $350,092. An increase to fleet replacements of $91,762 and an increase in IT related purchases of $128,913 also contributed to this variance. Small miscellaneous variances in other general plant categories account for the balance of the variance.

4.4.2 Forecast Period - Yearly Variation in Capital Expenditures

4.4.2.1 Variation in Capital Expenditures between 2014-2015 (Forecast)

System Renewal

2014: $4,168,904 2015: $5,469,405 Variance: $1,300,501

The largest variance in 2015 is explained by the replacement of MS9 by MS22 at a cost of $1,781,297, an increase of $1,069,995 over 2014 substation construction expenditures. The remaining variance is represented by an increase in major betterment projects, specifically underground replacement projects to address failing underground secondary servicing of $636,700, and the increase of $493,217 in relation to voltage conversion projects. These increases are offset by a reduction in other substation type expenditures of $686,650, which includes the purchase of the MS22 transformers in 2014; this was done in order to spread the MS22 costs over two years to the extent possible, keeping 2015 costs mitigated. The completion of the porcelain switch and insulator replacement project in 2014 results in a decrease over 2014 of $101,671. Reduced costs of various small projects result in a year over year decrease of $128,744.

System Access

2014: $1,800,867 2015: $1,143,704 Variance: $657,164

The completion of the Bell FSA Project decreases spending in 2015 by $744,212 over 2014. The remaining variance from 2015 to 2014 can be explained by the year over year fluctuations of the estimated spending in the various demand categories as determined by utilizing a 5 year average cost for the 2015 Test Year.

System Service

2014: $206,779 2015: $373,245 Variance: $166,466

The variance can be attributed to the conversion of 5 feeders from 4.16kV to 12.47kV representing an increase of $121,979 and work relating to meter infrastructure modernization and the 2015 replacement schedule which represents an increase of $51,072.

General Plant

2014: $967,211 2015: $771,603 Variance: ($195,608)

Although there is one large bucket truck, 3 small trucks, and 2 utility trailers being replaced in 2015 for an increase in fleet spending of $361,937, reduced spending on the building and yard in the amount of $451,386 coupled with reduced spending on IT related activities of $105,311 in 2015 offset the bulk of the spending in 2015 compared to 2014.

4.4.2.2 Variation in Capital Expenditures between 2015-2016 (Forecast)

System Renewal

2015: $5,469,405 2016: $4,180,343 Variance: ($1,289,062)

The main driver of the decreased spending in 2016 compared to 2015 can be explained by the lack of substation related activities in 2016; a decrease in spending of $1,502,768 over 2015. The replacement of MS9 in 2015 represents the last major substation project required over the next 5-10 years. Fluctuations amongst voltage conversion, major betterments and minor betterments projects account for the balance of the variance.

System Access

2015: $1,143,704 2016: $1,116,578 Variance: $22,874

As forecasted expenditures in the system access category are based strictly on average historical costs, the increase in spending from 2016 to 2015 is based on an inflation factor of 2%.

System Service

2015: $373,245 2016: $214,743 Variance: ($158,502)

The majority of the variance can be attributed to a decrease in scheduled meter conversions compared to 2015 of $98,218, and a decrease in feeder conversion costs of $45,170 as the voltage conversion program nears completion.

General Plant

2015: $771,603 2016: $373,400 Variance: ($398,203)

The majority of building, yard, and IT requirements were dealt with in the previous 5 years and as a result, there are minimal costs in 2016 relating to these categories, representing a decrease of $126,203. In addition, there is a reduction of $272,000 in fleet purchases, as only small fleet vehicles will be replaced in 2016.

4.4.2.3 Variation in Capital Expenditures between 2016-2019 (Trending)

System Renewal

The replacement of MS9, following the strategy of replacing a station every 2 years since 2009, concluded the replacement of all substations in poor or very poor condition in 2015. As a result of this program substation spending over the next 4 years is forecasted to be consistent and flat. Both pole renewals and underground replacement projects have been levelized from 2016 to 2019, keeping the System Renewal costs consistent and flat over the rate filing horizon.

System Access

As forecasted expenditures in the System Access category are based strictly on average historical costs, the system access category has been forecasted to increase each year through 2019 by an inflation factor of 2% per year.

System Service

There is not a significant amount of work planned in this category and the majority of the System Service costs are driven by the modernization of meter infrastructure scheduled from 2016 to 2019. This spending

follows the plan developed by the Metering Department in line with a 3rd party analysis and recommendation. With the completion of the voltage feeder conversion, projects will cease to exist in this category and will not have an impact on system service costs after 2016. Minor betterment work relating to system service investments is a very small piece of the costs and is forecasted to stay consistent and flat through to 2019.

General Plant

General Plant expenditures over the forecast period will for the most part vary based on the fleet replacement strategy, which is well documented throughout the DSP. As the bulk of the items related to the building, yard and IT department were handled over the previous 5 years, spending in those areas will remain very consistent through to 2019, aside from a larger IT expenditure forecasted in 2019 to handle the required replacement of main servers. Tool expenditures have also been levelized over the entire rate filing period at $45,000 per year.

4.4.3 Summary of Variations in Historical and Forecast Period Capital Expenditures

NBHDL's capital expenditures over the Historical Period years may appear to swing year over year, however, a review of the above yearly descriptions indicate that the major factors affecting the program were:

- fluctuations in demand based work outside of the control of NBHDL;
- adherence to the substation replacement program which has seen the replacement of a substation every 2 years since 2009; which in turn caused peaks in the System Renewal category in 2009, 2011, 2013 and forecasted in 2015; and
- the replacement of fleet vehicles and upgrades to the building, yard, and IT in accordance to replacement strategies and necessity.

System Service expenditures have made up a very small portion of the Historical Period expenditures and will continue to make up a very small portion of total capital expenditures over the Forecast Period. The demand work has been levelized over the Forecast Period due to the use of a historical average. NBHDL does expect fluctuations year over year in this category, however, the total envelope of dollars is anticipated to be within an acceptable tolerance range for accuracy. Substation expenditures have been reduced as the majority of poor assets will be replaced by the end of 2015. This, in turn, has levelized the System Renewal spend out between 2016 and 2019. This levelized spend occurs despite the introduction of the underground replacement renewal projects starting in 2015. Fleet expenditures going forward will continue to follow a fleet replacement strategy informed by the Fleet Assessment and NBHDL's knowledge of its assets. This will cause fluctuations year to year. All other general plant expenditures will remain fairly consistent throughout the filing period. NBHDL is forecasting to spend $1,571,053 less over the Forecast Period than what was spent during the Historical Period with respect to capital expenditures.

4.5 Justifying Capital Expenditures

The following information has been prepared by NBHDL to meet the distributor onus of providing data, information and analysis necessary to support NBHDL's capital related costs on which the Application is based. The sections below provide information on how this DSP delivers value to customers, with appropriate cost controls and optimal prioritization / pacing of investments. References to previous sections of the DSP will be provided as necessary.

4.5.1 Overall Plan (5.4.5.1)

4.5.1.1 Comparative Expenditures over the Historical Period

The proposed five (5) year capital program from (2015 to 2019), summarized in Table 4-11 below, reflects an average capital expenditure of approximately $6.4 million per year. For comparison sake, the capital expenditure in the previous five years is indicated in Table 4-12. A comparison of Table 4-11 with Table 4-12 reveals a reduction in proposed annual expenditure, in all categories, with the exception of System Service.

The total capital for 2015 varies from the historical period trends based on three specific factors. First, System Service is higher due to the meter replacement requirements due to expiration of seals. This specific cost will not carry forward into future years, which presents a higher value in Table 4-11. Secondly, as discussed above in Section 4.1.3.2, System Renewal for 2015 includes the replacement of substation MS9 with MS22. This one-off project provides a significant increase in capital expenditure for NBHDL that is not required beyond 2015. The MS9 replacement allows NBHDL to complete its SMART GRID Initiative. Third, as part of General Plant, NBHDL has budgeted a larger than average expenditure on the replacement of an end of life boom/bucket truck. These three significant variations, as well as other projects, are further discussed below and in the capital project summaries.

For a full year by year analysis based on the 4 categories of expenditure, please see Section 4.4.1 above.

		2015	2016	2017	2018	2019	TOTAL	AVERAGE
SR	**System Renewal**	$ 5,469,405	$ 4,180,343	$ 4,235,741	$ 4,266,049	$ 4,054,266	$ 22,205,804	$ 4,441,161
SS	**System Service**	$ 373,245	$ 214,743	$ 127,302	$ 89,044	$ 135,918	$ 940,251	$ 188,050
SA	**System Access**	$ 1,143,704	$ 1,166,578	$ 1,189,909	$ 1,213,707	$ 1,237,982	$ 5,951,880	$ 1,190,376
GP	**General Plant**	$ 771,603	$ 373,400	$ 549,000	$ 350,700	$ 642,000	$ 2,686,703	$ 537,341
	Total Capital Spending	**$ 7,757,956**	**$ 5,935,064**	**$ 6,101,952**	**$ 5,919,500**	**$ 6,070,166**	**$ 31,784,637**	**$ 6,356,927**

Table 4-11: Proposed Capital Investments

		2010	2011	2012	2013	2014	TOTAL	AVERAGE
SR	**System Renewal**	$ 5,164,759	$ 5,055,154	$ 2,313,746	$ 3,997,037	$ 4,168,904	$ 20,699,599	$ 4,139,920
SS	**System Service**	$ 396,490	$ 289,717	$ 200,907	$ 141,128	$ 206,779	$ 1,235,022	$ 247,004
SA	**System Access**	$ 1,283,260	$ 1,308,483	$ 2,022,775	$ 1,858,535	$ 1,800,867	$ 8,273,920	$ 1,654,784
GP	**General Plant**	$ 146,512	$ 829,735	$ 780,227	$ 423,463	$ 967,211	$ 3,147,148	$ 629,430
	Total Capital Spending	**$ 6,991,021**	**$ 7,483,088**	**$ 5,317,656**	**$ 6,420,163**	**$ 7,143,762**	**$ 33,355,690**	**$ 6,671,138**

Table 4-12: Historic Capital Expenditure

4.5.1.2 Forecast Impact of System Investment on system O&M costs

NBHDL expects that the impact of investments on system O&M will vary from project to project. Some projects are being undertaken to replace or renew aging infrastructure within the NBHDL distribution system. As these assets continue to reach the 'effective age' they are increasingly burdensome on O&M. In particular, NBHDL is addressing several underground projects (i.e. Turret Complex – Madelena) which have been driving O&M costs up with failing underground services. Renewal of these underground assets is anticipated to reduce future O&M costs. For clarity, O&M costs are inversely correlated with the declining asset condition; therefore, NBHDL anticipates a reduction in future O&M costs as these assets are replaced and increasingly onerous maintenance conditions are alleviated.

As discussed in Section 2.1.2, decommissioning of certain NBHDL substations will also provide cost benefits under system O&M as it will free staff from current tasks such as: monthly station inspections, preventative maintenance at the station every 4 years, annual infrared scanning at the station, annual oil sampling, and the small items needed to keep the station running (changing of batteries, cleaning of the yard, minor repairs). Time saved could be applied elsewhere in the system adding to productivity and decreasing requisite O&M costs.

In the case of System Renewal projects relating to the Voltage Conversion Plan, the impact of the investment on the system O&M costs is more of a gradual impact. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which could lead to a potential reduction in future O&M costs. The elimination of the 4kV system as whole has the potential to result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, NBHDL anticipates that system O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) could be available for other O&M tasks at NBHDL.

Should these renewal projects not be implemented, the O&M costs will continue to increase perpetually on the same level or under an increasing trend.

In Section 4.4, the amount listed for system O&M for 2015 is the amount calculated as part of the Application as set out in Exhibit 4. Beyond the high level discussion above, NBHDL is currently unable to provide a specific or detailed forecast the impact of its investments on system O&M costs.

4.5.1.3 Drivers of Investment

The following is a list of the key drivers for all the investments included in this Capital Plan and these are described in detail in Section 1.2.

- System Access
- System Renewal
- System Services
- General Plant

The proposed capital investments in each of these categories are summarized below:

System Access

As identified in Section 1.2.1, NBHDL applies the following key drivers to the System Access category:

- Customer service requests for new customer connections, requests for service modifications and load expansion at existing commercial and industrial customers; and

- Third party infrastructure developments requiring system plant relocates.

The proposed investments into System Access are summarized in Table 4-13. These include capital investments to implement customer service requests and line relocates to facilitate municipal infrastructure developments, such as road widening projects.

	2015	2016	2017	2018	2019	TOTAL	AVERAGE
Customer Service Requests	$ 912,236	$ 930,481	$ 949,090	$ 968,072	$ 987,434	$ 4,747,313	$ 949,463
Road Relocations	$ 231,468	$ 236,097	$ 240,819	$ 245,635	$ 250,548	$ 1,204,566	$ 240,913
Proposed Total System Access	**$ 1,143,704**	**$ 1,166,578**	**$ 1,189,909**	**$ 1,213,707**	**$ 1,237,982**	**$ 5,951,880**	**$ 1,190,376**

Table 4-13: Planned Capital Investments into System Access Projects

i. Customer Service Requests

NBHDL receives a modest number of customer service requests yearly depending on the number of new build homes. As discussed previously, the influx of new customers is proportionately balanced with a number of existing customers in multi-family dwellings that relocate or move out of town. NBHDL's service area currently has no backlog for customers requiring new services and does not anticipate this to change for the duration of the forecast period.

ii. Road Relocations

In addition to the customer service requests, NBHDL also has non-discretionary obligations relating to road widening projects undertaken by the City. Such relocation projects (requiring capital investments by NBHDL) are anticipated to continue throughout the next five years at a pace similar to level of investment over the historical period.

System Renewal

As discussed above in Section 1.2.2, the major renewal projects under System Renewal category are tied to the Voltage Conversion Plan. Voltage conversion projects involve all line construction work relating to the preparation to convert, or actual conversion of, NBHDL's existing 22kV subtransmission system to 44kV and the 4.16/2.4kV system to 12.47/7.2kV. The 22 kV and 4.16kV systems are the oldest in NBHDL's service territory and therefore most plant is at the end of its useful life and must be replaced. Voltage conversion projects not only prepare for or convert the voltage to 12.47/7.2kV but also renew NBHDL's oldest assets to current standards. Voltage conversion projects will lead to the harmonization of the distribution system voltage, lower line losses, eliminate safety hazards to the public and NBHDL employees, and lower future maintenance costs.

The proposed investments into System Renewal are summarized in Table 4-14 below. The program includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable. Much of the scheduled capital investment identified below in Table 4-13 relates to the completion of the Voltage Conversion Plan.

It is not possible to quantitatively determine the impact of capital investments on future O&M expenditure, but qualitatively, investments into system renewal generally result in a decrease in future O&M expenditure because replacement of old vintage assets with new assets results in fewer equipment failures and lower expenditure into emergency repairs.

	2015	2016	2017	2018	2019	TOTAL	AVERAGE
Substations	$ 2,052,768	$ 550,000	$ 450,000	$ 550,000	$ 300,000	$ 3,902,768	$ 780,554
Wood Poles	$ 2,020,937	$ 3,130,343	$ 3,235,741	$ 3,166,049	$ 3,234,601	$ 14,787,671	$ 2,957,534
Underground Cable Replacements	$ 1,395,701	$ 500,000	$ 550,000	$ 550,000	$ 519,665	$ 3,515,366	$ 703,073
Proposed Total System Renewal	**$ 5,469,405**	**$ 4,180,343**	**$ 4,235,741**	**$ 4,266,049**	**$ 4,054,266**	**$ 22,205,804**	**$ 4,441,161**

Table 4-14: Planned Capital Investments into System Renewal Projects

i. Substations

Investments in the substation category are driven mainly by the requirement to replace end of life assets that are in poor or very poor condition as determined by the ACA Report. Substation assets affect the greatest number of customers upon failure, and therefore NBHDL takes seriously the requirement to address assets that have fallen past their useful life and pose a threat to reliability, safety and cost control. Investments in 2015 will include the replacement of a substation that is in very poor condition with a state of art station that will ensure continued reliability for the service area and eliminate current safety hazards.

The largest investment in 2015 will be the last full replacement project needed for the next 10 years, as the investments will have addressed all the very poor assets operating at the end of their useful lives. Over the rate period, there will be equipment replacements in this category to address parts of substations, but the expenditures will be substantially less than when compared to the previous 5 years as no further full replacements are required. As a secondary driver, the replacement of the substation in 2015 will allow for the implementation of SCADA, completing the rollout of SCADA to all substations in the NBHDL system. This will allow for more efficient operation of the grid in this area of the City, increase worker productivity and improve reliability as outages will be shortened due to operation from our main office.

ii. Wood Poles

Investments in the wood pole category, like the substation category, are mainly driven by end of life assets that are in poor or very poor condition as determined by the ACA Report. The ACA Report states that NBH must replace around 250 poles per year to address said assets to ensure continued reliability, safety and cost control, however in the consideration of affordability NBHDL has structured investments into poleline replacement at a pace of 200 poles per year. This category not only involves the replacement of poles, but the renewal of all associated major assets that create the poleline formed by the poles. This other assets include transformers, conductor and switches, which for the most part generally follow the age and condition of the pole they are attached to.

NBHDL has been actively replacing poles at this rate over the past 5 years, and has done so predominantly in the areas of town operating at 4kV, as replacing poor assets in the 4kV area has the added benefit of voltage conversion over replacing poor assets operating at 12.47kV. The goal of eliminating the 4kV system and harmonizing the distribution grid to 12.47kV has been ongoing for 25 years and has tremendous advantages which are well articulated in Section 1.2.2. As the notion to eliminate the 4kV system has been around since the Initial VC Plan, the strategic planning leading to the Voltage Conversion Plan was necessary. This involved an investment strategy that employed conversion from outside in and targeted renewal of 3 substations, and the replacement of polelines involving 750 poles. It is extremely important to NBHDL to see the plan through and rid the system of the 4kV system to take advantage of the benefits of the investments made to harmonize to 12.47kV. The replacement rate of poles will continue through to and beyond 2019, but after 2016, pole replacements will be prioritized based on a new process defined in Section 4.2.3.

Safety is a secondary driver in this category, as the majority of old assets requiring renewal are either close to failure, involve obsolete equipment, are built to standards no longer acceptable, or designed using outdated methodologies, all which lead to safety related issues. Specifically, the following conditions are addressed when polelines are renewed: elimination of #6 Cu, elimination of delta servicing, elimination of underslung transformers, elimination of multiple services to one property, elimination of spacing issues (construction framing and separation to objects, i.e. buildings).

The replacement of poles ties directly back to the goals initially discussed in Section 1.2.2 by ensuring reliability is maintained and the health of NBHDL assets don't slip further into decline.

iii. Underground Cable Replacements

Investments in this category are driven, like both the categories above, by the requirement to replace end of life assets that are in poor or very poor condition as determined by the ACA Report. Investments in this category are aimed at ensuring reliability is maintained, but more importantly ensuring that O&M costs are controlled. Cable failures, especially cables that are direct buried, a characteristic of cables in this age demographic, are extremely costly to repair, as excavation in built up urban areas is very expensive. The program is aimed to proactively replace cables to avoid the high customer impact that is associated with their failure.

NBHDL has identified 5 large townhouse developments that have outdated design direct buried secondary underground systems which contribute significant costs to the annual O&M envelope in the form of cable failure and the resulting repairs. Three of the five projects have been scheduled for renewal in 2015 and the other two will be tackled in 2016. The capital expenditure plan for 2016 onward is levelized and will involve tackling underground primary cables with the highest risk of failure to the lowest. Cable injection is being considered as an alternative to full out replacement, and a pilot project will be attempted in 2016 to assess the feasibility of that technology.

The investment in this program will help ensure the reliability metrics outlined in Section 2.3 are maintained over the rate period.

System Service

Table 4-15 below summarizes proposed investments into system service program. It includes capital investments aimed at distribution system voltage upgrades from 4.16 kV to 12.47 kV and smart grid development initiatives to improve supply system security, reliability and power quality to levels commensurate with the needs of stakeholders. Investments into System Service category of projects are not expected to have significant impact on future O&M costs.

	2015	2016	2017	2018	2019	TOTAL	AVERAGE
Metering	$ 224,213	$ 125,995	$ 107,965	$ 69,320	$ 115,800	$ 643,293	$ 128,659
SCADA	$ 15,735	$ -	$ -	$ -	$ -	$ 15,735	$ 3,147
Feeder Conversion Projects	$ 123,445	$ 78,275	$ -	$ -	$ -	$ 201,721	$ 40,344
Minor Betterment Projects	$ 9,851	$ 10,472	$ 19,337	$ 19,724	$ 20,118	$ 79,502	$ 15,900
Proposed Total System Service	**$373,245**	**$214,743**	**$127,302**	**$89,044**	**$135,918**	**$ 940,251**	**$ 188,050**

Table 4-15: Planned Capital Investments into System Service Projects

i. Metering

In terms of priority, analysis and timing – in order to meet regulations NBHDL is required to complete this metering project. Given that NBHDL currently has 221 meters that are nearing expiration of meter seal

life, the optimal time to replace this system is now. Failing to push this project forward now would result in the need for costly interim measures and re-certification that could be avoided by replacement ahead of expiration. It would also run the risk of non-compliance with Measurement Canada requirements for recertification of meters.

Further information and justification on the Metering conversion will be included below in Section 4.5.2 for Capital Infrastructure Modernization – Conversion to Interval Meters.

The following are the internal components of the Miscellaneous Projects category underneath System Service:

ii. SCADA

The SMART GRID Initiative will be complete in 2015 upon the replacement of substation MS9. As MS22 is built, the SCADA system will be installed and complete the goal that NBHDL has been pursuing for 5 years since the 2010 rate application.

iii. Feeder Conversion

As discussed in Section 1.2.3, a number of NBHDL's feeders that have been upgraded or will be upgraded to the 12.47 kV construction standards continue to operate at 4.16kV after upgrading due to system configuration. When a 12.47kV supply becomes available to any upgraded feeders, NBHDL need only make a modest capital investment to change taps of the dual rated transformers to the higher voltage setting and replace fusing to match the lower current requirements. These capital investments are anticipated to end with a final upgrade to be completed in 2016. Table 1-4 above includes the list of feeders to be converted from 4.16 kV to 12.47 kV operations during the forecast period.

iv. Minor Betterment Projects

Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project. These projects represent a minor portion of the System Service capital expenditures for the forecast period, and as can be seen above in Table 4-14, NBHDL does not anticipate any major variation on a year to year basis.

General Plant

Table 4-16 below shows investments into general plant. These investments are intended to provide a safe work environment for employees to maintain high productivity levels, while providing customer services.

	2015	2016	2017	2018	2019	TOTAL	AVERAGE
Fleet	$ 515,000	$ 243,000	$ 400,000	$ 199,000	$ 435,000	$ 1,792,000	$ 358,400
Office Upgrades / Furniture	$ 56,652	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 156,652	$ 31,330
Tools	$ 46,151	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 226,151	$ 45,230
IT	$ 153,800	$ 60,400	$ 79,000	$ 81,700	$ 137,000	$ 511,900	$ 102,380
Proposed Total General Plant	**$ 771,603**	**$373,400**	**$549,000**	**$350,700**	**$642,000**	**$2,686,703**	**$537,341**

Table 4-16: Planned Capital Investments into General Plant

For the 2015 Test Year, NBHDL's budgeted costs for General Plant assets are $771,603. This budget consists of several different categories. Within each category, NBHDL's budget amount is based on costs by individual item. With the exception of the large bucket truck purchase, discussed below, which is justified through a capital project summary, the balance of NBHDL's costs are related to individual items

that do not exceed the materiality threshold. There are over 40 individual items with an average cost of $8,730. The largest individual items are between $10,000 and $35,000 and include the replacement of 3 pick-up trucks and 2 utility trailers which follow the fleet replacement schedule, 3 large server replacements, the purchase of mobile notebooks, a new Trimble XH Handheld replacement unit, and modifications to NBHDL's inventory storage area. NBHDL's General Plant budget varies year to year based on the individual items that are required and put forward by various members of the management team; these are reviewed and approved or denied on an individual item basis during the annual budget process.

i. Motor Fleet

As can be seen above in Table 4-16, the bulk of Fleet costs are focused in 2015. The major capital investment required for 2015 is the replacement of NBHDL's largest fleet vehicle.

This large vehicle ("Truck 30") has been determined to be at end of life by both the Fleet Assessment and NBHDL staff assessment. As it is at end of life, NBHDL required a replacement and as with all of its capital projects, considered alternatives. These alternatives are discussed in the Truck 30 Capital Summary below (**Appendix Q**).

As Truck 30 is a unique truck with a unique and required purpose, it would be detrimental if the truck was required for emergency work or planned work and was unavailable for use. Therefore NBHDL has proceeded with the replacement process.

In addition to Truck 30, the Fleet Assessment called for the replacement of three (3) pickup trucks in 2015 as well as the replacement of two reel trailers and one material trailer dating to 1976. These assets are beyond end of life and in immediate need of replacement.

NBHDL is following the recommendations made under the Fleet Assessment in completing these capital projects by the end of 2015.

After the completion of these projects, NBHDL anticipates no further major fleet investment other than the replacement of certain vehicles in 2017 and 2019. Even with the added capital investment of these vehicle replacements, NBHDL anticipates being well within historical averages for fleet investment.

ii. Building / Office Upgrades

NBHDL anticipates a marginal increase in this subcategory of General Plant investments due to the completion of its work on the HVAC and generator resizing at the company headquarters. Upon completion of this project in 2015, NBHDL will maintain $25,000 per year to account for typical maintenance and facility improvements that are based on historical averages and the Building Assessment.

iii. Tools

As discussed in Section 4.1.3.4 and 4.2.3.4, Tools are prioritized based on acute input from employees and imminent need based on condition and/or end of life. The projected values for Tools are consistent with the historical averages and NBHDL does not anticipate these costs to vary over the forecast period.

iv. IT System

In response to the IT Assessment, NBHDL has taken a systematic approach to addressing concerns in its IT system. A majority of the actions (that are driven by the IT Assessment and subsequent IT Strategy) are to be completed in 2015 which represents the higher investment requirement shown above in Table 4-15. The explanation of these IT strategic investments are as follows:

Improve TOU billing process.

NBHDL, along with vendor Sungard, has made modifications to its CIS to make a fourfold decrease in number of bill quantity requests issued per customer account. This significantly reduces the likely hood of delays in billing, and improves the efficiency of staff tasks, data circuits, and the MDM/R. NBHDL has also made efforts to address cross-training, by assisting its staff, and providing fallback and respite capabilities.

Enhance NaviLine utilization.

Naviline is the graphical front end to NBHDL's Sungard CIS system. Currently NBHDL uses a mix of Naviline, and terminal sessions (Green Screen as some call it). Sungard with the assistance and input of the Canadian users group is in a re-development of Naviline which will facilitate a more seamless integration with the desktop, and modernization of the tool set. Currently Sungard is beta testing, and NBHDL anticipates release of the new version in 2015. This among many things will allow integration of Naviline with MS-Office and other tools for enhanced utilization.

Establish a robust demand management program.

NBHDL has rolled out both commercial and residential DM programs with full web enablement and the ability for residential customers to not only view consumption, and adjust settings, but to participate in demand events from the IESO. Take up in the pilot programs is good with additional uptake expected in 2015 and forward. NBHDL is continuing to investigate cost effective ways to engage more customers in DR.

Develop "Business Continuity" & execution of smart meter operations.

NBHDL by participating in the D9 group gains the benefit of a full disaster prepped data center with full hot fail-over, and far less expense that if we implemented this solution solo. NBHDL has also been able to fine tune its network to get effective overlap in collector coverage, minimizing the likely hood that a failure of a tower will cause significant read loss. The current deployment of meters will store over 30 days of reads, giving NBHDL time to repair and recover and fault. NBHDL, in partnership with the other northern LDCs using Sensus as their AMI, is investigating the creation of a portable TGB (collector) to be deployed in the event of a prolonged failure. This will be a shared resource, and will have the ability to be deployed anywhere in the district within 12hrs.

Improvement of IT general controls & IT infrastructure.

With the implementation of a helpdesk portal, and configuration management database system, NBHDL has the ability to request, track, and monitor changes to all connected infrastructure. All requests for change are now tracked in the system, and wide spread impacts of changes are now easier to anticipate. This system came online in Q4 of 2013, and continues to evolve and improve.

Further utilize SunGard HTE testing environment for regulatory changes.

NBHDL now has two operational test environments allowing billing and regulatory testing to occur along side of version testing. Each can be independently updated and refreshed from production data to facilitate near parallel testing to production. NBHDL is currently running the most current versioning of the Sungard HTE system, and the only Sungard LDC to be running multiple test environments.

Reassess advanced metering infrastructure operations.

NBHDL, as part of its Meter to Cash audit, reviewed its current AMI operational efficiencies, and investigated changing contract options such as going independent from D9. At this time it is still more cost effective to share on the hardware and data center, than to duplicate it at NBHDL. The benefits of the shared D9 AMI far outweigh the negatives such as group consensus on changes and upgrades. At this point NBHDL has yet to have any group consensus road blocks. NBHDL continues to monitor its network performance, make adjustments, and as a result has one of the highest performing Sensus networks in Ontario, with our Read Interval Success (RIS) at 99.21%

Improve vendor management / communication with SunGard &Sensus

NBHDL continues to work directly with Sungard and Sensus, as well as participate in user groups and conferences where collective voices can be brought to the table on issues and development. The relationship with each vendor continues to improve, with Sungard recently taking additional steps to include NBHDL on international discussions, and development that will eventually benefit the Ontario users (Naviline etc.). Sensus is also interacting more directly with metering to shorten diagnostic time and improve problem resolution times. Deployment of new meters and changes to support DR programs has gone well with good support from Sensus.

Based on the IT Strategy and IT Assessment, NBHDL set a schedule to address the concerns with its IT system through to 2020. The capital investment requirements represent upgrades, server replacements and improvements to ensure optimal performance and minimal O&M costs.

The investment level drops after the larger investment requirements for 2015. The only other year projected to be of high investment is 2019. That particular year has a higher level of slated server and system replacements to achieve the goals of the IT Strategy.

4.5.1.4 Information related to NBHDL's system capability assessment

As indicated in Section 4.3, NBHDL's distribution system has more than enough capacity to accommodate not only REG projects but other new connections as required. Further, NBHDL does not anticipate any changes throughout the duration of the forecast period that would impose any capacity constraints or any changes in loading requirements of the system. As such, NBHDL's system capability assessment is not a factor in this DSP or NBHDL's capital investment planning as capacity is a non-factor for the distribution system at this time.

4.5.2 Material Investments (5.4.5.2)

The following section details all projects in 2015 that meet the materiality threshold of $65,000.00. The projects are detailed following the format presented in Section 5.4.5.2 of the Filing Requirements. Part A provides general information on each project, Part B provides evaluation criteria and information requirements for each project and Part C provides category-specific requirements for each project.

The majority of the 2015 capital investments are proposed in the System Renewal category. Specifically - $2,052,768 to the construction of a replacement substation, $2,020,937 to wood poles (with the majority tied to voltage conversion projects), and $1,395,701 to the replacement of end of life Underground facilities.

Material Capital Project Summaries are provided as attached **Appendix Q**. Supporting photographs for certain of these capital summaries are provided in **Appendix R**.

Appendix A – Intentionally Deleted

Appendix B - 2013 Asset Condition Assessment

ASSET CONDITION ASSESSMENT REPORT

Prepared by:

December, 2013

EXECUTIVE SUMMARY

This report prepared by METSCO Energy Solutions Inc. (METSCO), documents results of the health and condition assessment exercise completed in December 2013. The report covers the fixed assets employed on the power distribution system owned and operated by North Bay Hydro Distribution Limited (North Bay Hydro). The report provides a comprehensive picture of the existing health and condition of the distribution system assets as of 2013 and provides quantitative estimates of the assets found in poor and very poor condition, requiring rehabilitation or replacement in the near term. The condition assessment of revenue meters is not included in this report, because a vast majority of the assets in this class are virtually brand new, replaced in the recent past under the province's smart metering initiative. Auxiliary assets, such as motor vehicles, tools and equipment and IT systems etc. are not covered in this report.

The methodology utilized in this study is an integral part of a risk based asset management strategy that is based on the Asset Management Standard PAS-55, a specification developed by British Standards Institute (BSI) and commonly employed by progressive electric utilities. A risk based asset management strategy determines the timing and scope of investments into asset renewal, based on the risk of an asset's failure determined by the condition of the asset and consequences of its failure in service.

The first step towards implementation of a risk based asset management approach is to develop a yard stick to measure and benchmark the health and condition of assets and to determine the risk of in-service failure of assets. A comprehensive methodology for development of health indices for various assets has been developed and documented in Section 3 of the report, to quantitatively measure the health of all fixed assets employed on North Bay Hydro's distribution network, including the assets employed in substations, overhead lines and underground distribution system.

By applying this methodology, condition assessment of the assets has been completed and is documented in Section 4, providing the health indices and quantitative estimates of assets in different health index categories. In determining the health indices of assets, all available information relevant to the assets' health, described in Section 3 of this report, has been utilized. Where information on a health parameter was not available, health index has been calculated using a modified algorithm, utilizing only those parameters on which information was available.

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1 Introduction

This report summarizes the results of an Asset Condition Assessment study carried out by METSCO on behalf of North Bay Hydro, with the objective of establishing the health and condition of fixed assets currently in service on North Bay Hydro's distribution system.

The assets covered by the report include fixed assets employed on:

a) Distribution substations
b) Overhead distribution lines;
c) Underground distribution lines;
d) Distribution transformers; and
e) Switches and Cut-outs installed in pole-mounted and pad-mounted configurations.

The report is organized into four (4) sections including this introductory section:

- Section 2 describes the general principles of the risk based asset management strategy to achieve optimal operation of the distribution grid

- Section 3 describes the methodology for ranking and benchmarking the health of assets, through health index development

- Section 4 documents the results of asset condition assessment exercise

2 Strategic Management of Distribution Fixed Assets

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based Asset Management Strategy, therefore, determines the risk of asset failure based on the condition of the asset, which is commonly measured with the help of a yard stick of "Asset Health Indices", and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by the British Standards Institute (BSI) and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with the PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Exhibit 2-1.

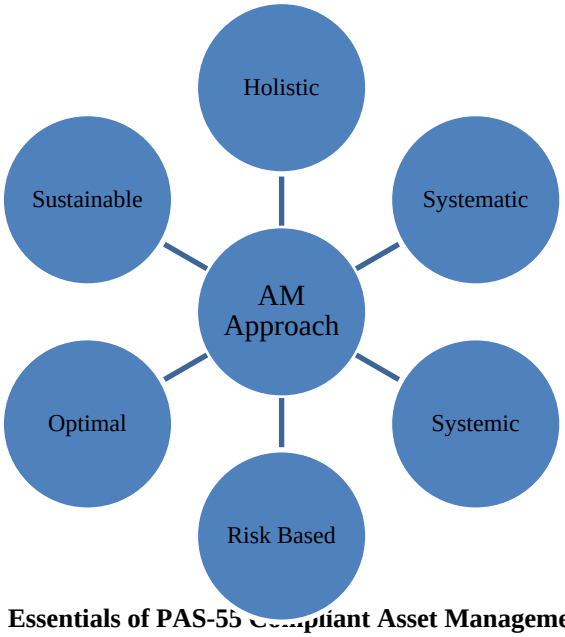


Exhibit 2-1: Essentials of PAS-55 Compliant Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of ten to twenty-five years to achieve optimal system performance by placing appropriate weights on corporate objectives and performance requirements, as shown in Exhibit 2-2.

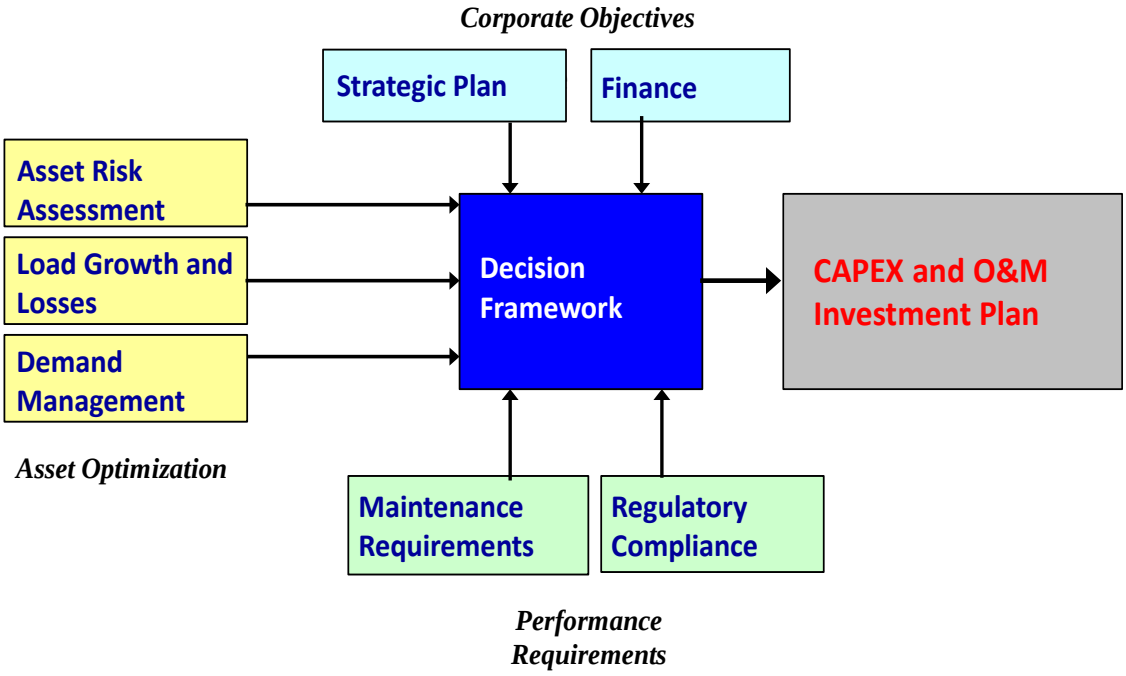


Exhibit 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Regulatory Compliance
b) Public and Employee Safety
c) Protecting Brand Name and Image
d) Operating Efficiency
e) Reliability and Supply System Security
f) Customer Service Quality
g) Getting Full Life out of Assets
h) Return on Investment
i) Risk Based Maintenance Strategy
j) Minimizing Asset Life Cycle Costs
k) Minimizing Risk of Premature Failures
l) Minimizing Environmental Risks

Exhibit 2-3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

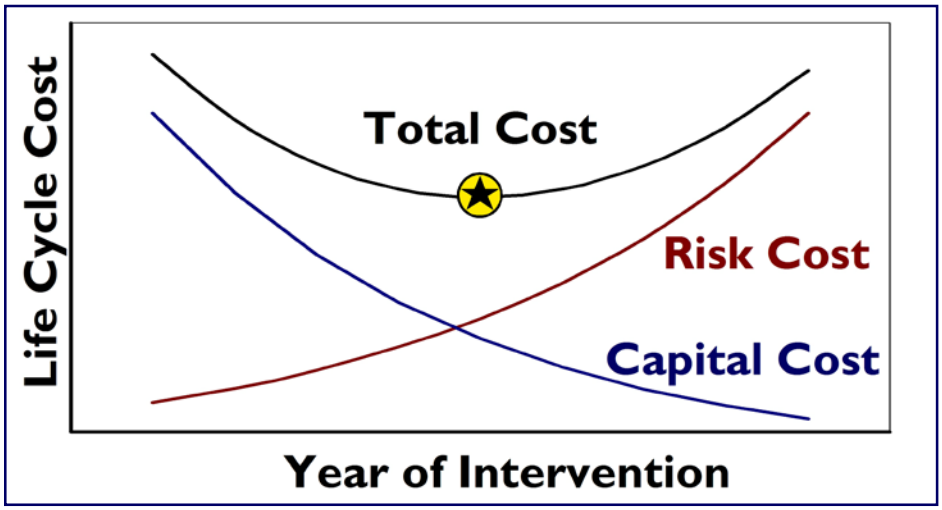


Exhibit 2-3: Risk Based Decision Support System

Exhibit 2-4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, as shown in Exhibit 2-5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan as shown in Exhibit 2-6 that could be implemented over a 5-10 year period.

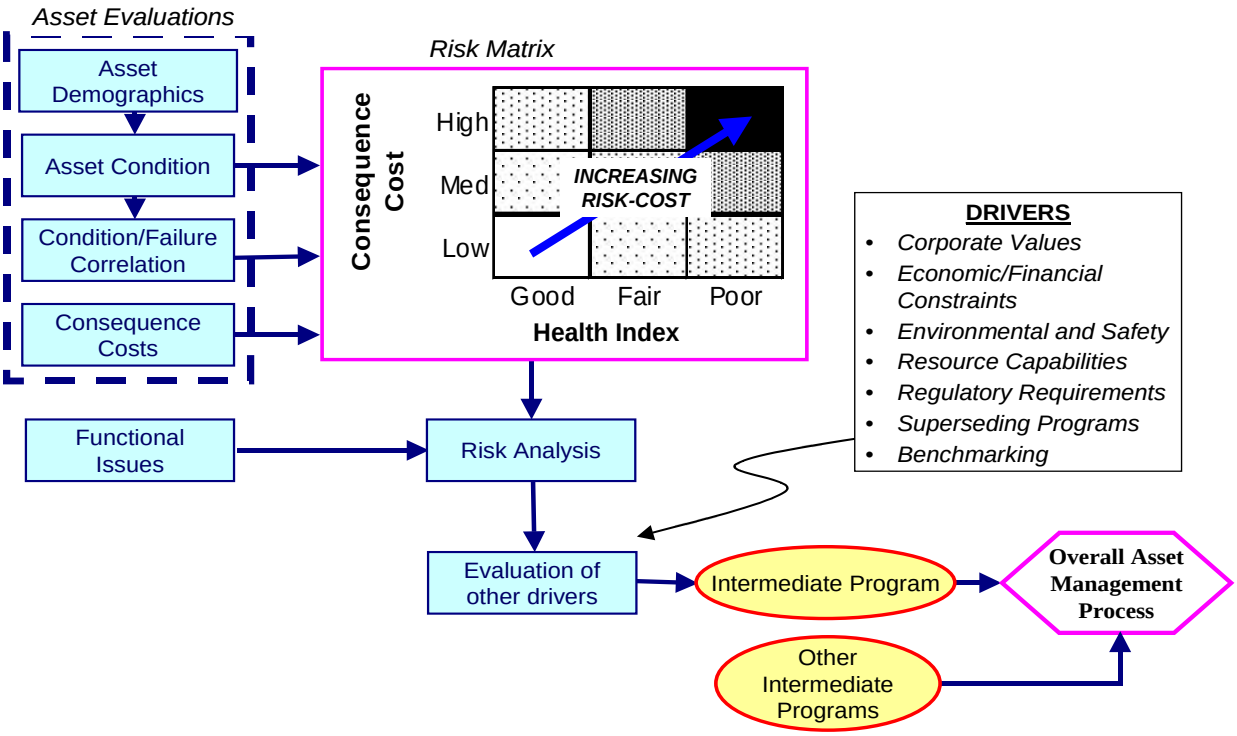


Exhibit 2-4: Model to Identify Assets with Highest Risks

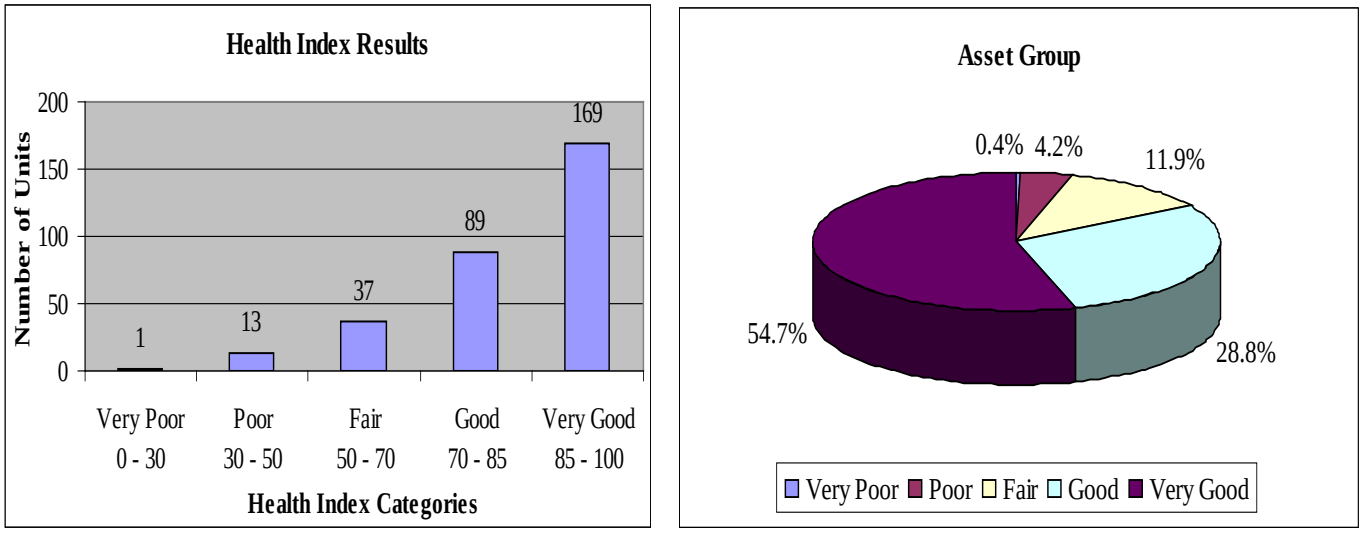


Exhibit 2-5: Graphs to Identify Assets with Highest Risks

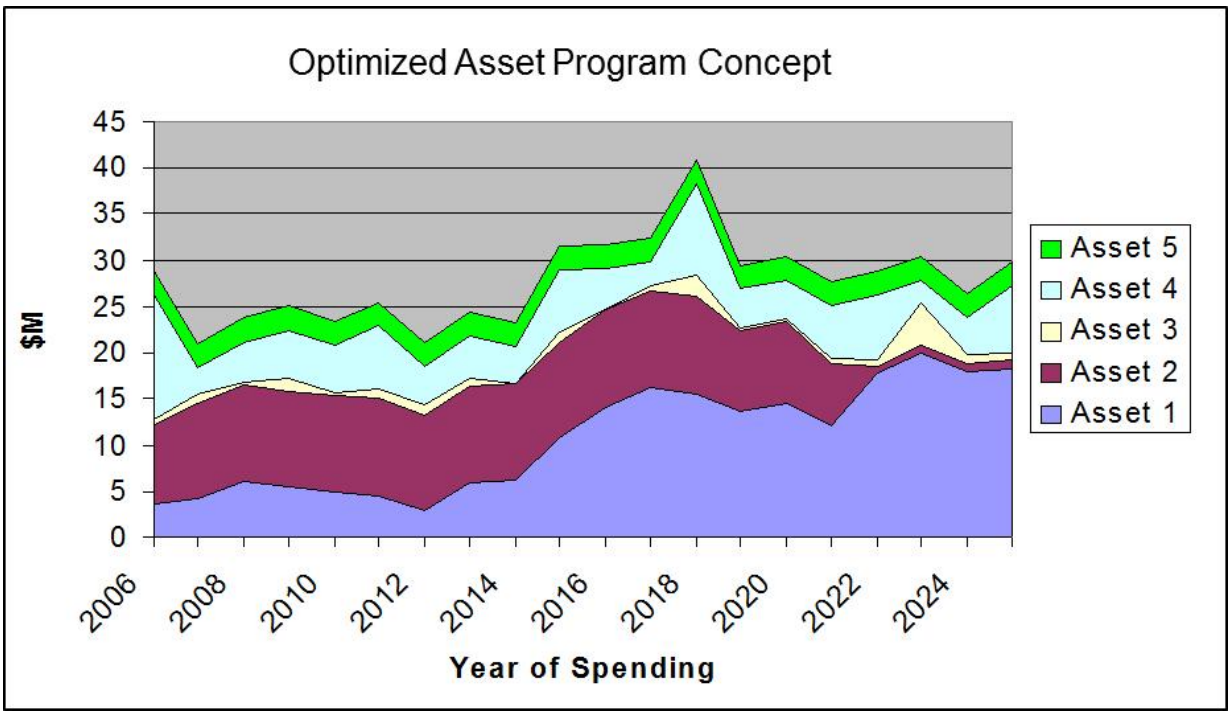


Exhibit 2-6: Investment Plan

3 ASSET CONDITION ASSESSMENT METHODOLOGY

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on North Bay Hydro's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Asset Condition Assessment methodologies are described below for the following distribution system asset categories:

a) Overhead Lines
b) Underground Lines
c) Substations
d) Distribution Transformers (pole mounted, pad mounted, pole trans and vault mounted)
e) Distribution Switches and Fused Cut-outs
f) Low Voltage system

The components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For purposes of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

- A= 5
- B = 4
- C = 3
- D = 2
- E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This allows for determining condition category for each asset in groups of Very Poor, Poor, Fair, Good and Very Good depending upon the resulting score.

3.1 Substations

The major assets employed in substations include:

- Station Transformers
- Circuit Breakers or Reclosers
- Controls and Protective Relays
- Control Battery and Chargers

- Ground Grid
- Perimeter Fences
- Buildings

3.1.1 Condition Assessment of Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. In case of North Bay Hydro, station transformers step down from 44 kV sub-transmission voltages to 12.47 kV or 4.16 kV.

The key components of pad-mounted power transformers employed at municipal stations are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of cellulose paper and mineral oil
- transformer tank, either sealed or breather type, and
- primary and secondary bushings.
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and cellulose paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, therefore, provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to insulation failure if the transformer is subjected to mechanical shocks that are common in normal operating conditions. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis provides information on three critical factors:

- condition of the oil from moisture, acidity and breakdown strength measurements,
- condition of the paper insulation from Furan, carbon dioxide, carbon monoxide and moisture measurements, and,
- presence of any incipient electrical or thermal faults within the transformer from the DGA results.

Some other tests that can be applied to oil samples such as interfacial tension, power factor etc.

3.1.2 Ranking Condition of Station Transformers through Multiple Criteria

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Condition Rating	Station Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 50 years
E	50 years or older

Exhibit 3-1: Station Transformers – Age Related Health Score

(b) Condition Assessment Based on Loading Level

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Circuit loading of 100% to 125% of its rating
E	Circuit loading of greater than 125% of its rating

Exhibit 3-2: Station Transformers – Load Related Health Score

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Condition Rating	Visual Inspections
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

Exhibit 3-3: Station Transformers – Health Score Based on Visual Inspections

(d) Condition Rating Based on Testing of the Insulating Oil

Various insulation tests, including dissolved gas in oil analysis (DGA), dielectric strength or water content measurement test can be interpreted by an expert to rank the overall condition of transformer insulation system:

Condition Rating	Test Results
A	Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition
E	Two or more of the tests indicate rapidly deteriorating insulation condition

Exhibit 3-4: Station Transformers – Health Score Based on Oil Tests

3.1.3 Condition Assessment Criteria for Circuit Breakers or Reclosers

Medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. A pole mounted recloser virtually provides the same functions as a circuit breaker. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil

circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or vacuum circuit breakers. In order to deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- Highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- High quality contact mating, capable of retaining high conductivity over time;
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

OCBs typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

Different types of circuit breakers employed on North Bay Hydro's distribution system are described below:

(a) Oil Circuit Breakers (OCB) or Oil Filled Reclosers

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced. Generally, after 4 to 8 fully rated interruptions, OCB's require preventative maintenance, during which excessive contact erosion, carbonisation of oil, and maintenance of operating mechanism may need to be attended to. The manufacture of new OCBs has been discontinued for at least 25 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

(b) Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

(c) Vacuum Circuit Breakers or Reclosers

In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time interval measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

(d) **SF_6 Circuit Breakers**

A SF_6 circuit breaker is designed to direct a constant gas flow to the arc that extracts heat from the arc and so allows achieving its extinction at current zero. The gas flow de-ionises the contact gap and establishes the required dielectric strength to prevent an arc re-strike. The direction of the gas flow either parallel or across to the axis of the arc has an influence on the efficiency of the arc interruption process. Research has shown that an axial flow creates a turbulence causing

an intensive and continuous interaction between the gas and plasma as current approaches zero. Recent developments concentrated on employing the arc energy itself to create directly the differential pressure needed, without using an external piston. Parallel to the self-pressurising design, the rotating arc SF_6 interrupter was also developed. In this design, a coil sets the arc in rotation while the quenching medium remains stationary. The relative movement between the arc and the gas is no longer axial but radial; it is a cross-flow mechanism.

3.1.4 Ranking Condition of Circuit Breakers and Reclosers through Multiple Criteria

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Condition Rating	Age
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years (or
D	25 to 32 years
E	33 years or older

Exhibit 3-5: Outdoor Circuit Breakers or Reclosers – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years (or
D	31 to 40 years
E	41 years or older

Exhibit 3-6: Indoor Circuit Breakers – Age Related Health Score

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers or reclosers, which can be ranked as indicated below:

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

Exhibit 3-7: Circuit Breakers – Visual Inspections Based Health Score

(c) Condition Rating Based on Evaluation of the tests

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of breaker insulation system:

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

Exhibit 3-8: Circuit Breakers and Recloser – Testing Based Health Score

3.1.5 Condition Assessment Criteria for Protection Relays and Remote Terminal Units

The function of protection relays on distribution systems is to detect and annunciate abnormal operating conditions and initiate circuit breaker or recloser trip to isolate faulty circuits from healthy circuits. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity.

Electro-mechanical designs of protection relays have been in use in the industry for several decades, but the industry best practice has been to replace these relays with solid state and microprocessor relays. Electro-mechanical relays have many moving parts and require calibration at regularly scheduled intervals to assure accurate operation. Modern micro-processor relays have no moving parts and can provide much more accurate operation without requiring frequent calibration.

The electro-mechanical relays with many moving parts lose their operating accuracy due to the moving parts developing friction or the springs becoming weak with passage of time and need to

be readjusted from time to time. Voltage and current surges can also harm electrical components of relays. The micro-processor and the solid state relays do not require frequent calibrations, but they are vulnerable to voltage and current surges.

3.1.6 Ranking of Protection Relays Condition through Multiple Criteria

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of protection relays. Since the relays are either installed indoors or in weatherproof cabinets, they are protected from the weather elements.

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Exhibit 3-9: Protection Relays – Age Based Health Score

(b) Condition Rating Based on Evaluation of the tests

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Condition Rating	Test Results
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

Exhibit 3-10: Protection Relays – Testing Based Health Score

3.1.7 Control Battery and Chargers

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. Two types of batteries are commonly used: lead acid batteries and nickel cadmium batteries. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

The key parts of a control battery include two electrodes immersed in an electrolyte inside a container. The battery terminals are brought out for cable connections. While the earlier vintages of control batteries required frequent maintenance and monitoring of electrolyte, modern batteries employ sealed design and are virtually maintenance free for the service life.

Battery chargers employ solid state rectifiers and are equipped with normal slow charge or fast charge functions.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions.

Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery.

3.1.8 Ranking Condition Control Batteries through Multiple Criteria

(a) Age Related Scoring

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of manufacturer recommended life expectancy:

Condition Rating	Actual Battery Age
A	Less than 25% of manufacturer recommended age
B	Less than 50% of manufacturer recommended age
C	Less than 75% of manufacturer recommended age
D	Less than manufacturer recommended age
E	More than manufacturer recommended age

Exhibit 3-11: Control Batteries and Chargers – Age Related Health Score

(b) Condition Rating Based on Evaluation of the tests

Condition Rating	Test Results
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

Exhibit 3-12: Control Batteries and Chargers – Test Based Health Score

3.1.9 Substation Ground Grids

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power

equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

3.1.10 Ranking Condition of Ground Grids through Multiple Criteria

The health and condition of a ground grid can be verified though ground grid resistance measurements and integrity tests.

(a) Age Related Scoring

Condition Rating	Age
A	Ground Electrode less than 10 years old
B	Ground Electrode Between 10 and 20 years Old
C	Ground Electrode Between 20 and 30 years Old
D	Ground Electrode Between 30 and 40 years Old
E	Ground Electrode More than 40 years Old

Exhibit 3-13: Ground Grid – Age Related Score

(b) Condition Rating Based on Evaluation of the tests

Condition Rating	Test Results
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

Exhibit 3-14: Ground Grid – Testing Related Health Score

(c) Rating Based on Condition of Surface Stone

Condition Rating	Test/Inspection Results
A	Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth

Exhibit 3-15: Ground Grid – Testing Related Health Score

3.1.11 Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life.

To achieve this objective the fence has to be of a minimum height of 1.8 m to comply with the Ontario Electrical Safety Code and topped with three rungs of barbed wire covering a height of 0.3 m. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 0.1 m or less. Where a substation fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations.
The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs.

3.1.12 Ranking Condition of Fences through Multiple Criteria

(a) Condition Rating Based on Evaluation of the tests

Condition Rating	Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

Exhibit 3-16: Fences Health Score based on Visual Inspections

3.1.13 Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

3.1.14 Ranking Condition of Substation Buildings through Multiple Criteria:

The health and condition of a substation building can be measured through visual inspections:

Condition Rating	Inspections
A	No deficiencies in the building
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

Exhibit 3-17: Substation Buildings Health Score

3.1.15 Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A - E	5	6	30
2	Peak loading	A - E	5	4	20
3	Visual inspection	A - E	5	2	10
4	Testing	A - E	5	8	40
	Total				100

Exhibit 3-18: Station Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	8	40
2	Visual inspection	A - E	5	4	20
3	Testing	A - E	5	8	40
	Total				100

Exhibit 3-19: Circuit Breakers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	10	50
2	Testing	A - E	5	10	50
	Total				100

Exhibit 3-20: Protection Relays and RTUs – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	10	50
2	Testing	A - E	5	10	50
	Total				100

Exhibit 3-21: Substation Control Batteries and Chargers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	8	40
2	Testing	A - E	5	8	40
3	Visual Inspection	A - E	5	4	20
	Total				100

Exhibit 3-22: Substation Ground Grid – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Visual Inspection	A - E	5	20	100
	Total				100

Exhibit 3-23: Substation Fences – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Visual Inspection	A - E	5	20	100
	Total				100

Exhibit 3-24: Substation Buildings – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Transformers	A - E	5	10	50
2	Circuit Breakers/Reclosers	A - E	5	5	25
3	Protection Relays/Controls	A - E	5	5	20
4	Ground Grids	A - E	5	1	5
5	Fences / Control buildings	A - E	5	1	5
	Total				100

Exhibit 3-25: Overall Health Index For Outdoor Substations

3.2 Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Poles
- Insulators
- Hardware
- Conductors and splices

3.2.1 **Condition Assessment Criteria for Poles**

As wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

3.2.2 **Condition Assessment Criteria for Insulators**

The types of insulators and configurations typically used in distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arcing damage/galvanizing;

Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM or silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

3.2.3 Condition Assessment Criteria for Metal Cross Arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.2.4 Ranking Condition of Poles and Accessories through Multiple Criteria

The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Score

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Condition Rating	Age
A	0 to 10 years
B	10 to 30 years
C	30 to 40 years
D	40 to 50 years
E	50 years or older

Exhibit 3-26: Overhead Lines – Age Related Health Score

(b) Preservative Treatment Based Scoring for Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Condition Rating	Type of Pole Treatment
A	Fully Treated
C	Butt Treated
E	No Treatment

Exhibit 3-27: Overhead Lines – Pole Treatment Based Health Score

(c) Condition Rating Based on Visual Examinations of Pole Line Components

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Condition Rating	Component Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component has damaged/degraded beyond repair and will require replacement

Exhibit 3-28: Overhead Lines - Visual Inspections Based Health Score

3.2.5 Condition Assessment Criteria for Conductors

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines

operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- Aluminium Stranded Conductors (ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

Because of the relatively short span lengths employed on distribution lines in relation to transmission lines, the tensile strength of conductors on distribution lines is not as critical as it is on transmission lines. Most distribution utilities these days, therefore, employ all aluminium conductors on distribution lines. Aluminium alloy conductors are sometimes used on distribution lines with longer span lengths.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation, corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of

aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Bird-caging.

Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

3.2.6 **Condition Assessment Criteria for Splices**

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor's life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor's strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.2.7 **Ranking Condition of Conductors and Splices through Multiple Criteria**

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the following parameters:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining strength of conductors and all the defects are not easily detected through visual inspections, an age based criteria is proposed as indicted below:

Condition Rating	Age
A	0 to 15 years
B	16 to 30 years
C	31 to 40 years
D	51 to 60 years
E	Older than 60 years

Exhibit 3-29: Conductors and Splices – Age Related Health Score

(b) Small Conductor Risk

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Condition Rating	Age
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

Exhibit 3-30: Overhead Lines - Small Conductor Related Health Score

(c) Valuation of System losses

In addition to the above criteria, percentage losses on the feeder will be calculated and when significantly greater than the average distribution system losses on North Bay Hydro's system, will be included in valuation as indicated below:

Condition Rating	Line Loss
A	Less than or Equal to Average system loss
B	5% higher from the average system loss
C	10% higher from the average system loss
D	20% higher from the average system loss
E	30% higher from the average system loss

Exhibit 3-31: Overhead Lines – System Losses Related Score

3.2.8 Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various Health Index criteria described in Section 3.2.1 through 3.2.7.

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of pole line	A - E	5	3	15
2	Pole treatment	A - E	5	1	5
3	Visual inspection of poles	A - E	5	1	5
4	Pole testing	A - E	5	4	20
5	Visual inspection of insulators	A - E	5	1	5
6	Visual inspection of hardware	A - E	5	1	5
7	Age of conductors	A - E	5	1	5
8	Small conductor risk	A - E	5	5	25
9	Energy loss in conductors	A - E	5	3	15
	Total				100

Exhibit 3-32: Overhead Lines – Health Index Calculation

3.3 Underground Distribution System

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables, splices and terminations
- Manholes and vaults

3.3.1 **Condition Assessment Criteria for Cables, Splices and Terminations**

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

3.3.2 Condition Assessment Criteria for Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

3.3.3 Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Condition Rating	Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 to 50 years or older

Exhibit 3-33: Underground Cables - Age Related Score

(b) Cable Design and Construction

Since PILC cable designs are known to provide significantly longer service life compared to XLPE cables and earlier vintages of XLPE cables that did not employ tree retardant designs are subject to premature failures, design of cable is employed in Health Index formulation, as indicated in the table below:

Condition Rating	Type of Treatment
A	PILC Cables
B	Tree Retardant XLPE
E	Earlier vintages of XLPE

Exhibit 3-34: Underground Cables – Design Related Health Score

(c) Circuit Loading

The rate of insulation degradation is directly related to the operating temperature. Assuming similar types of backfills result in uniform rates of heat dissipation for all circuits, current loading of circuits measured as percentage of circuit's rated current carrying capacity, can be employed as an indicator of cable health as indicated below:

Condition Rating	Component Condition
A	Circuit loaded less than 25% of its rating
B	Circuit loading of 25% to 50% of its rating
C	Circuit loading of 50% to 75% of its rating
D	Circuit loading of 75% to 100% of its rating
E	Circuit loading of greater than 100% of its rating

Exhibit 3-35: Underground Cables – Loading Related Score

(d) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable Health Index formulation as indicated below:

Condition Rating	Component Condition
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures per 10 km in the last 5 years
C	1.0 to 1.5 Failures per 10 km in the last 5 years
D	1.5 to 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

Exhibit 3-36: Underground Cables – Failure Related Score

(e) Condition of Cable Splices or Stress Cones

Physical condition of cable splices or stress cones can be employed in assessing overall condition of the cable circuit:

Condition Rating	Component Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

Exhibit 3-37: Underground Cables - Splice or Stress Cone Related Health Score

3.3.4 Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.3.5 Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non-functioning drains or sump pumps
- Inadequate space

(a) Structural Condition

Condition Rating	Inspections
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

Exhibit 3-38: Manhole and Vaults – Structural Health Score

(b) Flooding Incidents, Drains, Sump Pumps

Condition Rating	Inspections
A	No incidents of Flooding at this location
C	Occasional Flooding, working sump pumps and drains
E	Frequent Flooding, No sump pumps or drains

Exhibit 3-39: Manhole and Vaults - Flooding Related Health Score

(c) Vault Size and Access:

Condition Rating	Inspections
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement

Exhibit 3-40: Manholes and Vaults – Size Related Health Score

3.3.6 Health Index Formulation for Underground Cables, Manholes and Vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Cable Circuit	A – E	5	3	15
2	Type/Design of Cable	A – E	5	3	15
3	Loading of Cable Circuit	A – E	5	5	25
4	Historic Failure rates	A – E	5	8	40
5	Visual inspection of splices or stress cones	A – E	5	1	5
	Total				100

Exhibit 3-41: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Structural Integrity	A – E	5	8	40
2	Flooding and Its mitigation	A – E	5	4	20
3	Size and Access	A – E	5	8	40
	Total				100

Exhibit 3-42: Manholes and Vaults Health Index

3.4 Distribution Transformers

Four (4) main types of distribution transformers are commonly employed on distribution system:

- Pole mounted transformer
- Pad mounted transformer
- Vault transformer
- Transclosure

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, 120/208V, 240/416 V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.1 Ranking the Condition of Distribution Transformers through Multiple Criteria

Computing the Health Index for a distribution transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Condition Rating	Distribution Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Exhibit 3-43: Distribution Transformers – Age Based Health Scoring

(b) **Condition Assessment Based on Loading Level**

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformer expressed in percentage of the nameplate rating can therefore be employed as an indicator of transformer health:

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

Exhibit 3-44: Distribution Transformers – Load Based Health Scoring

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

Exhibit 3-45: Distribution Transformers – Inspections Based Health Scoring

3.4.2 Health Index Formulation for Distribution Transformers

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A – E	5	6	30
2	Peak loading	A – E	5	6	30
3	Visual inspection	A – E	5	8	40
	Total				100

Exhibit 3-46: Distribution Transformers Health Index

3.5 Disconnect Switches and Cut-outs

This asset class includes pad and vault mounted medium voltage switchgear as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Pad mounted disconnects have the following additional components:

- Pad or vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

3.5.1 **Ranking Condition of Disconnect Switches through Multiple Criteria**

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches, it is employed as an assessment parameter, with the following scores:

Condition Rating	Disconnect Switch Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Exhibit 3-47: Disconnect Switches and Cutouts – Age Based Health Scoring

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of disconnect switches. Infrared (IR) scan can provide indication of hot spots resulting from misaligned blades.

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Exhibit 3-48: Disconnect Switches and Cutouts – Inspections Based Scoring

3.5.2 Health Index Formulation for Disconnect Switches

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of disconnect	A - E	5	10	50
2	Visual inspections and IR Scan	A - E	5	10	50
	Total				100

Exhibit 3-49: Distribution Switches and Cutouts – Health Index

4 ASSET DEMOGRAPHICS AND CONDITION ASSESSMENT

The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed on North Bay Hydro's distribution system. This section of the report, documents the health indices for fixed assets employed on North Bay Hydro's distribution system, based on all available information from testing, inspections, service age and other demographic information retrieved from the GIS system.

4.1 Distribution Substations

There are a total of 16 distribution substations employed on North Bay Hydro's distribution system. Exhibit 4-1 shows the geographic location of each of the distribution stations within the city of North Bay. Two of the substations, MS1 and MS7, step down power from 44 kV to 4.16. One substation, MS-18 has dual winding transformers, capable of supplying both 4.16 kV and 12.47 kV, but is presently supplying at 4.16 kV. The remaining substations step down from 44 kV to 12.47 kV.

4.1.1 **Substation Transformers**

Exhibit 4-2 presents the age profile of power transformers employed at North Bay Hydro's substations. Two of the transformers, installed in substations MS7 and MS 1, have a service age of greater than 40 years. Exhibit 4-3 provides detailed demographic information on power transformers, including manufacturer name, rating, service location and year of installation for each of the power transformers.

Based on the condition assessment criteria detailed in Section 3, Health Index score has been calculated for each of the substation transformers and the results are summarized in Exhibit 4-4. As shown, three power transformers – MS-7-T1, MS-9-T1 and MS-13-T1 transformers have determined to be in "poor" condition, while the remaining transformers are ranked to be in "fair", "good" or "very good" condition. The transformers determined to be in poor condition present high risk of failure in service and are recommended to be replaced during the next five years. By taking into account the high probability of failure of the assets found in poor and very poor condition and the consequence of the assets' failure in service, Section 5 documents additional analysis supporting replacement of the assets found in poor and very condition.

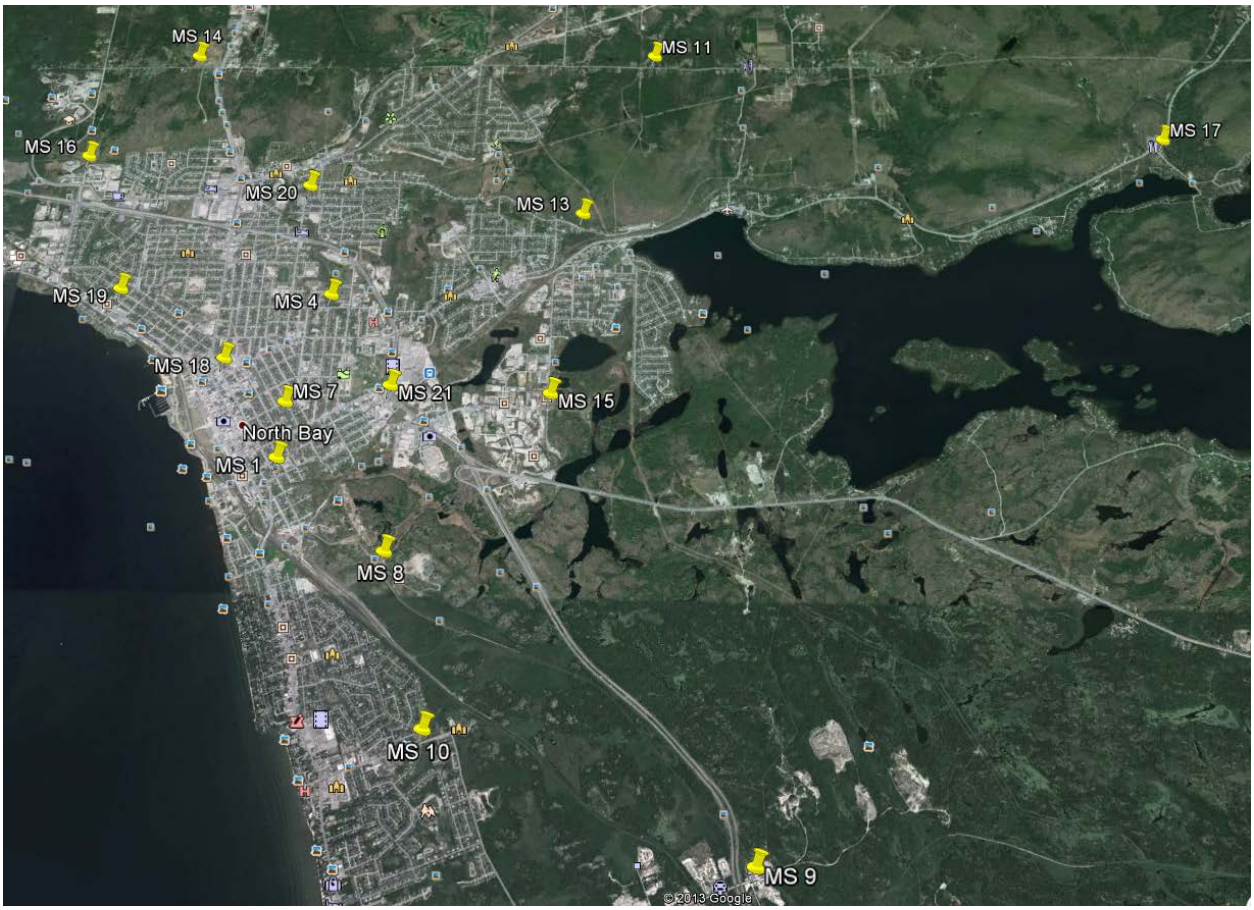


Exhibit 4-1: Distribution Substations and their Locations

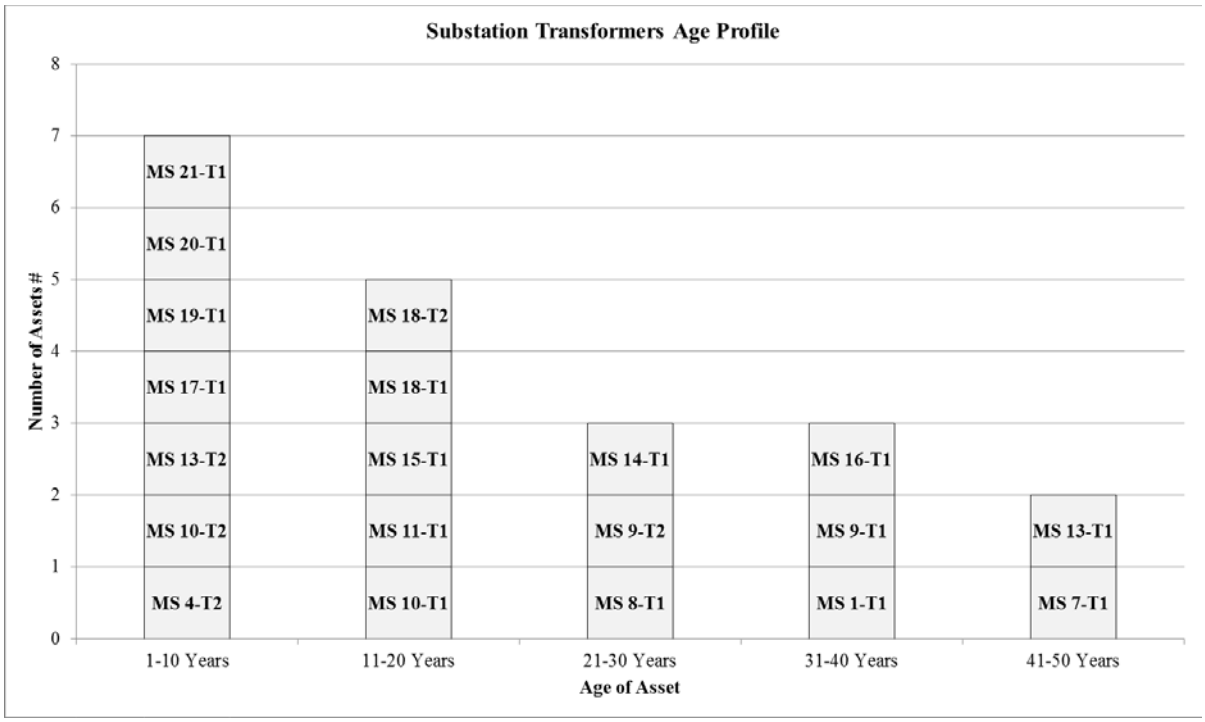


Exhibit 4-2: Substation Transformers Age Profile

Designation	Substation ID	Location	Rating	Manufacturer	Serial #	In Service Date
MS 1-T1	MS 1	561 Worthington St. East	5 MVA	MOLONEY ELECTRIC	274690	1974
MS 4-T2	MS 4	1367 High St.	7.5 MVA	Northern	051993	2008
MS 7-T1	MS 7	290 Third Ave. East	5 MVA	GE	286624	1967
MS 8-T1	MS 8	Old Callander Road	7.5 MVA	Northern	92863	1992
MS 9-T1	MS 9	30 Division Street	7.5 MVA	Westing House	A3S6394	1977
MS 9-T2	MS 9	30 Division Street	7.5 MVA	Northern	92890	1992
MS 10-T1	MS 10	290 Marshall Ave East	7.5 MVA	Northern	94-1090	1994
MS 10-T2	MS 10	291 Marshall Ave East	7.5 MVA	Northern	062035	2006
MS 11-T1	MS 11	571 Tower Road	7.5 MVA	Northern	961251	2002
MS 13-T1	MS 13	1336 Ski Club Road	6 MVA	Feranti Packard	12801	1966
MS 13-T2	MS 13	1336 Ski Club Road	7.5 MVA	VTC	477500A164-B806A	2012
MS 14-T1	MS 14	137 Cedar Heights Rd	7.5 MVA	Northern	90733	1991
MS 15-T1	MS 15	897 Wallace Road	7.5 MVA	Northern	951134	1995
MS 16-T1	MS 16	880 Gormmanville Road	7.5 MVA	MOLONEY ELECTRIC	244320	1975
MS 17-T1	MS 17	20 Penninsula Road	7.5 MVA	ABB	BS40157001	2011
MS 18-T1	MS 18	316 Worthington St.west	7.5 MVA	Northern	971309	1997
MS 18-T2	MS 18	316 Worthington St.west	7.5 MVA	Northern	971310	1997
MS 19-T1	MS 19	1299 Mcintyre St West	7.5 MVA	Northern	072153	2008
MS 20-T1	MS 20	1635 Mckeown Ave	7.5 MVA	ABB	BS40131001	2011
MS 21-T1	MS 21	398 McGaughey Ave	7.5 MVA	VTC	477500A170-B888A	2013

Exhibit 4-3: Substation Transformers Detailed Demographic Information

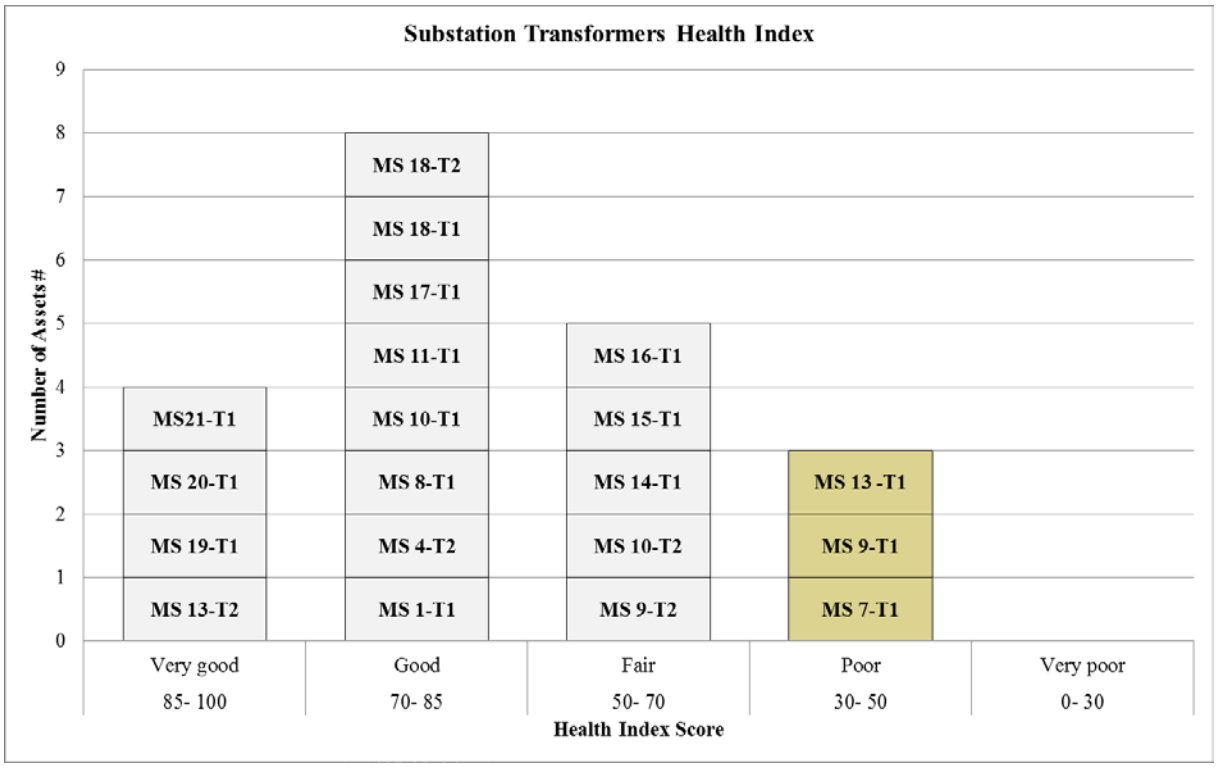


Exhibit 4-4: Substation Transformers Health Index Score

4.1.2 Substation Circuit Breakers and Reclosers

By taking into account the service age, the results of visual inspections and maintenance test reports (where available), Health Index score has been calculated for all circuit breakers and reclosers and the results are summarized in Exhibit 4-5. As indicated the reclosers at MS-9 have been determined to be in "poor" health and recommended to be replaced during the next five years. By taking into account the high probability of failure of the assets found in poor and very poor condition and the consequence of the assets' failure in service, Section 5 documents additional analysis supporting replacement of the assets found in poor and very condition.

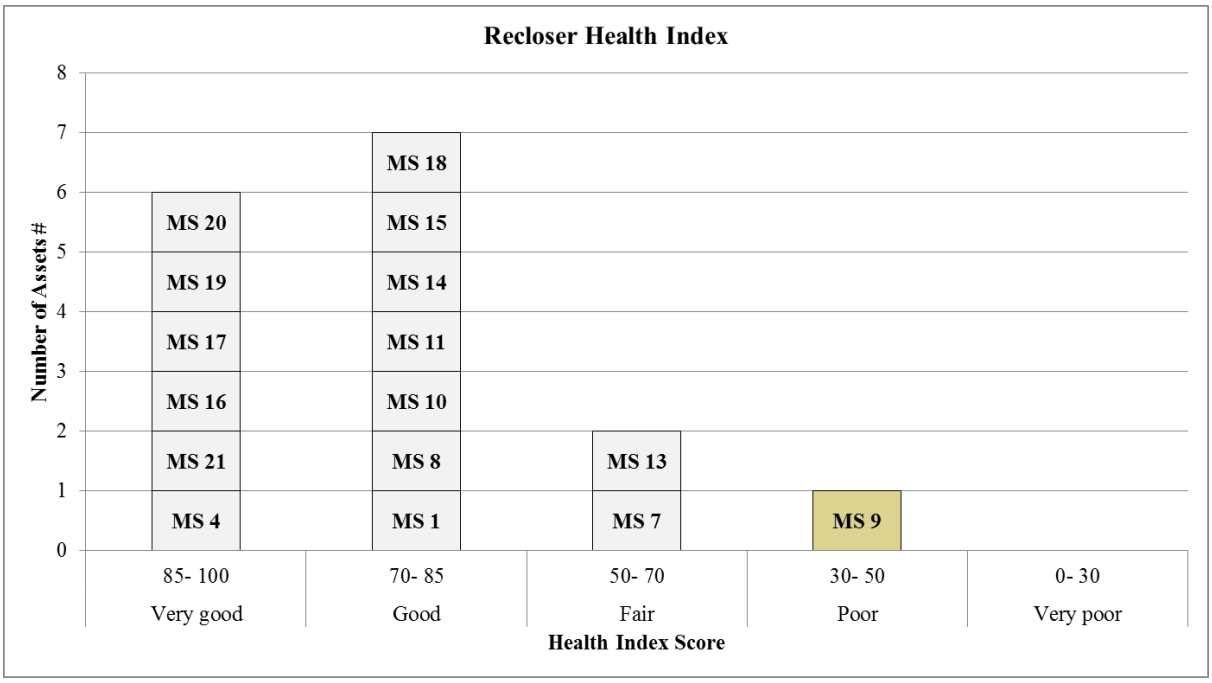


Exhibit 4-5: Substation Circuit Breakers and Reclosers Health Index Score

4.1.3 Substation Protection & Control Relays

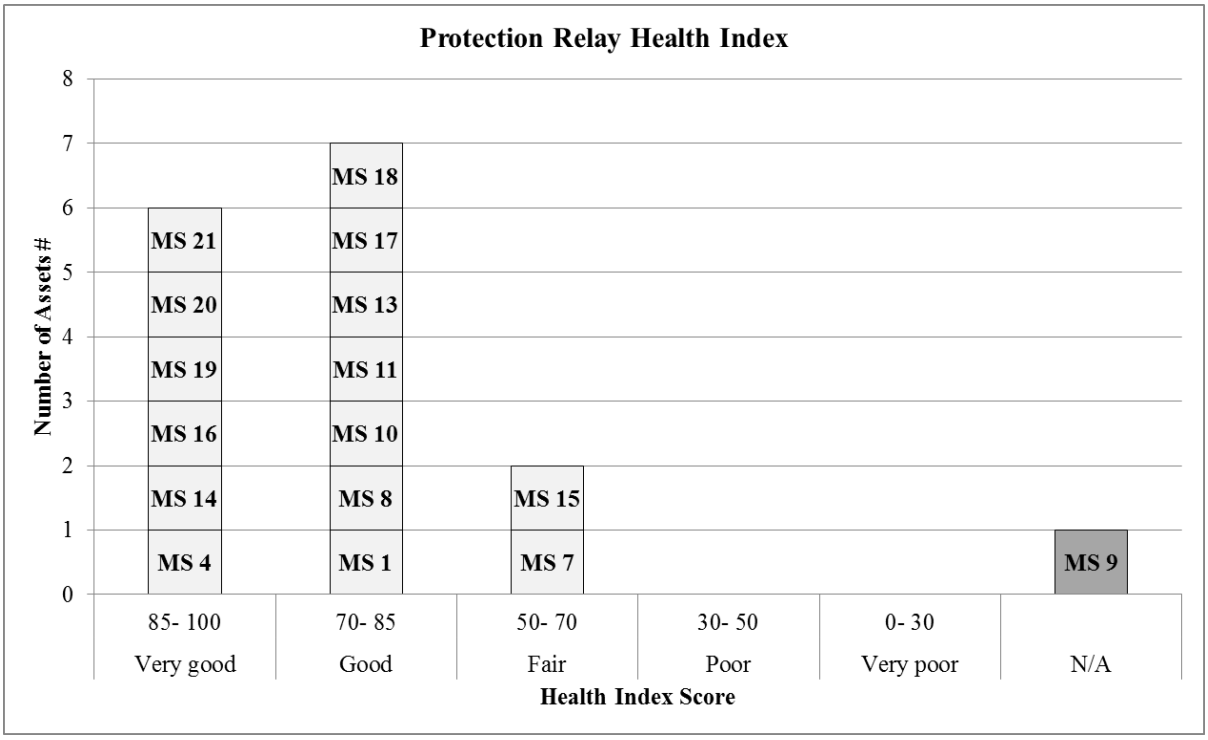


Exhibit 4-6: Substation Protection and Control Relays

As shown in Exhibit 4-6, with the exception of municipal stations MS-9 and MS-16, where no modern protection and controls (P&C) exist, the P&C equipment at the remaining stations has been determined to be in "fair", "good" or "very good" condition.

4.1.4 Substation Ground Grids

Based on the service age of ground grids and results of visual inspections, the Health Index score for ground grids is calculated and is summarized in Exhibit 4-7. As indicated, the ground grids at MS1, MS4, MS7, MS9, MS10, MS11, MS13, MS15 and MS16 are determined to be in poor condition, mostly due to the poor condition of the surface stone and the rest are in good and very good condition. It is recommended the surface stone found in poor condition be replaced during the next five years.

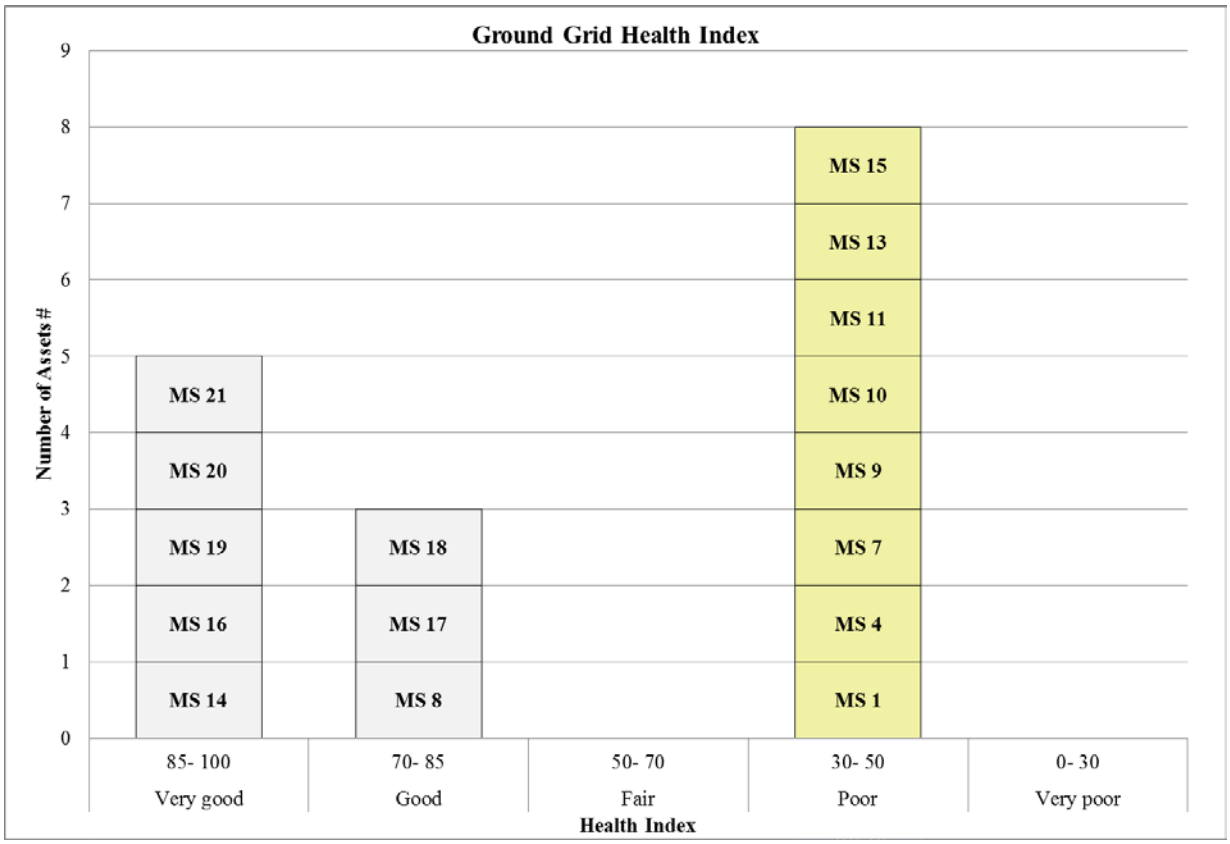


Exhibit 4-7: Substation Ground Grids Health Index Score

4.1.5 Substation Fences and Control Buildings

Based on the condition assessment criteria defined in Section 3, the Health Index score as summarized in Exhibit 4-8, is calculated for substation perimeter fences and control buildings. The perimeter fences and buildings at MS-15 and MS-16 are found in fair condition and the rest are in the good and very good condition.

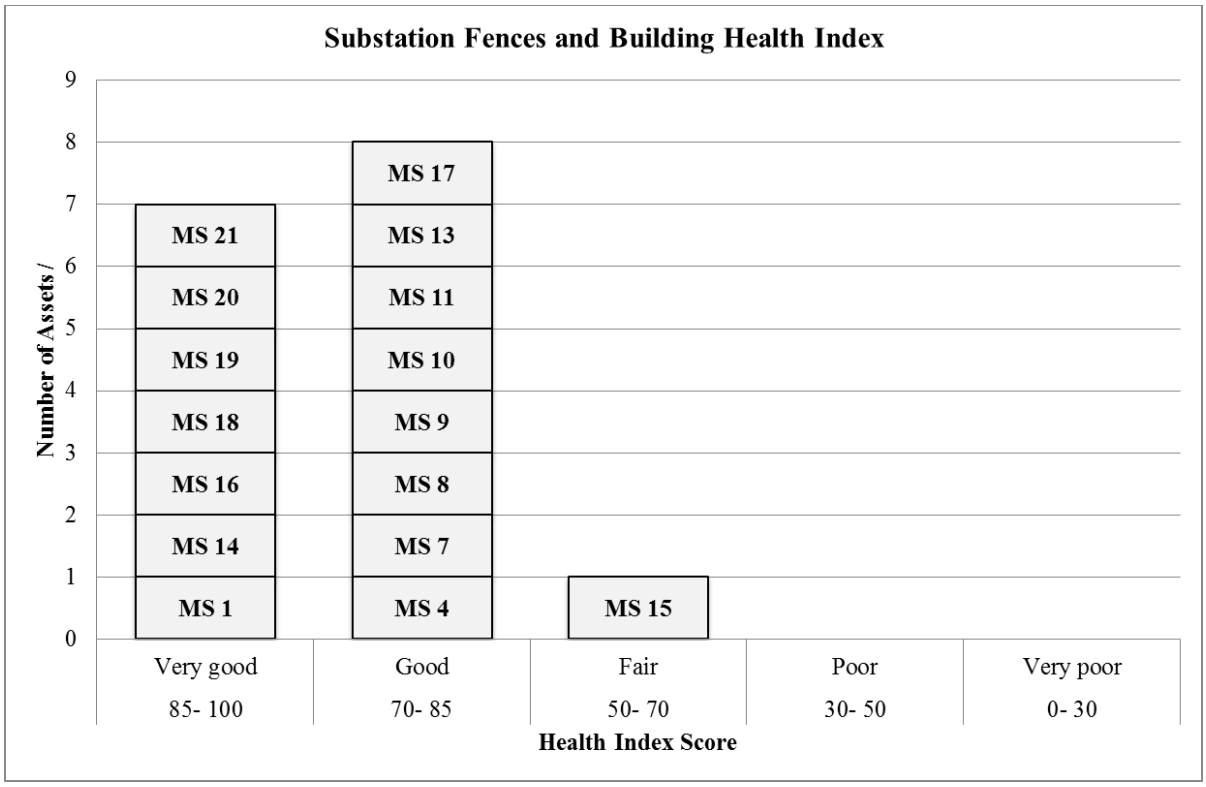


Exhibit 4-8: Substation Fences Health Index Score

4.1.6 Overall Health Index Scores for Substations

Based on the condition assessment criteria defined in Section 3, the overall Health Index scores for the substations currently in service at NBHDL are summarized in Exhibit 4-8.

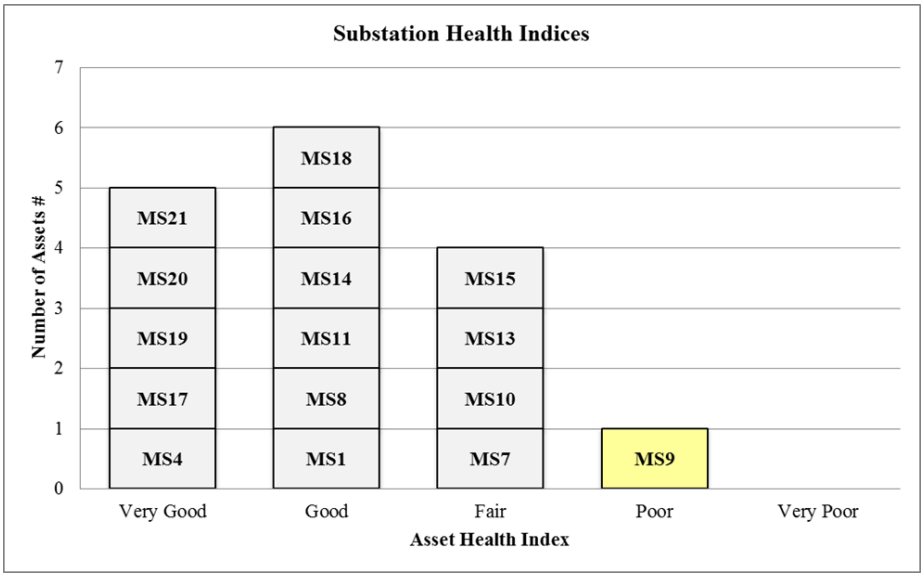


Exhibit 4-9: Overall Substation Health Index Score

4.2 Overhead Lines

4.2.1 Distribution Line Support Poles

Based on the demographic information retrieved from the GIS system, there are approximately 7180 wood poles and 71 other types of poles (including steel, concrete and fiberglass) employed on North Bay Hydro's medium voltage (MV) electricity distribution system. The total number of poles in services, per NB Hydro records is approximately 10,050, which means approximately 2870 poles are employed on LV lines and stub pole applications. For condition assessment of the assets we have employed the GIS data for poles employed on MV lines.

Exhibit 4-10 displays the age profile of wood poles employed on North Bay Hydro's distribution system. Approximately 1550 poles (shown in red) have been in service for more than 50 years and approximately 850 poles (shown in yellow) have been in service for more than 40 years. For approximately 550 poles the service age is unknown, but a vast majority of the poles in this category are expected to of older vintage with service life of more than 40 years. This means more than 40% of the poles currently in service have a service age of 40 years more, as of 2013 and a majority of these will required replacement during the next 10 years.

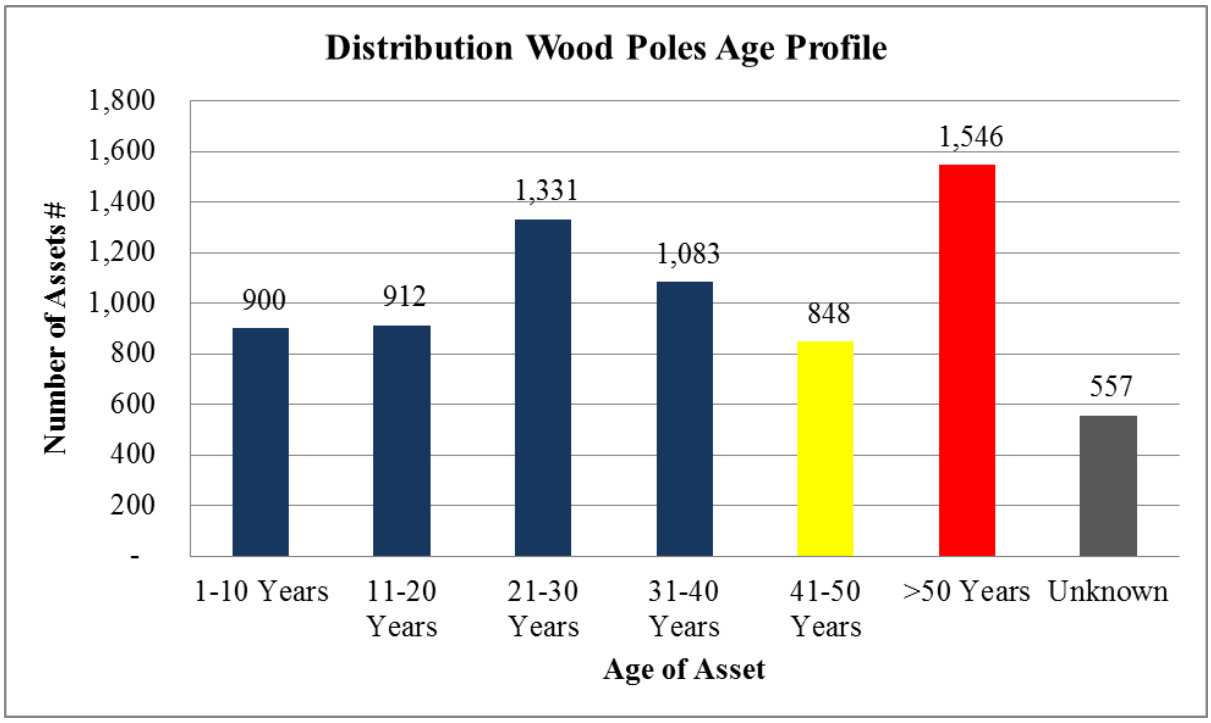


Exhibit 4-10: Age Demographics of Wood Poles

Exhibit 4-11 displays the feeder by feeder age profile of wood poles. As shown, feeders emanating from some of the substations, i.e. MS11, MS17 and MS8, etc., contain a much higher ratio of these older vintage poles.

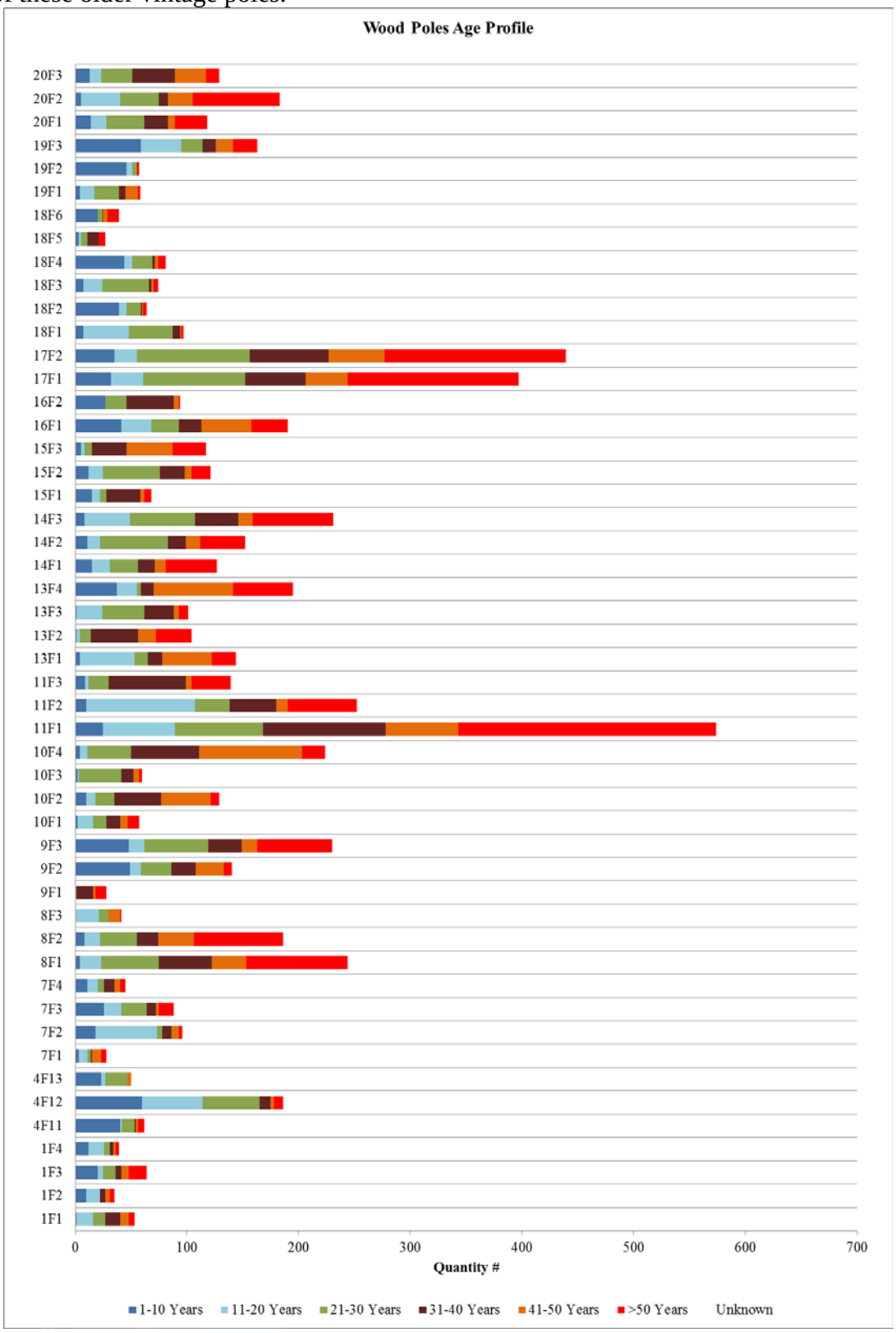


Exhibit 4-11: Age Demographics of Wood Poles

Exhibit 4-11 displays the number of poles in service age categories of “41-50 year”, “>50 years” and “unknown age” employed on 4 kV lines.

	41-50 years	>50 years	Unknown
MS1	21	28	13
MS7	23	26	49
MS18	11	32	21
MS19	26	26	24
MS4	8	14	9
TOTAL	89	126	116

Exhibit 4-12: Number of Poles Older than 40 years Employed on 4 kV Feeders

Poles on distribution lines are employed in different configurations; some support only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. Exhibit 4-13 indicates the approximate percentage of different pole heights employed on North Bay Hydro’s distribution system. As indicated, pole heights vary from 20 feet to 80 feet, however, 35ft, 40ft and 45ft poles are used most commonly. Poles 25 feet or less are typically stub poles.

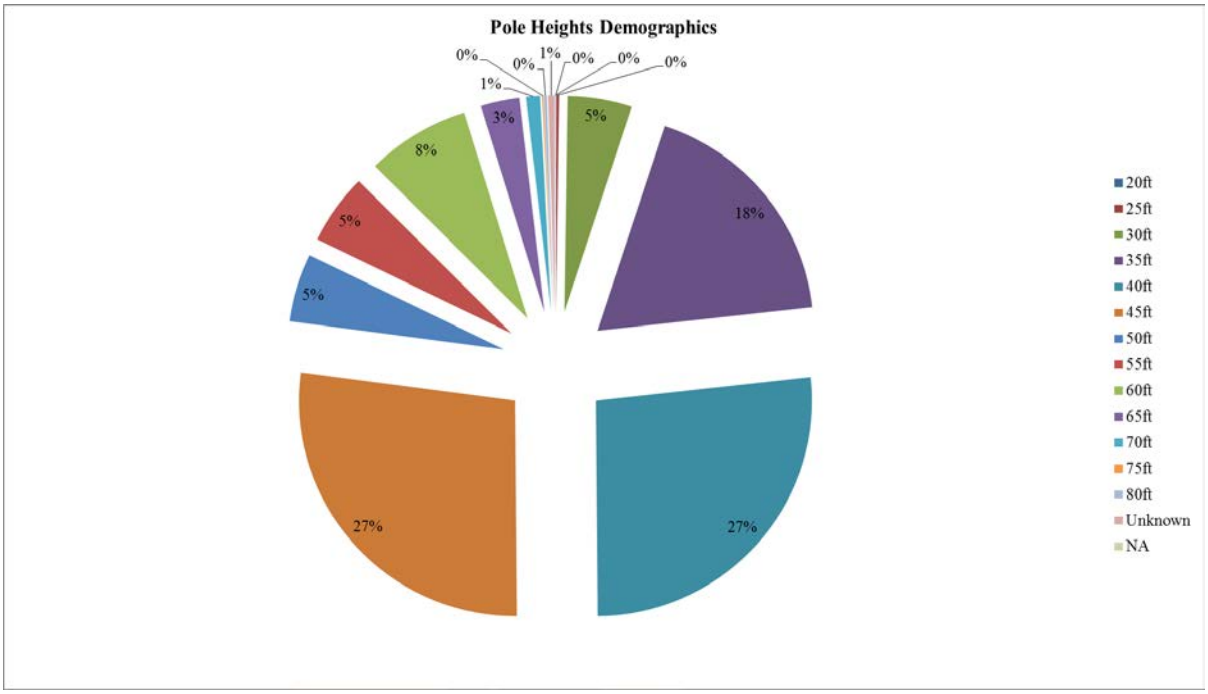


Exhibit 4-13: Distribution Poles Height Demographics

Exhibit 4-14 displays the age profile of the poles with respect to their heights and as indicated a majority of the poles that have reached more than 50 years of service age fall within the of 30', 35' and 40' height ranges.

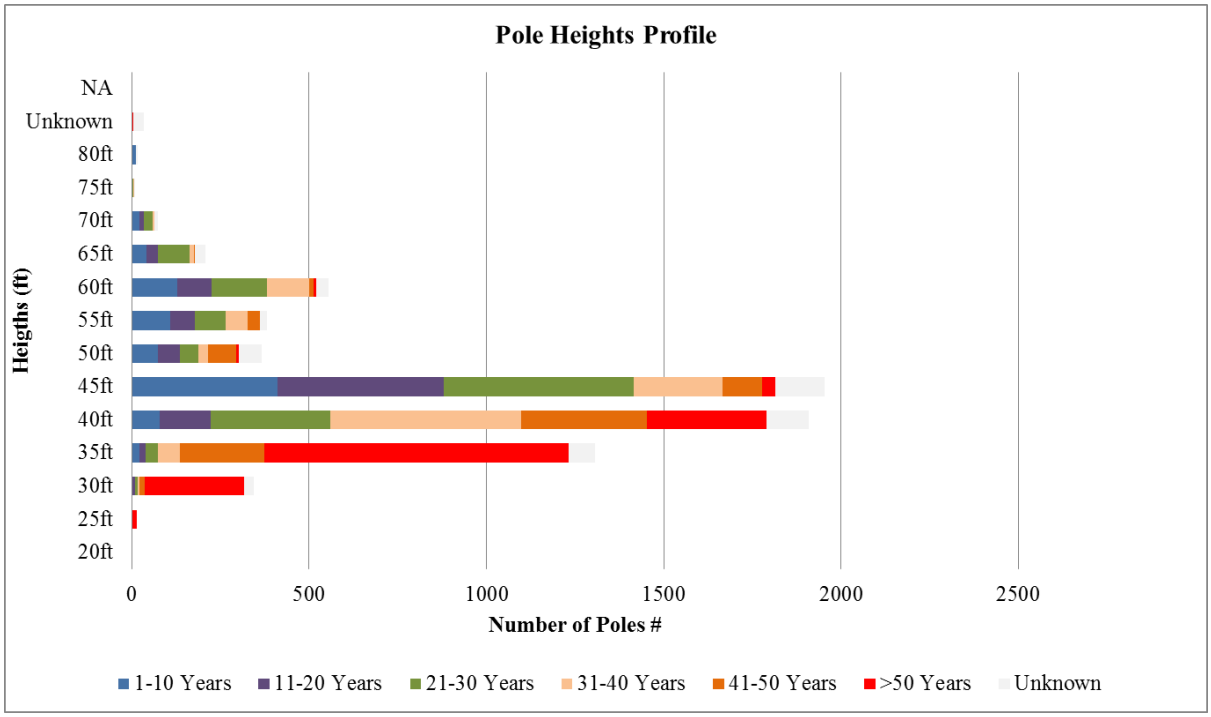


Exhibit 4-14: Age Profile of the Poles for different Heights

North Bay Hydro's has conducted non-destructive testing of wood poles. The test criteria have been that poles be at least 10 years of age. Approximately 2750 poles were tested and inspected by an independent contractor in 2010 and 2011; Exhibit 4-15 indicates the condition of poles inspected in 2011. In this case, the Health Index score is calculated based on the remaining strength of the pole, where "very poor" equates to less than 3 years of remaining useful life, "poor" equates to less than 5 years of anticipated remaining useful life and "fair equates to anticipated remaining useful life of "5 to 20" years. As shown, out of the test pole sample tested in 2010 and 2011, approximately 142 poles are found to be in very poor condition and 158 in poor condition, In other words based on testing of the poles approximately 11% of poles in service were found to have a remaining life expectancy of five years or less.

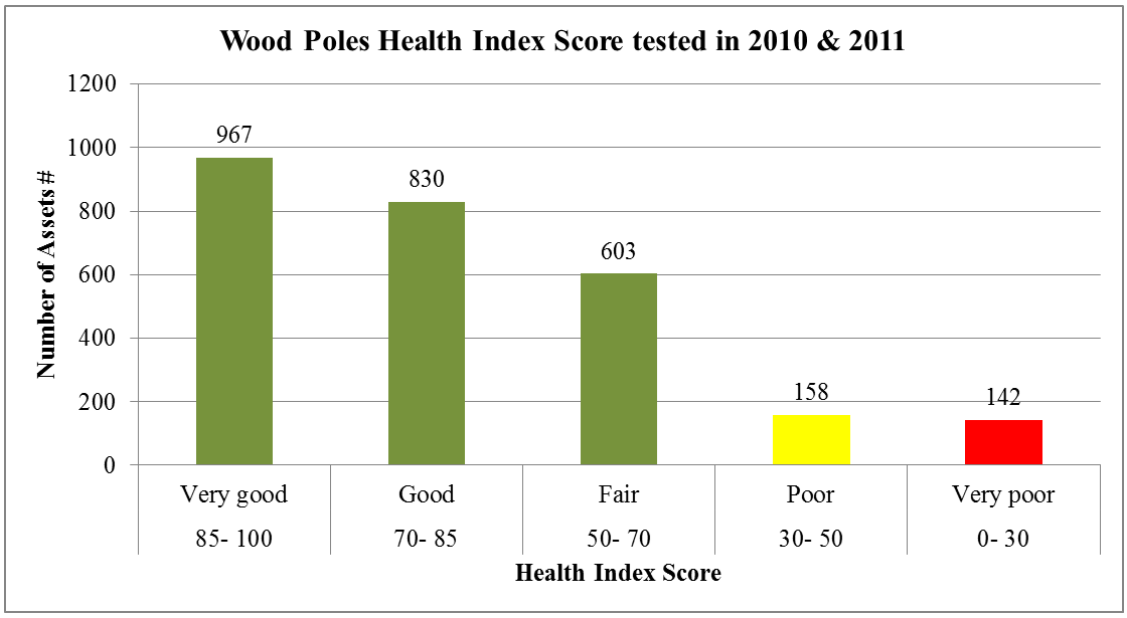


Exhibit 4-15: Wood Poles Health Index Score based on pole tests on a sample of 2754 Poles

Since the tests above were performed on a random sample of poles the results can be extrapolated to the full population of poles. The results of this analysis are presented in Exhibit 4-16.

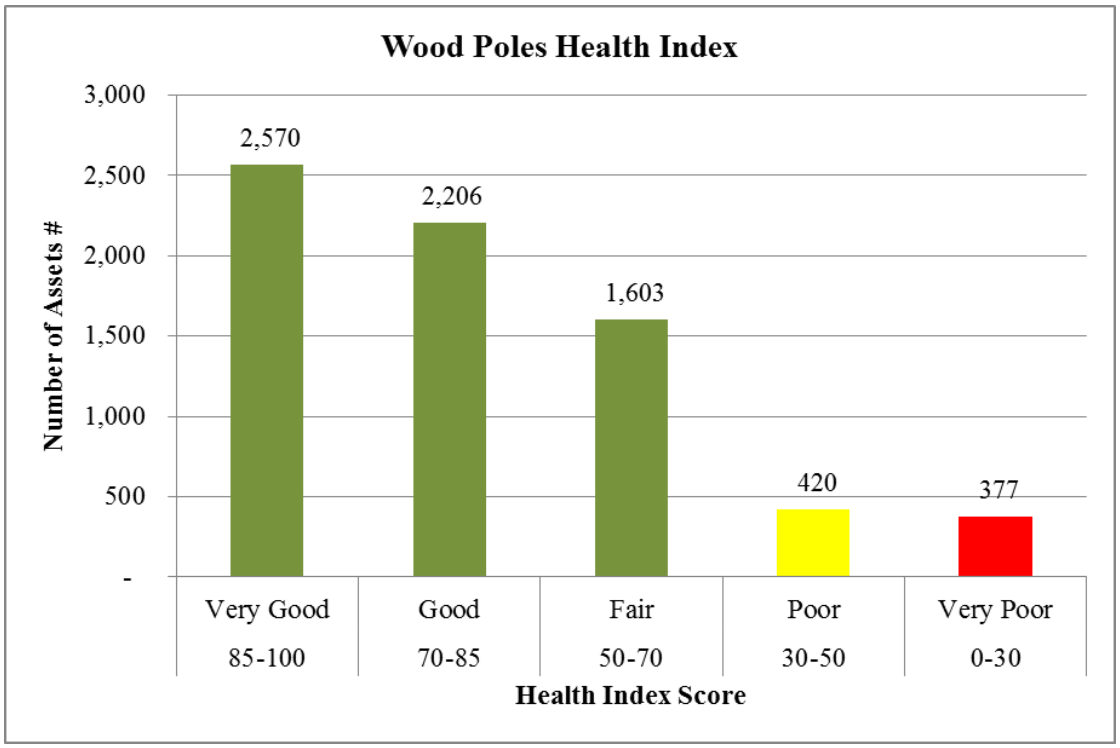


Exhibit 4-16: Wood Poles Health Index Score for Entire Pole Population

In this snap shot of the condition of poles in 2010 and 2011, poles with a health index of "30 or less" are determined to be in "very poor" condition and the poles with a health index in the range of "30 to 50" are determined to be in "poor" condition. The poles in poor and very poor condition present a high risk of failure in service under adverse weather conditions. It is noteworthy that with passage of time, about 50% of the poles found in "fair" condition during 2010 and 2011 testing, would also reach "poor" condition by the end of 2018, and the number of "poor" and "very poor" poles is expected to rise each year, unless a proactive pole replacement program is implemented.

We recommend approximately 1598 wood poles for replacement during the next five years: 377 shown in "very poor" condition, 420 shown in "poor" condition and 801 shown in "fair" condition in Exhibit 4-16. Since voltage upgrade of lines offers other economic benefits in addition to reducing the risk of asset failures, poles in "very poor" and "poor" condition employed on the 4 kV lines are recommended to be given priority in conjunction with the implementation of line voltage upgrades. Section 5 documents additional analysis supporting replacement of the assets found in poor and very condition.

4.2.2 44 kV Line Support Poles

While a majority of the 44 kV lines are overbuilt on top of 12.47 kV feeders, there are also some dedicated 44 kV lines. The age profile for poles employed on 44 kV lines is presented in Exhibit 4-17.

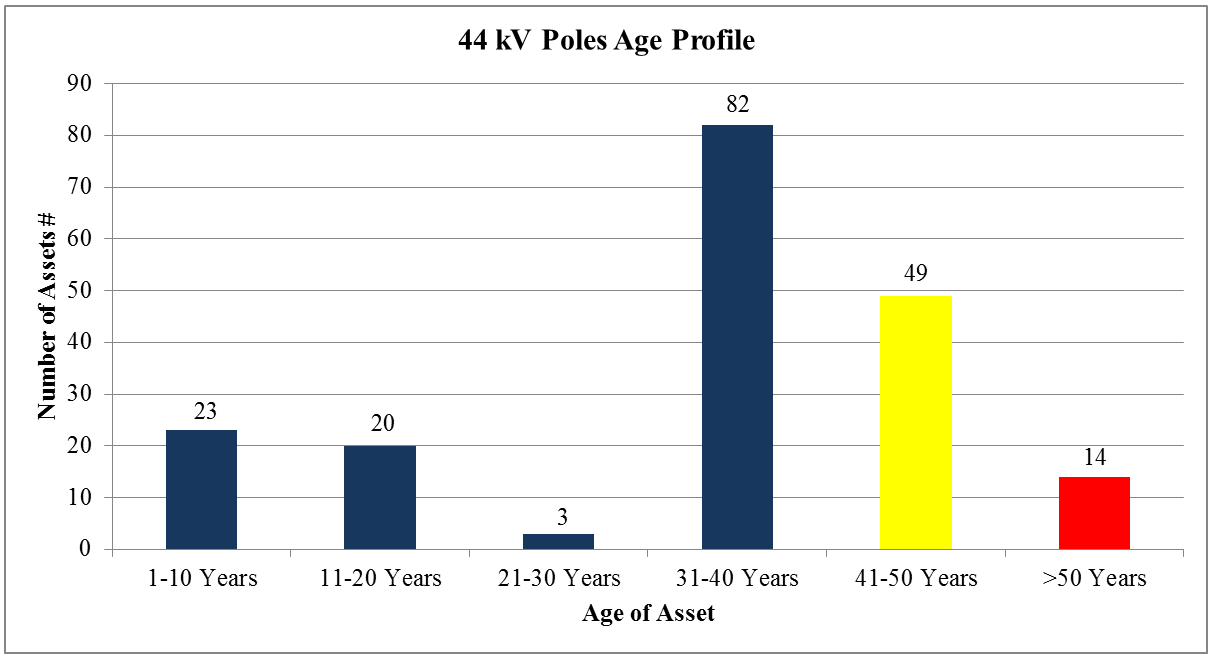


Exhibit 4-17: Age Profile of Wood Poles on 44 kV Lines

4.2.3 Overhead Primary Conductors

The overhead distribution network at North Bay Hydro employs approximately 400 kilometers of overhead distribution lines and approximately 90 km of 44 kV lines. For 44 kV lines, age profiles are not available. Age profiles for 12.47 kV and 4.16 kV lines are presented below.

The overall age profile of overhead primary conductors is presented in Exhibit 4-18. Approximately 35% of the conductors in service have reached a service age of greater than 40 years.

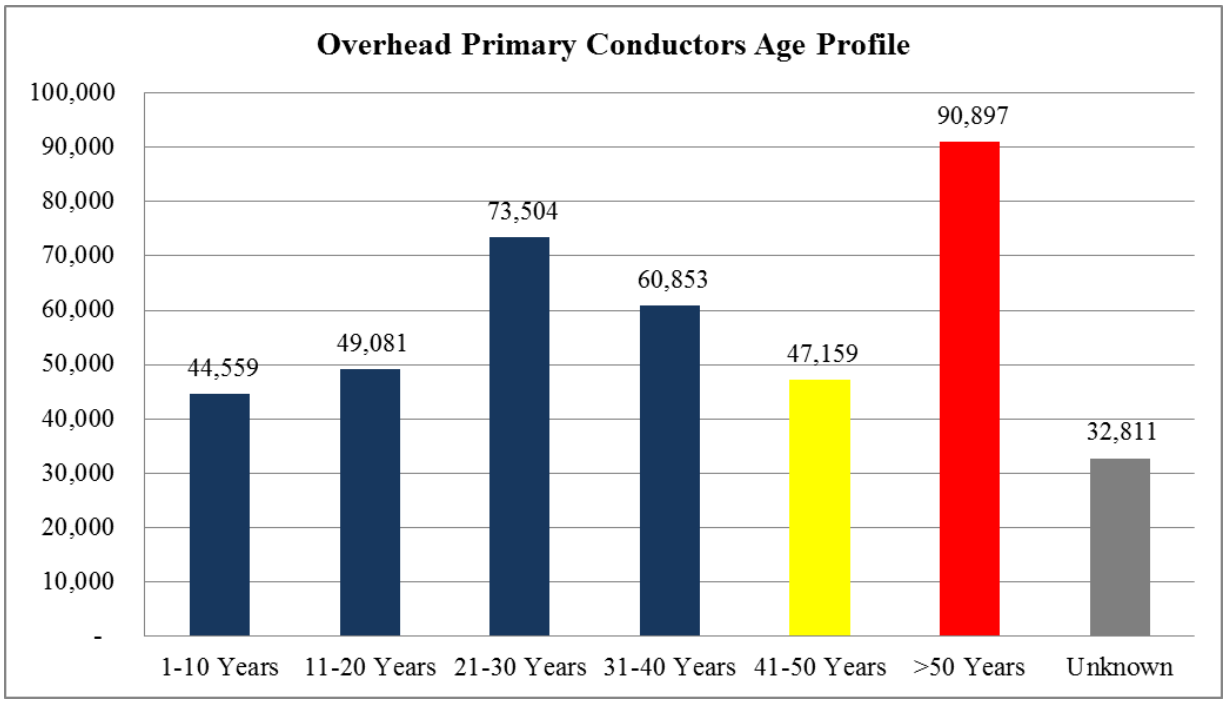
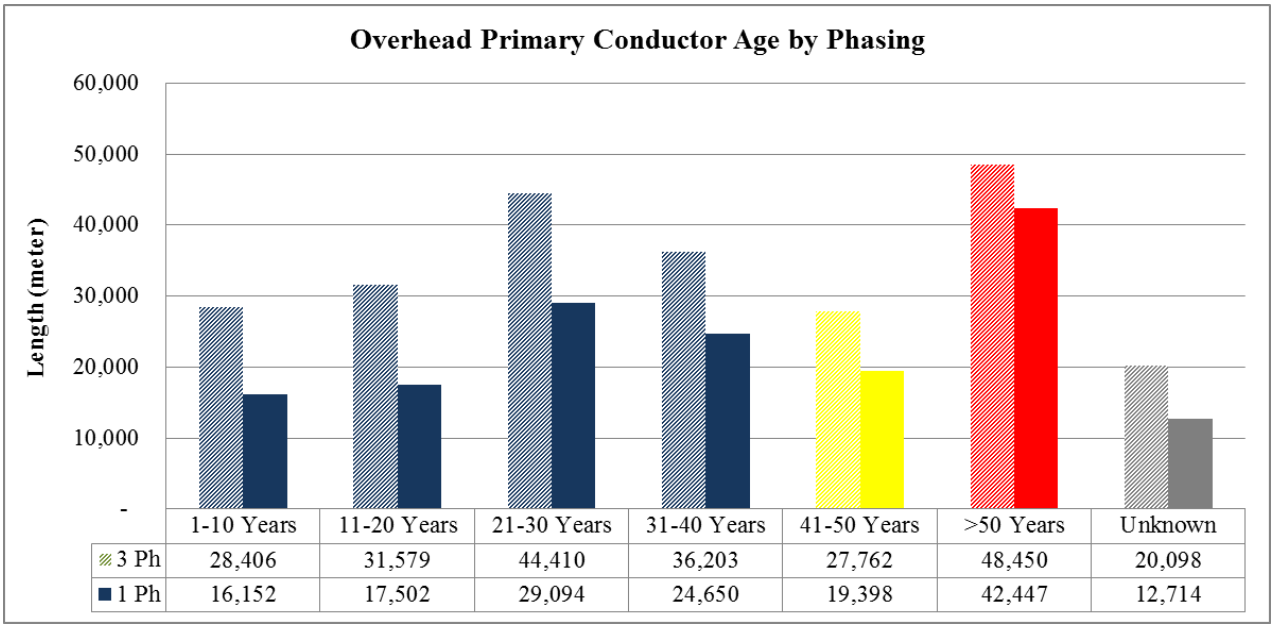


Exhibit 4-18: Overhead Primary Conductors Overall Age Profile

Exhibit 4-19 indicates the line lengths of different service age conductors, employed on 3-phase and 1-phase overhead lines. Exhibits 4-20 through 4-23 provide further breakdown of the overhead line sections into 4.16 kV and 12.47 kV; 3-phase and 1-phase lines. As indicated previously, age profiles of 44 kV sub-transmission lines are not available.



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years	Unknown
3 Ph	28,406	31,579	44,410	36,203	27,762	48,450	20,098
1 Ph	16,152	17,502	29,094	24,650	19,398	42,447	12,714

Exhibit 4-19: Overhead Primary Conductors Age Profile (1-Phase and 3-Phase)

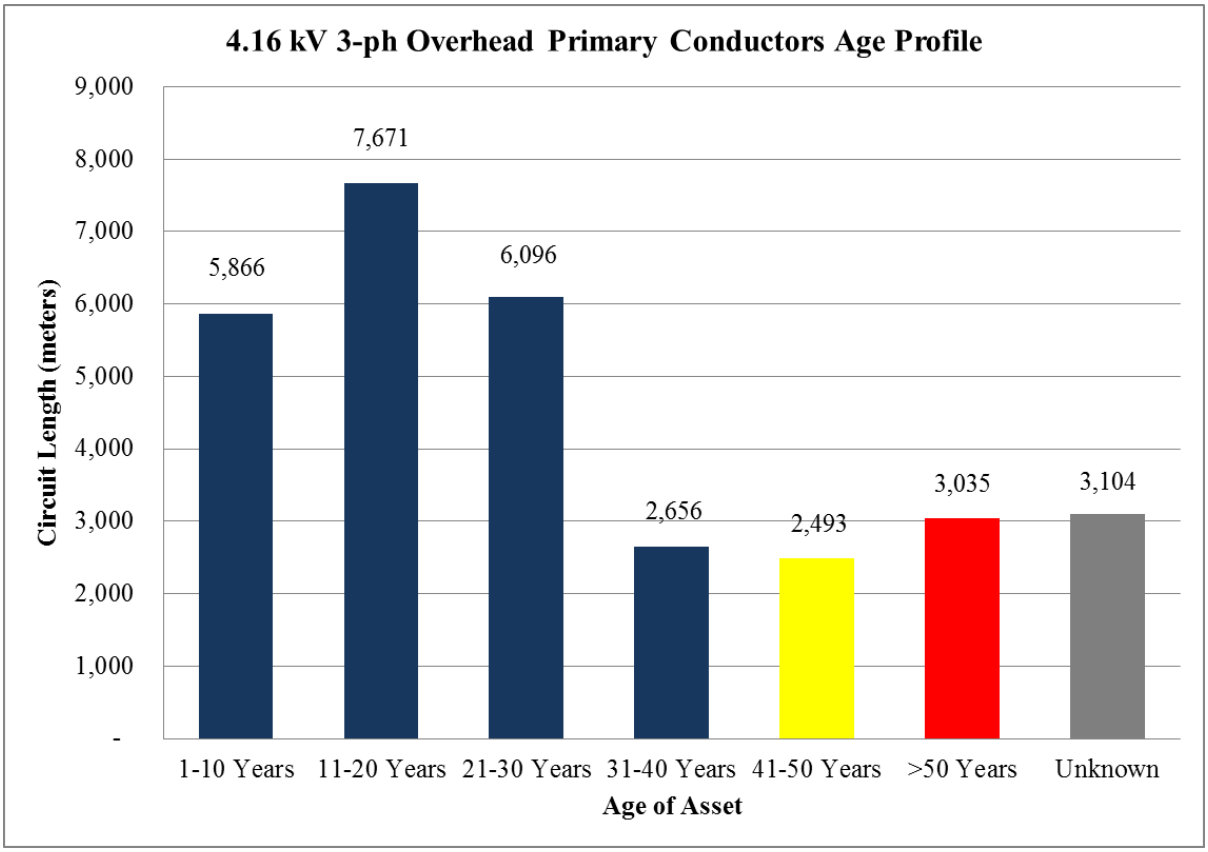


Exhibit 4-20: Overhead Primary Conductors Age Profile (4.16 kV; 3-Phase)

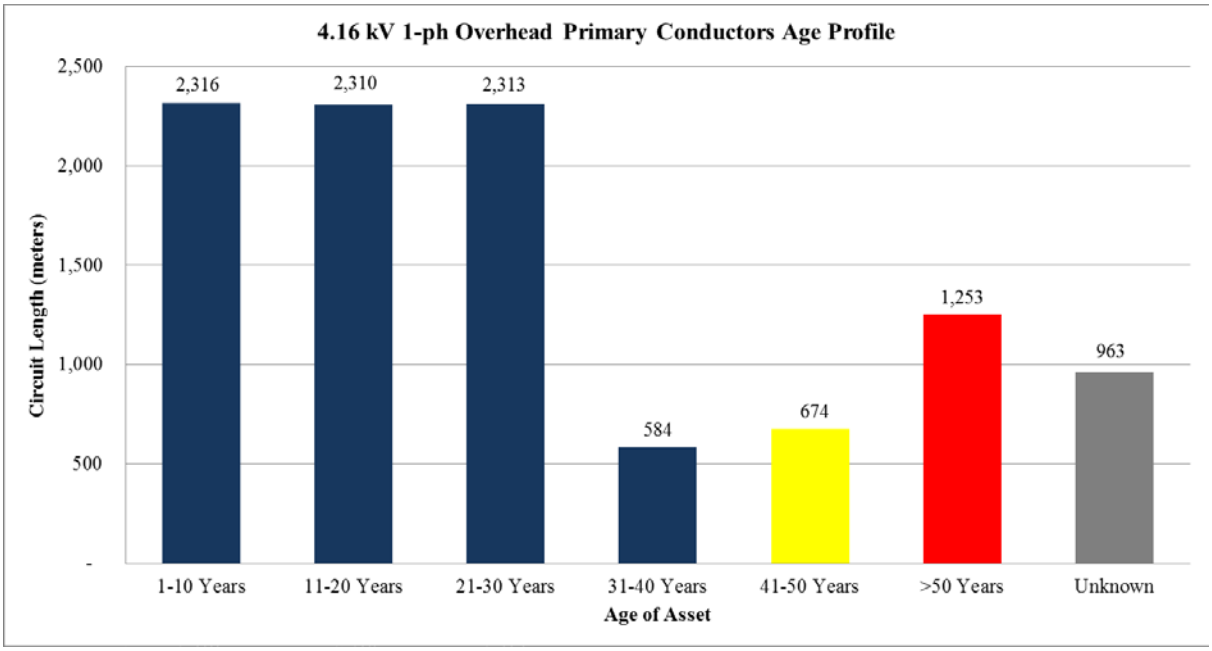


Exhibit 4-21: Overhead Primary Conductors Age Profile (4.16 kV; 1-Phase)

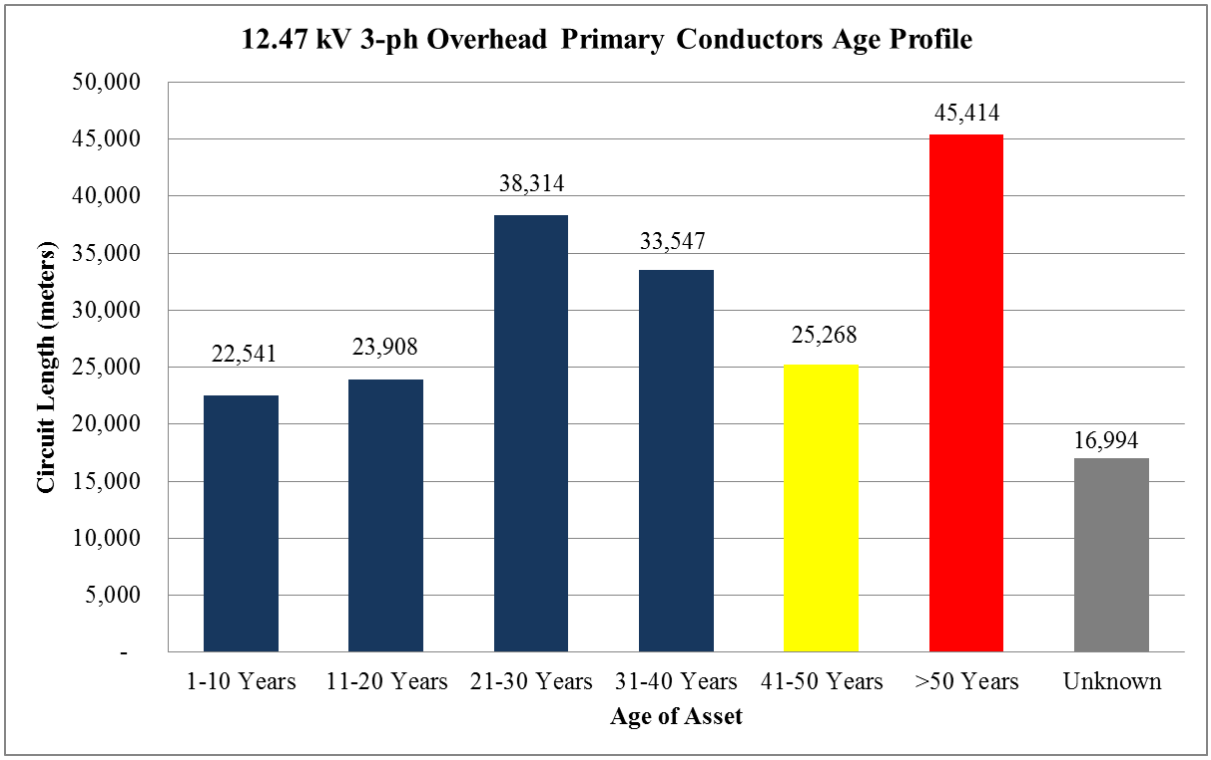


Exhibit 4-22: Overhead Primary Conductors Age Profile (12.47 kV; 3-Phase)

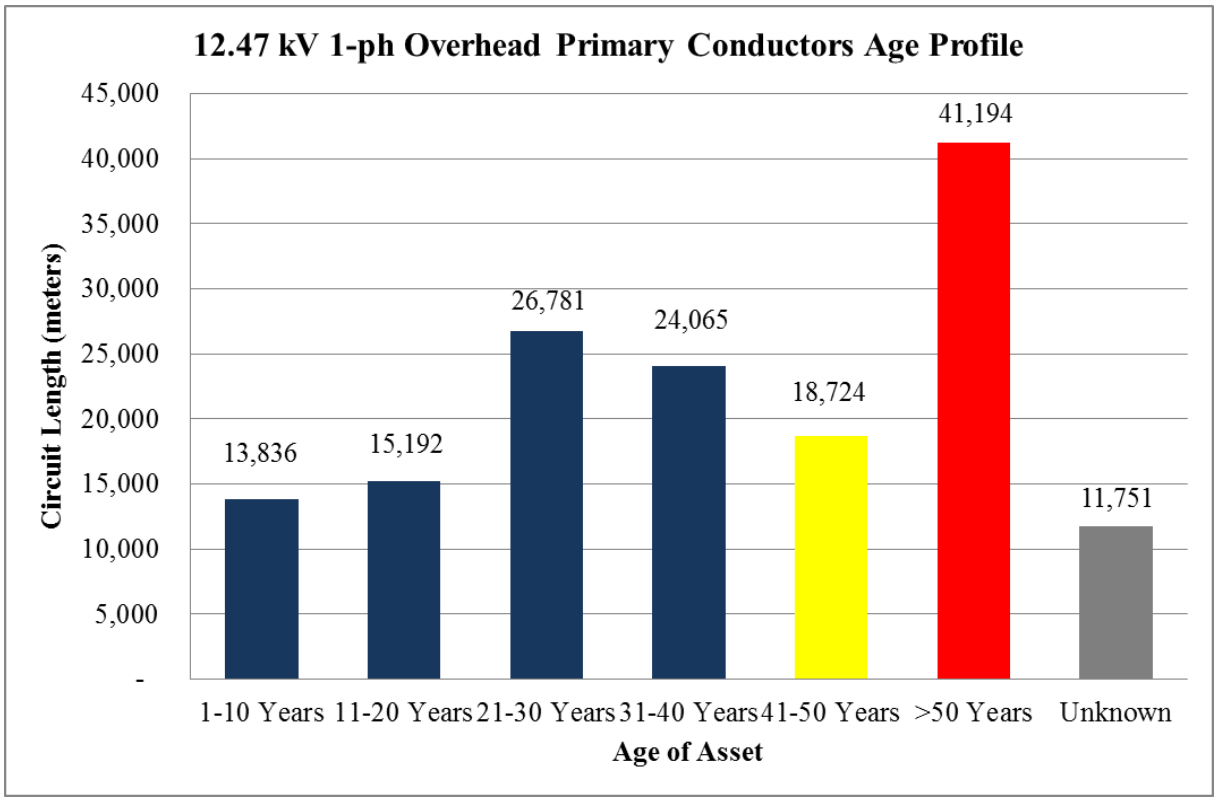


Exhibit 4-23: Overhead Primary Conductors Age Profile (12.47 kV; 1-Phase)

Exhibits 4-24 through 4-27 indicate the health indices for different categories of overhead line conductors. The conductors determined to be in "poor" and "very poor" condition are recommended to be replaced during the next five years.

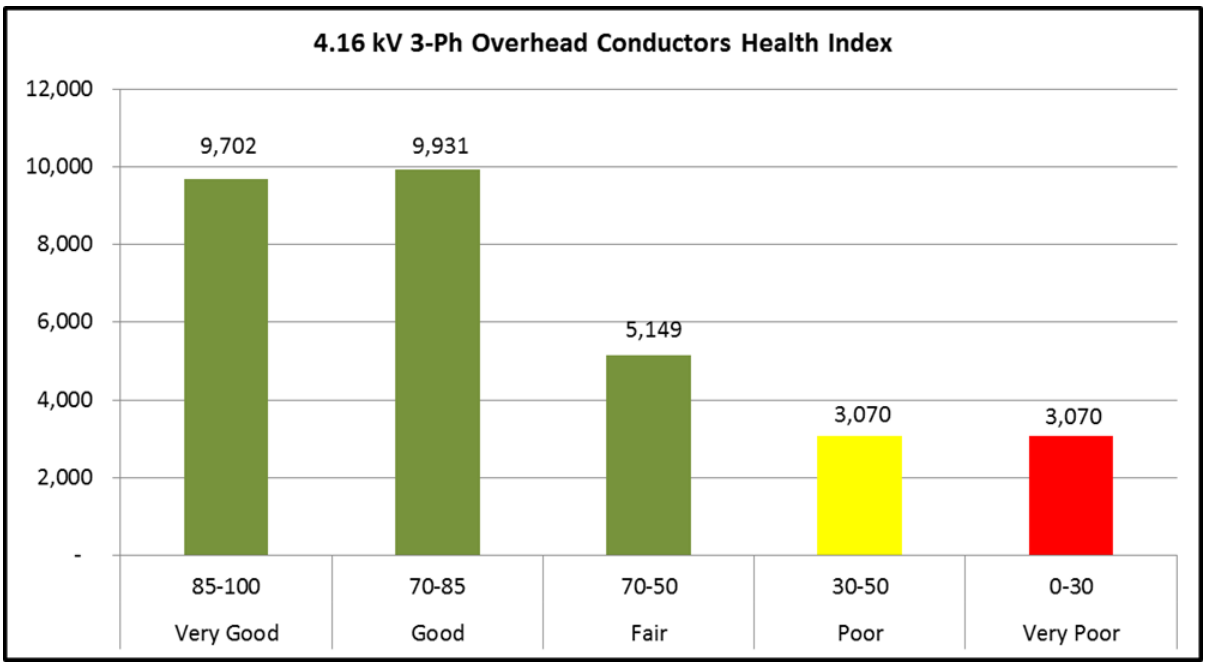


Exhibit 4-24: 4.16 kV 3-ph Overhead Primary Conductors Health Index Score

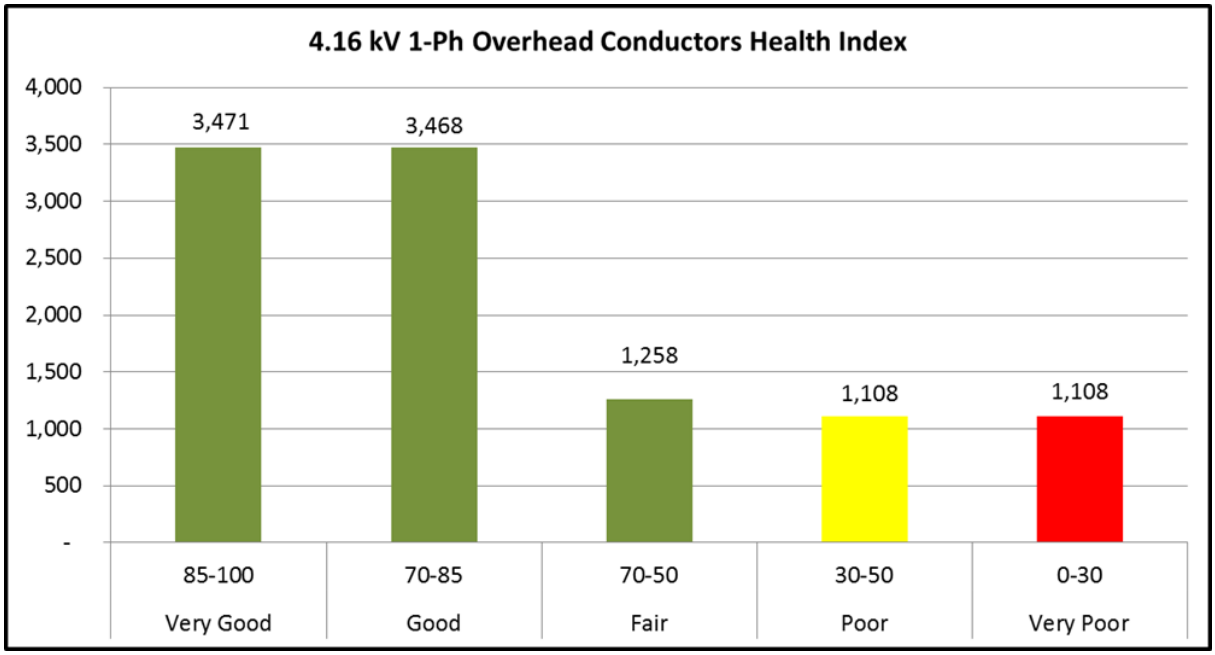


Exhibit 4-25: 4.16 kV 1-ph Overhead Primary Conductors Health Index Score

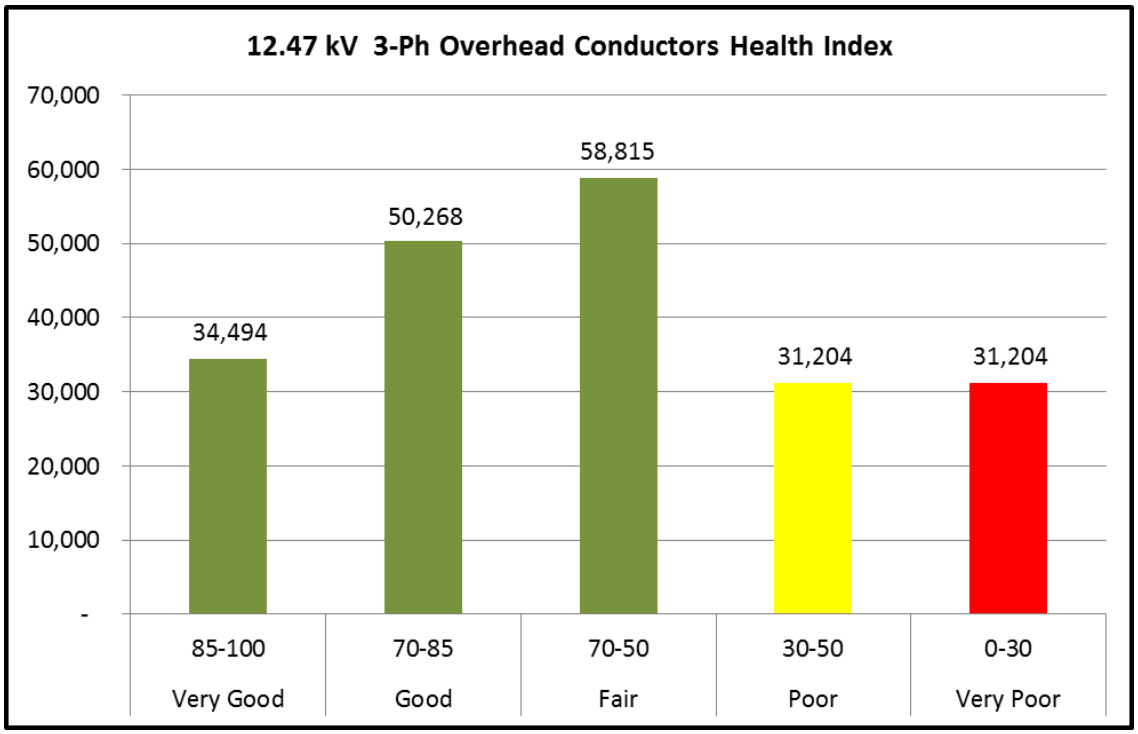


Exhibit 4-26: 12.47 kV 3-ph Overhead Primary Conductors Health Index Score

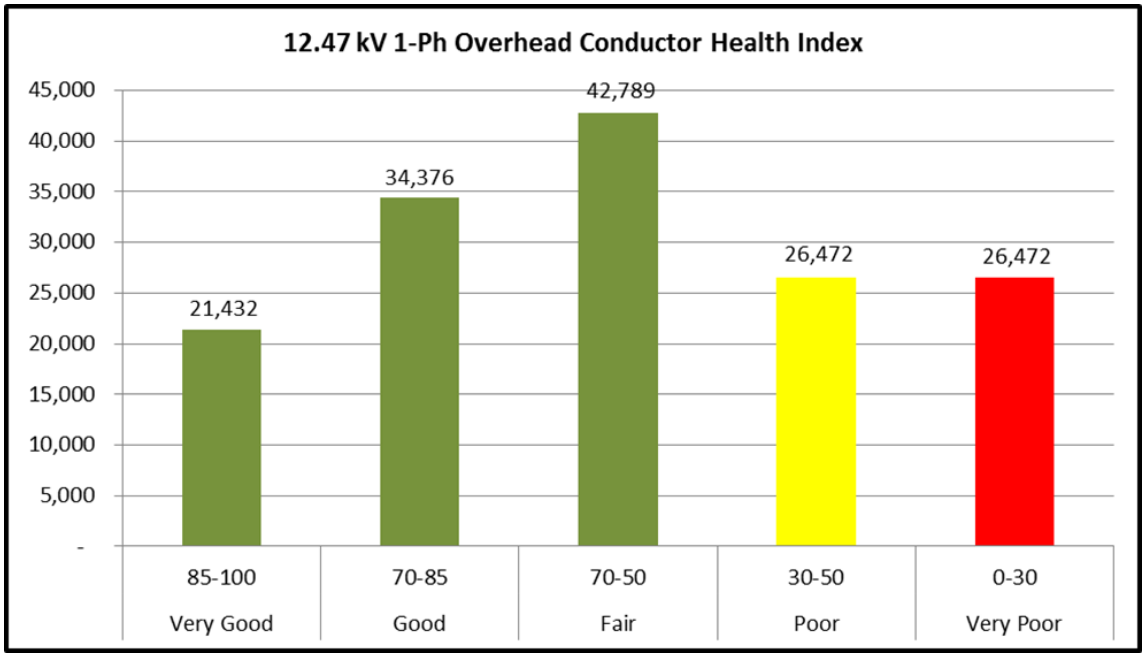


Exhibit 4-27: 12.47 kV 1-ph Overhead Primary Conductors Health Index Score

4.3 Underground Distribution System

4.3.1 Underground Primary Conductors

The underground distribution network at North Bay Hydro employs approximately 110 kilometers of primary underground cable circuits. The overall age profile of primary underground cables is presented in Exhibit 4-28. As indicated, a vast majority of the underground cables fall within the service age category of 20 to 30 years. Slightly more than 10% of the cables have reached the service age of greater than 40 years and these present a higher risk of failure in service.

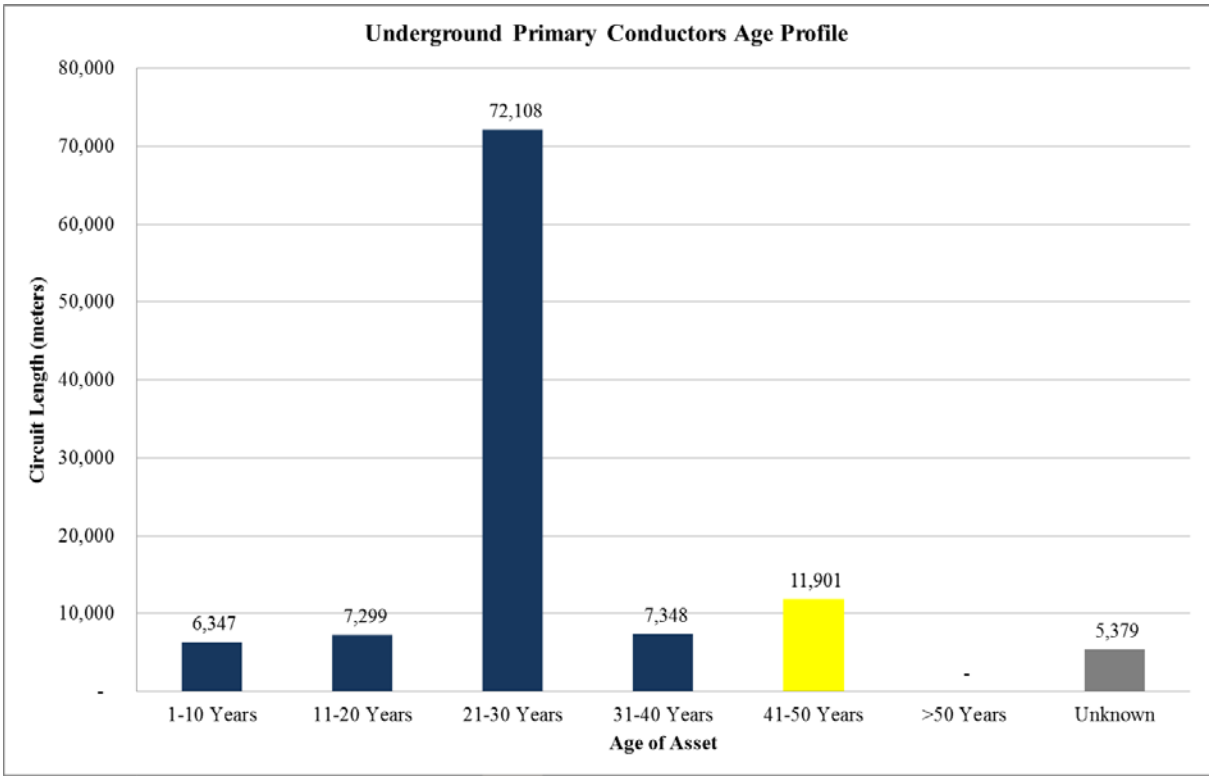


Exhibit 4-28: Underground Primary Conductors Overall Age Profile

Age profiles for 1-phase and 3 phase cables employed on different feeders operating at 4.16 kV and 12.47 kV are provided in Exhibit 4-29 through Exhibit 4-32. As indicated, most of the older vintage cables are employed in the service territories of MS-1, MS-7, MS-11 and MS-18 substations.

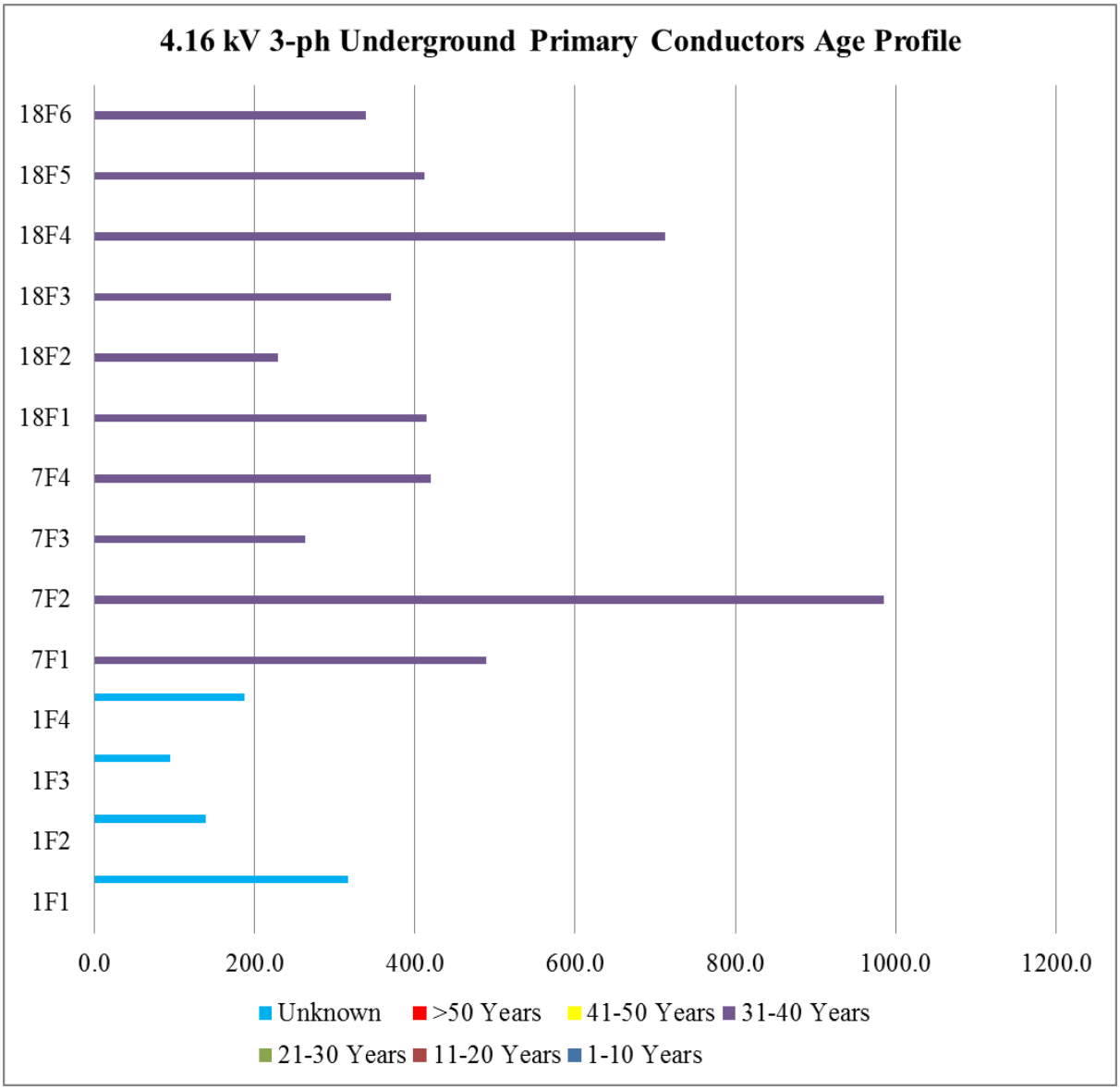


Exhibit 4-29: 4.16 kV Underground 3ph Conductor Age Profile

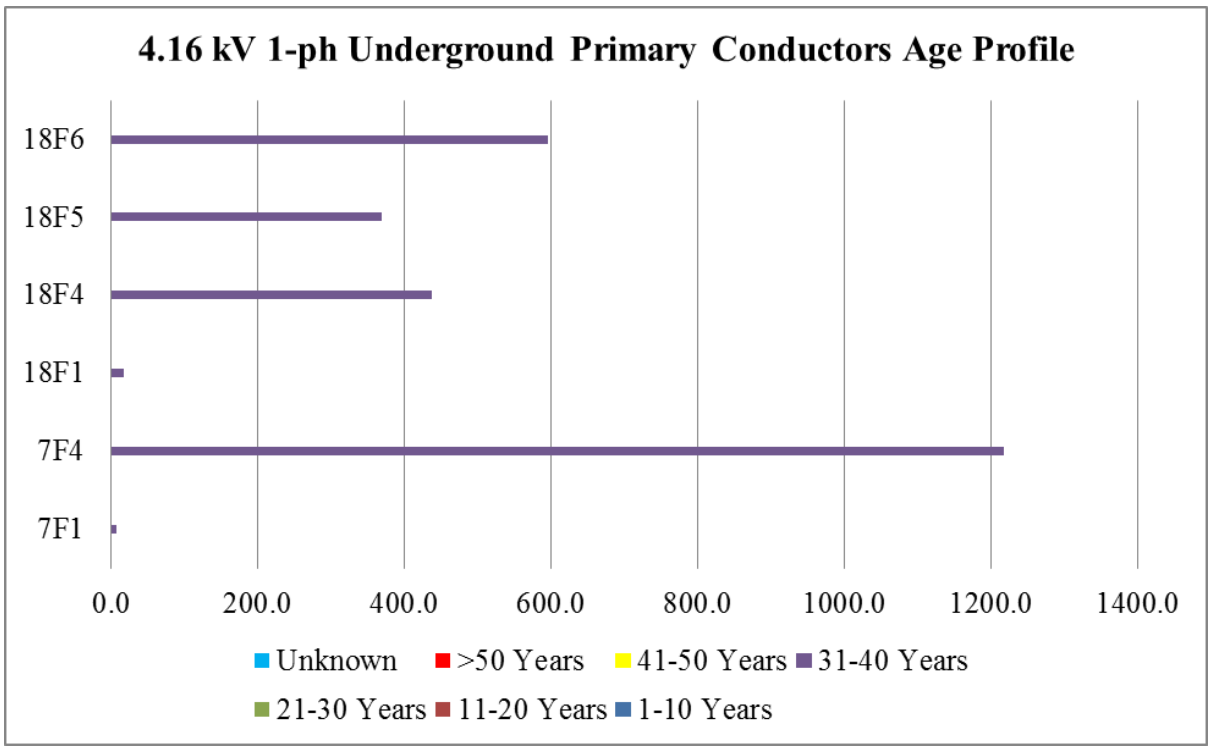


Exhibit 4-30: 4.16 kV Underground Primary 1ph Conductors Age Profile on different Circuits

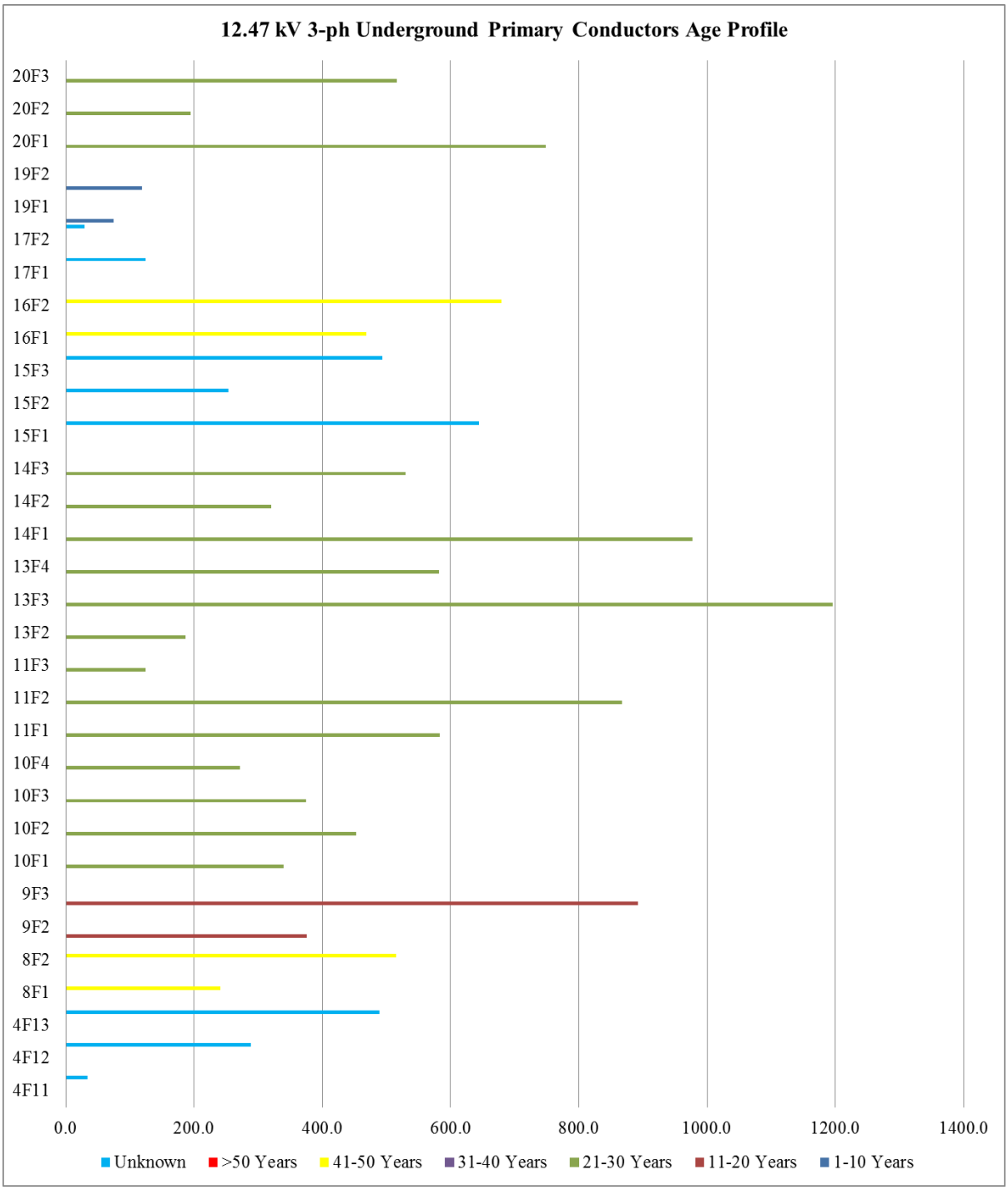


Exhibit 4-31: 12.47 kV Underground Primary 3ph Conductors Age Profile on different Circuits

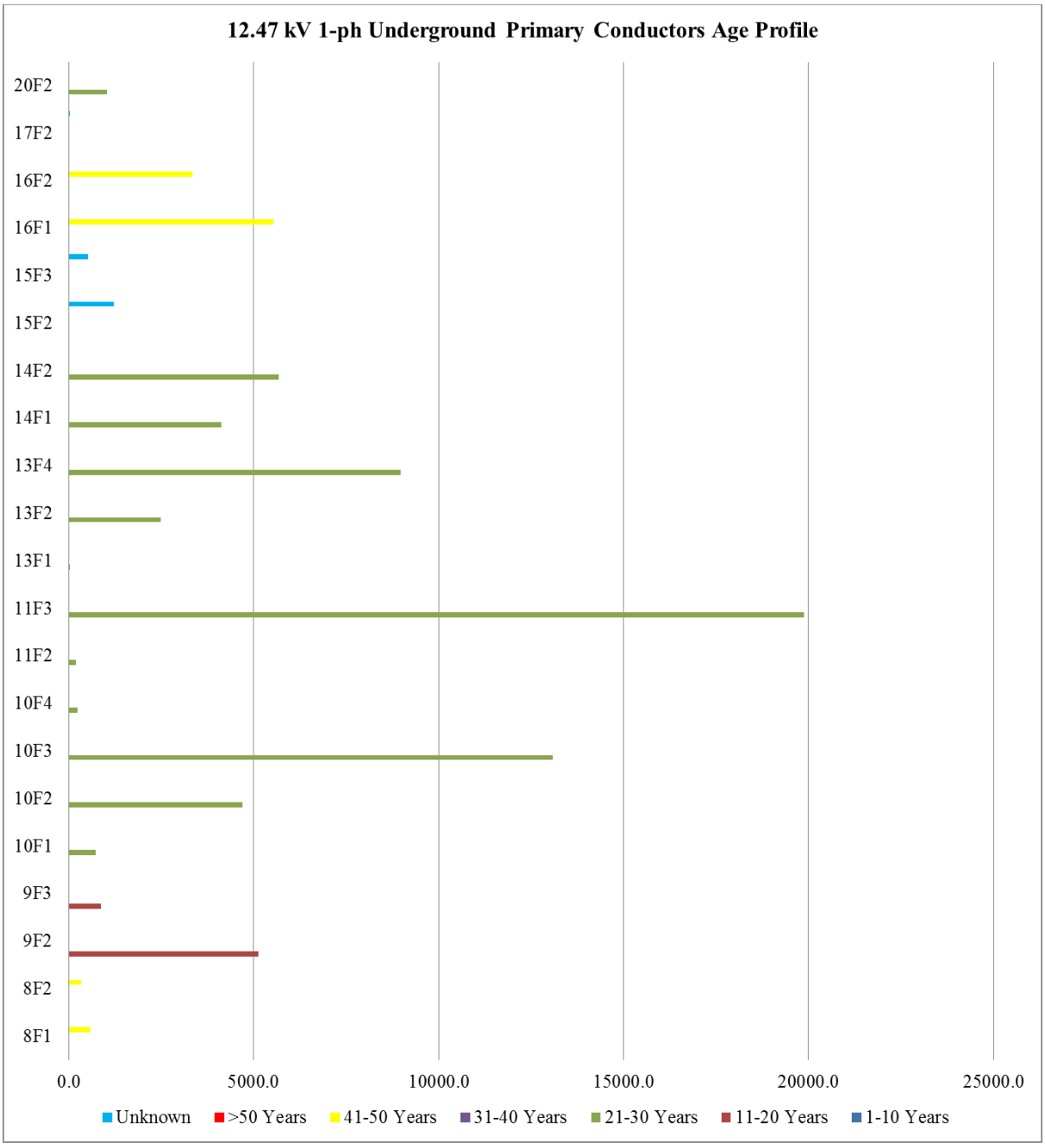


Exhibit 4-32: 12.47 kV Underground Primary 1ph Conductors Age Profile on different Circuits

Health indices for different voltage distribution cables, derived from available health indicators, are presented in Exhibits 4-33 through 4-36. Cables determined to be in poor and very condition present a high risk of failure in service and are recommended to be replaced during the next five years. Section 5 documents additional analysis supporting replacement of the assets found in poor and very condition, based on the consequences of assets failure in service.

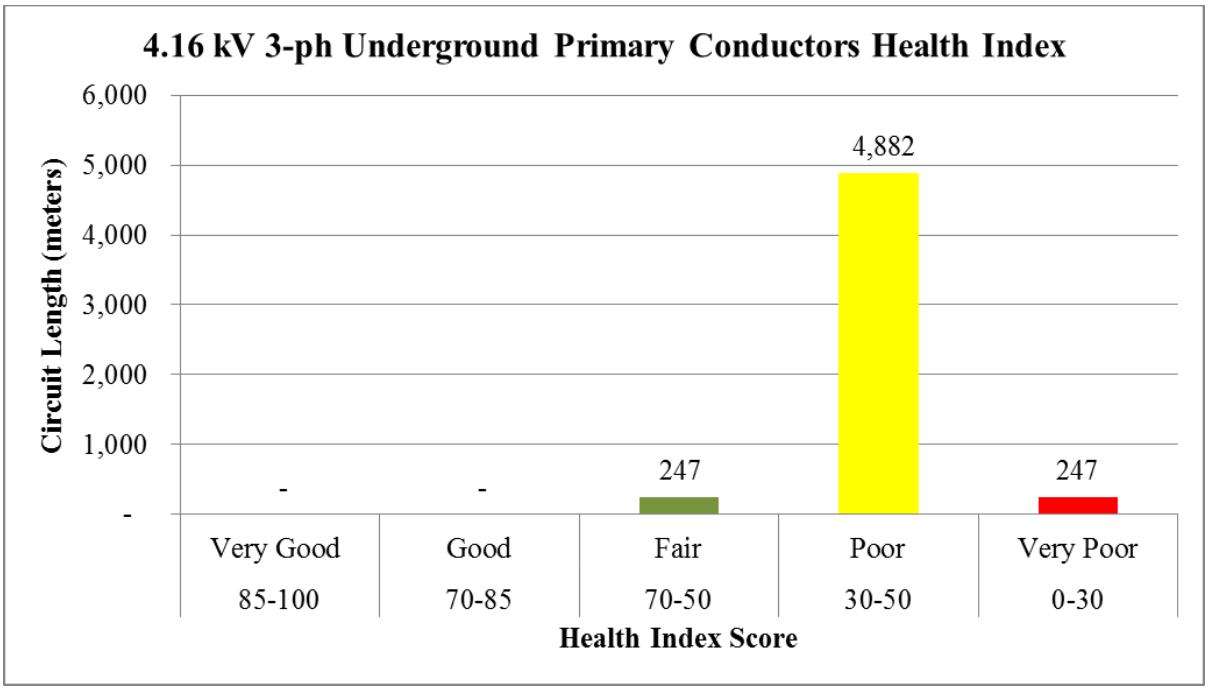


Exhibit 4-33: 4.16 kV, 3-Ph Underground Primary Cables Health Index Score

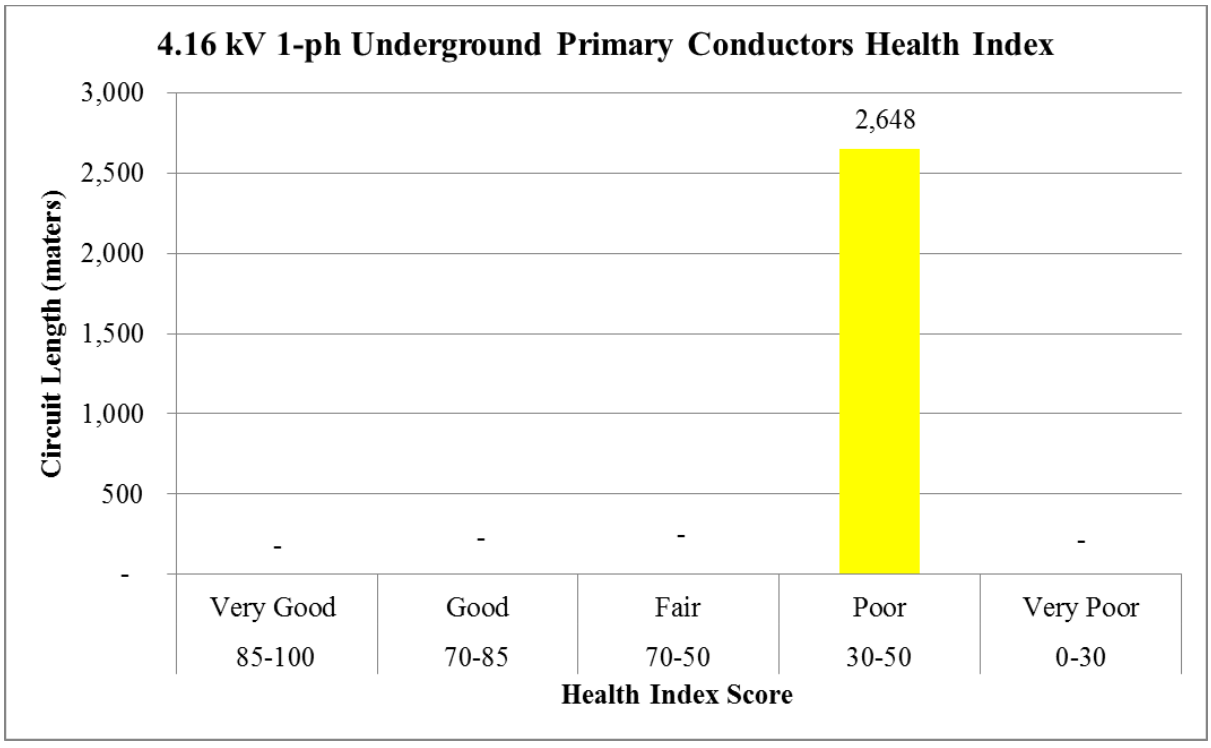


Exhibit 4-34: 4.16 kV, 1-Ph Underground Primary Cables Health Index Score

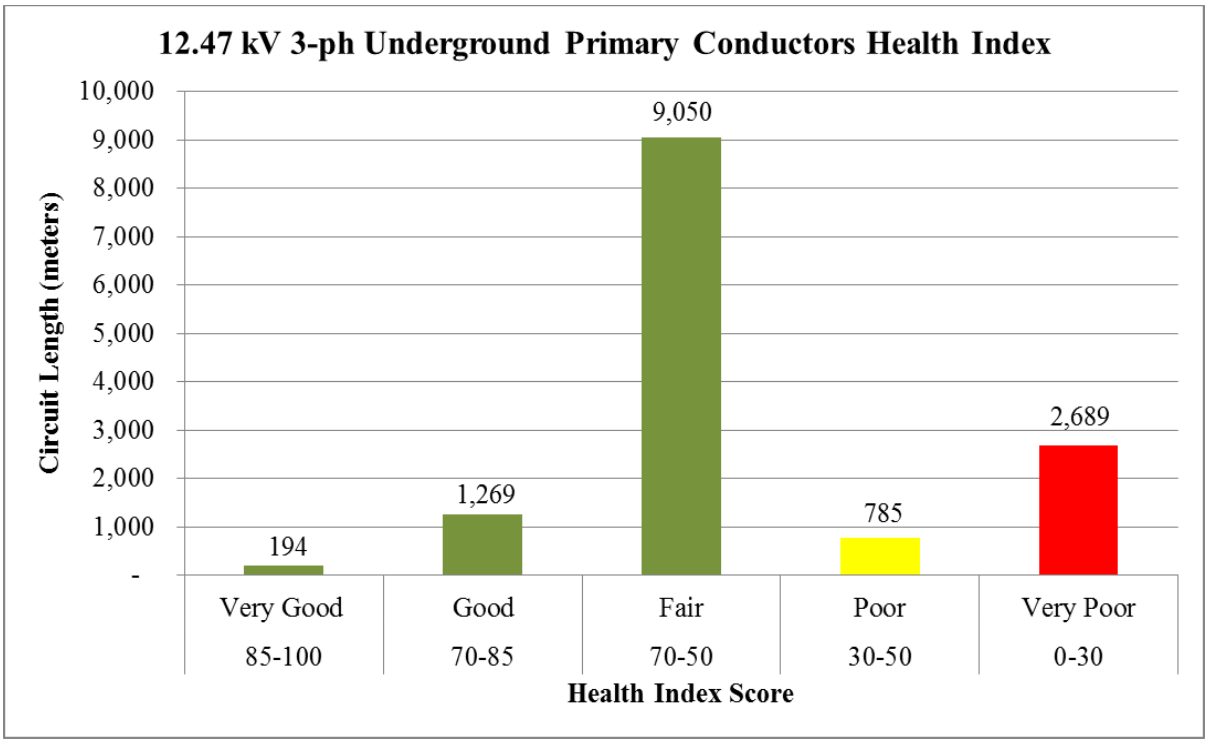


Exhibit 4-35: 12.47 kV, 3-Ph Underground Primary Cables Health Index Score

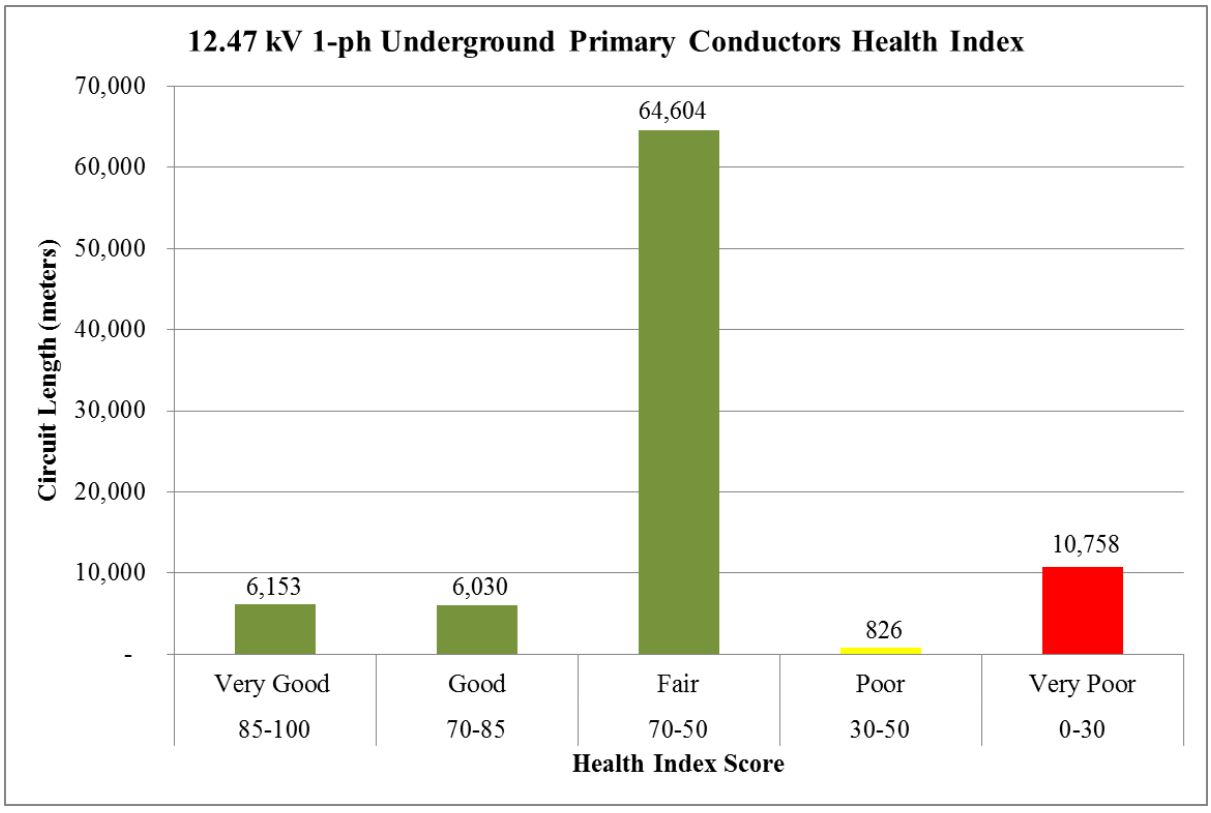


Exhibit 4-36: 12.47 kV, 1-Ph Underground Primary Cables Health Index Score

4.3.2 Underground Low Voltage Cables

Typical useful life of low voltage cables is of the order of 55 to 60 years, which is significantly greater than the typical useful life of medium voltage cables. Demographic information on this asset is not readily available to assess the overall health and condition of LV cables.

However in the following specific locations, where direct buried LV circuits serve multi-family dwellings, the LV cable circuits are experiencing repeated failures, resulting in poor power supply reliability and increase in operating costs due to emergency repairs. The LV cable circuits, determined to be at the end of their useful service life and requiring immediate replacement are listed below:

Manitou Complex:
- Approximately 760m of direct buried secondary bus/services
- 71 tapped services
- Installed in the early 1970's

Wickstead Complex:
- Approximately 860m of direct buried U/G secondary bus/services
- 103 tapped services
- Installed in the early 1970's

Sylvan Crescent:
- Approximately 800m of direct buried U/G secondary bus/services
- 119 tapped services
- Installed in the mid 1960's

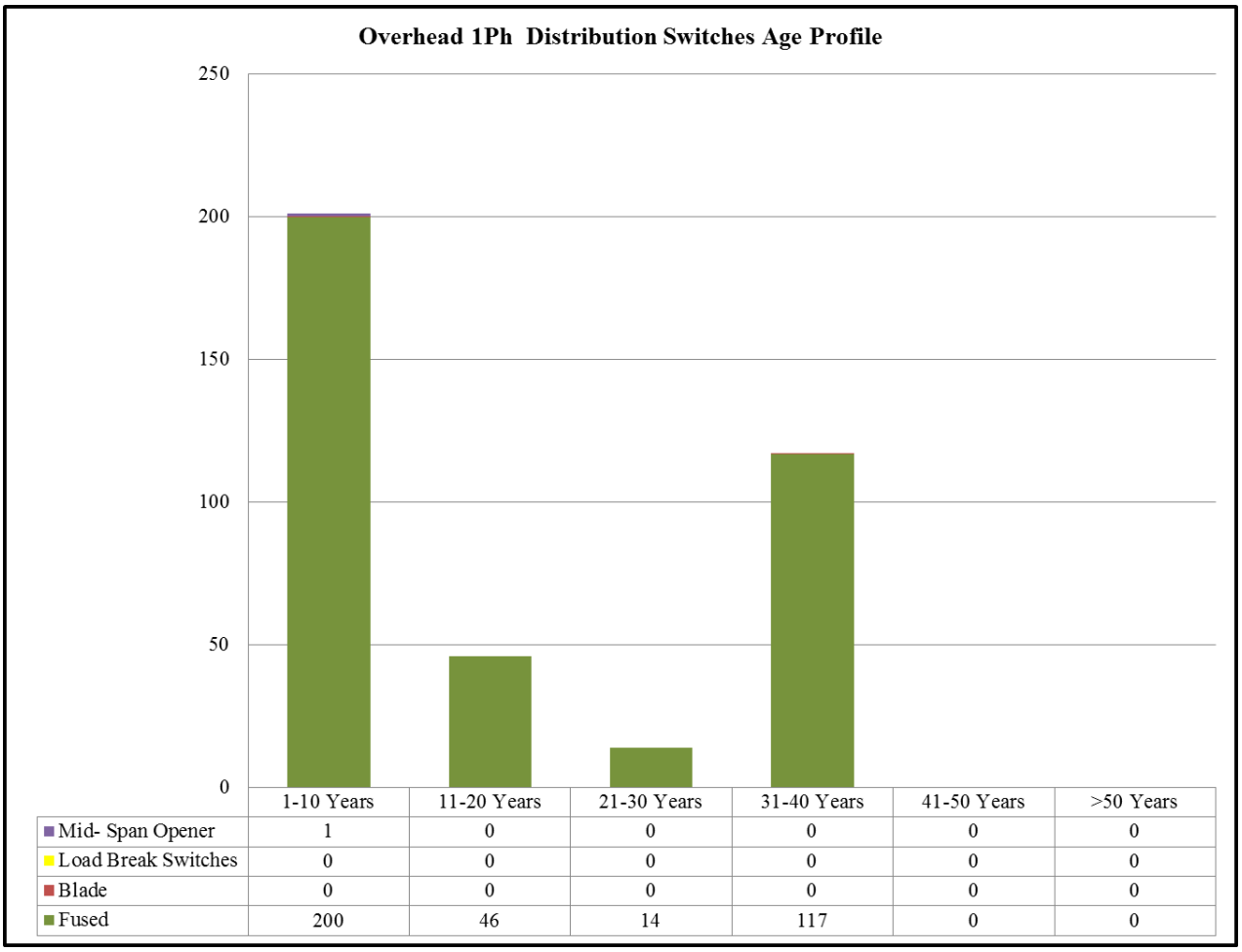
Melina Close:
- Approximately 734m of direct buried U/G secondary bus/services
- 73 tapped services
- Installed in the mid 1960's

Madelena:
- 844m of direct buried U/G secondary bus/services
- 117 tapped services
- Installed in the mid 1960's

4.4 Distribution Switches and Cutouts

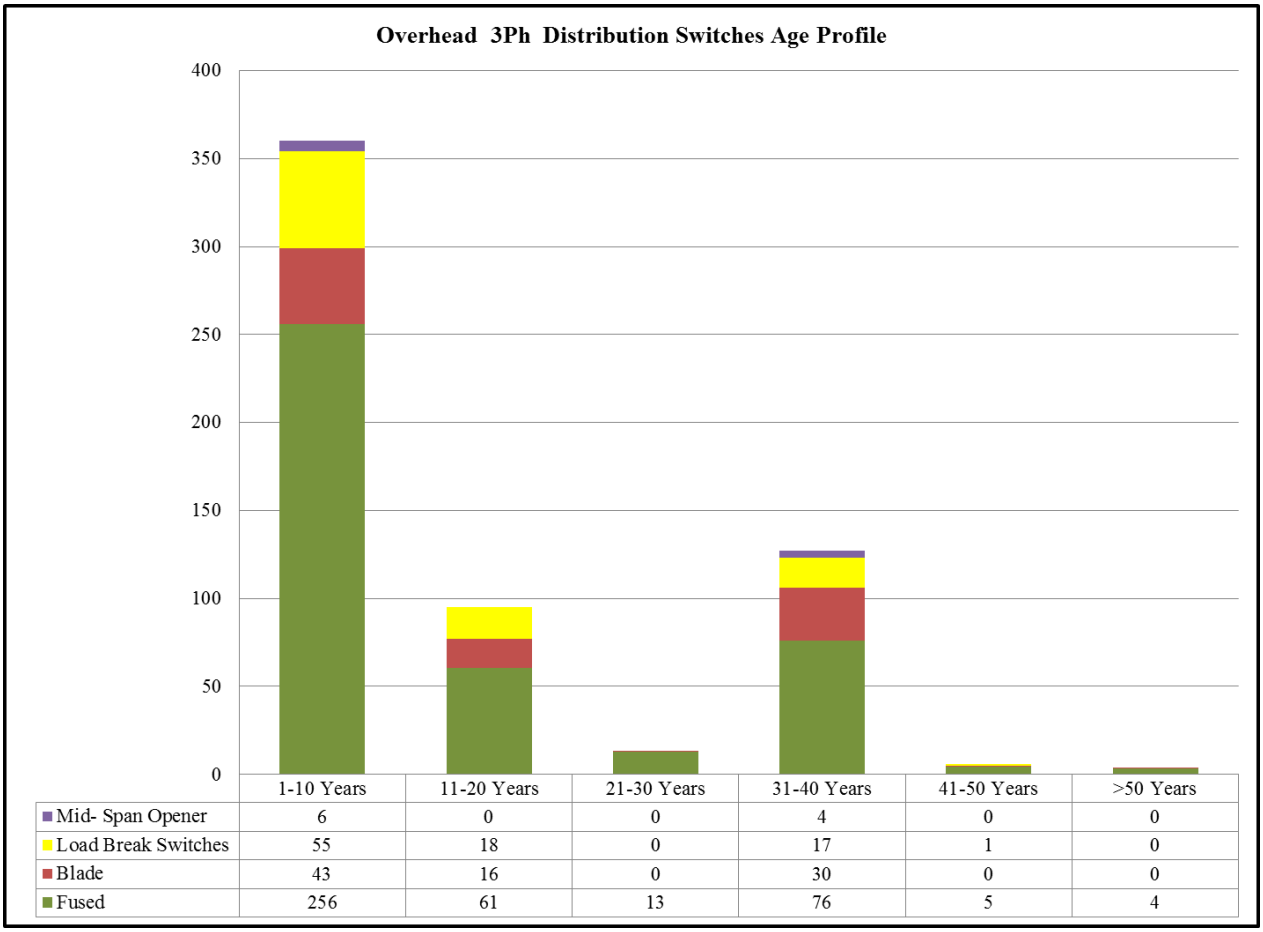
North Bay Hydro's distribution system is well equipped for disconnecting and isolating, load-breaking, and fault interrupting to provide means of isolation during power interruptions and operational functions and adequately protect the circuits during system faults. A majority of the line switches are pole type.

Exhibit 4-37 and Exhibit 4-38 display the age profiles of different types of 1-phase and 3-phase line mounted switches. As shown a vast majority of the switches are in form of fused or solid blade cutouts, but a smaller number of load break switches and mid span opener switches are also employed. Approximately 25% to 30% of the switches are approaching the end of their service life.



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Mid- Span Opener	1	0	0	0	0	0
Load Break Switches	0	0	0	0	0	0
Blade	0	0	0	0	0	0
Fused	200	46	14	117	0	0

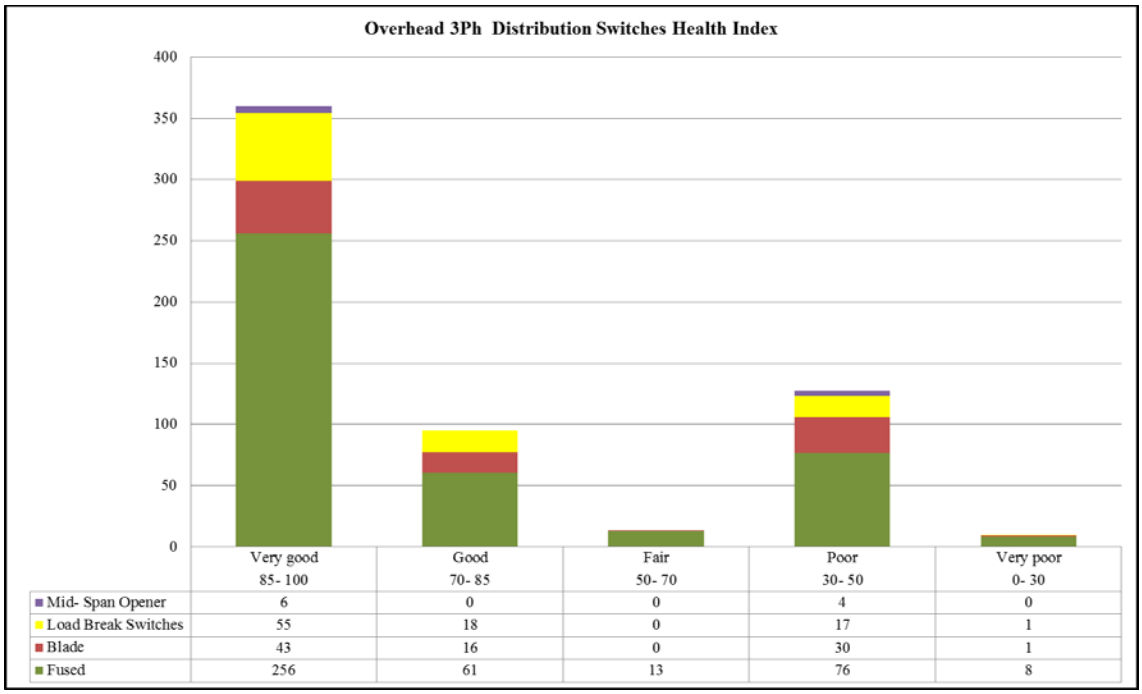
Exhibit 4-37: Age Profile of 3-Phase Pole-Mounted Switches



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Mid- Span Opener	6	0	0	4	0	0
Load Break Switches	55	18	0	17	1	0
Blade	43	16	0	30	0	0
Fused	256	61	13	76	5	4

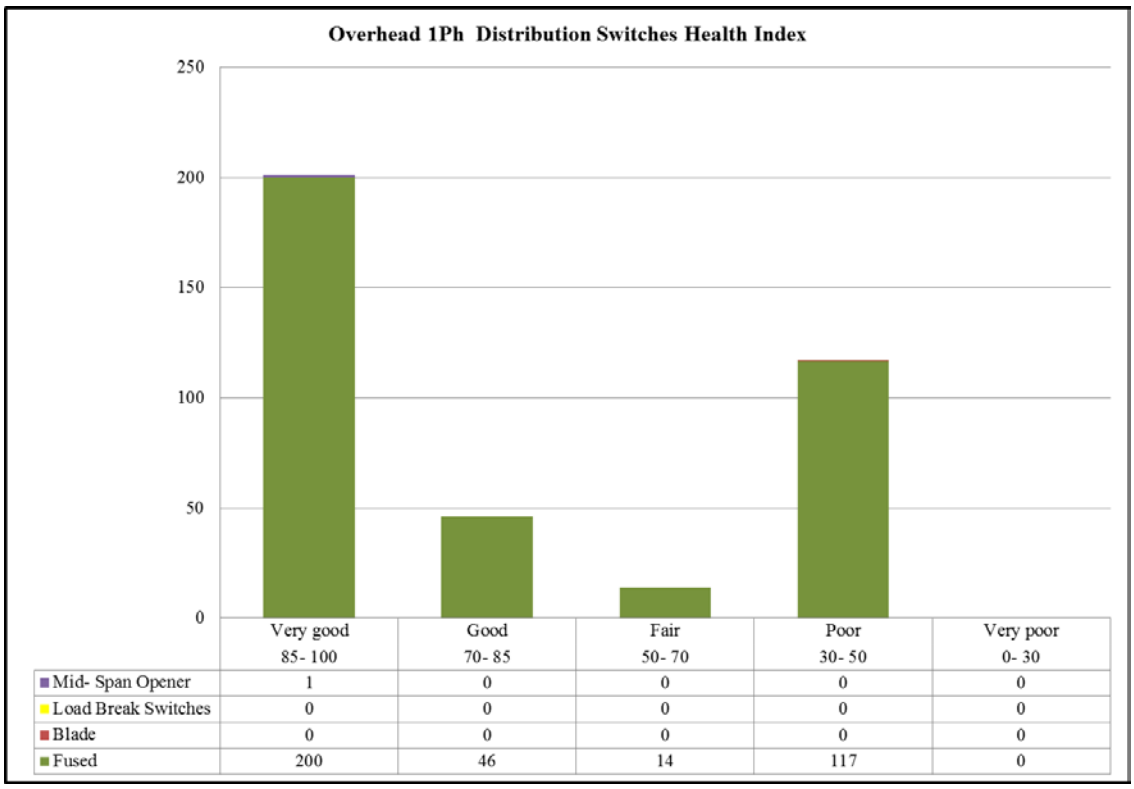
Exhibit 4-38 Age Profile of 3-Phase Pole-Mounted Switches

Based on the condition assessment criteria described in Section 3, the Health Index score is calculated for the 3-phase and 1-phase distribution switches and the 44 kV line switches and the results are presented in Exhibit 4-39 and 4-40. Exhibit 4.41 indicates assumed age profile for the 44 kV line switches and the health indices for 44 kV disconnect switches are indicated in Exhibit 4.42. Cutouts and disconnects determined to be in poor and very poor condition are recommended to be replaced during the next five years.



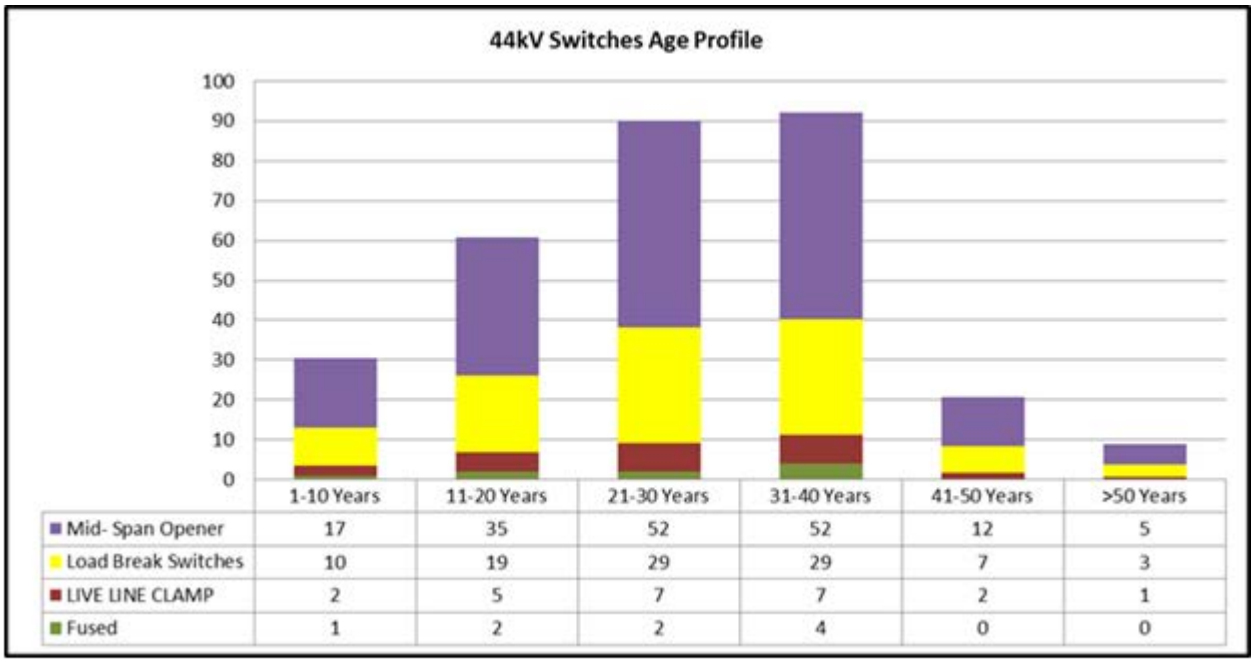
	Very good 85- 100	Good 70- 85	Fair 50- 70	Poor 30- 50	Very poor 0- 30
Mid- Span Opener	6	0	0	4	0
Load Break Switches	55	18	0	17	1
Blade	43	16	0	30	1
Fused	256	61	13	76	8

Exhibit 4-39 3-Ph Pole Mounted Switches Health Index Score



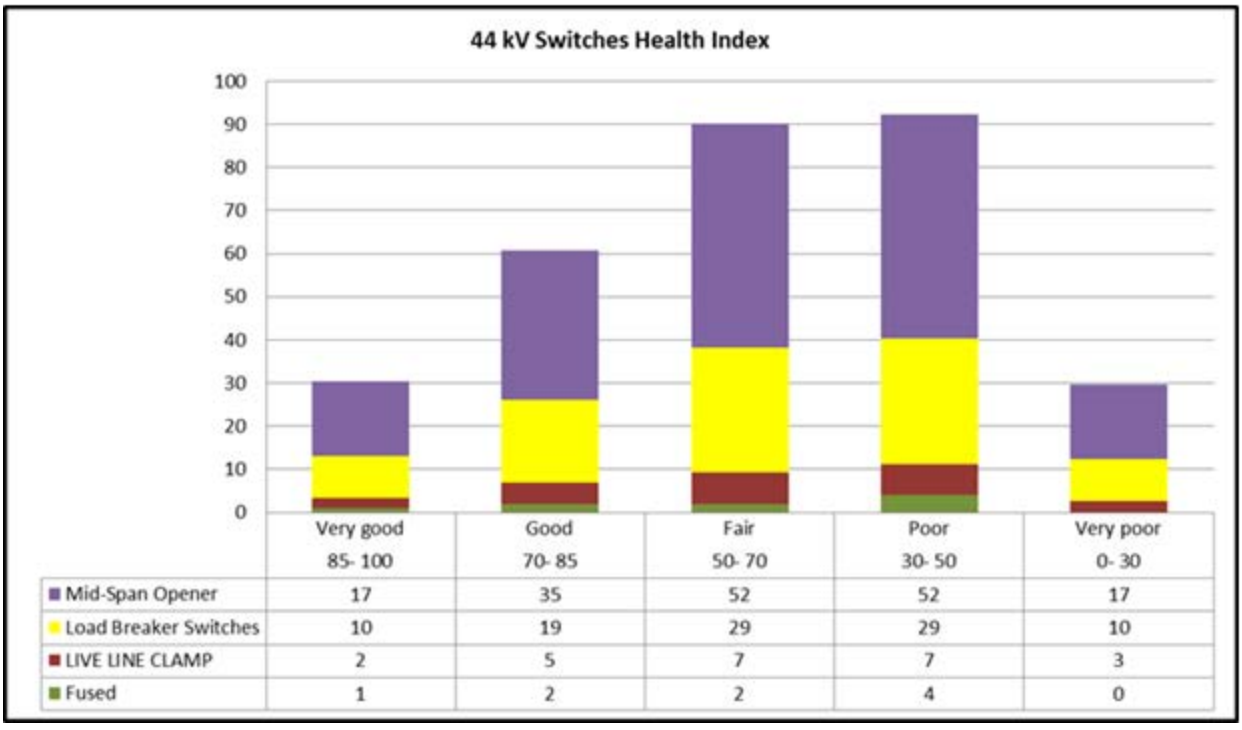
	Very good 85- 100	Good 70- 85	Fair 50- 70	Poor 30- 50	Very poor 0- 30
Mid- Span Opener	1	0	0	0	0
Load Break Switches	0	0	0	0	0
Blade	0	0	0	0	0
Fused	200	46	14	117	0

Exhibit 4-40 1-Ph Pole Mounted Switches Health Index Score



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Mid- Span Opener	17	35	52	52	12	5
Load Break Switches	10	19	29	29	7	3
LIVE LINE CLAMP	2	5	7	7	2	1
Fused	1	2	2	4	0	0

Exhibit 4-41 44kV Switches Age Profile



	Very good 85- 100	Good 70- 85	Fair 50- 70	Poor 30- 50	Very poor 0- 30
Mid-Span Opener	17	35	52	52	17
Load Breaker Switches	10	19	29	29	10
LIVE LINE CLAMP	2	5	7	7	3
Fused	1	2	2	4	0

Exhibit 4-42 44kV Switches Health Index Score

4.5 Distribution Transformers

The asset demographics of distribution transformers are presented in Exhibit 4-43. Overall age profile for distribution transformers is displayed in graphical format in Exhibit 4-44. As indicated, only a small fraction of distribution transformers have service age of more than 30 years.

Description	No. of Phase	Installed quantity	Asset Age (in years)						
			1-10	11-20	21-30	31-40	41-50	>50	Unknown
Pad mount									
37.5kVA	3ph	1	0	1	0	0	0	0	0
50kVA	3ph	4	2	0	2	0	0	0	0
75kVA	3ph	4	0	2	2	0	0	0	0
100kVA	3ph	7	2	2	3	0	0	0	0
150kVA	3ph	3	0	2	1	0	0	0	0
167kVA	3ph	13	1	11	0	0	0	1	0
225kVA	3ph	1	0	1	0	0	0	0	0
250kVA	3ph	2	2	0	0	0	0	0	0
300kVA	3ph	3	3	0	0	0	0	0	0
500kVA	3ph	5	3	1	1	0	0	0	0
750kVA	3ph	11	2	5	4	0	0	0	0
1000kVA	3ph	1	1	0	0	0	0	0	0
1500kVA	3ph	2	0	0	2	0	0	0	0
Unknown	3ph	18	10	2	3	0	1	0	2
10kVA	1ph	1	0	1	0	0	0	0	0
25kVA	1ph	1	0	0	0	1	0	0	0
37.5kVA	1ph	1	0	1	0	0	0	0	0
50kVA	1ph	68	29	27	9	1	0	0	2
75kVA	1ph	23	1	9	12	0	0	0	1
100kVA	1ph	330	30	120	172	3	0	0	5
167kVA	1ph	23	2	11	10	0	0	0	0
Unknown	1ph	9	4	2	0	0	0	0	3
Total		531	92	198	221	5	1	1	13

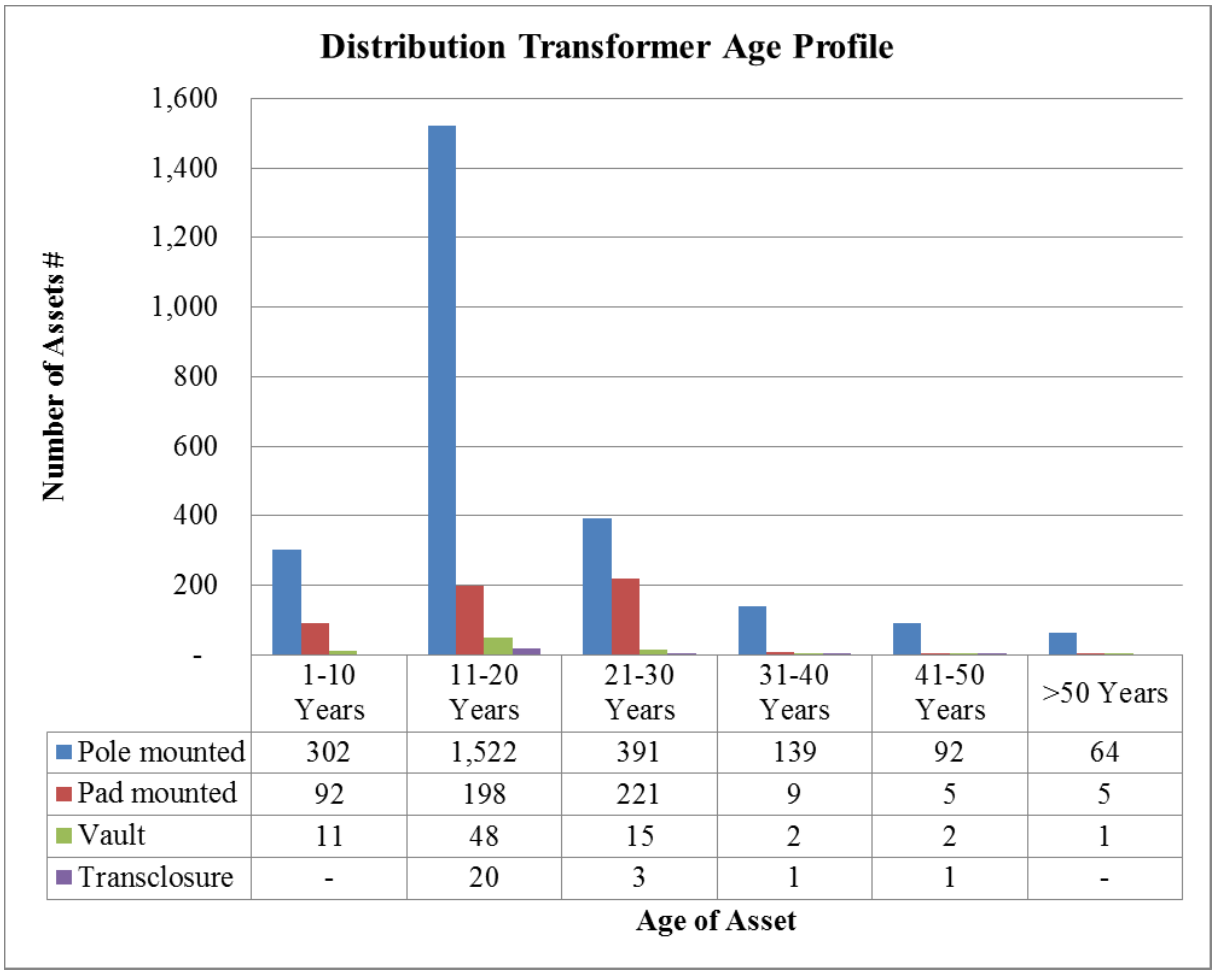
Description	No. of Phase	Installed quantity	Asset Age (in years)						
			1-10	11-20	21-30	31-40	41-50	>50	Unknown
Pole mount									
3kVA	1ph	9	1	5	0	1	0	0	2
5kVA	1ph	37	6	27	0	0	0	1	3
10kVA	1ph	139	33	74	4	1	3	3	21
15kVA	1ph	59	8	44	2	0	0	1	4
25kVA	1ph	714	43	402	182	42	2	2	41
30kVA	1ph	2	0	1	0	0	0	0	1
37.5kVA	1ph	153	13	117	3	1	7	2	10

50kVA	1ph	893	109	566	118	34	15	1	50
75kVA	1ph	333	39	203	61	5	6	1	18
100kVA	1ph	153	46	79	16	2	5	0	5
150kVA	1ph	2	0	1	0	0	0	0	1
167kVA	1ph	5	0	0	2	0	0	0	3
225kVA	1ph	4	0	0	3	0	1	0	0
250kVA	1ph	3	0	3	0	0	0	0	0
Unknown	1ph	5	4	0	0	0	0	0	1
Total		2511	302	1522	391	86	39	11	160

Description	No. of Phase	Installed quantity	Asset Age (in years)						
			1-10	11-20	21-30	31-40	41-50	>50	Unknown
Vault									
50kVA	3ph	1	0	1	0	0	0	0	0
75kVA	3ph	5	4	1	0	0	0	0	0
150kVA	3ph	1	1	0	0	0	0	0	0
167kVA	3ph	1	0	0	1	0	0	0	0
750kVA	3ph	2	0	0	2	0	0	0	0
25kVA	1ph	2	0	1	0	0	0	0	1
37.5kVA	1ph	1	0	1	0	0	0	0	0
50kVA	1ph	12	1	10	1	0	0	0	0
75kVA	1ph	18	3	12	3	0	0	0	0
100kVA	1ph	12	1	10	0	0	1	0	0
150kVA	1ph	5	1	2	1	0	0	0	1
167kVA	1ph	8	0	4	4	0	0	0	0
300kVA	1ph	1	0	0	1	0	0	0	0
750kVA	1ph	10	0	6	2	1	0	0	1
Total		79	11	48	15	1	1	0	3

Description	No. of Phase	Installed quantity	Asset Age (in years)						
			1-10	11-20	21-30	31-40	41-50	>50	Unknown
Transclosure									
25kVA	1ph	4	0	4	0	0	0	0	0
50kVA	1ph	6	0	5	0	1	0	0	0
75kVA	1ph	4	0	2	2	0	0	0	0
100kVA	1ph	5	0	3	1	0	1	0	0
167kVA	1ph	4	0	4	0	0	0	0	0
750kVA	1ph	2	0	2	0	0	0	0	0
Total		25	0	20	3	1	1	0	0

Exhibit 4-43: Distribution Transformers Demographic Information



	1-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Pole mounted	302	1,522	391	139	92	64
Pad mounted	92	198	221	9	5	5
Vault	11	48	15	2	2	1
Transclosure	-	20	3	1	1	-

Exhibit 4-44: Distribution Transformers Age Profiles

The health indices for distribution transformers are presented in Exhibit 4-45. The distribution transformers are recommended to be run to failure, i.e. replace a transformer only after failure. The budgets for renewal of this asset can be based on anticipated failure and replacement of the transformers found in poor and very poor condition.

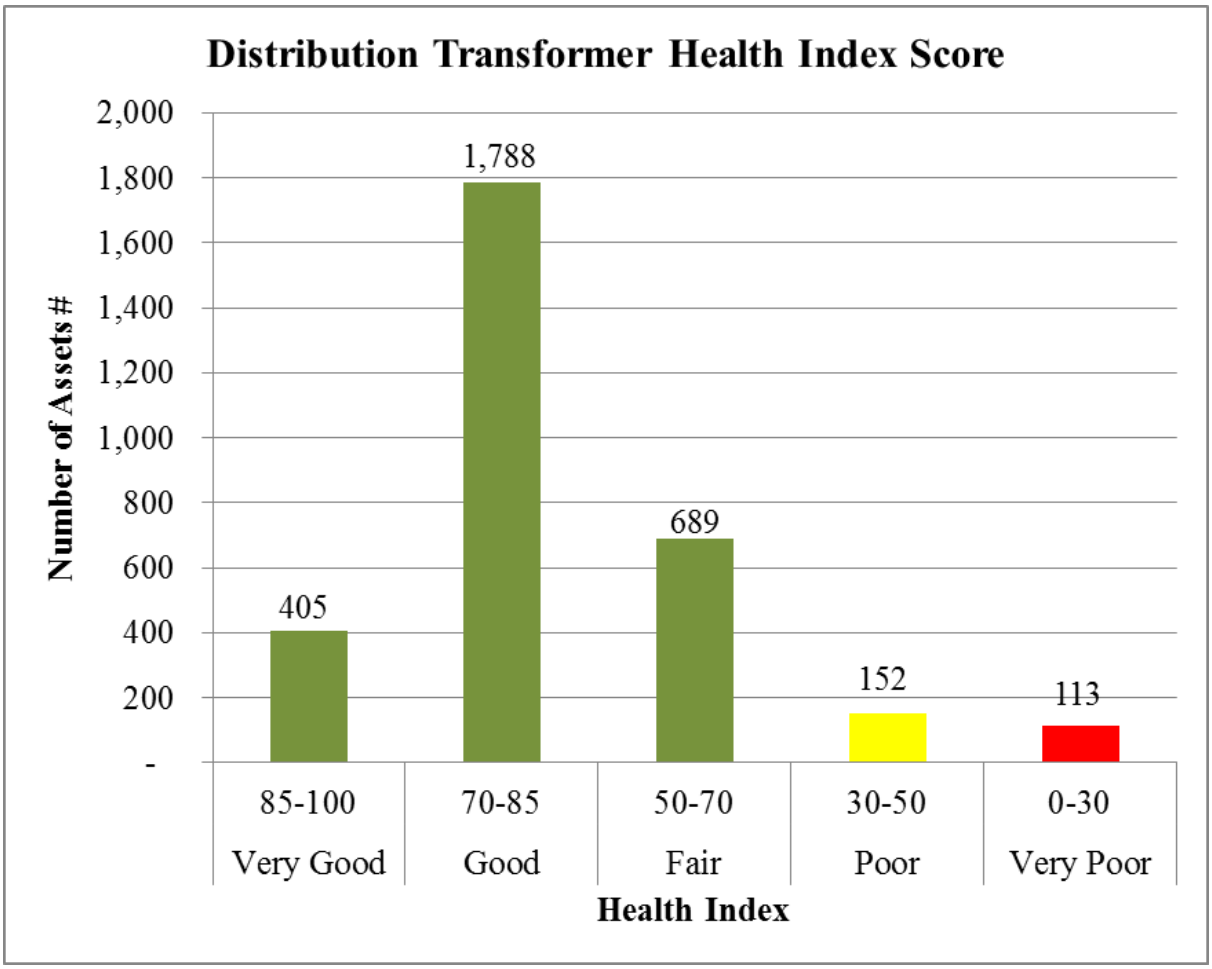


Exhibit 4-45: Distribution Transformers Health Index Score

5 METHODOLOGY AND RESULTS OF THE RISK-BASED ECONOMIC-LIFE ANALYSIS OF KEY ASSET

The methodology applied to determine the scope and timing of investments into asset renewal is the same as the Feeder Investment Model, used by many North American utilities, including Toronto Hydro, The objective is to identify assets that have reached the end of their economic life, and are due for replacement or refurbishment. The basic concept is that when deciding whether to replace an aging asset, a utility faces two competing objectives. On one hand, you would like to wait as long as possible to replace in order to minimize capital spending. On the other hand, as you wait longer you will face higher risk due to possible failures as the asset ages and becomes more likely to fail. The strategy that optimizes this trade-off is to minimize life-cycle cost.

The full range of relevant technical and economic considerations is integrated into this approach. Asset age and condition (i.e., health index) are used to estimate failure probability; criticality (i.e., customer effects) is used to define consequence of failure; and direct costs such as maintenance and capital replacement cost are integrated as well. All costs are defined from the perspective of the customer, which supports rate-making and budgeting with the regulator. In particular, the risk of failures captures the estimated customers' cost due to lost service.

Exhibit 5-1shows graphically how the optimization is performed; this example is for a station transformer. The horizontal blue-dashed line in the leveled life-cycle cost of a new asset. The orange upward-sloping curve is the risk plus maintenance cost of the existing asset as it ages; this is known as the marginal cost. Risk is defined as probability of failure (which increases as an asset ages) times consequence cost of failure. As long as the marginal cost of the existing asset is lower than the leveled cost of the new one, it is cheaper to leave the existing asset in operation. When the curves cross, the marginal cost of the existing asset is higher than the cost of a new one, and the asset is at the end of its economic life. In the example below, the transformer would be replaced at about age 44.

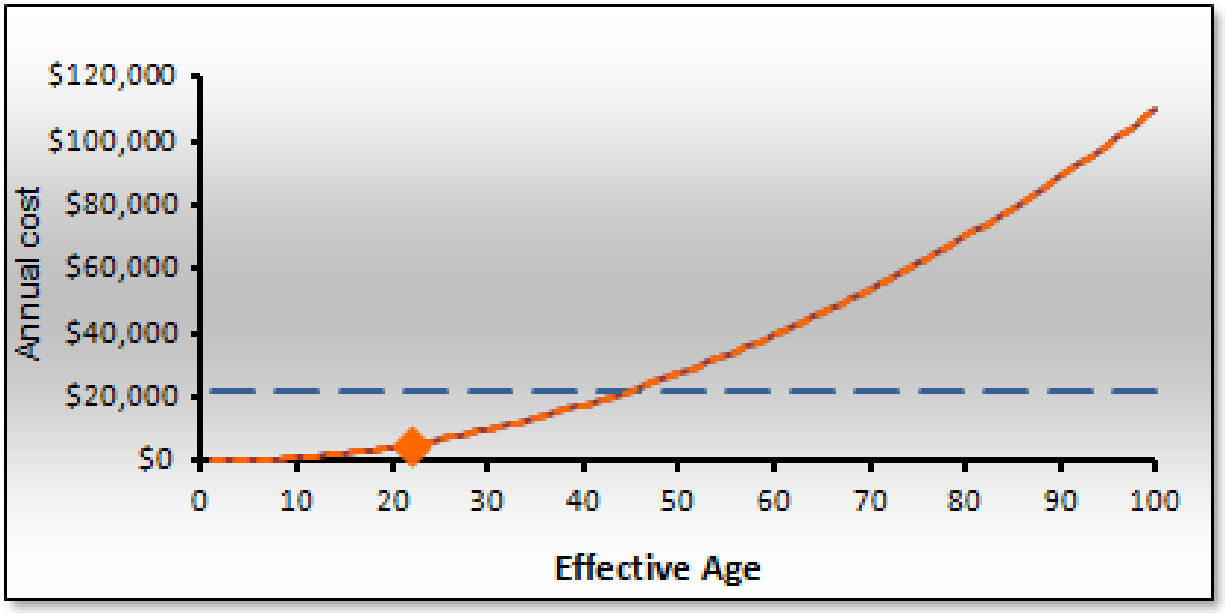


Exhibit 5-1: Station Transformer Optimization

This approach is asset specific. It is not possible to determine that, say; station reclosers have a 30-year life. Rather, we must say that this recloser has a 30-year life, but that one over there, which has different consequences of failure and different test results, has a different life. This analysis looks at each asset individually, and builds recommended spending plans from the bottom up.

The results of this analysis are discussed below, broken down by asset class. Detailed results can be found in the accompanying Excel workbook (*NBH Results Summary.xlsm*).

5.1 Key Assumptions

5.1.1 Health index

The results of North Bay Hydro's health indexing assessment have been integrated into the analysis. Assets in poor condition based on their health index are given a failure probability multiplier. For example, a 20-year-old power transformer would normally have about a 1 percent chance of failure before reaching age 21. If the transformer is known to be in poor condition, the expected failure probability is multiplied by as much as a factor of ten in order to capture the much faster than expected degradation.

The correlation between health index and failure probability is based on a combination of available historical data and expert opinion from work with other utilities.

5.1.2 Failure probability curves

The model includes curves defining failure probability as a function of age for each asset class. These curves are based on historical failure data and expert opinion from work with other utilities.

5.1.3 Customer outage cost

A significant element of the consequence of failure is customer interruptions. The economic life model quantifies customer outage cost, based on assumptions indicated below:

	Assumed value	NBH approach
Event	$30/connected kVA	Assume 5kVA connected capacity per customer
Duration	$15/hr/connected kVA	

Due to differences in available data, the approach to quantifying customer outage costs in modified somewhat. Specifically, NBH does not have connected capacity data but does have customer counts. For our analysis, we have assumed an average connected capacity per customer of 5 kVA.

The values used and the approach should be reviewed periodically as better surveys or other data sources become available.

5.1.4 Discount rate

This analysis uses a real discount rate of 5.5 percent for calculating net present values and annualized costs.

5.2 Overview of results

Detailed asset-by-asset results are delivered in the accompanying Excel workbook. The following is a summary of the results and interpretation.

5.2.1 Station transformers

Exhibit 5-2 shows the long-range replacement plan for station transformers. There are five transformers at or near end of life; their identifiers can be seen in the results summary workbook. MS 7-T1 and MS 13-T1 are the oldest two; MS 9 T-1 is in poor condition. These three are at end of life and due for immediate replacement. We recommend executing these replacements as quickly as possible, in order of decreasing benefit/cost ratio.

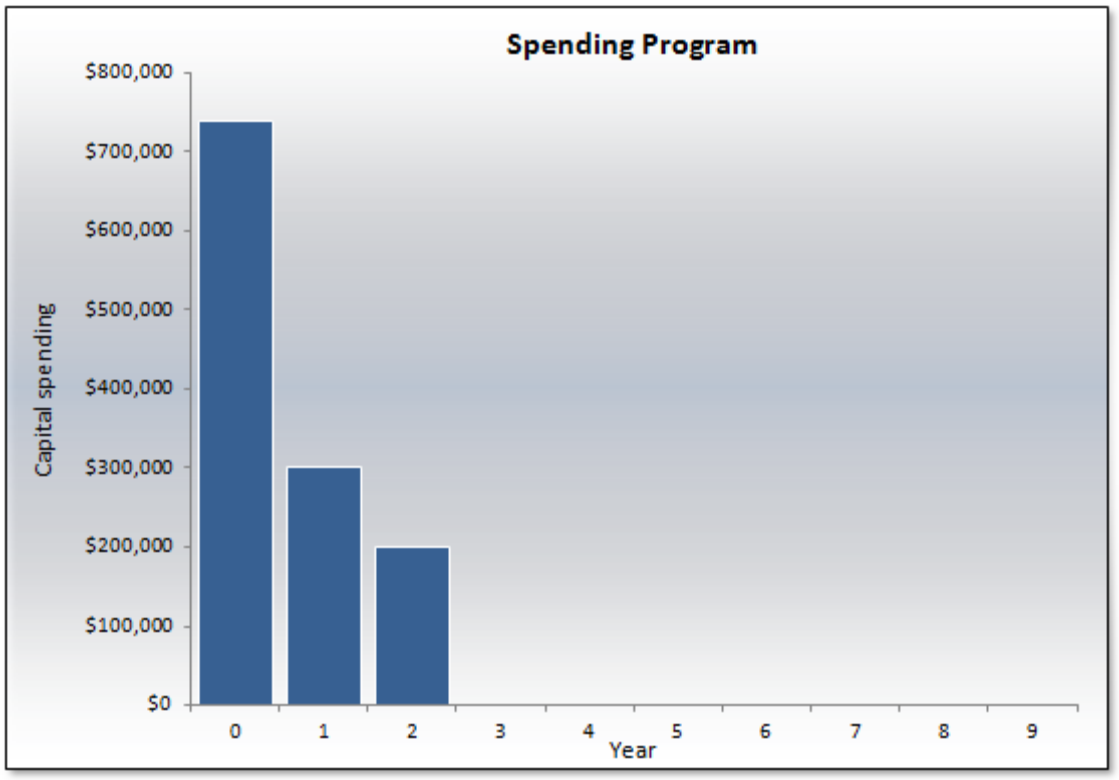


Exhibit 5-2: Station Transformers Spending Program

Exhibit 5-3 shows the transformer population risk matrix. Each asset is plotted relative to its current failure probability and expected consequence cost of failure. Assets at end of life are red, those not at end of life are blue.

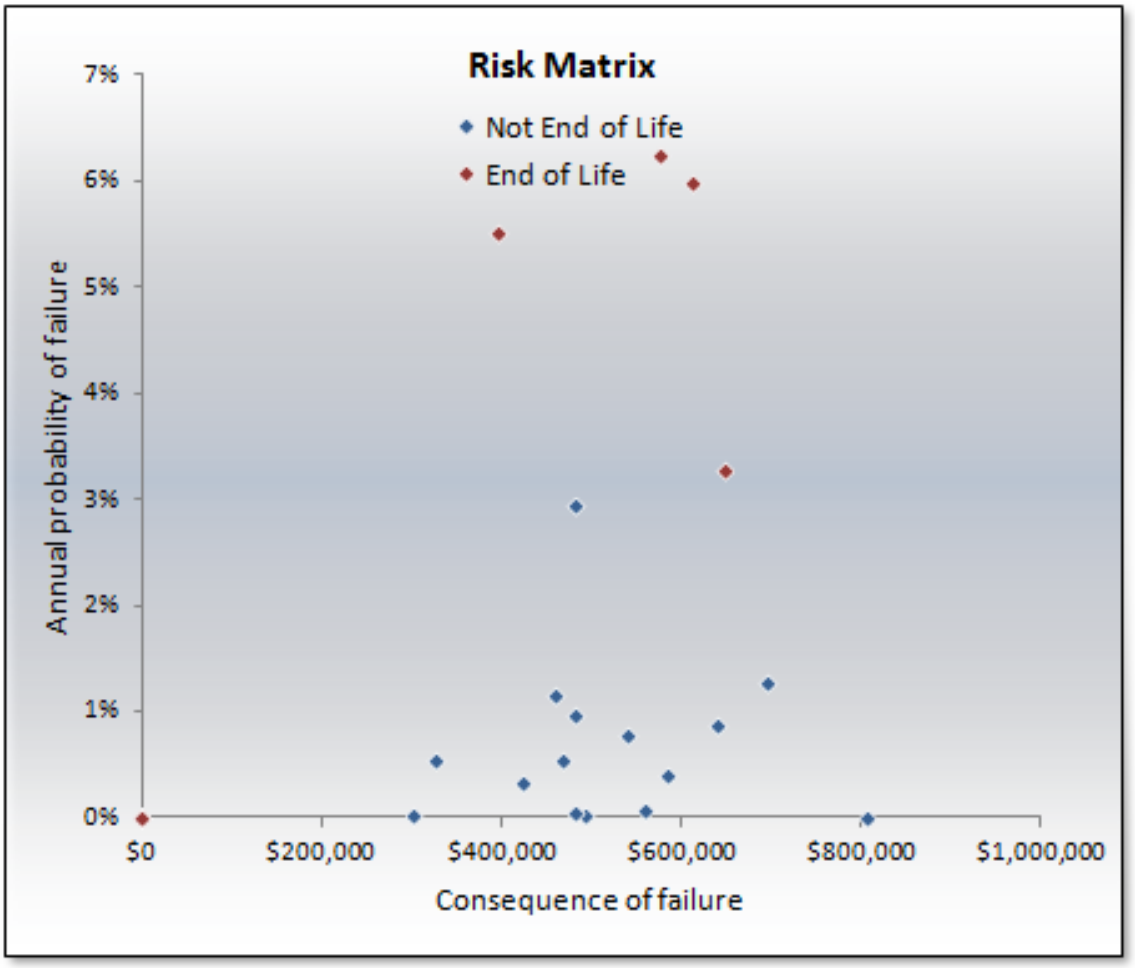


Exhibit 5-3: Station Transformer Risk Matrix

Some key assumptions are described below.

- Failure scenario: The station transformer failure scenario assumes that all customers served by the station (or the bus for multiple-transformer stations) will be out of service for four hours. There is a one-half percent probability of significant associated cost, assumed to be $20 million. This scenario is consistent with industry standard assumptions.
- Replacement cost is estimated at $40,000 per MVA, based on industry data.
- Refurbishment options are not evaluated for station transformers.

5.2.2 Underground cable

The long-range replacement program for underground cables is shown in Exhibit 5-4. We recommend leveling this spending over the entire duration – approximately $300,000 per year.

The analysis considered replacement for cables installed prior to 1992.

In general, the data available for analysis of cables was incomplete. NBH should consider a survey or sample to improve the precision of the analysis.

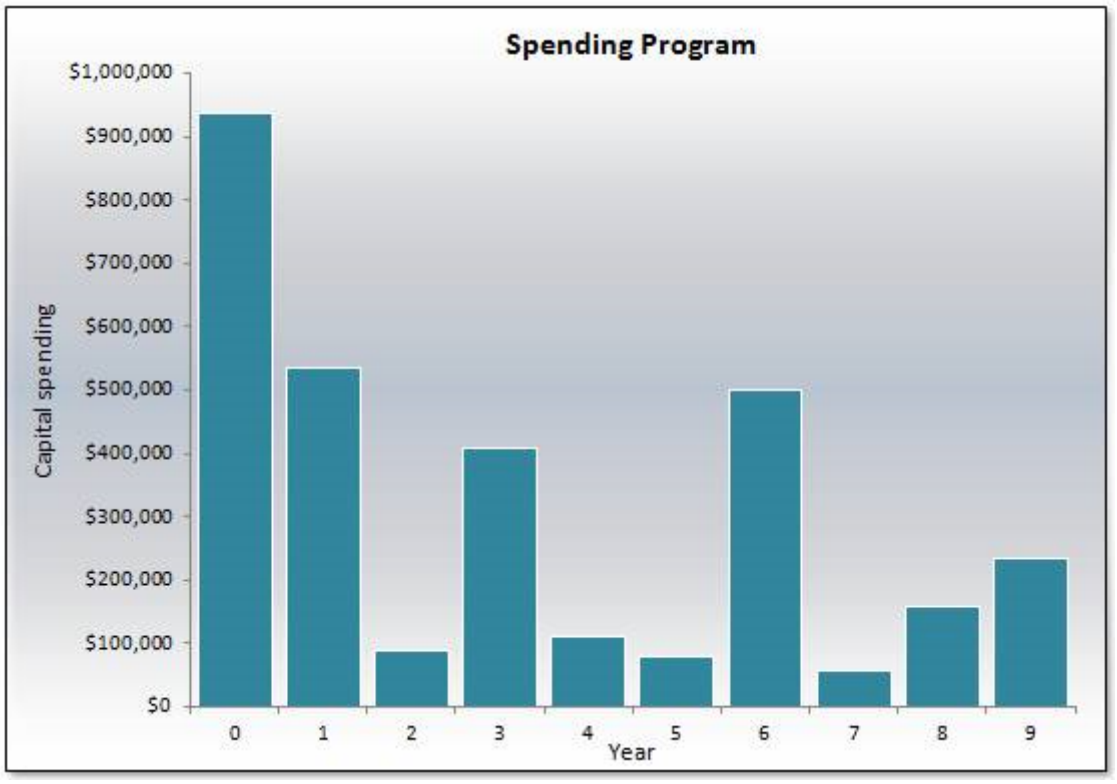


Exhibit 5-4: Underground Cable Spending Program

Exhibit 5-5 shows the underground cable population risk matrix. Each asset is plotted relative to its current failure probability and expected consequence cost of failure. Assets at end of life are red, those not at end of life are blue.

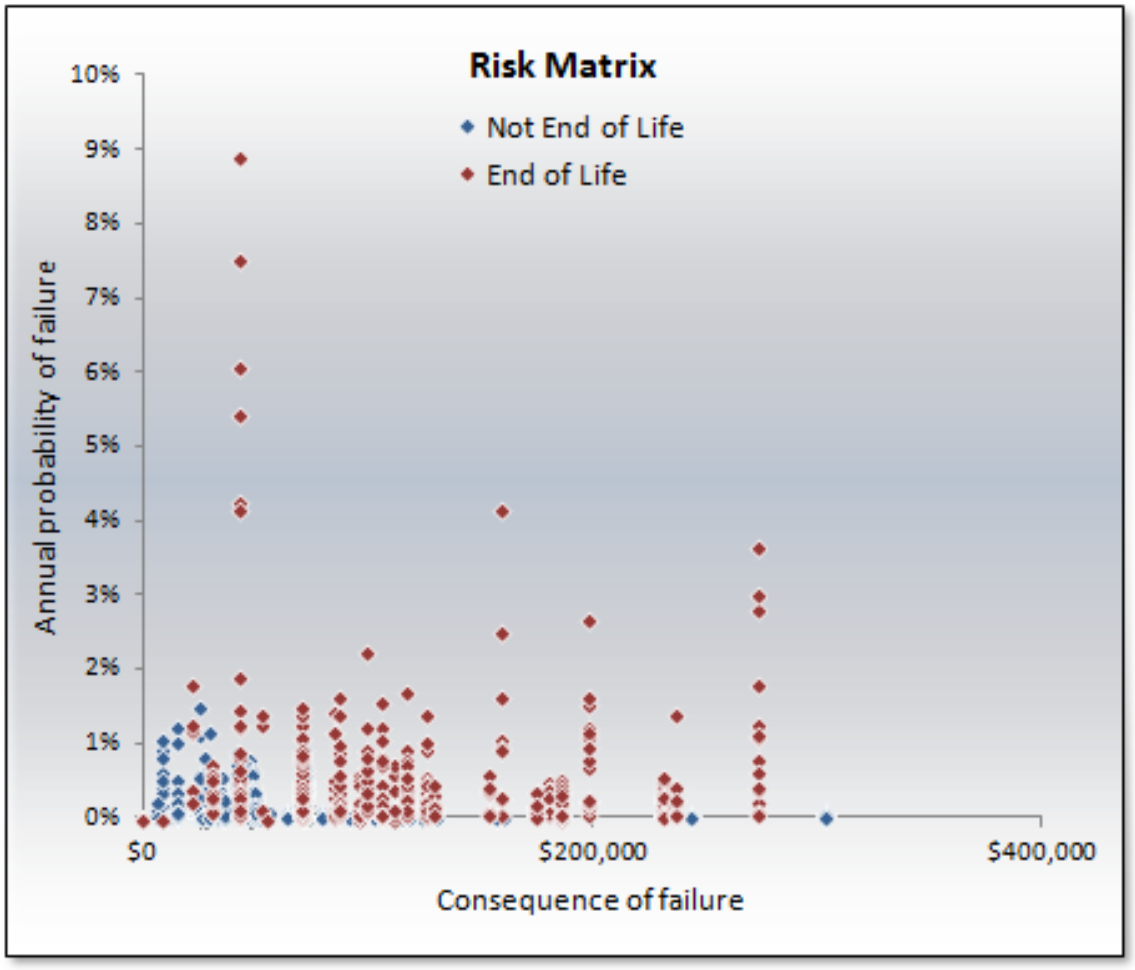


Exhibit 5-5: Underground Cable Risk Matrix

Some key assumptions are described below.

- Failure scenario: The analysis assumes that faults in three-phase cables will cause the entire feeder to be out for a two-hour switching duration. Faults in single-phase cables are assumed to be under a protective zone (i.e., fuse). Data on the zones was not available, so we have assumed an average of four zones per feeder. The same two-hour switching duration applies to single-phase faults.

- Replacement cost is estimated at $120 per meter for trenching plus $30 per phase-meter for cable. Cable will be replaced with very reliable modern XLPE cable in conduit.

- Injection cost is $40 per phase-meter and is assumed to reduce the effective age by 20 years. These are all typical values used in the industry.

5.2.3 Station reclosers

The station recloser spending program is shown in Exhibit 5-6. The replacement program comprises one to two reclosers per year, which should be executed based on benefit/cost ratio.

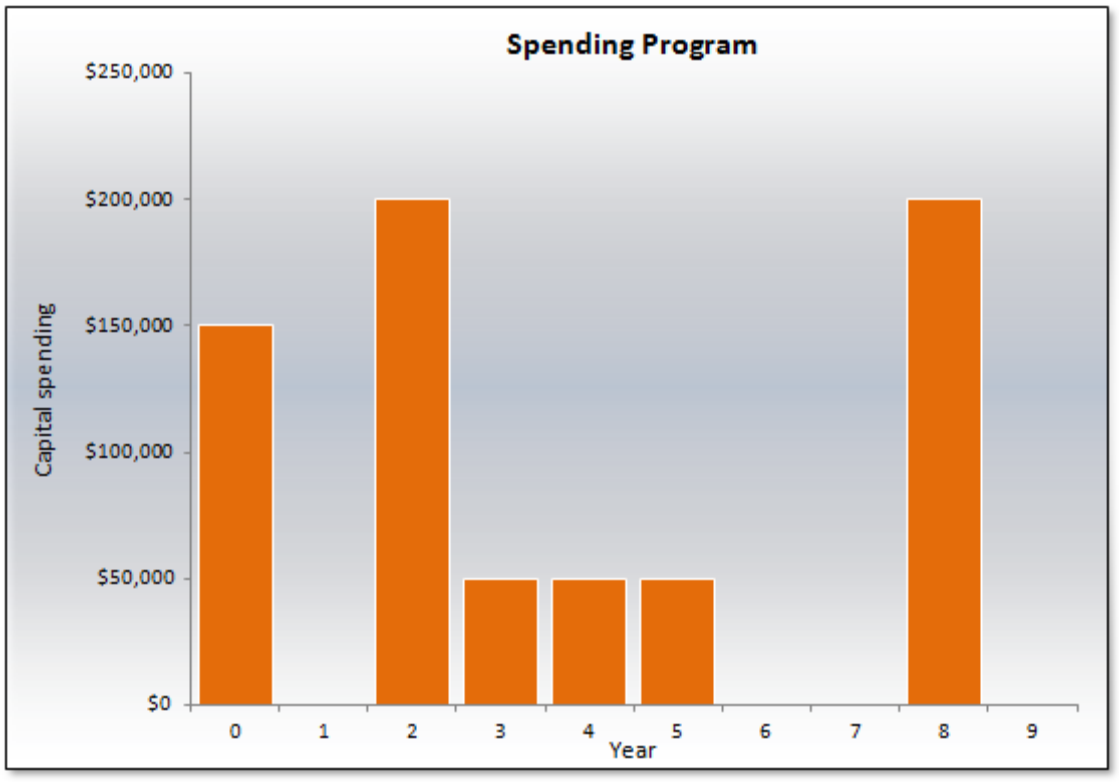


Exhibit 5-6: Reclosers Spending Program

Exhibit 5-7 shows the recloser population risk matrix. Each asset is plotted relative to its current failure probability and expected consequence cost of failure. Assets at end of life are red, those not at end of life are blue.

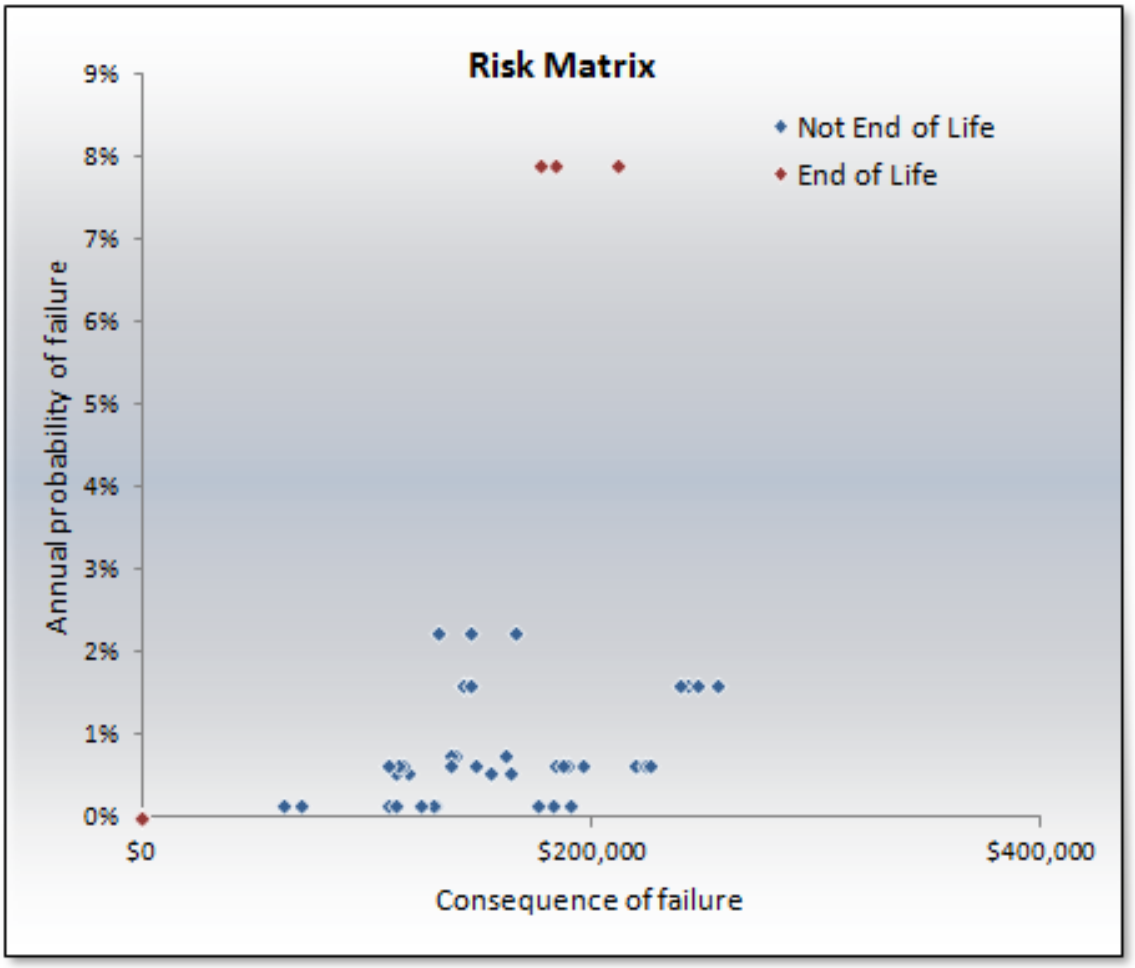


Exhibit 5-7: Reclosers Risk Matrix

Key assumptions include the following.

- Failure scenario: There are four failure scenarios modeled for reclosers, based on the industry standard approach.

Scenario	Description	Relative probability
Maintenance finds failure	Minor repair, $5000 direct cost.	50%
Failure to open	Recloser fails to open, taking out the entire bus for four hours.	20%
Failure to reclose	Recloser fails to reclose, extending an existing outage by four hours	25%
Catastrophic	Failure to open with associated damage.	5%

- Replacement cost is estimated at $50,000 per recloser, based on industry data.
- Refurbishment options are not evaluated for station transformers.

5.2.4 Wood poles

The model for wood poles focuses on estimating when poles will reach end of life based on testing and inspection criteria. Our experience has been that an economic model for pole replacement consistently recommends a run-to-failure strategy. The projected pole replacement program is shown in Exhibit 5-8. The program increases steadily as the population ages.

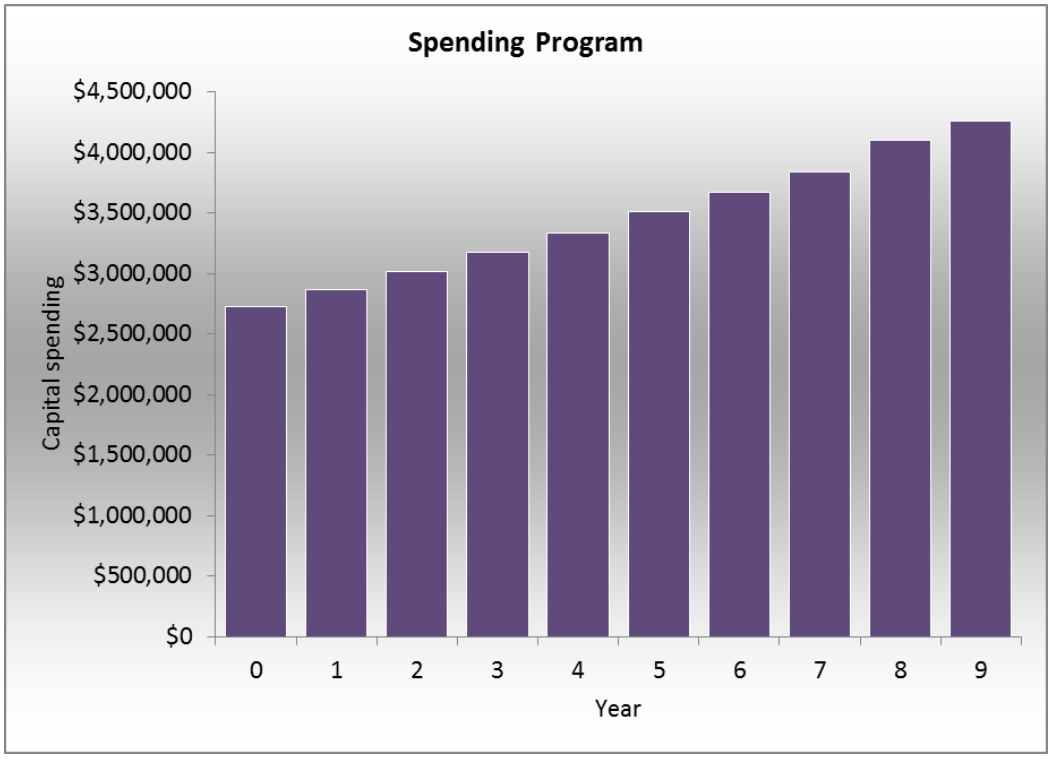


Exhibit 5-8: Wood Poles Spending Projection

The pole health results depended heavily on age, so they were not used as part of the long-range projection. Failure rate is determined using a hazard rate curve developed using data from other area utilities, which have similar weather and regulatory requirements for pole replacement.

Replacement cost per pole is estimated at $13,000, based on input from North Bay Hydro.

5.2.5 Feeder results

The risk contribution of all the assets comprising each feeder has been summed up to give a measure of the feeders' relative risk. A summary is shown in Exhibit 5-9. This summary includes the risk contributions from all the assets evaluated in this study as well as from pole- and pad-mount transformers.

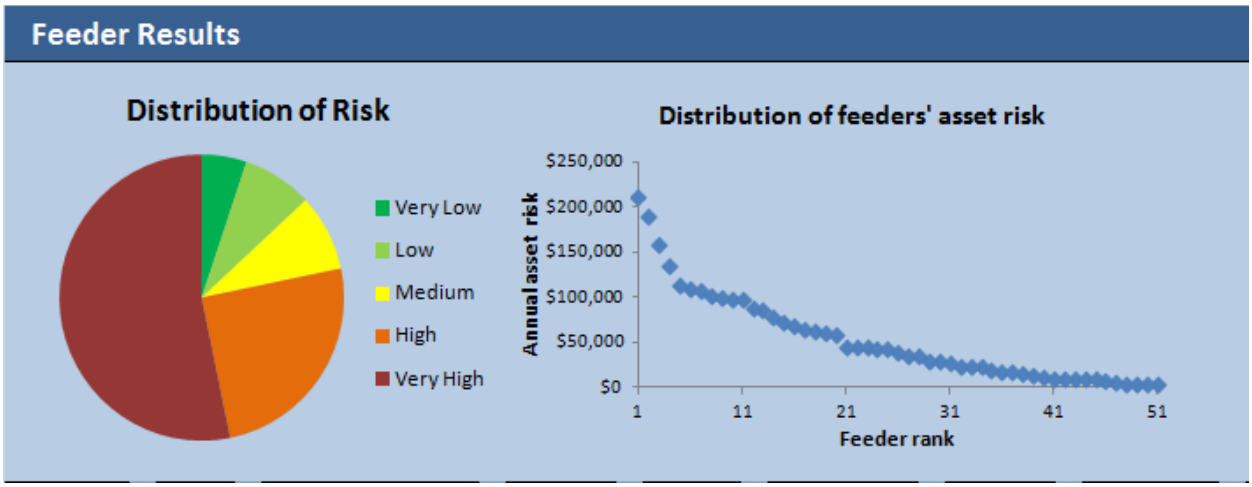


Exhibit 5-9: Quintiles Distribution of Risk

The main takeaway from this assessment is that there is a great deal of stratification of risk among feeders. Nearly half the total asset risk comes from the top 10 feeders, as shown by the red section of the pie chart.

Appendix C - Building Assessment Report

Building Condition Assessment

North Bay Hydro - 74 Commerce Crescent

Building, Services and Equipment Review

Piotrowski

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GENERAL INTRODUCTION

This report is broken into two distinct sections, the first is the Architectural Building Condition Assessment performed by Evans Bertrand Hill Wheeler Architecture Inc. This is followed by the Mechanical and Electrical Building Condition Assessment performed by Piotrowski Consultants LTD.

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5. PHOTOGRAPHS AND COMMENTS 6
6. HIGH LEVEL SUMMARY AND COSTING SPREADSHEET 2

1. INTRODUCTION

1.1. At the request of North Bay Hydro, Evans Bertrand Hill Wheeler Architecture Inc., thru Piotrowski Consultants Limited conducted a visual inspection of the facility in August 2013.

1.2. The purpose of the inspections was to investigate and record the current facility conditions and equipment that directly impacts the short and long term maintenance costs of the building. This was completed on all life cycle items and did not include any structural reviews.

1.3. Northland Engineering was the original engineer for the original facility. There have been two additions to the facility since the original construction as well as two interior renovations.

1.4. Comments from the staff noted that the building was extremely hot during the warm summer months in specific locations and very cold in the winter during the long cold days.

2. GENERAL NOTES OF THE FACILITY

2.1. Upon visual review of the interior layout and building perimeter, it was noted that some changes have occurred since the completed construction of the facility. Much of the lighting scheme was as per the original plans, with some exceptions in minor areas. The original construction of the facility was completed in the late 1970's.

2.2. There was an addition to the south of the building (change area), for which no information has been obtained. From its construction and the state of the finishes, it appears that this addition was completed in the late 1980's or early 1990's. This area is generally staff lounge, change areas, washrooms and showers. The 2 main staff washrooms appear new and have had a recent renovation.

2.3. There was an addition to the east side (metering area) of the building, completed in 2009.

2.4. There have been two recent interior renovation projects completed on the facility with the main level office area finishes being completed in 2011 and the 2nd level office area renovation occurring in 2009.

2.5. According to the existing drawings provided to us, the floor areas of the facility is as follows;

.1. Garage Area (with stores) = 12,100 ft²
.2. Meter Room (east) Addition = 1,100 ft²
.3. 1st Floor Office Area = 4,000 ft²

.4. South Addition = 2,200 ft²
.5. 2nd Floor Office Area = 4,000 ft²

2.6. A reduced copy of the overall layout plan are included as "Appendix" in Section 4 of this report.

3. OBSERVATIONS

3.1. Site Works

1. The site generally comprises of asphalt paving, landscaping and gravel storage areas in the rear of the building. Areas appear generally in good condition. Implementation of a maintenance and patching program would assist to extend the life span of the existing asphalt surfaces another 5 to 8 years. A program for asphalt repair and replacement should be undertaken at that time.

3.2. Masonry

1. The existing exterior of the south facing addition (change area) consists of exterior split face block which appears in reasonable condition.

   Water damage is present on the foundation wall from water drainage, snow and ice buildup, due to a missing eave trough. The eave trough appears to have once been in place and was either removed or damaged from ice off the roof. A program should be put in place to design a solution and implement a repair.

3.3. Metal Siding

2. The majority of the building is generally metal siding which would have been original to the steel building. Although, faded from years of sunlight, for its age, the metal siding appears in reasonable condition. The east addition constructed recently has a metal siding exterior which is in good condition. A painting program could be put in place to improve the aesthetics of the building, however would not be considered a required scope of work.

3.4. Millwork

1. The millwork is generally in good condition having been replaced over the past 5 years in the upper and lower office areas. Millwork in the south facing addition (change area / washrooms) appears to be original construction. With proper maintenance, the life span of the millwork in this area should extend another 10 years.

2. The millwork, washroom accessories and misc. items should be replaced in the lower level office area washrooms. These items have reached the end of their life cycle.

3.5. **Windows**

1. In general, the windows within the original facility on the 2nd floor office area appear to be of original construction and require replacement. There are a total of 8 windows on the 2nd floor which should be replaced and 2 on the ground floor which require replacement.

2. The windows in the south and east additions, are aluminum, in good condition and require no work in the next 10 years.

3.6. **Doors - Exterior**

1. Entry and exit doors were reviewed for air tightness and condition.

2. Public and main office staff entry doors are aluminum door systems, often with sidelights, are in good condition and would require no replacement over the next 10 years with continued maintenance.

3. Exit doors are hollow metal steel doors, without glazing in most cases.

4. In general, most doors were found in fair condition. Maintenance, particularly for weather stripping, is highly recommended. All exterior doors should have weather stripping repaired and / or replaced in the next 5 years. This would be a cost effective means of ensuring the heating and cooling performance of the building during winter and summer.

6. Door hardware appears to be in good condition with ongoing maintenance. A replacement program should be set in place on a door by door basis. We would suggest commencement of this program in approximately 5 to 8 years.

3.7. **Doors - Interior**

1. Interior doors are mostly hollow metal construction on the ground floor and are in good shape. With proper care and maintenance, life expectancy is unlimited.

2. The 2nd floor office area consists of hollow metal frames with hollow core wood doors, which have been recently installed and painted and should last beyond the 10 year replacement program

identified in this report.

3.8. Doors - Garage

1. The existing garage doors are in need of replacement within the next 5 years. There are current visible gaps on the tops and sides. The seals should be replaced immediately.

2. Total replacement of the overhead doors should be implemented within the next 5 to 7 years.

3.9. Building Envelope - Roofing

1. The thermal properties of the roof when installed would have been approximately R12, with noted deterioration and sagging over time, a current value of R8 would be a reasonable assumption. The ceiling was insulated with 4"+/- of bag insulation provided with the original pre-manufactured building during the original construction. There is an area of heat tracing in place, above the north facing garage doors which would be an indication of ice build up along the roof edge due to heat loss from the insulation system.

   An insulation improvement program to upgrade the facility energy efficiency could be considered but is not required. An assessment on the financial payback of such a program could be undertaken to determine the financial feasibility of such a project.

2. Soffits and fascia are in good shape with slight fading due to exposure to sunlight. The performance of the products are not in jeopardy, however could be replaced to enhance the appearance of the facility. This approach could be reviewed, in locations more exposed to public view, such as the main entrance and completed when funds are available.

3. The roofing system of the original pre-engineered building is a metal roofing system made of approximately 24" wide panels, with a staggered seam along both sides. The metal roofing appears in good condition and with proper care and maintenance its lifespan could extend another 12+ years.

   There are missing flute closures at the ends (eaves) of the metal roof system. New closures should be installed to protect insects from entering the roof system.

   The roofing system on the front appears to be an existing modified bitumen roof, with a new coating protection applied in the recent years. From a review and discussion with a local roofing company,

a Garland roofing product was installed in the past 5 to 8 years and should span beyond our 10 year projections.

Additional chevrons, (ice / snow break system), should be installed along the entire length of the roof upon completion of new gutter installation to protect it from damage.

4. There are steel members from the steel building which project to the exterior at the underside of the soffit. These should be insulated and covered in sheet metal in order to minimize the cold thermal transfer into the building.

3.10. Building Envelope - Walls

1. The walls are generally insulated with pre-engineered building insulation and clad with metal siding. Drywall coverings clad the interior side of the office areas. The exposed insulation in the shop is damaged in areas and should be repaired.

2. The insulation on the two additions was not visible for inspection as it was covered with drywall, however, being included in more recent additions / upgrades, the level of insulation should be within reasonable industry standard.

3.11. Flooring

1. The type of flooring product through the facility varies depending on location. The entire garage area and east addition are concrete floors which will last the life of the building.

   The other areas of the building have the following flooring finishes:

   a. Office Area 1st Floor - Carpet tile, select areas of vinyl tile and ceramic tile within the main entrance area.
   b. Office area Upstairs – Carpet tile with select areas of vinyl tile.
   c. Front Addition (South) – Vinyl tile with area of original ceramic tile.

2. Our report suggests the replacement of the existing VCT flooring through the front addition (change area) and the employee washrooms on the main floor within 5 years.

3.12. Ceilings

1. Within the offices there are minor areas of ceilings which are surfaced with gypsum board, including some bulkheads, vestibule ceilings and main entrance areas. The remainder of the office area is t-bar type ceiling. T-bar ceiling with proper building conditions will last indefinitely; the only reason for replacement would be

damage from some event or aesthetic replacement.

2. The shop area has an open ceiling setup and does not require any work.

3. The stores area and metering area (east addition) have drywall type ceilings that are in reasonable shape and require no improvements.

4. The south addition (change area) has original drywall ceilings throughout most of the area with a stipple surface. The washrooms which were upgraded recently have experienced drywall repairs or replacements, (could not be determined) and have a flat painted finish. The drywall in all areas within this portion of the building is in good condition and will last for years to come with some maintenance and painting. Cosmetic upgrade would be the only consideration for completing work in this area.

3.13. **Drywall and Painting**

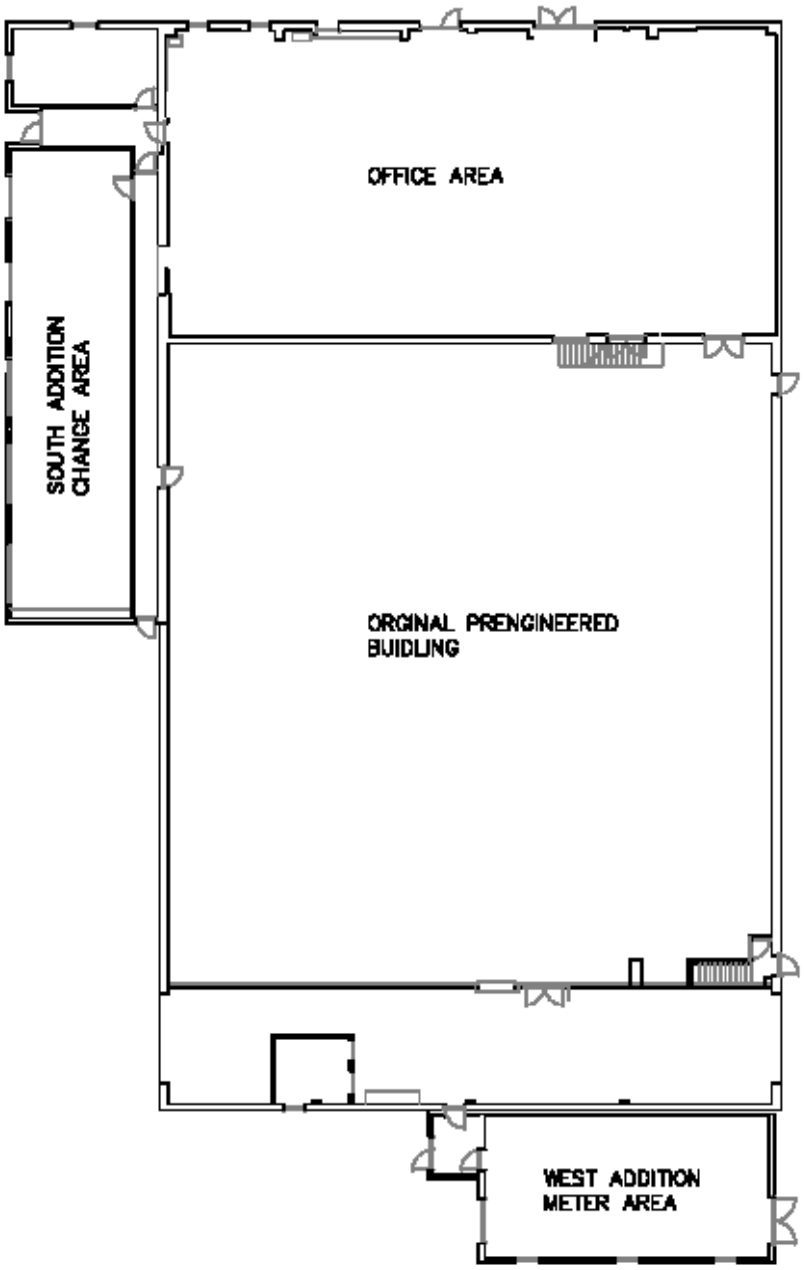
1. Surfaces appeared in good shape with minor cosmetic damage in some locations. Owner and consultant to discuss painting program. Our suggestion would be to complete a painting program in 5-10 years for the areas that have not been recently painted.

Thank-you for the opportunity to submit this report. Please contact us should there be further concerns or questions. Thank you.

Sincerely,

Trent J. Collie, OAAAS, A.Sc.T
Project Manager

4. Overall Layout Plan – Appendix



5. PHOTOS AND COMMENTS

Photograph of the rear of the building

Photograph of the back area of the building

Photograph of the rear of the building

Example of asphalt cracking / heaving to be repaired

Example of asphalt cracking / heaving to be repaired

Photo identifying condition of foundation flashing at South addition (change area) See item 6.1.3

West elevation. Some windows to be replaced.

West elevation. Some windows to be replaced.
.

Exterior door to change area – Maintenance required. See item 6.1.6

Exterior door to change area – Maintenance required. See item 6.1.6

Garage door to main shop – Maintenance and replacement required. See item 6.1.8

Garage door to main shop – Maintenance and replacement required. See item 6.1.8

Roof condition photographs - General

Roof condition photographs - General

Roof condition photographs – Install closures in ends of flutes. See item 6.1.9

Building steel projecting to the exterior should be insulated. See item 6.1.14

General condition of existing ceilings in south addition. See item 6.1.12

General photograph of south stairwell leading to the 2nd floor office area.

6. HIGH LEVEL SUMMARY OF REQUIRED REPAIRS

6.1. Below is a summary of required repairs included within our spreadsheet "**Appendix A" BCA breakdown** for quantity and estimated costs :

6.1.1 Asphalt repair / replacement program.

6.1.2 South addition (change area) eave trough

6.1.3 South addition (change area) foundation wall repair detail

6.1.4 Washroom replacement upgrade program in 1st level office area (2 total)

6.1.5 Window replacement program – original engineered building – 8 total

6.1.6 Exterior door seals and weather stripping

6.1.7 Exterior door hardware maintenance and replacement

6.1.8 Garage door replacement program

6.1.9 Install missing closure flutes on metal roofing

6.1.10 Add chevrons to roof on south addition (change area)

6.1.11 Miscellaneous ceiling tile replacement program where damaged or stained

6.1.12 Drywall ceiling upgrade plan – Generally south addition (change area)

6.1.13 Replace existing Vinyl tile flooring – see spreadsheet for locations

6.1.14 Insulate steel building frames which extend to the exterior

6.1.15 Repair insulation to walls and ceilings in shop area

6.1.16 Repair crack in masonry on the west side of the shop

6.1.17 General unforeseen maintenance costs to be reviewed and discussed for value

1. INTRODUCTION

1. Piotrowski Consultants Ltd. was commissioned by North Bay Hydro to conduct a building condition assessment of 74 Commerce Court. Our report will include existing building, services and equipment condition, recommended upgrades within a given timeline as well as energy efficient upgrade options.

Piotrowski Consultants Ltd.
1820 Bond St, North Bay, Ontario
705-472-2536 : pcl@onlink.net

2. PURPOSE AND METHODOLOGY OF THE STUDY

1. The purpose of this study is to review the mechanical, electrical and architectural building systems in order to evaluate their current state and, if required, recommend courses of action to extend the building's service life for the next 10 years.

   Our recommendations within this report are based on:

   - Existing conditions
   - Estimated costs/project budgets
   - Construction timelines
   - Standard Materials
   - Life Safety
   - Best Engineering Practices
   - Applicable Codes and Standards

2. Information in this report is based on site investigations of exposed services with non destructive / intrusive techniques, as well as discussions with maintenance and operational staff.

3. Applicable codes and standards include:

   1. Ontario Building Code (OBC) - 2006 Edition.
   2. 2011 ASHRAE Handbook: HVAC Applications - American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE).
   3. Ontario Electrical Safety Code (OESC) - 2009 Edition.

3. DESCRIPTION OF MECHANICAL AND ELECTRICAL SYSTEM

For the purpose of this report we will be breaking the building up into sections based on building layout. The first area reviewed in this report is the metering addition done in 2008 followed by the general stores and vehicle storage (garage), lunch and linemen addition and main office space (2 floors). In each section the heating, cooling and ventilation, plumbing, life safety, lighting, electrical distribution and security systems will be reviewed.

3.1. HEATING, COOLING AND VENTILATION

3.1.1 - Metering Addition

Heating in the metering addition is provided by a Carrier heat pump/air conditioning unit Model No.: 25HCCA/FX4C. This 1000 cfm unit is combined with a 2 stage 10 kW (34.12 MBH) electric heater. As well as a 2.5 ton (30 MBH) cooling coil combined with a remote condensing unit located outside the building. The unit is operated via a thermostat located at the entrance to the addition. The system is 5 years old and in good condition.

Additional heat is provided to the garage space in the metering area is heated via a Modine Unit heater, Model No.: HD30. The unit is gas fired with 30 MBH input. This unit is also 5 years old and in good condition.

Supplementary heat is provided to the space via two 2 kW electric baseboard heaters, which are tied in with the heat pump.

The entry vestibule into the area is heated via a 3 kW fan forced heater.

3.1.2 - Stores and Vehicle Storage

The Stores and Vehicle Storage area is heated by a combination of gas fired radiant tube heaters in the garage area, and electric baseboard and unit heaters in the stores area. Age of heating systems is unknown but estimated greater than 15 years; they are however in fair condition. The radiant panels are exhausted to the rear of the building in the material storage area.

There is no cooling in this space.

Ventilation in the garage area is provided by two roof mounted exhaust fans which are tied into a CO_2/NO detector. The exhaust fans appear to be in fair condition.

3.1.3 - Lunch room and Linemen Addition

Ventilation in the addition is a mix of PTAC units, HRV's (mounted in vehicle storage area) and exhaust fans.

In the office and lunchroom areas heating and cooling is provided by Packaged Terminal Air Conditioning Units, these are manufactured by Applied Comfort and provide heating and cooling in the space. One is located in the office, and two are located in the lunch room. All three units are the same type and size:

- Applied Comfort Model No.: DMA15K50SC01
- 14000 Btu/hr Cooling capacity

- 17500 Btu/hr Heating Capacity

Supplementary heat in the office is provided by a fan forced heater with an output of 3600 W (12.3 MBH).

Two Venmar AVS Heat Recovery Ventilators feed the linemen, and lunch room in the addition, with the control thermostats located in each room. These units provide fresh tempered air to the space.

The linemen room heat is provided by baseboard heaters with a fan forced cabinet unit heater located in the closet area for clothes/uniform drying purposes.

3.1.4 - Main Office and Reception

The office areas (both main and second floor) heating and cooling are primarily provided by the three existing air handling units located outside the building in the storage area near the rear of the building. All units are mounted on steel stands which are in poor to fair condition. These units are roughly 15 years old and all air handling units are gas fired, with direct expansion cooling coils.

Existing units are as follows:

AHU#1: Carrier - Model No.: 48TFE012 - 12 ton / 144 000 BTU/hr of cooling
224 MBH heating input
144/179 MBH heating output
EER: 9.0
SEER = 9.0/.875 = 10.28

AHU#2: Carrier - Model No.: 48TFE005 - 5 ton, 60 000 BTU/hr
SEER = 9.7
115 MBH heating input
92 MBH heating output

AHU#3: Carrier - Model No.: 48TFE007 - 7 ton, 72 000 BTU/hr
EER: 9.0
SEER = 9.0/.875 = 10.28
115 MBH heating input
92 MBH heating output

These units all contain the refrigerant R-22 which is currently being phased out of production, and have approached there ASHRAE median life. These units are scheduled to be replaced in the 2013 year.

These units provide heating and cooling through a ducted supply and return system throughout the ceiling space of the first and second floors.

AHU#1 serves the entire second floor through insulated ductwork in the ceiling space; AHU#2 and AHU#3 both serve the main level, with AHU#3 serving the external offices, and AHU#2 serving the internal offices.

These three units are scheduled to be replaced during the next construction project. They will be upgraded to 4 newer units with associated ducting for better zone control. This new design also incorporates variable air volume boxes to aid occupant comfort by allowing more control over the amount of air that is allowed in the space. This is also coupled with the existing electric baseboard heat so that there is no overlap between heating and cooling modes.

3.2. PLUMBING

3.2.1 - Metering Addition

No plumbing fixtures are found in the metering addition.

A 3/4" compressed air line is located in the space for occupant use.

3.2.2 - Stores and Vehicle Storage

The building's main incoming water service and meter is located in the vehicle storage area. The lines appear to be in fair to good condition. These lines are currently uninsulated and could be condensing during the summer months. The piping age was unable to be determined on site; however it is estimated to be the age of the building.

It was noted that the water main and all associated cold and hot water lines within the space (and building) are uninsulated.

The vehicle storage area has an eyewash station located by the fire extinguishers and is fed from a cold water line. The unit appears in fair condition.

The building's main air compressor is located in the vehicle storage. The unit in question is a DV-Systems compressor/tank combined with a 1" main line. The unit is under 10 years old and appears in good condition. The piping appears to the age of the building.

3.2.3 - Lunch room and Linemen Addition

The office, lunchroom and linemen building addition contains two washroom groups (male and female).
The men's washroom contains water closets and urinals complete with flush valves. These fixtures appear in good condition and are their consumption is 6 L/flush. The men's washroom also contains a stainless steel wash basin sink with two fixtures estimated at 0.5 USGPM controlled via push button and is in good condition. There is also a three piece shower unit in the washroom also in good condition.

All taps appear to be 2.0 to 2.2 USGPM, standard consumption for most fixtures; the stainless steel basin sink is a low flow type sink with push button operation for reduced water consumption.

The women's washroom contains one water closet complete with flush valve and appears to be 6 L/flush. One lavoratory sink with associated 2.0-2.2 USGPM faucet and one shower, all of which are in fair to good condition.

The additions hot water supply is provided by a 70 gallon electric hot water heater: Giant,

Model No.: 172E-3F7M - 4500 W.

3.2.4 - Main Office and Reception

Existing plumbing on the first and second floor is a mix between low consumption flush tanks on the main level (6 L/flush) and flush valves on the water closets on the second level. All urinals are flush valve type, and all taps appear to be the standard 2.2 USGPM.
All valved water closets and urinals are in fair condition; however some consideration should be given to a fixture upgrade during the next washroom upgrade.

One electric hot water heater is installed in the rear storage room containing emergency panel and switchgear. The main and second level office space has its hot water supplied by at 70 gallon electric hot water heater: Giant, Model No.: 172E-3F7M -CC 4500 W. This unit is 8 years old and approaching its median life. Replacement should be considered in the next 3 to 5 years.

3.3. LIFE SAFETY

3.3.1 - Metering Addition

The Building does not have a sprinkler system; the building is equipped with a fire alarm system complete with fire detectors, bells and pull stations.

Emergency lighting and exit signs are provided at each exit to the space via a combination exit sign/emergency lighting unit, Lumacell 3LER400 series.

3.3.2 - Stores and Vehicle Storage

Fire suppression in the building is primarily through pull stations, heat detectors and fire extinguishers located throughout the space

All exit signs in the Stores and Vehicle Storage space appear to be LED type located at all doors leading from the building.

Emergency lighting heads and battery packs are installed throughout the facility. Lighting level measurements were not conducted at the time of visit as well as the half hour battery back-up test to ensure they comply with Ontario Building Code. The emergency lighting appeared to be in fair condition

3.3.3 - Lunch room and Linemen Addition

The space contains several heat detectors and pull stations throughout all tied into the front end which is located by the entrance vestibule in the addition

.

The existing Fire alarm control panel is a Honeywell Notifier series Model SFP-10UD, and is located at the addition entrance vestibule. The system is a fully addressable system and is in good condition, however the age of the unit was unable to be determined. The fire detection devices consist of heat detectors and pull stations throughout. Audibility of the fire alarm system consists of bells throughout. There is some carbon monoxide detectors installed however they do not appear to be tied into the fire alarm system.

All exit signs in the Office/Lunchroom/Linemen Addition space appear to be LED type

located at all doors leading from the building.

The emergency lighting and battery packs within the area are older style. The age was undetermined but estimated at the life of the addition (<10 years) and as such are beginning to show the signs of age. No battery back up test was done on the system however based on the age of the battery pack and given that the useful life of any emergency battery pack is 10 years, it is a safe assumption that this aged product is in need of replacement.

3.4.4 - Main Office and Reception

The main source of fire suppression in the space is via several fire extinguishers located throughout the space. This is combined with heat detectors and pull stations. The age of all associated heat detectors, pull stations, and fire extinguishers varies between the main level and second level offices. A majority of the heat detectors on the main level were upgraded during the office renovation in 2011, however some consideration should be given to updating the second level to newer heat detectors.

The exit signs in the office area are varied; the main level is predominantly LED type, whereas the upper level is a mix between incandescent/fluorescent types and some LED type located at all doors leading from the building.

The emergency lighting on the main and second floor varies. Newer heads are installed on the main floor, however there are older battery packs and heads in the second floor office area.

3.4. LIGHTING

3.4.1 - Metering Addition

Lighting in the area provided by several 1'x4' T-8 fixtures, all surface mount. Fixture and lenses appear to be in good condition. The lighting system in the metering area is controlled via switch as well as occupancy sensors.

Several outdoor fixtures are installed around the perimeter of building addition, the fixtures are a mix of fluorescent (28 W) and High intensity Discharge (HID) fixtures.

3.4.2 - Stores and Vehicle Storage

Lighting in the Stores area is all surface mounted 1'x4' T-8 light fixtures, lenses and fixtures appear to be in fair to good condition.

Lighting in the Vehicle storage area are all 2'x4' T-5 high bay fixtures. All fixtures appear to be in good condition.

3.4.3 - Lunch room and Linemen Addition

Lighting in the area is surface mounted 1'x4' combined with T-8 lamps, the fixtures and lenses appear in fair to good condition.

3.4.4 - Main Office and Reception

Lighting in the area is mixed throughout each floor. The main level primarily consists of 2'x4' Lay-in T-bar style fixtures with T-8 lamps, whereas the upper floor is all surface

mounted 1'x4'. A majority of the lighting in the space is switched however in the newly renovated areas there are switch style occupancy sensors with manual override.

3.4.5 - Outdoor and Parking Lot Lighting

The lighting in the parking area is primarily pole mounted lights, which appear to be high-intensity discharge (HID) type.

The outdoor lights on the building are a mix between compact fluorescent on the newer building additions and High-Intensity Discharge type (HID) and Metal Halide (MH) for the older fixtures and pole mounted lights. These lights were unable to be verified due to access issues, so the assumption is based primarily off of older drawings and the consultants discretion.

3.5. ELECTRICAL DISTRIBUTION

3.5.1 - Metering Addition

The metering addition power is fed from a 150 A sub panel which provides power to all devices and outlets in the area.

3.5.2 - Stores and Vehicle Storage

Electrical power is supplied by North Bay Hydro via an underground feed from 3 - 25 kVA pole mounted transformers on commerce court. The electrical service is 400A 120/208 Volt, three phase and is located in the garage. There are several sub panels and disconnects of the main splitter located in the same area.

The main service entrance electrical panel is located in the garage facility and is equipped with a 400A/3P main disconnect. The panel is the age of the building and is in fair to poor condition. This panel is past its useful life (30 years) and replacement should be considered in the near future.

Secondary power is supplied throughout the building with multiple electrical sub-panels being fed from the main service panel splitter (c/w panel disconnects located in the same room) the equipment varies in age but ranges from 10-20 years of age.

Cables installed in the facility mostly consist of armoured cable (BX), wiring run in EMT conduit and some TECK cabling. The cabling appears to be in fair to good condition.

3.5.3 - Lunch room and Linemen Addition

Power is fed to this addition from a subpanel located in the garage area.

3.5.3 - Main Office and Reception

A majority of the power distribution for the office space is fed from subpanels A, B C, and several smaller panels on the second floor. These sub panels are off the main splitter and the associated disconnects are found there (vehicle storage).

There is a 50 kW/3 Phase emergency generator on site CAT Model No.: G50F3, which is tied into an emergency switchgear and panel located on the first floor storage room. The emergency generator is a gas fired unit which is installed in an enclosed area at the rear of the

building. This unit is not capable of running the entire buildings systems and power requirements, as such only a few essential systems are on emergency power.

3.6. SECURITY

3.6.1 - Metering Addition

The entrance to the building is secured via a pass code security system, and access into the stores from the metering area is via key card. The system appears in good condition.

Security cameras are located outside the building and tied into monitors in the office area.

3.6.2 - Stores and Vehicle Storage

Access to the vehicle storage is via a key card reader located at each garage door entrance, strobes are in place to notify persons outside when a vehicle is moving out of the bay

The entrance from the lunchroom and linemen addition is also a secure door requiring key card access from the garage to enter the space.

.3.6.3 - Lunch room and Linemen Addition

The Security alarm keypad is located just outside the main vestibule of this addition. Along with the security alarm panel there are security cameras located throughout the space.

3.6.4 - Main Office and Reception

Several cameras are located throughout the space, with a keypad access at the main vestibule. the main entrance from the reception area to the office space is a key card accessible lock, this door is also controlled by the reception desk.

Security system is present on the main entrances to the office space from the outdoors as well as several security cameras located on the outside of the building. The monitoring areas are located on the main and second floor at reception as well as in an internal office.

4. SUMMARY AND RECOMMENDATIONS

4.1 - MECHANICAL

4.1.1 - HVAC

A majority of the mechanical systems within the building are being upgraded under the HVAC Upgrade which is taking place during the fall of 2013. The three existing HVAC units will be replaced with 4 new units for improved zoning control and a reduced gas and electricity consumption. Also included in these upgrades is the addition of a variable volume terminal system which allows for greater occupant control and reduced consumption of resources. All existing PTAC units will be replaced with new of the same manufacturer for reduced maintenance and improved functionality.

Existing HRV's serving lunchroom and linemen addition should have filters replaced at regular intervals (bi-annually at a minimum) and the heat recovery core should be cleaned/washed annually.

The existing CO_2/NO detection should be calibrated annually and system operation verified.

4.1.2 - Plumbing

The only remaining upgrade on the existing building would be the addition of low flow fixtures, which although not a main priority for building efficiency, some consideration should be given to upgrading all fixtures in the building that are older than 15 years. This would allow for a lower overall consumption of water, and reduced maintenance cost on aging valves and faucets.

All cold and hot water piping should be properly insulated and labelled to prevent any excess corrosion due to condensation on the lines during the warmer summer months and shoulder seasons. This will also reduce heat loss on the domestic hot water lines while protecting personnel in any space that contains exposed hot water piping.

4.2 - ELECTRICAL

4.2.1 - Life Safety

The addressable fire alarm system is adequate for the space needs, however it is recommended that the older heat detector on the second floor office space be updated within the next 5 years, this should be done as a general life safety upgrade where the heat detector can be upgraded with the exit signs and emergency lighting.

Older exit signs throughout the building should be upgraded to newer LED style, these units will consume less energy as well as reduce maintenance as there is minimal to no lamp replacement needed (life expectancy of LED Exit signs is 20-25 years).

Older emergency lighting within the space should be upgraded, however the lighting level measurements were not conducted at the time of visit as well as the half hour battery back-up test to ensure they comply with Ontario Building Code. All battery packs should be tested to ensure functionality, those battery packs which no longer function properly should be replaced as soon as possible.

We recommend a full review of the exit signs and emergency lighting system to be completed to ensure that proper coverage is maintained throughout the facility and adding devices as required.

4.2.2 - Lighting

A majority of the lighting fixtures within the space use T-8 lamps (T-5 high bay fixtures in the Vehicle Storage Area), and as such an upgrade isn't recommended at this time. A general clean-up of all fixtures, lenses and covers should be done to increase the efficiency and quality of lighting.

It is recommended that all outdoor lighting including wall packs and pole mounted lights be upgraded to the newer LED type combined with a general timer and photocells for improved operation and reduced energy consumption. Further studies will have to be completed to determine zoning and number required.

4.2.3- Power

Some consideration should be given to upgrading the existing older emergency lighting and exit signs within the office area, vehicle storage and lunchroom/linemen addition as they are of the older variety and are showing signs of their age. By upgrading these fixtures to the lower consumption type, their overall life expectancy will increase and maintenance costs/responsibilities will be decreased.

It is recommended that all panels have their circuits and wiring devices (outlets, equipment, etc.) properly labeled for ease of maintenance in future projects.

It should be noted that all panels must have a 1 meter clearance around panel. Any and all obstructions such as storage materials, files, carts etc. are not to be stored within this clearance area.

We recommend that all electrical equipment receive general maintenance in accordance with NFPA 70B (Recommended Practice for Electrical Equipment Maintenance - 2006 Edition). To ensure optimal performance and functionality be maintained. We suggest a thermal scan of each electrical panel to be complete to determine if any circuits are being overloaded. Also, all existing electrical panels should be complete with type written panel schedules and be labelled to ease any maintenance or electrical upgrades in the future.

5. REPORT DISCLOSURE

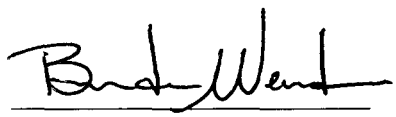
This report is intended solely for the use of North Bay Hydro. Any use which a third party makes of this report, or any reliance on or decisions to be made based on it, are the responsibility of such third parties. Decisions made or actions taken as a result of our work shall be the responsibility of the parties directly involved in the decisions or actions. Any third party user of this report specifically denies any rights to any claims, whether in contract, tort and/or any other cause of action law, against the Consultants, its officers, agents, sub-consultants and employees.

The design reflects the Consultant's best judgment in light of the information reviewed by them at the time of its preparation. Unless otherwise agreed in writing by Piotrowski Consultants Ltd., it shall not be used to express or imply warranty as to the fitness of the property for a particular purpose. This is not a certification of compliance with past or present regulations. No portion of this report may be used as a separate entity, it is written to be read in its entirety.

The work does not wholly eliminate uncertainty regarding the potential for existing or future costs, hazards or losses in connection with the property. No physical or destructive testing and no design calculations have been performed unless specifically recorded.

Conditions existing but not recorded were not apparent and/or noted given the level of study undertaken.

Only the specific information identified has been reviewed. The Consultant is not obligated to identify mistakes and insufficiencies in the information obtained from the various sources or to verify the accuracy or completeness of the information.



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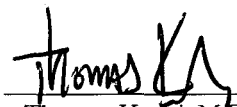

Thomas Krajci, M.E.Sc., P.Eng.

APPENDIX A

Architectural, Mechanical and Electrical BCA Breakdown

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1820 Bond St, North Bay, Ontario
705-472-2536 : pcl@onlink.net

Project No.: 5701
Date: October, 2013

North Bay Hydro - Building Condition Assessment

74 Commerce Crescent
North Bay, Ontario

Building Age - Original building - 30+ Years
Date Reviewed - September 16th 2013
Reviewed By - Piotrowski Consultants Ltd. & EBHW Architects

Priority	Condition	Quantity Identification
A - Life Safety	G - Good	LS - Lump Sum
B - Structural Integrity	F - Fair	m2 - square meters
C - Legislative Requirements	P - Poor	lf - Linear feet
D - Building Functionality		sf - square feet
E - Cost Effective Upgrades		EA - Each

	Photo Number(s)	Priority	Condition	Replacement Cost ($)/ Routine Maintenance (RM)	Approximate Age (yrs) Age Varies (Y)	Useful Life (yrs)	Estimated Remaining Life (yrs)	Cost with associate Escalations (3% per annum)	Observations	Recommendations
ARCHITECTURAL										
Parking Lot										
6.1.1 Asphalt				$60,000.00	17	25	8	$74,400.00	Driveway and Parking Lot - Repaving Program: Asphalt generally in good shape with some minor cracking, if repaired will extend the life of the asphalt for another few years.	
6.1.1 Asphalt				$10,000.00	17	25	8	$12,400.00	Driveway and Parking Lot - Repaving Program: Repair minor cracking and one larger crack to extend life of entire asphalt surface.	
Building Exterior										
6.1.2 Eaves Trough				$2,400.00	0	0	0	$2,400.00	Add eaves trough along the south addition: Eave trough required along the south addition to stop water damage at foundation wall	
6.1.3 Bottom of Brick				$10,000.00	0	0	0	$10,000.00	South Addition Foundation wall flashing: Bottom of the masonry wall on the south addition (change area) has deteriorated and requires replacement.	
Doors										
6.1.6 Exterior H.M. Doors				$2,500.00	0	0	0	$2,500.00	Hardware - Weather Stripping on all exterior doors: Repair / replace all weather stripping.	
6.1.7 Exterior H.M. Doors				$20,000.00	0	0	6	$23,600.00	Hardware - to be upgraded and replaced: Currently in good condition. Owner to review and advise on replacement program	
6.1.8 Garage Doors.				$20,000.00	30	20	-10	$14,000.00	Replace 2 shop garage doors: Replace garage doors and operators. Review installation of new high speed doors.	
Roof										
6.1.9 Closure Flutes on Steel Roof				$6,000.00	0	0	0	$6,000.00	Main pre-engineered building: Replace garage doors and operators. Review installation of new high speed doors.	
6.1.10 Roof Chevrons				$8,000.00	0	0	0	$8,000.00	Add chevrons to south addition (change area): Install chevrons to assist with holding back the ice, keeping the eave trough working.	
Building Interior										
6.1.4 Washroom Replacement				$10,000.00	25	25	5	$11,500.00	Main Floor Office Area - 2 total: 2 main floor washrooms could be upgraded in the near future.	
6.1.5 Windows				$6,000.00	34	20	-14	$3,480.00	Exterior Windows: Windows identified in report to be changed.	
6.1.11 Misc. Ceiling Tile				$6,500.00	0	0	8	$8,060.00	Misc. replacement of ceiling tile through the building: Misc. ceiling tile replacement as required through the building.	
6.1.12 Drywall Ceiling upgrades				$7,500.00	30	25	6	$8,850.00	Upgrade ceilings generally in south addition: Areas noted with existing vinyl tile should undergo a replacement program with the next 5-8 years. Tile is visibly faded and wearing. Tile may last 10 years, however cosmetic appearance is highly affected.	
6.1.13 Replace ex. Vinyl tile				$9,000.00	15	20	5	$10,350.00	Interior area in south addition and office area washrooms	
6.1.14 Insulate building steel				$7,500.00	0	0	0	$7,500.00	Insulate steel building frames which extend to the exterior: Metal building steel outriggers require insulation.	
6.1.15 Repair insulation				$5,000.00	0	0	0	$5,000.00	Walls and Ceilings in the shop area: Misc. minor insulation repairs required.	
6.1.16 Repair Masonry Crack				$750.00	1	1	1	$772.50	West wall of shop area: Crack in existing west wall of the shop area which should be repaired.	
6.1.17 General				$0.00				$0.00	General annual unforeseen maintenance cost: Discuss and review with owner to determine if this is required.	

	Quantity Description	Area or Quantity	Cost Per Unit	Description of Work/Comments and Observations
Parking Lot				
6.1.1 Asphalt	m2	1500	$40.00	Driveway and Parking Lot - Repaving Program: Asphalt generally in good shape with some minor cracking, if repaired will extend the life of the asphalt for another few years.
6.1.1 Asphalt	LS	1	$20.00	Driveway and Parking Lot - Repaving Program: Repair minor cracking and one larger crack to extend life of entire asphalt surface.
Building Exterior				
6.1.2 Eaves Trough	lf	200	$12.00	Add eaves trough along the south addition: Eave trough required along the south addition to stop water damage at foundation wall
6.1.3 Bottom of Brick	lf	200	$50.00	South Addition Foundation wall flashing: Bottom of the masonry wall on the south addition (change area) has deteriorated and requires replacement.
Doors				
6.1.6 Exterior H.M. Doors	EA	1	$2,500.00	Hardware - Weather Stripping on all exterior doors: Repair / replace all weather stripping.
6.1.7 Exterior H.M. Doors	LS	1	$20,000.00	Hardware - to be upgraded and replaced: Currently in good condition. Owner to review and advise on replacement program
6.1.8 Garage Doors.	LS	2	$10,000.00	Replace 2 shop garage doors: Replace garage doors and operators. Review installation of new high speed doors.
Roof				
6.1.9 Closure Flutes on Steel Roof	LS	1	$6,000.00	Main pre-engineered building: Replace garage doors and operators. Review installation of new high speed doors.
6.1.10 Roof Chevrons	LS	1	$8,000.00	Add chevrons to south addition (change area): Install chevrons to assist with holding back the ice, keeping the eave trough working.
Building Interior				
6.1.4 Washroom Replacement	EA	125	$2.00	Main Floor Office Area - 2 total: 2 main floor washrooms could be upgraded in the near future.
6.1.5 Windows	EA	8	$750.00	Exterior Windows: Windows identified in report to be changed.
6.1.11 Misc. Ceiling Tile	LS	1	$6,500.00	Misc. replacement of ceiling tile through the building: Misc. ceiling tile replacement as required through the building.
6.1.12 Drywall Ceiling upgrades	sf	1500	$5.00	Upgrade ceilings generally in south addition: Areas noted with existing vinyl tile should undergo a replacement program with the next 5-8 years. Tile is visibly faded and wearing. Tile may last 10 years, however cosmetic appearance is highly affected.
6.1.13 Replace ex. Vinyl tile	sf	1500	$6.00	Interior area in south addition and office area washrooms
6.1.14 Insulate building steel	LS	1	$7,500.00	Insulate steel building frames which extend to the exterior: Metal building steel outriggers require insulation.
6.1.15 Repair insulation	LS	1	$5,000.00	Walls and Ceilings in the shop area: Misc. minor insulation repairs required.
6.1.16 Repair Masonry Crack	LS	1	$750.00	West wall of shop area: Crack in existing west wall of the shop area which should be repaired.
6.1.17 General	-	1	$0.00	General annual unforeseen maintenance cost: Discuss and review with owner to determine if this is required.

North Bay Hydro - Building Condition Assessment

74 Commerce Crescent
North Bay, Ontario

Building Age - Original building - 30+ Years
Date Reviewed - September 16th 2013
Reviewed By - Piotrowski Consultants Ltd. & EBHW Architects

Priority	Condition	Quantity Identification
A - Life Safety	G - Good	LS - Lump Sum
B - Structural Integrity	F - Fair	m2 - square meters
C - Legislative Requirements	P - Poor	lf - Linear feet
D - Building Functionality		sf - square feet
E - Cost Effective Upgrades		EA - Each

	Photo Number(s)	Priority	Condition	Replacement Cost ($)/ Routine Maintenance (RM)	Approximate Age (yrs) Age Varies (Y)	Useful Life (yrs)	Estimated Remaining Life (yrs)	Cost with associate Escalations (3% per annum)	Observations	Recommendations
MECHANICAL										
Heating and Ventilation Systems										
HVAC Equipment										
Indoor HRV's	M1	D	F	RM	10	15	5	-		**It is recommended that the filters be replaced/cleaned quarterly (4 times/annum), and clean/wash the heat recovery core annually for improved efficiency and improved air quality.**
AHU#1	M2	D	P-F	*	15	15	2	-	Older unit being replaced fall of 2013	***This unit is currently being upgraded under the 2013 project "North Bay Hydro HVAC Upgrade" with Piotrowski Consultants Ltd. And KRB Mechanical Ltd.**
AHU#2	M2	D	P-F	*	15	15	2	-	Older unit being replaced fall of 2013	***This unit is currently being upgraded under the 2013 project "North Bay Hydro HVAC Upgrade" with Piotrowski Consultants Ltd. And KRB Mechanical Ltd.**
AHU#3	M2	D	P-F	*	15	15	2	-	Older unit being replaced fall of 2013	***This unit is currently being upgraded under the 2013 project "North Bay Hydro HVAC Upgrade" with Piotrowski Consultants Ltd. And KRB Mechanical Ltd.**
Exhaust Fan Garage	M3	D	F-G	RM	>10	20-25	5-10	-	Units appear in fair condition	**Routine maintenance to be provided to ensure equipment longevity.**
Metering Ventilation and Cooling System	M4	D	G	RM	4-5	15	10-15	-		
CO2/NO Detection System	M5	A	F	RM	10	15	5	-	Existing system functional	**Recommend annual testing and verification of system.**
Cooling System										
Ductless Split Air Conditioner	M2	E	F-G	RM	>5	15	5-10	-	Unit appears in good condition, routine maintenance recommended to ensure equipment longevity.	**Routine maintenance to be done to ensure equipment longevity.**
Heating System										
Gas fired Radiant Tube Heater	M6	D	F-G	$40,000.00	>15	15	5	$46,000.00	Unit is in fair condition	**It is recommended that the gas fired radiant tube heaters be upgraded in the next 5 years.**
Electric Baseboards	M7	D	P-G	RM	>15	15-20	5	-	Units condition range from poor (surface corrosion, age) to good.	**Units are being tied into new VVT system, possible baseboard upgrade in the next 3**
Water Supply										
Domestic Water Supply										
Domestic Water and Valves		D	G	RM	>15	20-30	10-15	-	Lines uninsulated	**Recommended that all domestic water lines (hot and cold) be insulated and labelled.**
Addition Domestic Hot Water Heater	M8	D	G	RM	1	10	10	-	Domestic hot water heater is in good condition, routine maintenance should be performed to ensure	
Main Floor Domestic Hot Water Heater	M9	D	G	RM	8	10	2-4	-	Domestic hot water heater is in good condition, routine maintenance should be performed to ensure equipment longevity	**Replacement of the unit should be based on functionality, given that the unit is approaching it's median life expectancy, it should be expected that this unit will require replacement in the next 2 to 4 years.**
Fire Extinguishers	M10,E7	A	G	RM	Varies	-	Varies	-		**Annual inspection for all fire extinguishers with verification/testing/tagging to be done by certified technician**
Sanitary Waste Removal										
City Sewer		D	-		Varies	25-40	-	-		
Plumbing Fixtures										
Misc Areas										
Sinks	M11,M12, M16	D	F	RM	Varies	15-20	-	-	Older sinks showing signs of age, but are still functional, no leaks observed	**To be upgraded in next washroom renovation**
Urinals	M13,M16	D	F	RM	Varies	15-19	-	-	Older flush valve type water closets in main office area showing signs of age, however still functional,	**To be upgraded in next washroom renovation**
Toilets	M14,M15	D	F	RM	Varies	15-20	-	-	Older flush valve type water closets in main office area showing signs of age, however still functional,	**To be upgraded in next washroom renovation**
Service Areas										
Service Sinks	M17	D	F	RM	15+	15-20	-	-	Service sinks all showing signs of age, still functional, suggest routine maintenance to extend service life	**To be upgraded in next area renovation.**

North Bay Hydro - Building Condition Assessment

74 Commerce Crescent
North Bay, Ontario

Building Age - Original building - 30+ Years
Date Reviewed - September 16th 2013
Reviewed By - Piotrowski Consultants Ltd. & EBHW Architects

Priority	Condition	Quantity Identification
A - Life Safety	G - Good	LS - Lump Sum
B - Structural Integrity	F - Fair	m2 - square meters
C - Legislative Requirements	P - Poor	lf - Linear feet
D - Building Functionality		sf - square feet
E - Cost Effective Upgrades		EA - Each

	Photo Number(s)	Priority	Condition	Replacement Cost ($)/ Routine Maintenance (RM)	Approximate Age (yrs) Age Varies (Y)	Useful Life (yrs)	Estimated Remaining Life (yrs)	Cost with associate Escalations (3% per annum)	Observations	Recommendations
ELECTRICAL										
Distribution										
Main Electrical Panel	E1	A,D	P-F	RM	25+	40	0-10	-	Main panel is in fair condition	**We recommend that all electrical equipment receive general maintenance in accordance with NFPA 70B (Recommended Practice for Electrical Equipment Maintenance - 2006 Edition). To ensure optimal performance and functionality be maintained. We suggest a thermal scan of each electrical panel to be complete to determine if any circuits are being overloaded. Also, all existing electrical panels should be labelled to ease any maintenance or electrical upgrades in the future.**
Secondary 120/208V Panels	E2	A,D	F-G	RM	Varies	40	0-15	-	Secondary panels located in office are in good condition, smaller sub panels in additions range from fair to excellent (metering addition) condition.	
Cables	E3	D	F	RM	Varies	40	20	-	All cables appear in fair condition, it should be noted that some cables are routed through Structural Steel Members	
Fire Protection										
Fire Alarm Control Panel	E4	A,D	F-G		>10	30	10-15	-	In Fair Condition	
Heat/Smoke Detectors	E5,E6	A,D	P-G	RM	Varies	25	0-15	-	Older heat detectors on second floor and in linemen/lunchroom addition showing signs of age, consider replacement during next renovation.	**It is recommended that the older heat detectors be upgraded to new type during next fire alarm upgrade.**
Pull Stations	E7,E8	A,D	P-G	RM	Varies	25	0-15	-	Condition varies based on the age of the pull station ranging from fair condition to good.	**To be reviewed annually with fire alarm panel to determine if replacement necessary.**
Bells	E7,E8	A,D	F-G	RM	Varies	20	0-15	-	Condition varies based on the age of the pull station ranging from fair condition to good.	**To be reviewed annually with fire alarm panel to determine if replacement necessary.**
Security Systems										
Security Door System	E9	D	F-G	RM	Unknown	20	20	-	Good condition, no upgrades recommended	
Security Cameras	E10	D	G	RM	Unknown	20	20	-	Good condition, no upgrades recommended	
Communications System										
PA System		D	F	RM	Unknown	10	-	-	P.A. System including speakers in Garage Area are in poor to fair condition, age unknown but estimated at +10 years.	
Exterior Lighting										
Building Exterior	E11,E12, E13	D	F-G	$11,000.00	Varies	20	5	$12,650.00	Pole mounted lights and older metal halide types are high consumption fixtures.	**It is recommended that all outdoor lights be upgraded to LED style to conserve energy and reduce maintenance costs, this would be coupled with photocells and a timer.**
Interior Lighting										
Metering Area		D	G	RM	4-5	20	15	-		
Stores Area		D	F-G	RM	15-20	20	5	-		
Vehicle Storage		D	G	RM	6	20	15	-		
Front Building Addition		D	F-G	RM	10-15	20	5	-		
Main Floor Office Space		D	G	RM	6	20	15	-		
Second Floor Office Space		D	F	RM	10-15	20	5	-		
Emergency Systems										
Emergency Generator	E14	A	G	$150,000.00	5+	20	15	$217,500.00	The gas fired emergency generator is located outdoors in and enclosed area, This unit is not sized for entire building load.	**It is recommended unit be replaced with larger to carry the entire building load. The existing generator should have all sides clear of any debris a minimum of 3 feet around unit for servicing.**
Emergency Lighting	E15	A	P-G	$8,000.00	Varies	11	5	$9,200.00	The emergency lighting in the building is varied based on the age of the addition/renovation. Lunchroom and Linemen addition as well as second floor office space have older style lights and	**It is recommended that all older emergency lighting battery packs tested monthly to determine which units require replacement as per CSA C282.**
Exit Lighting	E16	A	P-G	$5,000.00	Varies	10	5	$5,750.00	The exit lighting within the space is varied from newer LED type to fluorescent/incandescent types in the older additions/unrenovated space.	**It is recommended that all older non-LED type exits to be upgraded to new to reduce maintenance cost/time, as well as reduce overall consumption.**

APPENDIX B

Mechanical and Electrical Photos

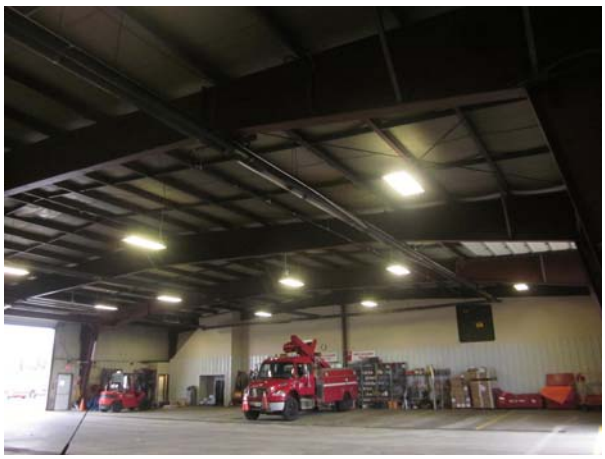
M1: Interior HRV's

M2: AHU#1, AHU#2, AHU#3,

M3: Exhaust Fan

M4: Metering Addition HVAC Unit

M5: CO_2/NO Detector



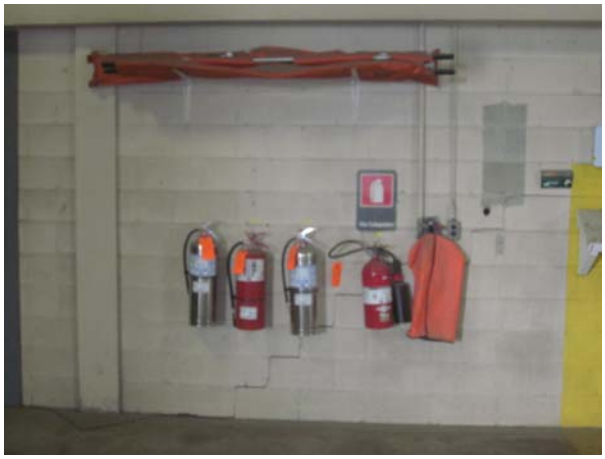
M6: Radiant Tube Heaters

Piotrowski Consultants Ltd.
1820 Bond St, North Bay, Ontario
705-472-2536 : pcl@onlink.net

M7: Electric Baseboard Auxiliary Heat

M8: Electric Hot Water Heater

M9: Electric Hot Water Heater



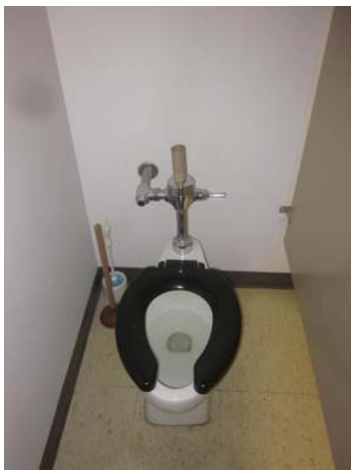
M10: Fire Extinguishers

M11: Hand Washing Station (Men's)

M12: Counter Sink

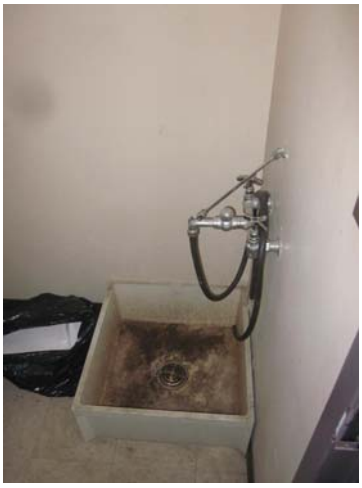
M13: Urinals c/w Flush Valve

M14: Water Closet c/w Tank



M15: Water Closet c/w Flush Valve

M16: Older Sink and Urinal c/w Flush Valve



M17: Service Sink

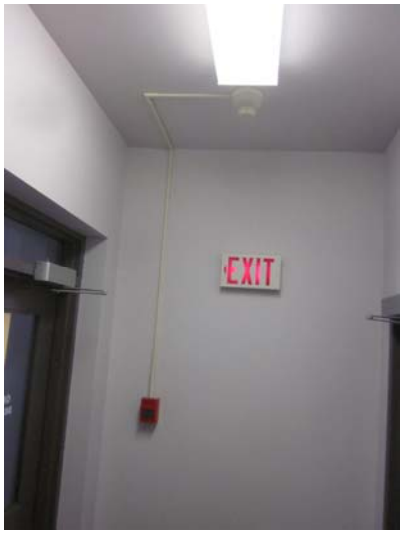
E1: Main Distribution and Panel

E2: Sub Panels and Transfer switch

E3: Cabling

E4: Fire Alarm Panel

E5: Emergency Lighting, Heat Detector



E6: Pull Station, Heat detector and Exit

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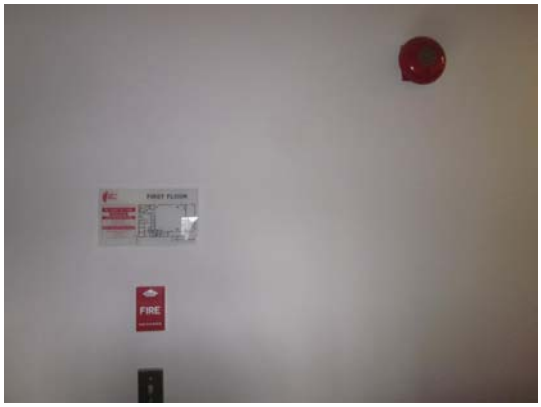
E7: Pull Station



E8: Pull Station and Bell

E9: Garage Door Access

E10: Security Camera

E11: **Pole Mounted Light**

E12: Exterior Lighting

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1820 Bond St, North Bay, Ontario
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E13: Exterior Lighting

E14: Emergency Generator

E15: Emergency Battery Pack

E16: Older Exit Sign

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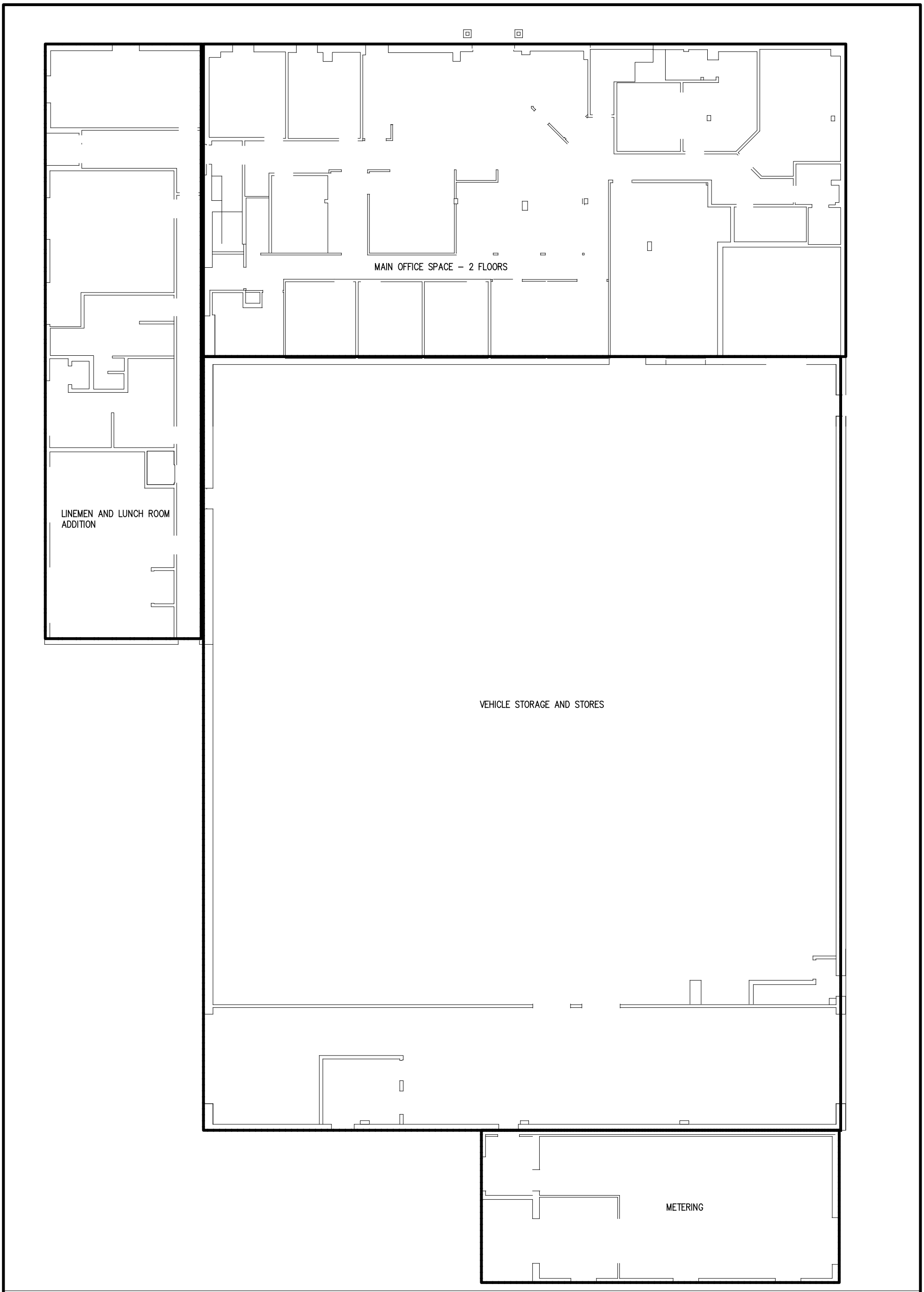
APPENDIX C

Building Layout



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BCIN # 29003

NORTH BAY HYDRO - BUILDING CONDITION ASSESSMENT
74 COMMERCE CRESCENT

NORTH BAY

BUILDING LAYOUT

drawing no.

C

project no.: 5701 **date:** **scale: NTS** **drawn by: BW**

Appendix D - Fleet Assessment Report

John Saunders Utility Services

8280 Sideroad 30
R.R. 3, Rockwood, On

Dec. 5, 2013

Background

I have been in the utility industry since 1969, spending 34 years at Guelph Hydro. My position when I retired was Line Superintendent. For the last 20 years there I was responsible for fleet, specifications and budgeting. During this time I sat on the EDA's vehicle advisory committee and became very familiar with utility fleet practices.

Since I retired in 2009, I have assisted Waterloo North Hydro, Haldimand County Hydro and Guelph Hydro with their vehicle specifications and research for fleet replacements.

Industry Practices

Most utilities have adopted the practice of replacing small vehicles between 5 and 7 years and large vehicles between 10 and 14 years. Differences in service territory, hours of use and class of equipment will dictate the differences.

For a medium size utility like yourselves, with your service territory , the fact that most line construction is done in house and after discussions with Paul Ridley, I would recommend that you adopt a 7 year replacement program for most of your small vehicles (less than 8600 lbs.). The large trucks should be on a 12 year replacement , with the exception of your RBD's and large elevator bucket that could be placed on a 15 year replacement because they are not on the same duty cycle as the smaller aerial devices.

Although you have only asked for a five year projection schedule, you cannot get a proper picture of the impacts of deferring vehicle replacement unless you project out at least 12 years. The accuracy on a 12 year projection is still limited to the first 3 to 5 years.

Depending on maintenance cost and condition of the vehicles, they can be adjusted ahead or extended on the replacement cycle if required. Another influence on vehicle replacement would be if you bought a piece of equipment that was too light for the job, or that your construction methods have changed, creating a need for a larger or heavier duty piece of equipment.

While everyone likes to make equipment last as long as possible you want to replace it before any major repairs are required, such as diesel engine, Allison transmission failures or major overhaul of aerials.

The longer you intend to keep your vehicles increases the importance of annual Krown rust proofing programs to limit body and frame corrosion issues. Vehicles on 6 year replacement do not require annual rust proofing but large vehicles on a 12 or 14 year replacement schedule is money well spent, approximately $2,400 over the life of the truck.\

So far, we have only talked about power units and have not touched on trailers or other equipment. Industry wide they are the most neglected pieces of equipment and are often overlooked, until something goes wrong or the MTO writes you up. This is why trailers, stringers and forklifts should be included in any vehicle replacement schedule and placed on a 20 year replacement schedule. Depending on their condition, they can always be extended, and this forces you to evaluate their condition when their time is up and has allocated budget dollars if required. A good example, of how fast the years go by, is you presently have two 1976 trailers in your fleet making them 38 years old.

In summarizing, I have put your vehicles with a GVW weight less than 8600 lbs. on a 7 year replacement schedule with the exception of a couple of lower usage that have been scheduled at 8 years. Large vehicles, over 8600 lb GVW have been put on either 12 or 15 year replacement and trailers on a 20 year schedule.

The accuracy of the projections depends on pricing of the various classes of vehicle being updated annually as well as new vehicle classes being added or deleted. The spreadsheet should be modified at the end of the year to drop the present year off and insert a new column at the end to maintain 12 years of projections.

John Saunders
John Saunders Utility Services

John Saunders Utility Services
8280 Sideroad 30
R.R. 3, Rockwood, On

Apr. 1, 2014

North Bay Hydro,
5 year Projected Fleet Replacement

2014 - $535,000	Replacement of a 1997 70` aerial device with an 83` double bucket aerial. The existing vehicle will be over 16 yrs. old and has had an assessment done on it by Posi Plus Ontario stating it's at the end of it`s life. A ten year old half ton pickup will be replaced as well.
2015 - $105,000	Will be the replacement of 3 pickup trucks. Two 1976 trailers have also been scheduled for replacement.
2016 - $243,000	Will be the replacement of 7 small vehicles, 4 pickups and three vans. Two of the operations pickups will be replaced as ¾ ton instead of ½ ton.
2017 - $400,000	Has one large RBD up for replacement which is a 1999 Telelect 5052 RBD which will be 18 years old, it will be replaced with a similar class of RBD.
2018 - $199,000	Replacements will be 2 - ¾ ton pickups, an electric vehicle and a forklift that will by then be 28 years old. The forklift may have to be upgraded to a heavier outdoor use unit.

These are the vehicles to be replaced in each of the years, but the new vehicle weights and types will have to be reassessed in each of the budget years.

NORTH BAY FLEET PROJECTIONS

REVISED DATE: 1/04/14

Truck Number	Reference Number	Make	Model	Year	Description	LIFE EXPT	Dept	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
4		FORD	F150	2008	4X4	8	ENGINEERING			PU1								PU1		
5		FORD	F150	2008	4X4	7	OPERATIONS		PU1							PU1				
6		FORD	E150	2009	CARGO VAN	7	SUB-STATIONS			V							V			
9		FORD	F150	2006	4X4	8	ENGINEERING		PU1								PU1			
10		FORD	F150	2006	4X4	7	OPERATIONS		PU1							PU1				
11		FORD	F250	2011	4X4	7	OPERATIONS					PU2							PU2	
12		GMC	1500	2004	4X4	7	OPERATIONS	PU1							PU1					
14		DODGE		2009	GRAND CARAVAN	7	ENGINEERING			MV							MV			
15		FORD	F150	2009	4X4 CREW CAB	7	OPERATIONS			PU2							PU2			
16		FORD	F150	2009	4X4 CREW CAB	7	OPERATIONS			PU2							PU2			
18		PONTIAC	MONTANA	2009	MINI VAN	7	OPERATIONS			PU1							PU1			
20		DODGE		2009	GRAND CARAVAN	7	METERING			V							V			
21		DODGE	2500	2011	4X4	7	OPERATIONS					PU2							PU2	
22		DODGE		2012	GRAND CARAVAN	7	ENGINEERING						PU1							PU1
23		CHEVROLET	1500	2012	4X4 EXENDED CAB	7	OPERATIONS						PU1							PU1
24		DODGE		2012	GRAND CARAVAN	7	OPERATIONS						PU1							PU1
25		CHEVROLET	VOLT	2012	ELECTRIC CAR	7	SERVICES					C							C	
26		FORD	F150	2013	4X4 EXENDED CAB	7	METERING							PU1						
30		FREIGHTLINER	FL80	1997	TELELECT 57/70 OM	15	OPERATIONS	T4												
31		FREIGHTLINER	M2 106	2009	POSI PLUS 400-46A	12	OPERATIONS									T2				
33		FREIGHTLINER	FL80	1999	TELELECT 5052 RBD	15	OPERATIONS				T3									
34		FREIGHTLINER	M2 106	2008	POSI PLUS 500-55	12	OPERATIONS							T2						
35		FREIGHTLINER	M2 106	2005	TELELECT 4045 RBD	15	OPERATIONS						T2							
38		FREIGHTLINER	M2 106	2009	POSI PLUS 400-50A	12	OPERATIONS								T2					
43		FREIGHTLINER	M2	2012	ALTEC TA-40	12	OPERATIONS												T1	
44		FREIGHTLINER	M2	2012	ALTEC TA-40	12	OPERATIONS													T1
T1		TIMBERLAND	DPT30-B	2006	STRINGER	18	OPERATIONS											ST		
T3		TIMBERLAND	DPT30-B	2008	STRINGER	18	OPERATIONS											ST		
T5		KING	30TH-108	1976	REEL TRAILER	25	OPERATIONS		TR1											
T6				1976	MATERIAL TRAILER	20	OPERATIONS		TR1											
T7		CZ ENG	CZ30KP	2011	POLE TRAILER	20	OPERATIONS													
T8		BROOKES		2011	DOUBLE REEL TRAILER	20	OPERATIONS													
T9				2011	CLOSED IN TRAILER	20	OPERATIONS													
				1990	FORKLIFT 12000 lb.	20	STORES					FL								

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
T1...40' SINGLE BUCKET ... $250,000	T1	0	0	0	0	0	0	0	0	0	0	0	1	1
T2...50' SINGLE BUCKET (MEDIUM DUTY DIGGER/DERRICK)... $330,000	T2	0	0	0	0	0	1	1	1	1	0	0	0	0
T3...68' DOUBLE BUCKET (HEAVY DUTY DIGGER/DERRICK) ... $400,000	T3	0	0	0	1	0	0	0	0	0	0	0	0	0
T4...83' DOUBLE BUCKET ... $500,000	T4	1	0	0	0	0	0	0	0	0	0	0	0	0
T5...	T5	0	0	0	0	0	0	0	0	0	0	0	0	0
PU1...PICK UPS 1/2 TON... $35,000 (includes outfitting)	PU1	1	3	2	0	0	3	1	1	2	2	1	0	3
PU2...PICK UPS 3/4 TON... $37,000 (includes outfitting)	PU2	0	0	2	0	2	0	0	0	0	2	0	2	0
V....FULL SIZE VANS ... $35,000 (includes outfitting)	V	0	0	2	0	0	0	0	0	0	2	0	0	0
MV...MINI-VANS ... $29,000	MV	0	0	1	0	0	0	0	0	0	1	0	0	0
C....Electric Car....$40,000	C	0	0	0	0	1	0	0	0	0	0	0	1	0
ST....STRINGER...$80,000	ST	0	0	0	0	0	0	0	0	0	0	2	0	0
FL....FORK LIFT...$85,000	FL	0	0	0	0	1	0	0	0	0	0	0	0	0
TR1....TRAILER ...$20,000	TR1	0	2	0	0	0	0	0	0	0	0	0	0	0
TR2 ....TRAIL $35,000	TR2	0	0	0	0	0	0	0	0	0	0	0	0	0
EST .... Estimating put $$$ in cell D91	EST	0	0	0	0	0	0	0	0	0	0	0	0	0
* Replace with existing vehicle		0	0	0	0	0	0	0	0	0	0	0	0	0
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	(thousands)	$535	$145	$243	$400	$199	$435	$365	$365	$400	$243	$195	$364	$355

Appendix E - IT Assessment Report

Information Technology Strategy: Forward to 2020

Information technology (IT) has transitioned from a purely supportive role into a key and essential component in the delivery of all services at North Bay Hydro Distribution Limited (NBHDL). IT has enabled the efficient managing of the organization's customer base, the automated of repetitive task work, and the enabling of the staff to focus on more customer centric value added activities. From the electrical distribution side IT has been integral in the modernization of the North Bay grid, and the improvement in efficiencies for our work teams. IT provides advanced SCADA, work management access to critical data, diagnostics tools, and planning support. IT also helps in inventory control, cost management, and efficiencies in stock management. All of this contributes to all staff being focused on the customer and efficient cost effective distribution of power

The driving force behind the IT Strategy is to ensure that the Information Technology (IT) team remains focused on activities that are aligned with the corporate goals and business unit initiatives. IT is not a self-serving department since it is a service provider to the organization. For the business to be successful IT must support the business goals, be versatile in enabling agility, and be vigilant in protecting the assets so that business units can remain focused on their goals and the customer. When successful IT enables the business to meet changing demands or quickly react to opportunities that arise and have an impact – either positive or negative – on the business of power distribution at NBHDL.

As evidenced in many other industries both regulated and not, the continued growth and demand for IT services will not go away and it is imperative that IT has a plan in place to meet the need and anticipate where possible the challenges that lie ahead. This strategic plan has a 36 month horizon as beyond that, it becomes it becomes increasingly less clear on where the business is going. Information technology has a lifetime of 24 to 36 months on average today's environment. In fact most technology vendors and software developers are working on an 18 month development cycle, and rarely commit beyond 24 months. This is evidenced in several major vendors re-aligning their extended warrantees to not exceed 36 months, and in some cases are refusing renewals beyond that. This and along with other business elements, IT anticipates that there will be ongoing challenges of providing services in a cost effective and efficient manner and this strategy will assist in helping guide IT and the business in meeting those challenges.

Planning is required to manage and focus IT resources, keeping them in line with the business strategy and priorities, and delivering the highest possible quality to our customers.

North Bay Hydro Distribution Limited 2014

Information Technology Strategy: Forward to 2020

IT Mission

We deliver customer-enabled IT services by being an agile responder to changing business needs through the implementation of standardized technology and project frameworks allowing North Bay Hydro Distribution Limited to serve and protect IT customers, partners, and their data while delivering those services in a timely, efficient and cost effective manner.

Aligning / Integrating Business and IT

IT will engage in various actions in order to ensure that it is providing services aligned with business strategy and priority. These actions are intended to be bi-directional – communications is dynamic and flows both to and from IT.

IT Business Engagement

IT engages all business. The management team at NBHDL will operate as a coordinating and information exchange organization to help establish strategic direction and priorities as well as to recommend key projects and actions.

Periodic Reporting / Status

IT will:

- Be invited to Leadership Team status meetings.
- Be engaged in the budget cycle at all stages.
- Be engaged in the Rate Application cycle at all stages.
- As required, be invited to board, and board sub-committee, meetings to represent IT initiatives.
- Receive copies of project management reports from the project manager.
- At Leadership Team status meetings, report at least the following KPIs:
    - Performance of service desk
    - At-risk projects

Measurement

Bi-annually, at points in time yet to be determined, IT will present to the Leadership Team:

- A mapping of IT objectives against the business' strategic plan; KPI to be what percent of the IT objectives support the business' strategic plan.
- A mapping of IT projects against the IT Tactical Plan Inventory; KPI to be what percent are traceable to the IT Tactical Plan Inventory.
- A supported assessment of delays between IT Strategic Plan updates and IT Tactical Plan Inventory updates; KPIs to be average and outlier delays; key element to be trending over time.
- A supported assessment of delays between business strategic plan updates and IT Strategic Plan updates; key element to be trending over time.

Managing the IT Project Inventory

NBHDL IT does not have a PMO (Project Management Office), but will have PMO-like reporting to help manage projects. The business will also have a suitably-sized project management methodology, including gates to progress from one stage to the next.

IT will, as aligned with the corporate project governance:

- maintain a published project matrix, showing active / inactive, RAG status (red, amber, green light status)
- maintain a requested-project matrix
- maintain the IT Strategy Tactical Plan
- Report as required to senior management when such is available

Core IT Strategy

Energy Leadership

Reliability

Predictive maintenance of field assets would further optimize reliability management for electrical supply. Currently, NBHDL aggregates data and replaces components in a preventative maintenance manner – looking at predicted lifespan of key types of equipment, results of visual inspections and an annual maintenance plan – for example thermography and pole testing. Ideally, NBHDL would be able to review the performance of each individual component, using statistical methods to predict imminent failure in advance of preventative maintenance. At the same time, if a piece of equipment was seen to be exceeding its normal lifespan, it could be considered for extended service.

IT will enable predictive maintenance through integration of existing systems, enablement of business intelligence through data sharing / reporting / warehousing, and through other initiatives, noted elsewhere in the IT Core Strategy, to become a more effective business partner. IT will also procure and maintain any diagnostic and information gathering solutions, and ensure their reliability.

Asset Management (field)

In order to provide consistent and guaranteed power, knowledge of assets in the field is a key element in developing a comprehensive maintenance and capital build program. The average life-time of electrical assets can be up to 80 years depending on the asset however, knowing the history on such assets is key to the development of an ongoing maintenance work plan. By being able to track changes to assets and to measure the life time remaining on assets will position the company to be proactive to the electrical needs of IT customers. Such a capability is based on business analytics, accurate history of field assets and an understanding of the maintenance history on the equipment.

IT will enable and enhance, through tool provisioning and training for NBHDL's Engineering and Operation departments, a comprehensive field asset management program to be and delivered in a manner that meets the needs of the company.

Performance

Performance improvement is a core value for NBHDL and a core requirement for its customers, especially industrial ones. By taking Change Management principles to heart, NBHDL departments will be better positioned to offer performance improvements to NBHDL customers in a timely, efficient and reliable manner. Through the use of change management processes, there will be improved communication between departments and an overall better understanding on how changes can or will impact customers.

IT embraces standardized change management principals through ITIL, and will offer up change

management mechanisms to other parts of the business, for example Operations and Engineering, geared to internal processes, to assist them in bringing greater visibility into the changes that are undertaken in order to assist with the tracking of issues related to the delivery and supply of power. The foundation of this offering will be a sound Service Desk / ITIL capability organic to IT.

Asset Management (office)

Real-time knowledge of assets - from desktop devices to personally-managed devices to PPE - from both the financial and physical perspective, facilitates efficiency and effectiveness in reduction of dollars tied up in inventory, rapidly locating assets required to provide services, retrieving / retaining assets during off boarding, and of course accurately representing the value of assets in financial statements.

When the business moves to integrated (information available between departments) and more-automated asset management, IT will facilitate through tool provisioning and training, and lead by more-transparently tracking its own asset inventory.

Extracting Value

Most of the time, existing systems can provide desired services - in transactional work, reporting, communications - to the business. The gap arises in knowing the full available, or achievable, capability of any given system or collection of systems. IT will facilitate a culture of inquiry, first asking the question "can we do what we want with existing systems" when net-new service, or service changes, are raised by the business. IT will do this through managing, and assisting management of, vendor / partner relationships, and through building organic capability awareness by involvement, and facilitating involvement, in various system support communities, both physical and virtual.

People

Recognizing people as a key support for business-mission delivery, IT will assist the business in supporting its people by:

- Providing tools and techniques to enhance communications, reporting, and training. IT will work with HR to determine the best fit in each of these areas, especially in training, which IT envisions being supplied through eLearning for scalability, measurability, and accessibility at any time and place.
- Providing enhanced training, either directly or through eLearning, for IT-provided office tools. IT will integrate this training into the onboarding process, and provide a mechanism for on-demand eLearning. At first, the foundational tools will have available training - over time, the business will come to expect that all of the significant tools will have matching eLearning as a matter of course.

IT's own staff have specific support needs to continually ensure that they are well-suited to IT' mission delivery. IT will support IT people with two key initiatives.

Change is the one constant in the world of technology - skills, and even attributes, that are critically valuable one year may become obsolete a few short years later as disruptive shifts in both technology, and how it is delivered, wash constantly through the industry. IT will invest in IT people through

professional development (training and courseware) suited to specific roles and anticipated roles, setting IT people up for success as the industry, NBHDL, and their own roles change and adapt.
Further, many professionals have aspirations and concerns beyond the moment and are motivated by knowing where they might be - what their value might be - within the organization over time.

Operational Efficiency

Planning Culture

NBHDL is improving its planning culture and matching capability, by bringing in governance, structure and procedures to manage programs.

IT will closely support the automation and reporting requirements through direct involvement, and assisting with development and extraction of KPIs.

Managing Documents

Currently NBHDL has an electronic document solution that was implemented in 2010 from Mindoka. This is a fully functional electronic document management solution that could be further utilized across the organization. The solution can be used to reduce paper volumes in the following areas: Finance for the storage of monthly financial reporting, standard query reporting such as job costing and to control access to key financial reports and/or analysis documentation, for vendor invoices, HR for the storage of employee records, Engineering for the storage and versioning of design documentation once complete, for the storage of documents related to contracts for services etc.

By expanding the delivery of this service, it will allow for the automated retrieval of key corporate documents in a timely manner. Through time, it will reduce the need to store additional volumes of paperwork and hence reduce storage needs. Staff will see reductions in time searching for paper documentation once all key documents are transferred into the solution since adequately indexed documentation will be retrieved quicker. Documentation retention will also be improved as the rules for documentation retention could be automated based on tax, legal and regulatory requirements.

IT, with support from Mindoka, will collaboratively assist in the delivery of this key capability to the business.

Managing Workflow

Throughout the organization, workflow within and between departments - and workflow that reaches to and from partners - will be significantly more efficient and predictable if it is standardized and automated.

IT will facilitate, through pioneering tools and techniques, and training in same, automated management of information and document creation, management, approval, and other elements of workflow.

Business Continuity Planning (BCP) and Disaster Recovery (DR)

Having an effective Business Continuity Planning process, as well as tested Disaster Recovery plans and processes is part of good corporate governance, and essential for NBHDL to deliver its core mission. Gone are the days of simply having a good backup of your data. The businesses dependence on technology to deliver daily services is very evident, and the need by our customers for reliable service has never been greater.

IT will develop its BCP and assist departments in developing their plans, and integrating it, resulting in an overall BCP for the organization. IT will also facilitate periodic testing and validation of the BCP elements, and help to close any gaps.

An effective BCP focuses on people as well as services and technology. IT will work with HR and department heads to create the people part of the BCP to ensure that NBHDL and its staff needs are covered.

Disaster Recovery involves people, plan, process, and testing to be effective. IT will establish appropriate redundancy, alternate location services, off-site storage, hot-live fail-over, and backup to support quick and efficient DR. This will involve analysis of existing assets, co-locating with partners, sharing of common platforms with other LDCs BCP/DR for cost reduction and support simplification, and eventually inclusion into larger (district) plans.

Business Intelligence

Information in multiple silos is difficult to share, likely to be inconsistent, and results in replication of effort and resources.

IT will work with the business to:

- Consolidate systems, resulting in less overlap and replication.
- Determine information owners, and link systems to ensure consistent information across systems.
- Develop business-wide reporting and analysis capability, commonly called Business Intelligence, to unlock broad trends and help transform information into knowledge.
- Do a sweeping review of current reporting capabilities, leading to more-useful, self-managed reports to assist departments in financial and other forms of management.

Communication

Internally, strong communications promotes unified corporate culture, a sense of corporate citizenship, mission alignment, and, put simply, reduction in confusion. Externally, strong communications promotes responsible crisis communication, professional and effective relations with customers, stakeholders, and partners. IT enables both process and underlying tools in these areas:

- Reporting, internally and externally.

- Meeting facilitation, creating more-effective meeting spaces, both virtual and physical.
- eServices for customers, reducing delinquency and foot traffic into NBHDL's lobby.
- Outage management for customers, helping customers plan their response to outages while freeing staff to more-quickly restore service.
- Internal messaging (deploying content by push and pull through multiple means) for all departments, especially Human Resources and Customer Service.
- External messaging (also deploying content by push and pull through multiple means), largely for Customer Service.

Shared Services

Many services benefit from economies of scale - sharing the costs of a given service among other LDCs reduces the cost of service delivery and positions NBHDL in a leadership role, while accommodating government requests to identify opportunities for cost savings.

IT will periodically examine its service portfolio, and, where appropriate, reach out to other LDCs with the objective of offering, or taking advantage of, a shared service. Each time IT creates a net-new service, a key question will be "is this service suited to sharing?"

This approach, where other LDCs are its customers, will drive professionalism, predictability, partnering capability and transparency - because other LDCs are readily able to choose alternate service providers. IT will be incented to be the best partner, which produces behaviours directly beneficial to NBHDL.

Enterprise Solutions

Enterprise systems impact many or most elements of the NBHDL community, whether staff, partner or customer. Vital to the operations of NBHDL, Enterprise solutions support business processes, provide tools for analysis and decision-making, enable collaboration with colleagues, promote data security, and address compliance and regulatory requirements. In collaboration with colleagues across NBHDL, IT will continue enhancing the effectiveness of these systems through improving their functionality (directly or through vendor change quests), usability, availability, and integrity. By increasing the integration of enterprise systems, this will allow easy self-service access to information anytime and anywhere across a variety of devices and platforms.

Key Enterprise Solutions are listed in the Appendix.

Portable Workplace

Working in an integrated manner wherever staff need to be in the course of their duties improves efficiency by reducing movement, improves decision-making by bringing needed information to hand, and facilitates DR and enables BCP by making work less-tied to a specific location.

IT will develop capabilities to provide service as staff move about, wherever this is both feasible and cost-effective. The guiding principle is to provide a usable workspace, without IT intervention, at whatever location is in use (either in office or field work).

This may take the form of laptops, tablets, Roaming Profiles, Virtualization, web delivery, and other technology enablers.

IT Engagement

When IT is involved in change – net-new or adjustment of an existing service / process – the entire organization benefits from IT's expertise in IT-related contract management, change management, and finally service delivery.

IT will be actively involved in net-new and change from inception of an idea to decommissioning of a given service or process. As the organization develops increasingly-mature project management practices, IT will ensure that it is present in each stage of the organization's formal governance system.

IT Service Orientation

IT recognizes that it is a service organization, existing for the purpose of facilitating the business while ensuring compliance with corporate standards designed to manage risk, enable financial stewardship, and generally enable mission delivery.

To this end, IT will develop additional transparency in operations and accept additional guidance from the business in prioritization.

Transparency will increase through public posting of all policy and procedure, communications driven through improved change management, and visibility of service request progress.

Additional guidance will come through periodic management team meetings.

Managing IT Expenditures

Managing one's own departmental budget suggests managing one's own departmental IT-related purchases – provided that departments comply with governance and oversight mechanisms by acquiring standardized IT assets.

IT will develop transparent, published IT asset standards to enable self-purchasing, in conjunction with self-management budgets.

Partnering

Recognizing that IT cannot do everything – and need not, as long as services are delivered as NBHDL requires – IT will seek partners while shifting from a "how can we do it" approach to a "who can do it" approach to meeting the NBHDL's IT-enabled goals.

Simply outsourcing is not a panacea, so IT will produce a thoughtful partner management strategy, policy, and operating procedures to maximize the success in the two-way interaction that is partnering. Continuous, structured interaction, extending the NBHDL enterprise partly into a partner's enterprise and vice-versa, converts vendors to partners and, in binding partner success to NBHDL success, enhances the flow of new ideas and capabilities into IT to better support NBHDL's mission.

IT Operational Efficiency and Risk Management

Cloud Services

The inexorable maturation of "cloud" service offerings creates an opportunity for IT to control future costs and investments, allow for growth and flexibility in IT infrastructure, and facilitate DR and enable BCP. IT, and NBHDL, will also reap the rewards of shared investment as noted below.

Further, many infrastructure-management and deployment skills are rarely used and simply not cost-effective (or even possible) to acquire or maintain within IT – examples include deep knowledge around information security management, complex network configuration and troubleshooting, and net-new knowledge when disruptive technology shifts impact NBHDL.

Using external cloud services leverages the knowledge and skills investments that cloud providers amortize over their many clients, resulting in IT requiring less net-new headcount for any given expansion and less overall cost for same. Cloud providers depend absolutely on perceptions of security, so we expect to benefit from their necessarily-aggressive information security management practices.

When IT is considering a new initiative, a key question will be "why not use a cloud service" – this will drive a shift within IT from direct service provision to managing partner relationships, which may in turn drive a refresh in IT organization and staff skills and training.

Service Delivery

ITIL

The act of service delivery, industry-wide, has matured into well-understood and widely-practiced frameworks, promising and providing predictable management of known services.

IT will bring in appropriate elements of ITIL, the most widely adopted approach for IT Service Management, which provides a practical, no-nonsense framework for identifying, planning, delivering and supporting IT services to the business.
When IT has established a stable Service Desk (SD) and Configuration Management Database (CMDB), it will offer the capability – in terms of both technology and practice – to other service-oriented parts of the business.

Self Help

The fastest resolution to a service interruption is the one done by the immediate consumer of the service. IT will identify areas of opportunity for self-help, and develop, deploy and measure training and information programs to enable self-resolution of common service issues. Identification will rely on sound metrics organized by a stable Service Desk.

Core Focus

As part of focusing on core capability, IT will continually review IT suite of responsibilities and determine

if, in coordination with the business, non-core services would be better managed by another part of the organization or through a third party.

Currency

Current technology – recent version of software, hardware, and partner-provided services – is the foundation on which to build flexible, reliable, desired services. When technology falls too far behind, net-new capability may be difficult or impossible to use; reliability and maintainability suffers as vendor and other knowledge pools move on – in some cases support for services is simply discontinued; and visibly-outdated technology creates barriers to work efficiency as staff, incoming and current, experience a significant disconnect between their daily interaction with technology and their NBHDL-provided technology.

IT will, as core policy and practice, maintain current versions of the services and underpinning technology that supports the business, making exceptions where warranted by specific circumstances. At the same time, being on the "bleeding edge" – moving too-quickly to immature services and underpinning technology – will be reserved for situations where the risks are matched by identified benefits.

Part of remaining current is awareness of disruptive technology shifts – IT will continually, through engagement with media, conferences, analyst sources, and peer support networks, scan industry trends to see the next wave as it advances.

Information Security

Organizations enact Information Security programs to achieve two key results: genuine change in staff and partner behaviour resulting in reduced risk and actualization of risk, and deflection of liability from the organization and its officers to where it belongs: with persons who wilfully or negligently violate well-communicated norms of behaviour.

A fully-active Information Security program will protect the confidentiality, integrity, and availability of NBHDL's valuable information assets, while informing management of the ongoing information risk profile to make for better-informed policy and resource-allocation decisions.

IT will, in several phases, deploy and act on an Information Security program.

Standards

Standards are the foundation of predictability and measurement – leading to improved performance and transparency in service delivery.

IT will cooperatively create and publish a Service Catalogue (as part of implementing ITIL) of standard services it offers to NBHDL, starting with those deemed most in need and extending eventually to all of the offered services. Over time, the business will come to expect consistent, measured service

information as a norm of interacting with IT. As part of this, IT will eventually offer only 'best-effort' support for non-published services.

Self-Management

The quickest way for business units to respond to change is to self-manage – this puts workflow accountability and priority with the unit / person most affected and most accountable.

IT will enable self-management of common operational needs (such as access control and information sharing), and will cooperatively create the governance mechanisms to ensure that self-management remains visibly-aligned with corporate policies and norms of behaviour. IT will also ensure that adequate training for self-management is delivered to staff.

Proactive Infrastructure Management

IT is implementing round-the-clock alarms for out-of-pattern usage of the infrastructure – both internally- and externally-provided – so it be aware of service disruptions before the business is impacted, or at least be actively remediating disruptions before the business has reported an issue. This will also facilitate seeing more-accurately forward to future usage needs and more-closely match existing capacity to need (mitigating over-capacity), and will help build net-new capacity before the business is constrained by capacity.

IT will consider and then implement two operating centers – Network and Security – either internally or through service partners, to more-clearly and quickly become aware of at-risk infrastructure conditions. Where applications are not currently compatible with NOCs and SOCs, IT will facilitate instrumentation to integrate those applications into the monitoring framework.

IT will use the data gathered by these operating centres to enable periodic capacity planning, either for daily operations growth / change or net-new capability as the organization potentially enters new lines of business or operations.

Appendices

IT Organization

NBHDL has an Information Technology Services department on site with a current staff complement of two including the IT and Billing Manager. IT support is also augmented with support from the City of North Bay IT, and various contractors as needed.

NBHDL will be re-aligning the Billing and Customer Accounts staff to enhance customer service, provide greater redundancy (as flagged in the IT Risk Assessment Audit and the Meter to Cash Audit). One FTE with be shifted from Billing to IT centric functions.

The changing staff deployment is required due to the increased focus on IT and the need to ensure that the software applications, infrastructure, security and recoverability of the NBHDL information technology environment can be accomplished with acceptable disruption to business operations. Additionally, successful delivery of the IT Strategy as tied to the Corporate Strategy will require additional functionality in order to deliver planned work as well as normal maintenance activities – software upgrades, asset turnover and ongoing support activities to ensure that the IT environment operations in an efficient and effective manner. It will also result in a more responsive and resilient front office and billing function.

The strategic positioning of the IT department through the noted staffing changes will enable the department to transform into a more business-responsive team, positioned to deliver on the corporate needs as documented in this IT Strategic plan. The key goals of delivering more automation, enabling improved and net-new business workflows, consolidating enterprise systems through integration efforts and the standardization of IT services will enable the transformation of IT at NBHDL from a tolerated cost centre to a business enabler. These goals will be significantly impacted without the staffing re-alignment that can provide sufficient resources to meet the continuing challenges and need for automation that are detailed in this plan.

Industry best practices, suggest that the compliment of IT staff in the Utility sector is 6.6% of the total organizational headcount. This suggests a NBHDL IT staff compliment of approximately 3 FTE positioning NBHDL to be within industry norms and also strongly enabling delivery of improvements to operational and capital work efforts at NBHDL as outlined in the Corporate and IT Strategic plans.

The core value provided by this shift is to significantly reduce expenses from Third Party solution providers, who would otherwise provide and invoice for their services. So, this shift will assist in reducing third party costs with respect to the development of business requirements, IT functional requirements, test planning, test case development and testing support. The IT environment evolves continuously as software updates and upgrades are delivered by vendor partners – this suggests that that additional IT support will provide continuous value through testing and validating these ongoing changes, as well as continuous response to the business' directional changes and net-new deployment.

Enterprise Solutions

Core System	Business Owner	Vendor	Support	Future Direction	Notes
ERP - HR	HR	SunGard	Contract support SunGard PS	NBHDL will continue to use SunGard for the foreseeable future. It currently is the only fully integrated solution, and other vendors are only beginning to approach this level of integration. We have built custom web apps for locates, dis/re-connects, and are integrating customer web forms. We also have a fully integrated web portal that is very fast, robust, and extensible (we quickly were able to adopt the green button).	The product was flagged as a potential risk in our BDO IT audit due to the low penetration in the Ontario market (5 LDCs), but SunGard is currently working on several possible conversions. The 5 LDCs have a strong mutual assistance history, with many collaboration efforts, and are that driving anchor for the Canadian SunGard users group.
ERP - Finance	Finance	SunGard/Cognos	Contract support SunGard PS & IBM		
ERP - Time Reporting	Finance	SunGard/Executime	Contract support SunGard PS & Executime		
ERP - Inventory/Purchasing	Finance/Operations	SunGard	Contract support SunGard PS		
ERP - CIS	Billing / Customer Service	SunGard	Contract support SunGard PS		
ERP - Work orders	Operations/Customer Service	SunGard	Contract support SunGard PS		

Integrated ERP Solution on IBM AS-400

AutoCAD	Engineering	Autodesk	Autodesk & Web	AutoCAD is still the main drafting/design tool world wide, and is the defacto standard. We have added Spidacalc to assist in pole design	Nothing significant was identified in risk audit, but licensing costs continue to be high.
Locates	Operations	Mindoka	Mindoka	We will continue to adapt this custom app to provincial needs, and expectations of the customer	This app is designed to work with SunGard, and we own the open source based source code.
Disconnects/Reconnects	Customer Service	Mindoka	Mindoka	We will continue to adapt this custom app accommodate change, and expectations of the customer and business.	This app is designed to work with SunGard, and we own the open source based source code.
Customer Web Site	IT	Mindoka/WordPress	Mindoka & Clark Communications	We have recently migrated to an industry supported content management system which opens up vast	The open source nature, and large development community will ensure that this platform is versatile, and adaptable.

				possibilities for remaining current, and deploying new functionality to the customer.	
Customer Web Portal	IT	Mindoka	Mindoka	We will continue to adapt this custom app accommodate change, and expectations of the customer and business.	This app is designed to work with SunGard, and we own the open source based source code.
E-billing	Billing/IT	Mindoka	Mindoka	We will continue to adapt this custom app accommodate change, and expectations of the customer and business.	This app is designed to work with SunGard, and we own the open source based source code.
Bill Generation/Print	Billing/IT	Mindoka	Mindoka	We will continue to adapt this custom app accommodate change, and expectations of the customer and business.	This app is designed to work with SunGard, and we own the open source based source code.

SCADA	Engineering	Survalent	Survalent & Costello Assoc.	Survalent is the SCADA solution of choice as this industry changes and develops. It is capable of growth, and has the ability to integrate future enhancements easily.	A Canadian product, Survalent is now installed world wide, and is on the leading edge for utilities SCADA, and security.
GIS	Engineering	ESRI	ESRI	ESRI continues to be one on the major solutions, and it will interface well with ACAD, and Survalent	
AS2	Billing	Cleo	Cleo & Savage Data	This is the main transfer agent for billing requests to the MDM/R.	This will continue to be used as long as we are using an MDM/R or variant.
Document Management	IT	Mindoka	Mindoka	Mindoka has created a fully extensible DMS, with integration of scan, PDF, and various document formats. It is DMS choice for Ricoh Inc. customers	Mindoka has also created extensions to allow the DMS to communicate with our SunGard ERP.

Configuration Management DB (CMDB)	IT	Spiceworks	Spiceworks & Spiceworks Community	Spiceworks is the standards based solution for 3000+ companies world wide. It is directly supported by over 2000 vendors such as IBM, Cisco, Dell, Microsoft, Oracle etc. It continues to develop and has the ability to be customized via customer plugins.	This solution is versatile and low cost in comparison to vendor specific products like Tivoli which do not provide CMDB or Help Desk/Service Desk functionality.
Help Desk Ticketing	IT	Spiceworks	Spiceworks & Spiceworks Community		
AMI	Billing/Metering	Sensus	Sensus & Util-Assist	NBHDL has one of the highest performing Sensus deployments in the province, and will continue to leverage this AMI to the benefit of our customers and business.	As technology progresses continued investment in the AMI solution will be needed to keep pace.
ODS	Billing	Savage Data	Savage Data & Util-assist	Savage has over 1/2 of the LDC market as customers, and is local to North	ODS continues to evolve along side the MDM/R, and provide services complimentary to utility billing, and business functions.

				Bay, so support is exemplary.	
Commercial Billing - MV90	Metering/Billing	Itron	Itron	MV90 is still the industry choice for commercial customer reads. We anticipate a gradual phase out as we move these customers to our AMI solution	
Network Security & Filtering	IT	Cisco & Trend Micro	Cisco & Bell Aliant	Cisco and it's partnership with TrendMicro for security results in a standards based and dynamic security solution well supported, and scalable.	Cisco is known world wide and the provider of choice. Bell Aliant provides Cisco certified support with the most current technology experience.
Phone System - Lines, Call Accounting, Call Record	IT	Mitel, Prairie Fyre, & Oxilio	Bell Aliant, Prairie Fyre, & Oxilio	This is a solid well supported system with capability to grow, and interface with diverse communications platforms.	Mitel systems are one the most deployed systems in Ontario, and is well supported by Bell Aliant
File/Print	IT	Dell/Microsoft	Dell & Microsoft	Two industry leaders with well-known and supported platforms.	

Email	IT	Microsoft	Microsoft	An industry standard, Exchange continues to grow and adapt o industry needs. It is also well supported in cloud deployment and BC/DR deployments.	

Appendix F – Green Energy Plan and Transmittal Letter

Appendix F – Green Energy Plan and Transmittal Letter

NORTH BAY HYDRO

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Engineering / Purchasing
Customer Services / Accounting
Operations

June 02, 2014

Regulatory Affairs,

Ontario Power Authority

120 Adelaide Street West, Suite 1600,

Toronto, Ontario, M5H 1T1

RE: Green Energy Plan – Investments to Accommodate Renewable Energy Generation Connections – Request for Ontario Power Authority Comment Letter

Dear Sir/Madame:

North Bay Hydro Distribution Limited ("NBHDL") is currently preparing its 2015 Cost of Service Rate Application as set out in the report of the Board: Renewed Regulatory Framework for Electricity (RRFE). As per Chapter 5 – Consolidated Distribution System Plan Filing Requirements, NBHDL is hereby requesting that OPA provide NBHDL with a "Letter of Comment" in regards to NBHDL's attached Green Energy Plan, identifying the Renewable Energy Generation investments.

NBHDL would appreciate receiving the OPA's Letter of Comment at the earliest to allow NBHDL to incorporate OPA's comments into its Distribution System Plan.

Should you require any additional information or clarifications, please feel free to contact me.

Yours Truly:

Matt Payne, P. Eng.

Manager, Engineering

North Bay Hydro Distribution Limited

Green Energy Plan

Filed with

NB Hydro’s 2015 Costs of Service Application

Renewable Energy Generation Investments Plan

Filed with

NB Hydro's 2015 COS Application

Executive Summary

This Renewable Energy Generation Investments Plan, identifying investment requirements for accommodating Renewable Energy Generation connections provides information to OEB and interested stakeholders, regarding the readiness of NBHDL's distribution system to connect renewable energy generation, including investment requirements for any expansion or reinforcement necessary to remove grid constraints to accommodate the connections of renewable energy generation over the period of 2015-2019.

There are approximately 2.14 MW of renewable energy installations connected to NBHDL's distribution system, under FIT and micro-Fit programs. There are seventeen (17) micro-FIT installations that are currently registered with OPA, but have not yet proceeded to the development stage. There are currently no applications in queue, under the FIT program waiting for connections.

Based on the evaluation of the distribution system to accept green energy generation connections, no constraints have been identified in the system, preventing the connection of renewable energy generation installations.

Therefore, NBHDL is not proposing any capital investments to mitigate constraints on the distribution system to accommodate the applications for the connection of renewable energy generation plant, over the next five years from 2015 to 2019. NBHDLs' smart grid development initiative requires all municipal distribution stations to be equipped with supervisory control and automated data acquisition (SCADA) system by 2015, to provide improved control and monitoring of all distribution feeders. All distribution stations have been previously equipped with bidirectional protection relays to allow seamless connection of green energy projects. The only station still requiring SCADA is MS9. Approximately $16,000 of capital investments are proposed for installation of the SCADA systems at MS-9, in 2015. Funds have also been budgeted to connect one or two FIT projects per year to the distribution grid.

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1 Introduction 4
2 North Bay Hydro's Distribution Grid 5
3 Existing and Proposed Distributed Generating Connections 8
4 System Assessment to Identify Constraints 10
5 Distribution Automation and Smart Grid Development 12
6 Proposed Investments to Facilitate Renewable Energy Generation Connections 13

1 Introduction

North Bay Hydro Distribution Limited ("NBHDL") is preparing the Cost of Service Rate Application as set out in the report of the Board: Renewed Regulatory Framework for Electricity (RRFE), for rates to be in effect January 01, 2015. 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 (EB-2010-377), NBHDL has prepared this Renewable Energy Generation Investments Plan, identifying the investment requirements for accommodating Renewable Energy Generation connections for its service territory for the five year period 2015-2019.

This Renewable Energy Generation Investments Plan, identifying investment requirements for accommodating Renewable Energy Generation connections provides information to OEB and interested stakeholders, regarding the readiness of NBHDL's distribution system to connect renewable energy generation, including any expansion or reinforcement necessary to remove grid constraints to accommodate the connections of renewable energy generation over the period of 2015-2019.

2 North Bay Hydro's Distribution Grid

NBHDL is the local distribution company, responsible for electricity distribution in the City of North Bay. NBHDL's distribution network serves a population of approximately 54,000 and approximately 23,740 customers. The service area served by NBHDL covers approximately 312.28 square kilometers, of which 270 square kilometers is rural.

NBHDL receives power from Hydro One at the following Hydro-One-owned Transformer Stations:

- 115/44 kV North Bay TS; and
- 115/44 kV Trout Lake TS.

There are 8 sub-transmission feeders operating at 44 kV that supply a total of 16 Municipal Distribution Stations (MS), where power is stepped down to 4.16kV or 12.47kV. Figure 2-1 indicates the MS locations within the NBHDL service territory and as shown, these MS locations provide good coverage within the entire service territory for renewable energy generation plant connections.

The single line diagrams for the municipal distribution stations are summarized in Appendix A. Figure 2-2 shows the rated capacities of the municipal distribution stations and the peak load served from each MS during the past five years.

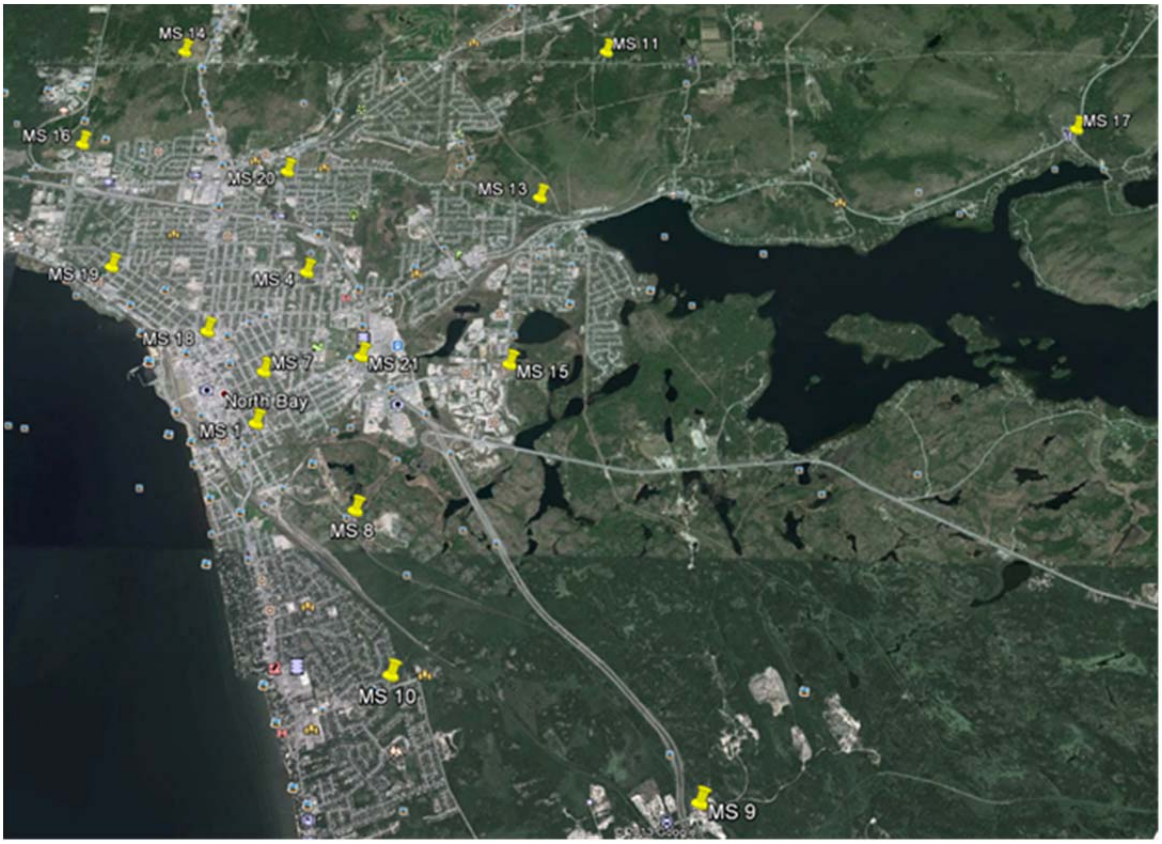

Figure 2-1: NBHDL Distribution Station Locations

12.47 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS4	7.5	10	7.19
MS8	7.5	10	5.9
MS9	T1 - 7.5, T2-7.5	No fans	T1 - 5.00, T2 -4.00
MS10	T1-7.5, T2 - 7.5	T1-10, T2-10	T1-5.94, T2-6.54
MS11	7.5	10	7.21
MS13	T1-6, T2-7.5	T1-No fans, T2-10	T1-6.32, T2-6.46
MS14	7.5	10	5.93
MS15	7.5	10	6.55
MS16	7.5	No fan rating	5.42
MS17	7.5	10	5.36
MS19	7.5	10	7.21
MS20	7.5	10	8.5
MS21	7.5	10	**

4.16 kV Supply Distribution Stations

Distribution Station	MVA rating		Peak Load During Last Five Years
	ONAN	ONAF	
MS1	5	No fans	3.93
MS7	5	6	5.24
*MS18	T1 - 7.5, T2-7.5	T1-10, T2-10	T1-5.24, T2-6.34

* MS18 is a dual voltage station on the LV side, however at this time it is operating at 4.16kV

** just put into operation, peak load not known at this time

Figure 2-2: Municipal Distribution Station Capacities and Loads

3 Existing and Proposed Distributed Generating Connections

There are a total of 34 renewable energy generation installations presently connected to NBHDL's distribution system under the province's Feed-in-Tariff (FIT) and micro FIT programs, as summarized below and detailed in Tables 3-1 and 3-2, respectively.

- Three (3) FIT installations with generating capacity of 1.88 MW, as listed in Table 3-1.
- Thirty One (31) micro-FIT installations with 259.84 kW installed capacity, as shown in Table 3-2.

In addition to the above, there are seventeen (17) micro-FIT installations that are currently registered with OPA, but have not yet proceeded to the development stage. There are currently no applications in queue, under the FIT program waiting for connections.

S. No.	Fuel Source	kW Rating
1	Solar Power	30
2	Landfill Site	1600
3	Solar Power	250

Table 3-1: FIT Generation Facilities

Micro-FIT Reference #	Meter Install Date	Rating (kW)
M398BVN	18/01/2010	10.00
M3ERPKX	28/10/2010	2.70
MHT2DVF	13/05/2010	8.00
MRTCG3X	25/06/2010	10.00
MXTD9JV	13/08/2010	10.00
MP422N8	03/12/2010	4.14
MB8I8C2	18/11/2010	10.00
MBEZI3Q	10/02/2011	4.14
MU6YEEB	13/06/2011	8.46
MJT2MR2	09/09/2011	10.00
M31YDMU	09/01/2012	10.00
M9M6FT9	20/03/2012	2.60
M2EB668	28/02/2012	10.00
M3NMX47	12/01/2012	10.00
MJDDAKJ	13/12/2011	10.00
MQF4F2F	04/07/2012	10.00
MPZMKKT	20/03/2012	10.00
MYU6YJC	27/02/2013	10.00
MQCN8YN	27/04/2012	10.00
MJIWG4D	30/10/2012	10.00
MM39FQM	05/07/2012	10.00
MB8JUWN	23/01/2013	10.00
MXTPJQI	27/11/2012	8.30
M2ZPA6G	29/05/2013	10.00
MKD2AV8	01/11/2013	5.00
M3MKIDY	12/06/2013	10.00
MBMFAQN	13/09/2013	10.00
MDTPJ2C	11/12/2013	5.50
M84JXDZ	28/06/2013	10.00
MJ8V8CI	20/09/2013	5.00
MXA97NF	25/10/2013	6.00
Total		259.84

Table 3-2: MicroFIT Generation Facilities

4 System Assessment to Identify Constraints

Under conservative assumptions of the maximum permissible generation capacity at a distribution station being equal to 60% of the power transformer nameplate rating plus the minimum station load (equal to 15% of station rating) and 90% power factor, the approximate available capacities for connecting renewable energy generation to various municipal stations is indicated in Tables 4-1 and 4-2.

The 12.47 kV and 44 kV feeders employ 336 kcmil and 556 kcmil conductors, respectively, on the main trunk line and these conductors have sufficient thermal rating to permit the connection of the largest Green Energy Generation plant up to 10 MW, allowed under OPA's FIT contracts.

As shown, based on the applications currently in hand or anticipated to be received during the next five years, no system constraints exist, preventing the connection of green energy generation developments, within NBHDL's service territory. Therefore, no capital investments are needed for capacity upgrades to facilitate the connection of renewable energy generation plant. However, funds have been budgeted to connect one or two FIT projects per year to the distribution grid.

Distribution Station	MVA rating		Approximate Available Capacity (MW) for Generation Connections	System Constraints for Connection of Generation
	ONAN	ONAF		
MS4	7.5	10	6.75	No Constraints
MS8	7.5	10	6.75	No Constraints
MS9	T1 - 7.5, T2-7.5	No fans	10.13	No Constraints
MS10	T1-7.5, T2 - 7.5	T1-10, T2-10	10.13	No Constraints
MS11	7.5	10	6.75	No Constraints
MS13	T1-6, T2-7.5	T1-No fans, T2-10	9.11	No Constraints
MS14	7.5	10	6.75	No Constraints
MS15	7.5	10	6.75	No Constraints
MS16	7.5	No fan rating	5.06	No Constraints
MS17	7.5	10	6.75	No Constraints
MS19	7.5	10	6.75	No Constraints
MS20	7.5	10	6.75	No Constraints
MS21	7.5	10	6.75	No Constraints

Table 4-1: 12.47 kV Stations Distributed Generation Connection Capacity

Distribution Station	MVA rating		Approximate Available Capacity (MW) for Generation Connections	System Constraints for Connection of Generation
	ONAN	ONAF		
MS1	5	No fans	3.38	No Constraints
MS7	5	6	4.05	No Constraints
MS18	T1 - 7.5, T2-7.5	T1-10, T2-10	13.50	No Constraints

Table 4-2: 4.16 kV Stations Distributed Generation Connection Capacity

5 Distribution Automation and Smart Grid Development

NBHDLs' current distribution automation and smart grid development initiative requires all municipal distribution stations to be equipped with supervisory control and automated data acquisition (SCADA) system by 2015. Aside from reliability improvements, SCADA controlled stations provide improved control and monitoring of distribution feeders to which green energy generation plant is connected.

NBHDLs' smart grid development initiative requires all municipal distribution stations to be equipped with supervisory control and automated data acquisition (SCADA) system by 2015, to provide improved control and monitoring of all distribution feeders. All distribution stations have been previously equipped with bidirectional protection relays to allow seamless connection of green energy projects. The only station still requiring SCADA is MS9. Approximately $16,000 of capital investments are proposed for installation of the SCADA systems at MS-9, in 2015.

6 Proposed Investments to Facilitate Renewable Energy Generation Connections

Based on the evaluation of the distribution system to accept green energy generation connections, no constraints have been identified in the system, preventing the connection of renewable energy generation installations. Therefore, NBHDL is not proposing any capital investments for capacity upgrades on the distribution system to accommodate the applications for the connection of renewable energy generation plant, over the next five years from 2015 to 2019. Approximately $16,000 of capital investments are proposed for installation of the SCADA systems at MS-9, in 2015. Funds have also been budgeted to connect one or two FIT projects per year to the distribution grid.

Appendix A

Station Single-Line Diagrams

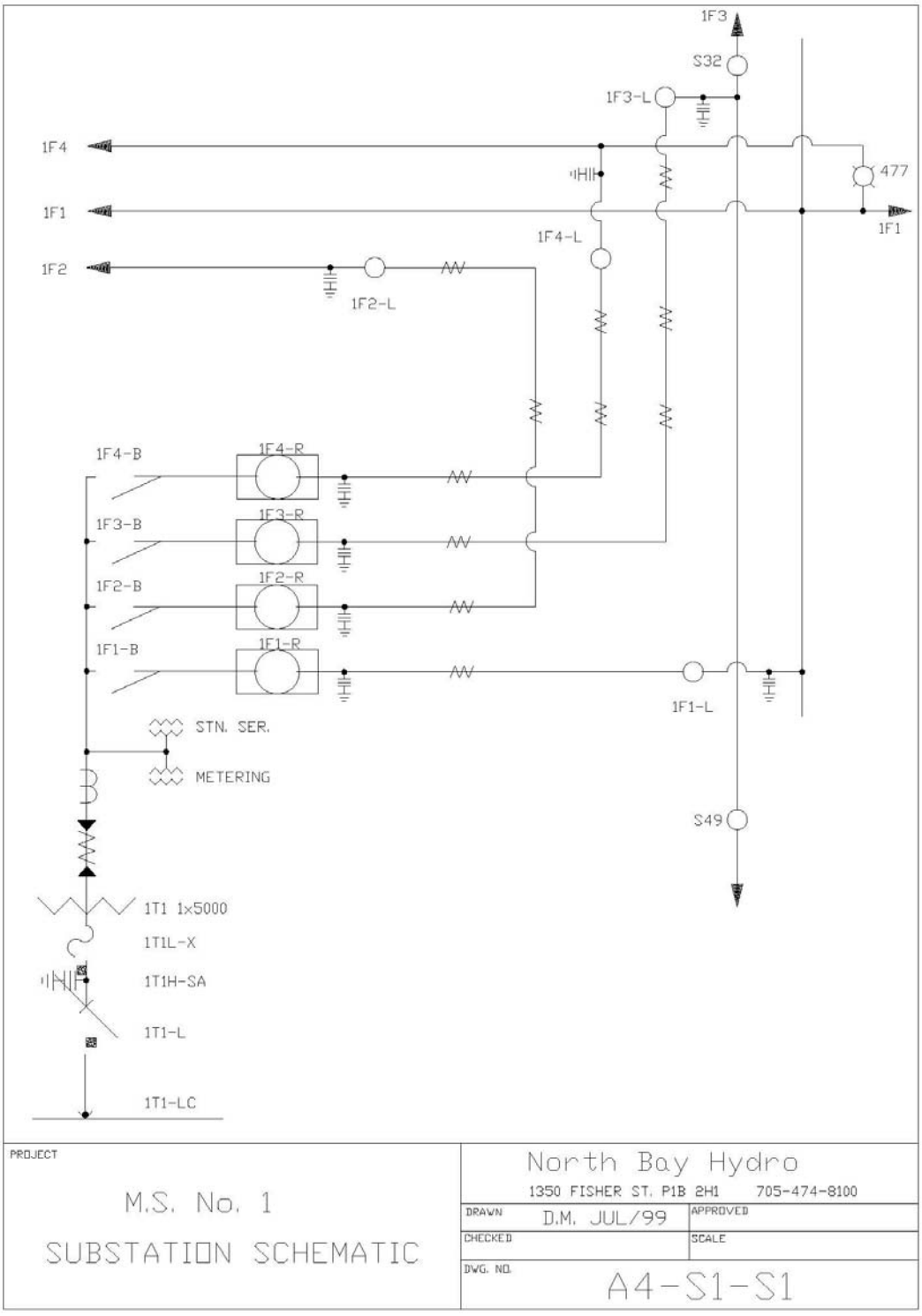

Figure 1: MS1 Single-Line Diagram

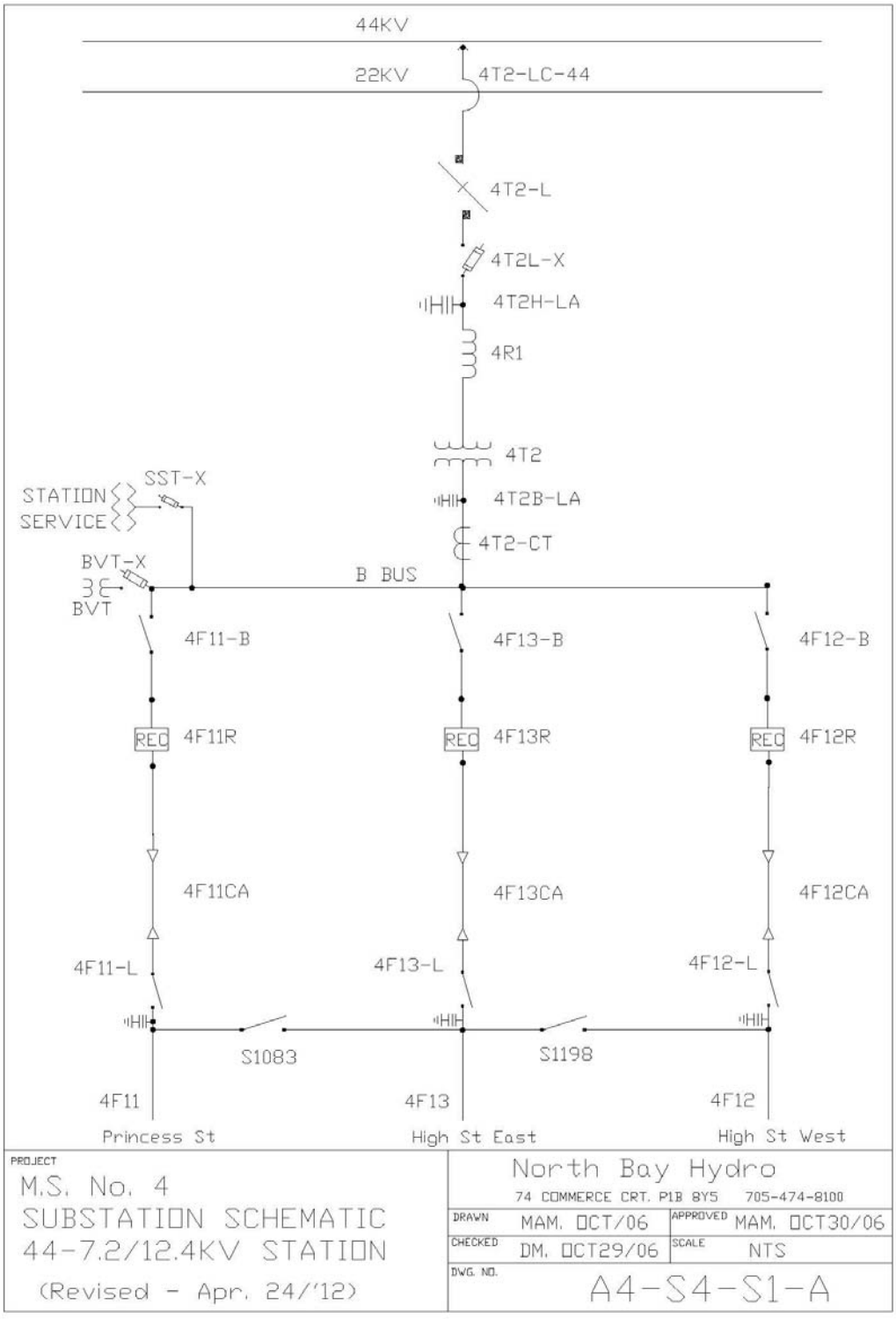

Figure 2: MS4 Single-Line Diagram

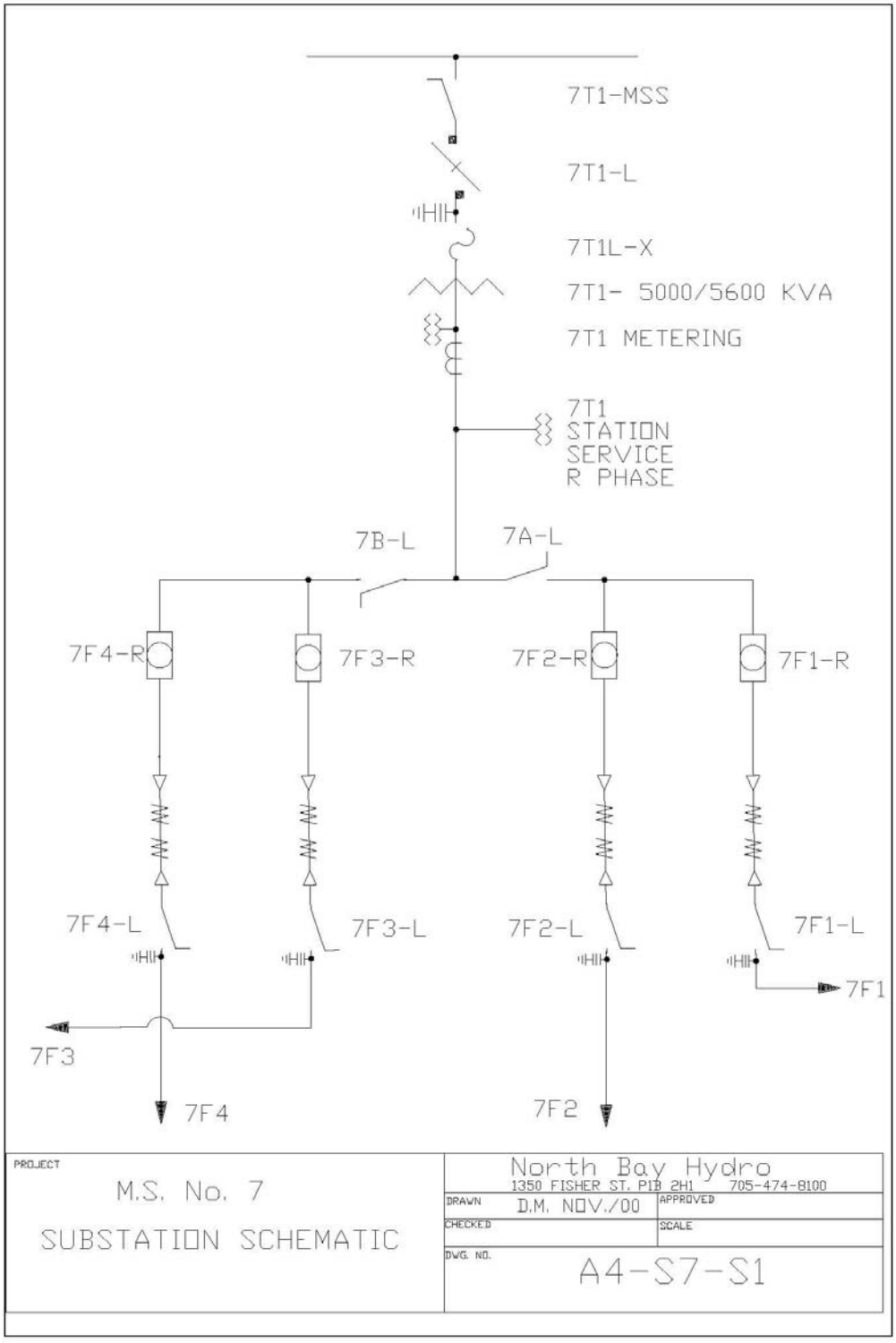

Figure 3: MS7 Single-Line Diagram

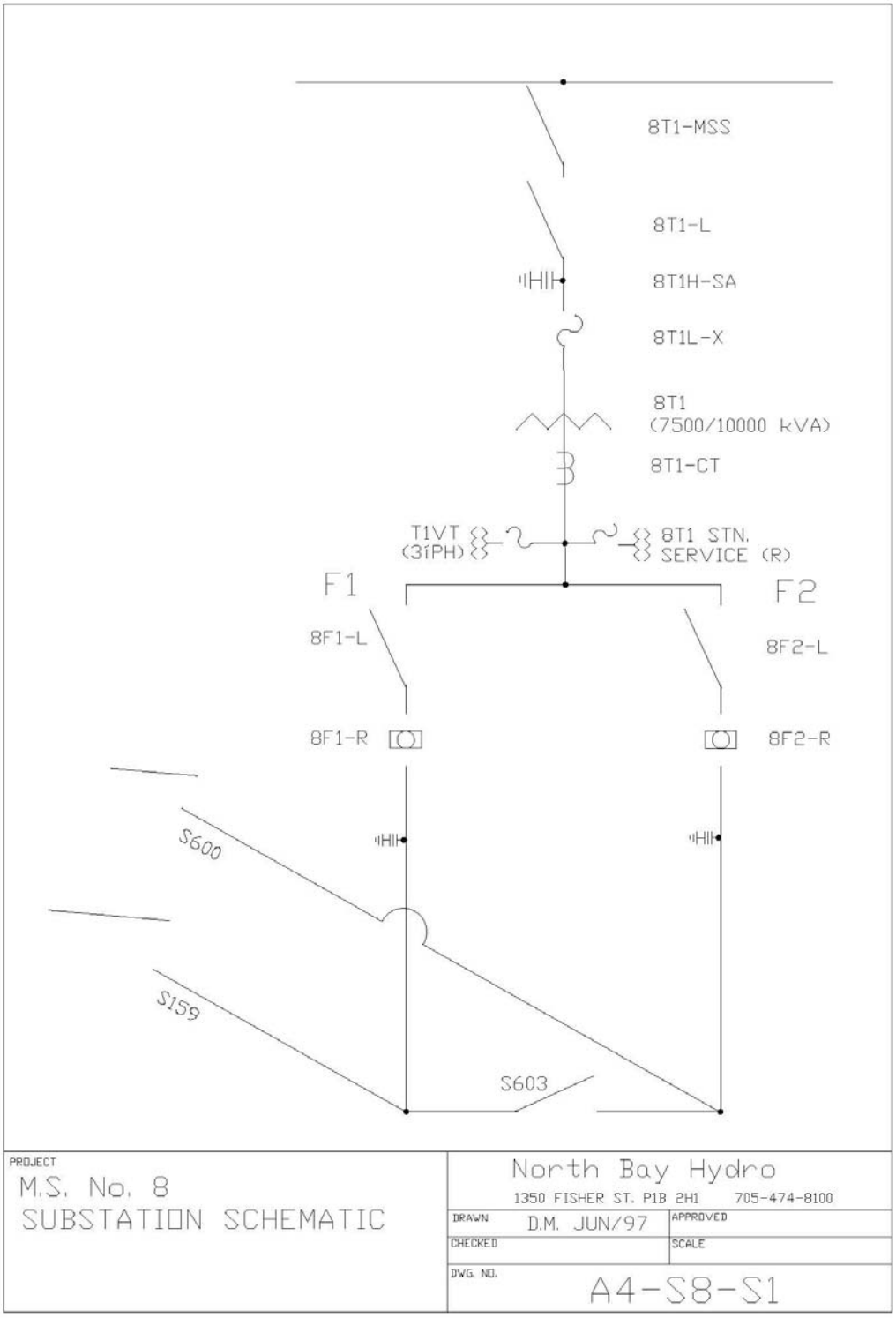

Figure 4: MS8 Single-Line Diagram

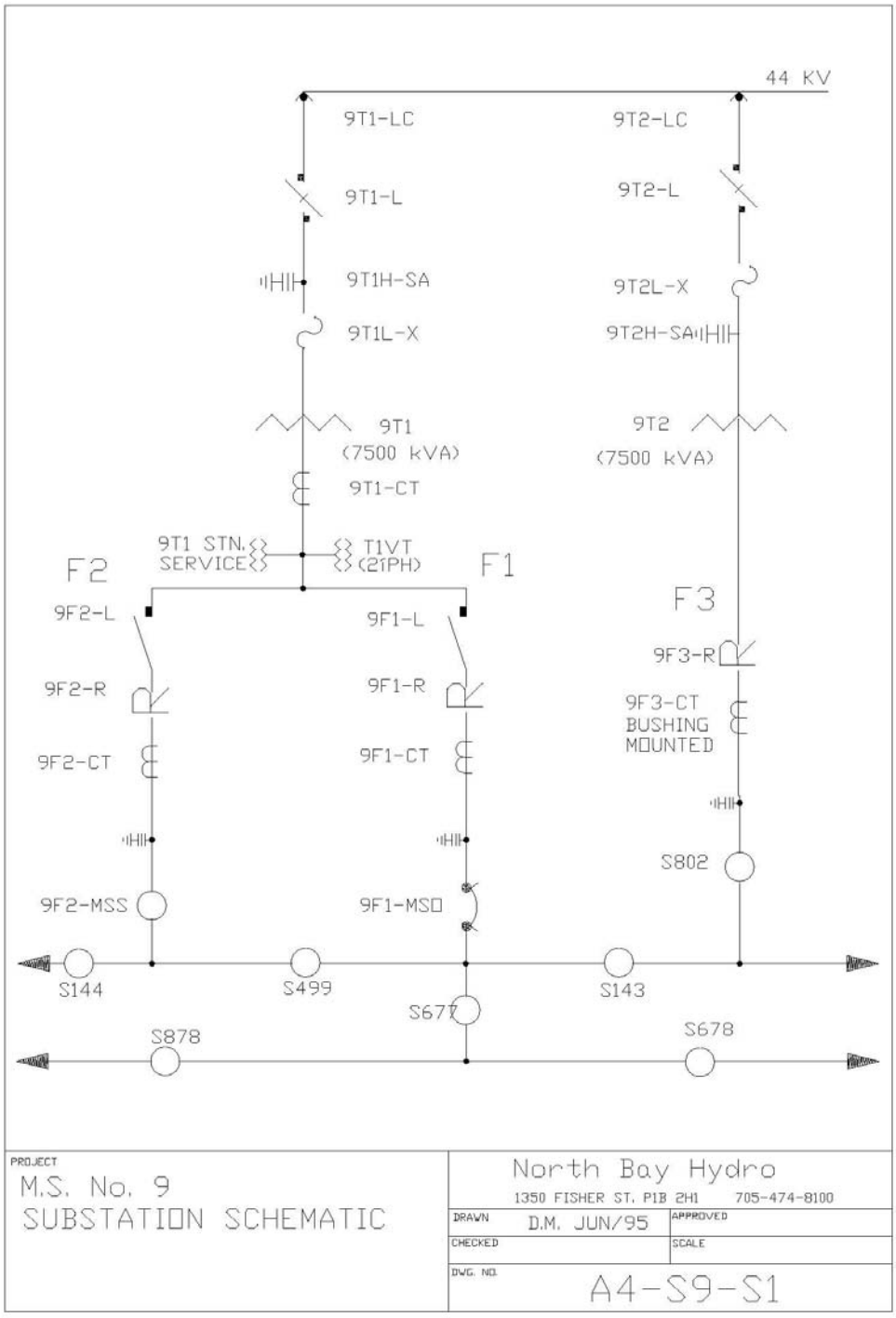

Figure 5: MS9 Single-Line Diagram

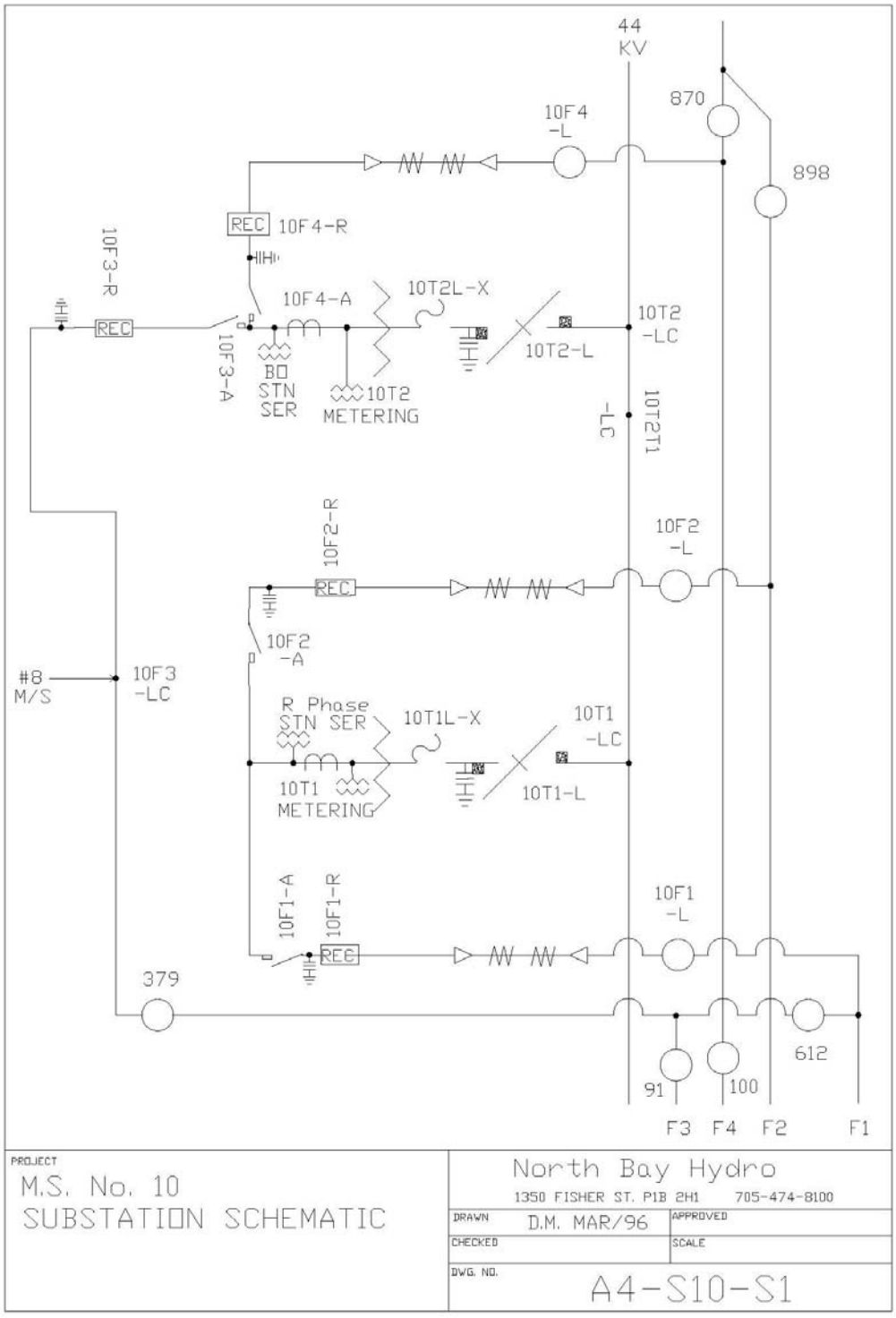

Figure 6: MS10 Single-Line Diagram

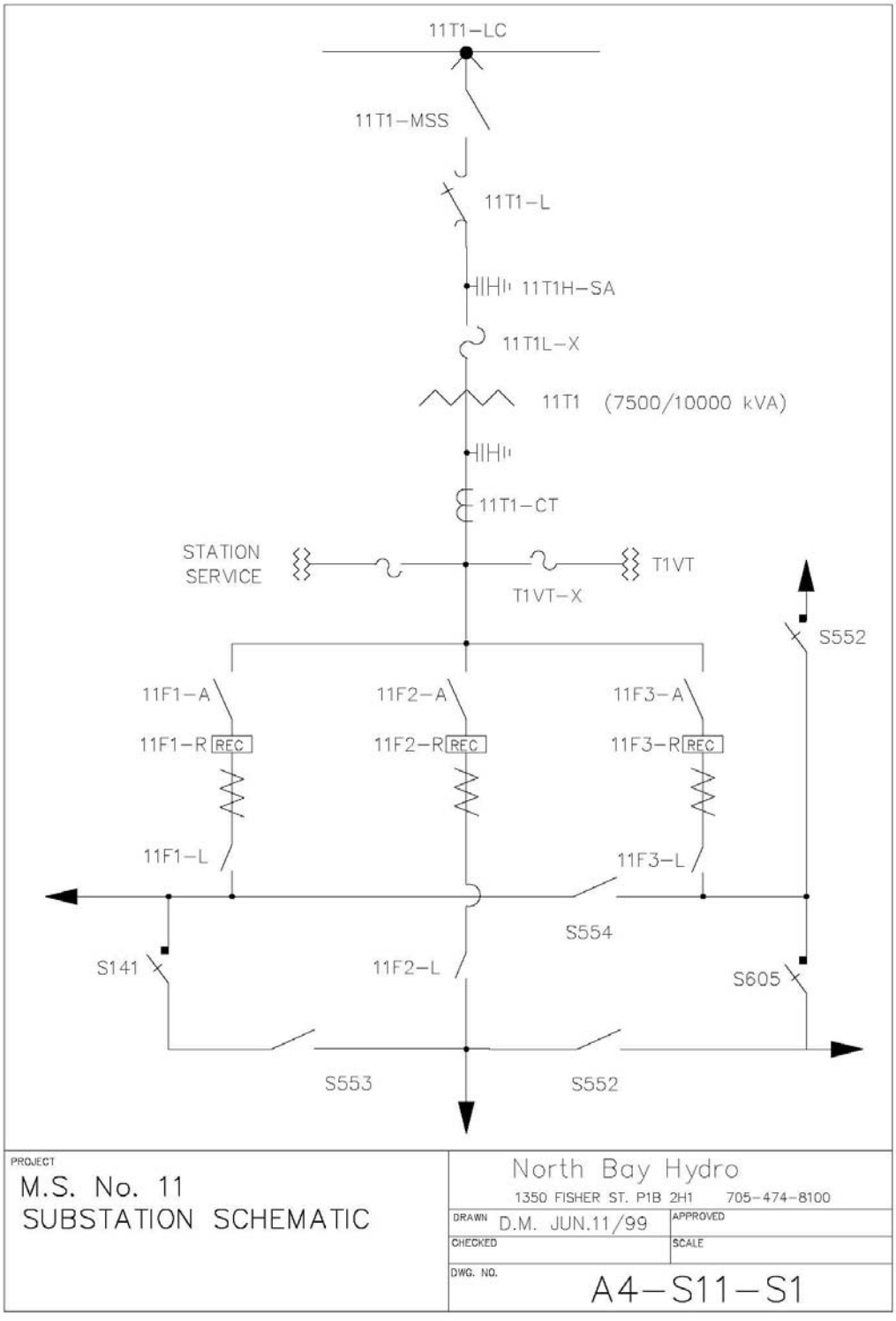

Figure 7: MS11 Single-Line Diagram

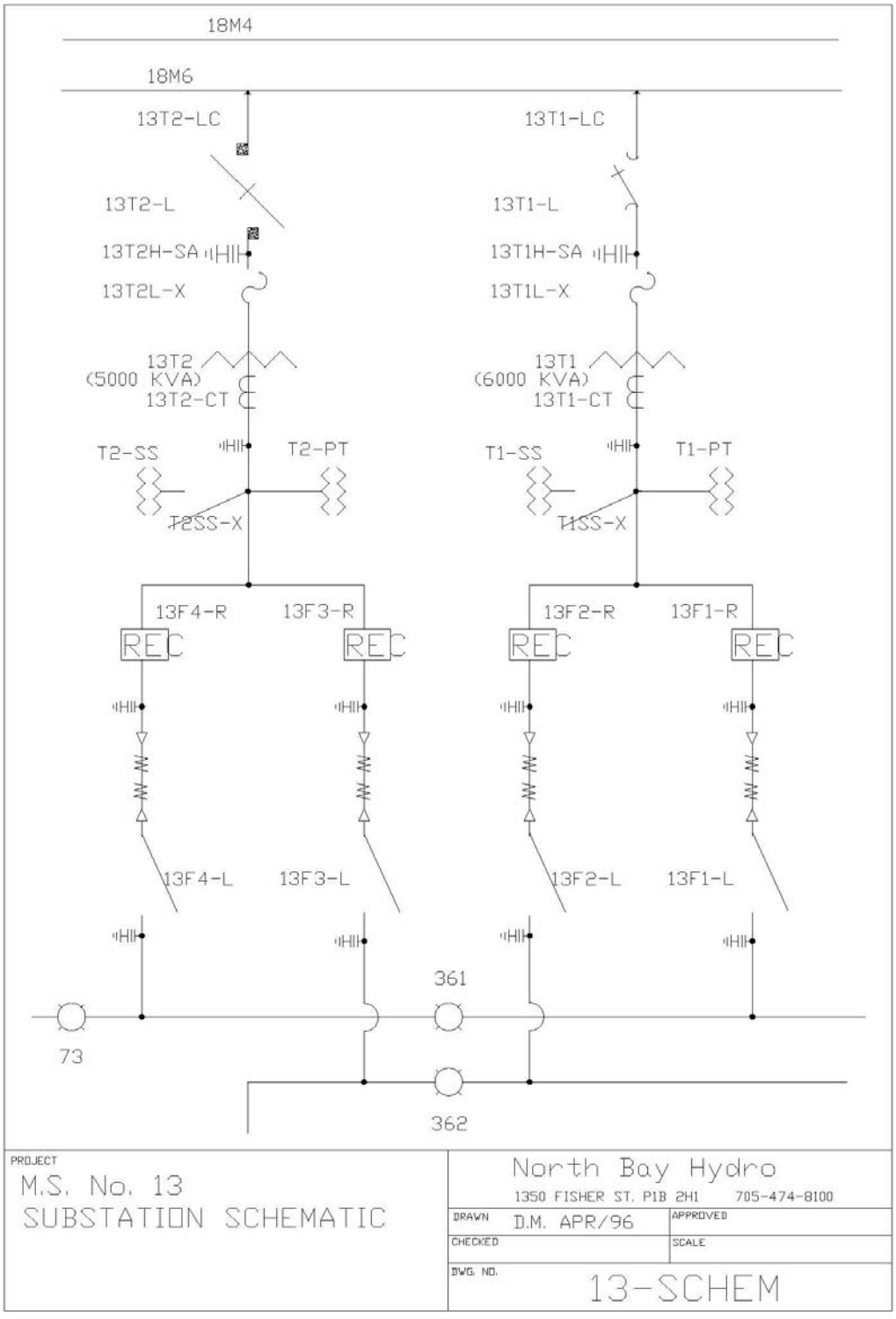

Figure 8: MS13 Single-Line Diagram

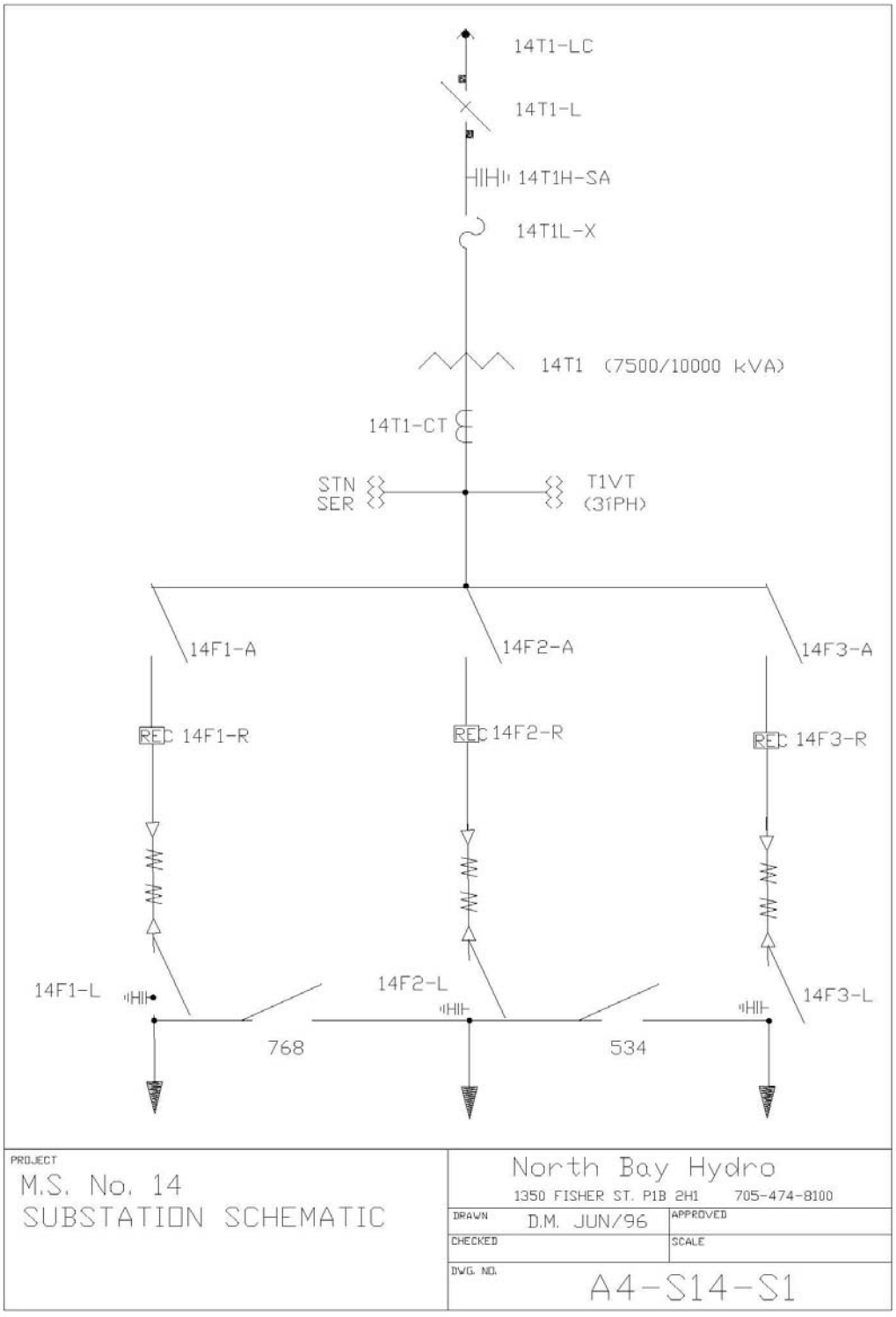

Figure 9: MS14 Single-Line Diagram

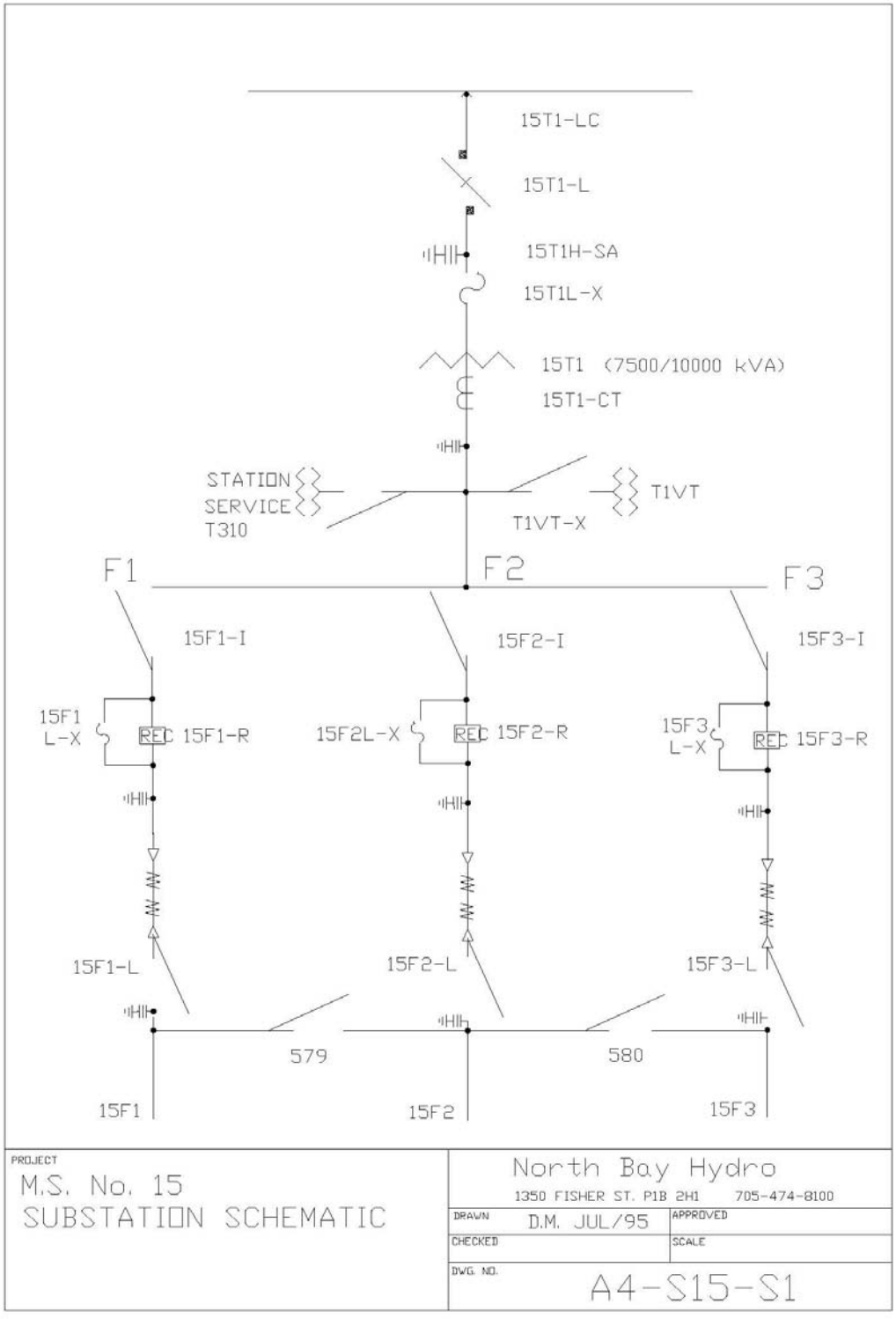

Figure 10: MS15 Single-Line Diagram

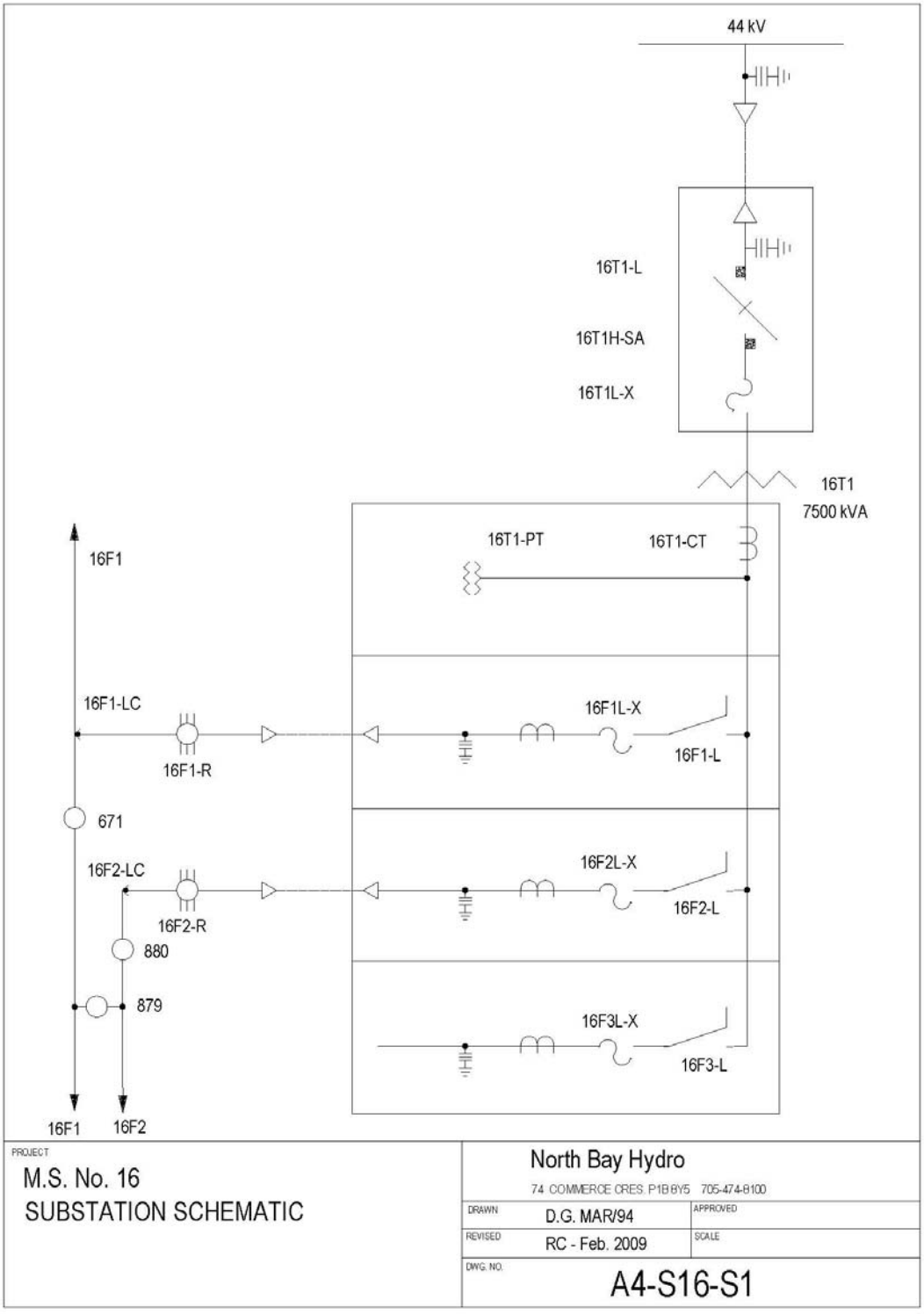

Figure 11: MS16 Single-Line Diagram

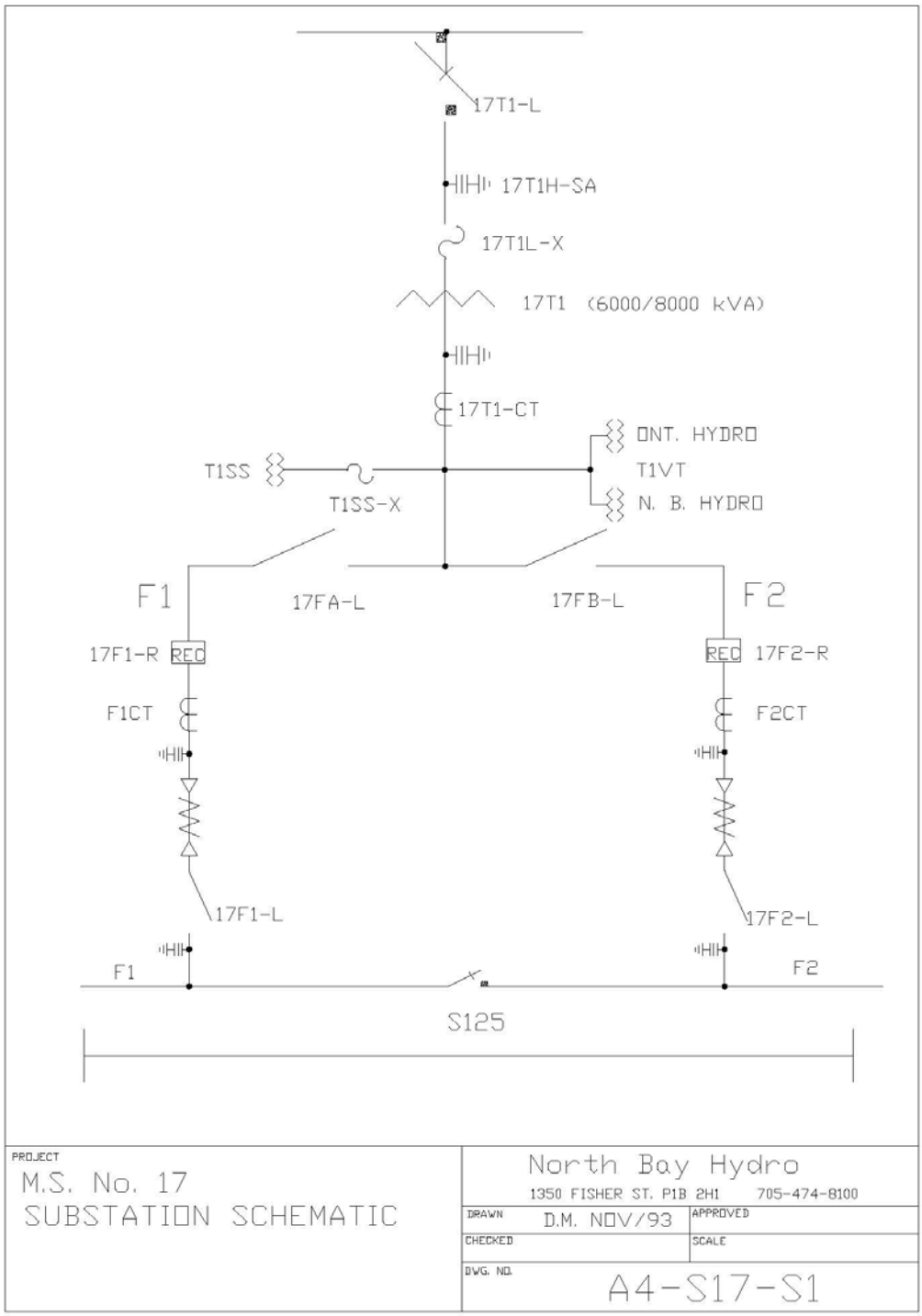

Figure 12: MS17 Single-Line Diagram

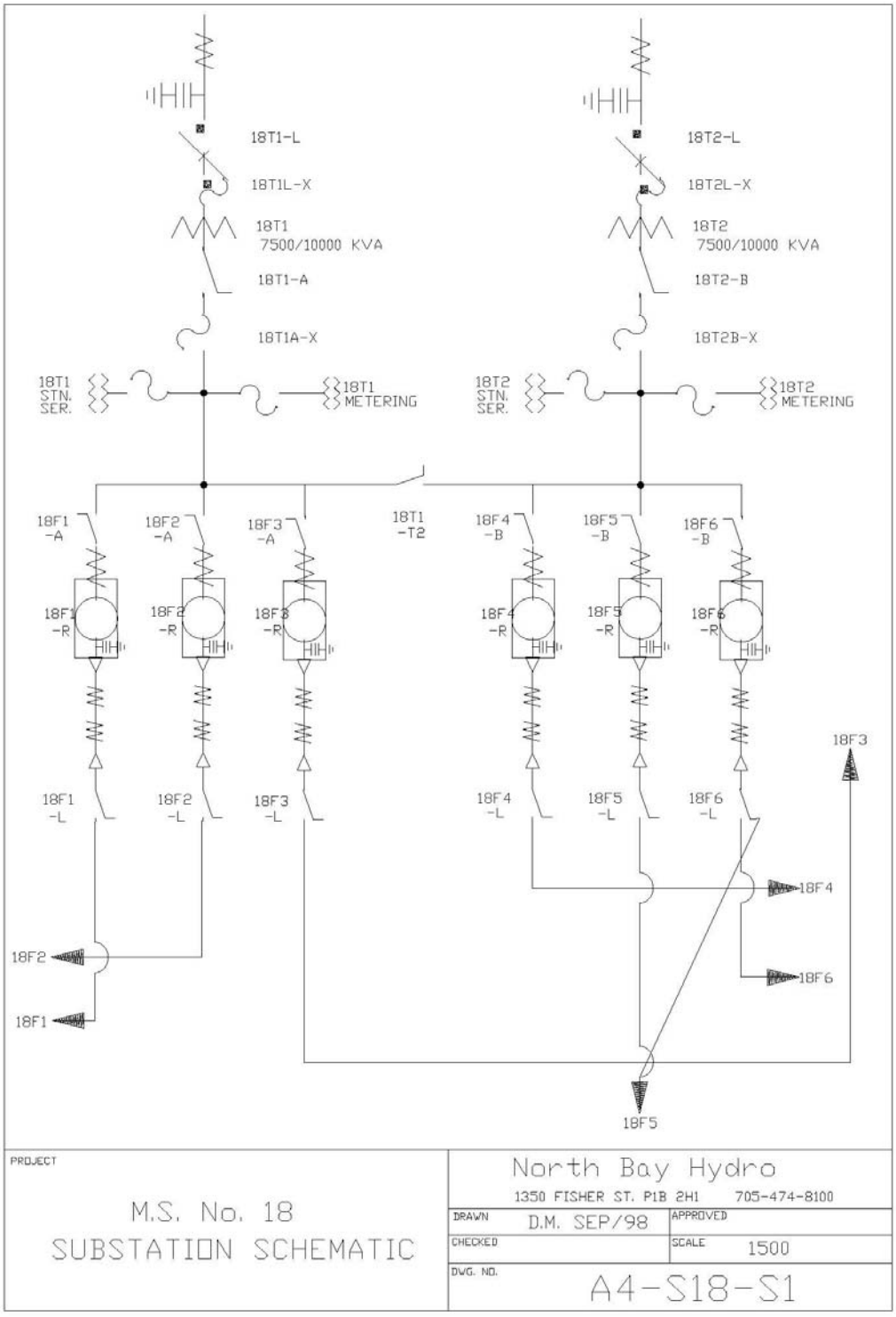

Figure 13: MS18 Single-Line Diagram

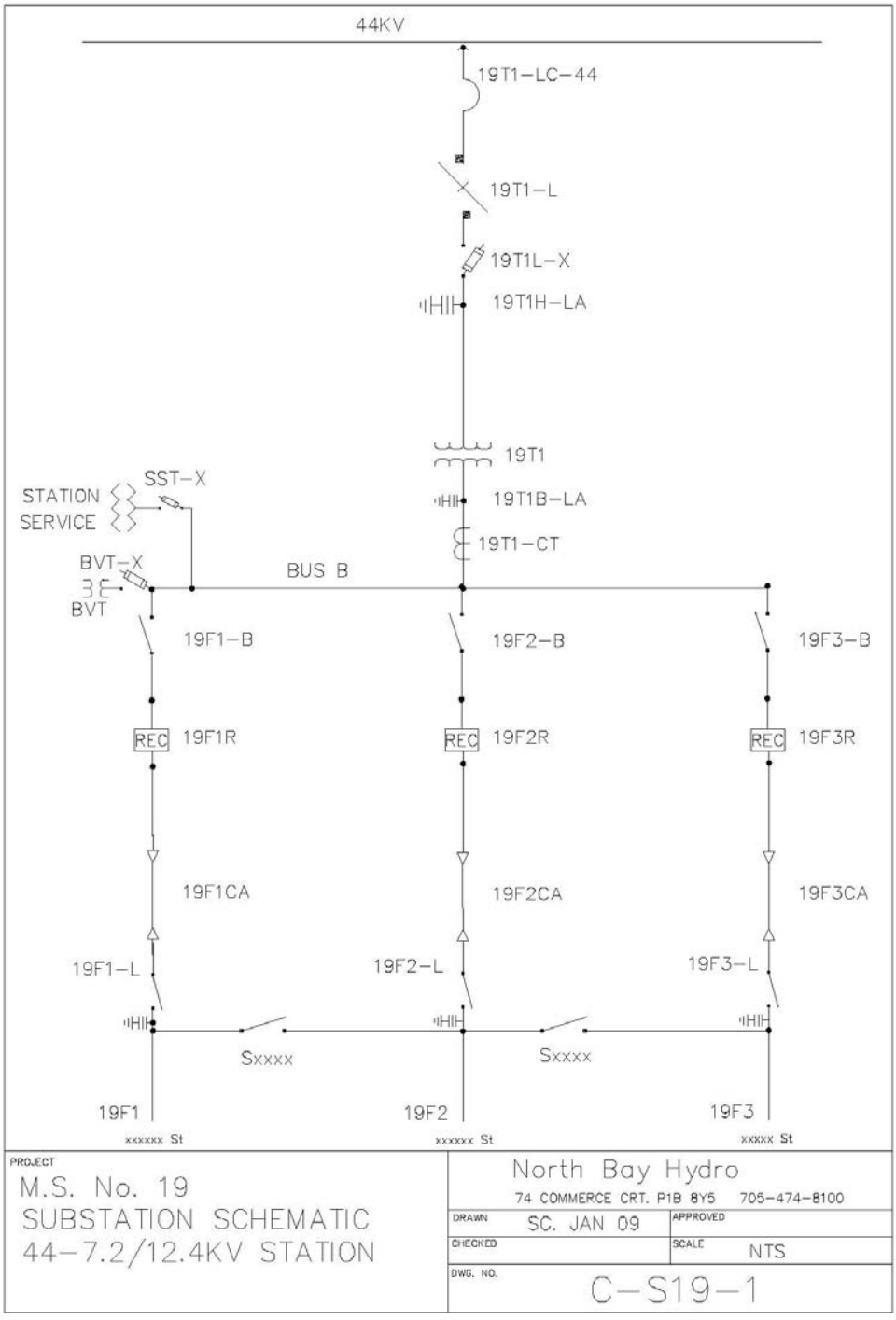

Figure 14: MS19 Single-Line Diagram

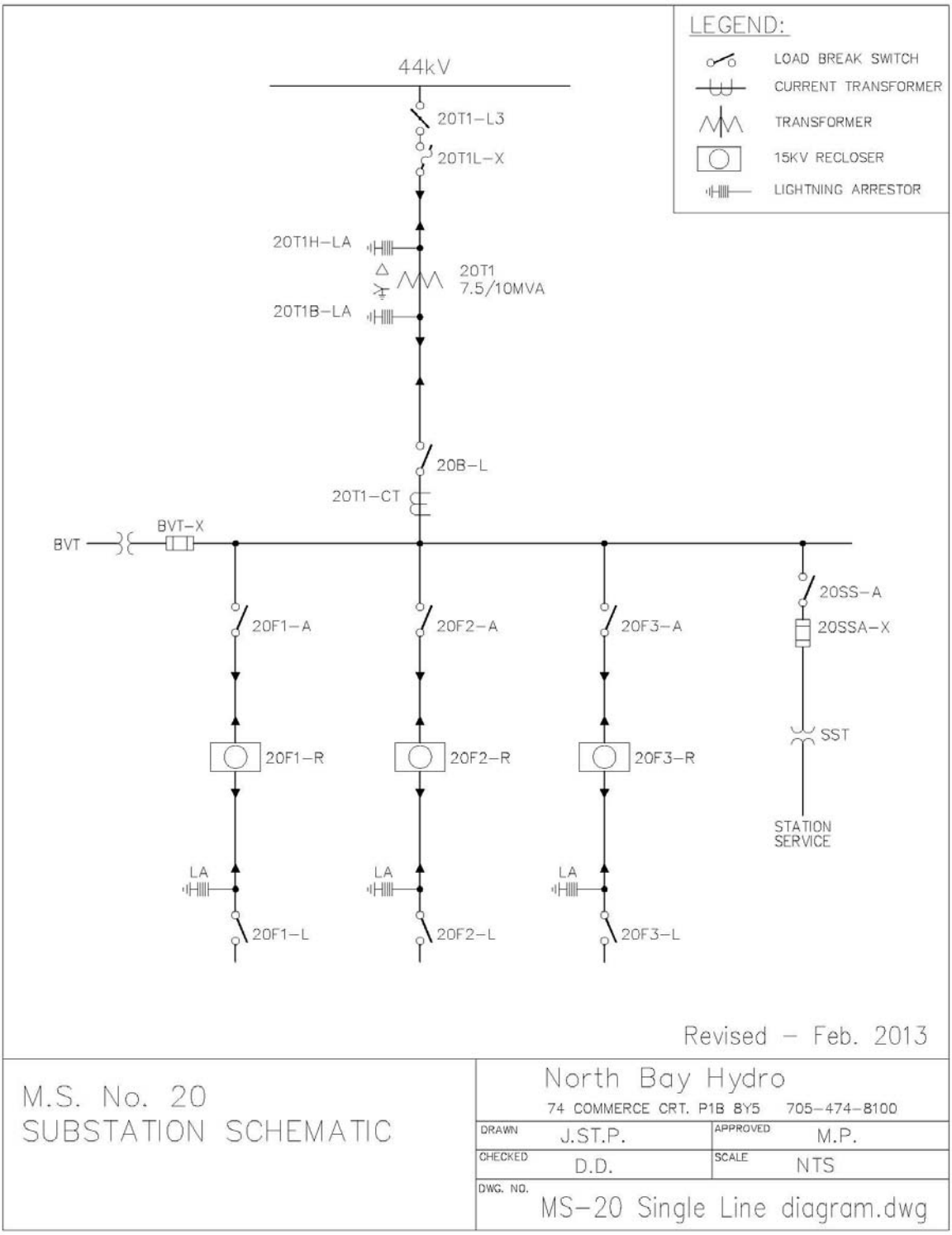

Figure 15: MS20 Single-Line Diagram

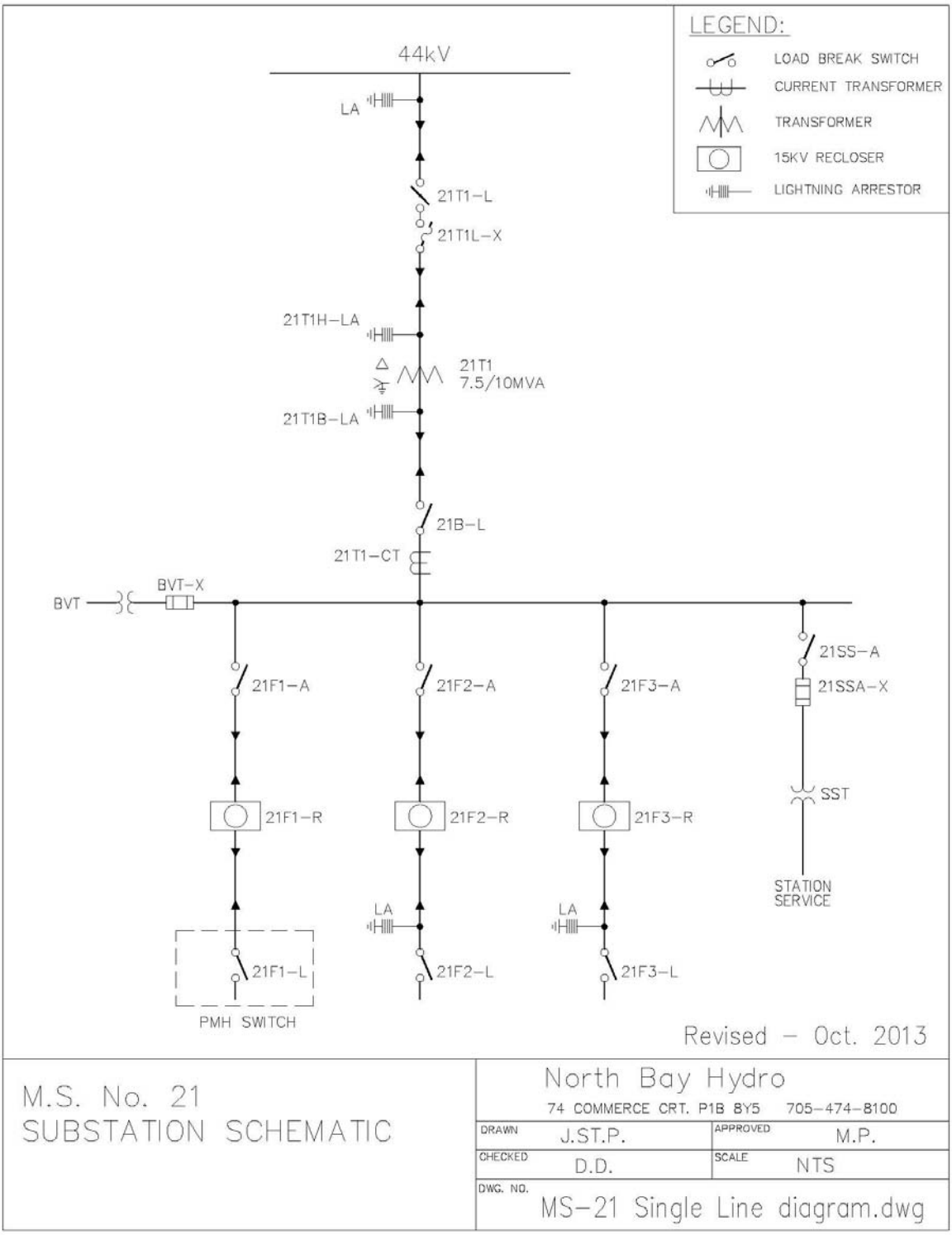

Figure 16: MS21 Single-Line Diagram

Appendix G – OPA Letter of Comment

Appendix G - OPA Letter of Comment

North Bay Hydro Distribution Limited

Renewable Energy Generation Investments Plan

ONTARIO POWER AUTHORITY

July 10, 2014

Introduction

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

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

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

North Bay Hydro Distribution Limited – Distribution System Plan

On June 9, 2014 the OPA received the Renewable Energy Generation Investments Plan ("Plan") of North Bay Hydro Distribution Limited ("NBHDL") related to its Distribution System Plan. The OPA has reviewed NBHDL's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

On page 8 of its Plan, NBHDL indicates that presently it has connected 31 microFIT projects totalling 259.84 kW of installed capacity, and 3 FIT projects totalling 1,880 kW of installed capacity. In addition, NBHDL notes that there are 17 microFIT projects that are currently registered with the OPA but that have not proceeded to the development stage. For additional FIT projects, NBHDL indicates that there are currently no applications in the queue.

According to the OPA's information, as of May 2014, the OPA has offered contracts to 31 microFIT projects totalling 246.48 kW of capacity, and only 2 FIT projects totalling 280 kW of capacity. Through conversations with NBHDL, the OPA was able to obtain the following additional information:

The third FIT project which is the landfill FIT project totalling 1,600 kW of capacity identified in NBHDL's Plan was included because although the generator is a customer of Hydro One and technically connected to a Hydro One circuit, that circuit is embedded in NBHDL's electricity distribution system. For further clarity, Hydro One has pole and wire assets only with respect to the circuit, whereas the circuit is NBHDL owned and originates from a NBHDL owned substation, 1/2

MS14 where all the protection for the generator (transfer trips, two way power flow protection, etc.) exists. Further, this circuit serves only a handful of Hydro One customers it supplies approximately 340 NBHDL customers. Therefore, NBHDL considers this landfill generator to be part of its distribution system for planning purposes.

With this understanding, the OPA finds that its information is consistent with NBHDL's information regarding renewable energy generation applications and connections to date.

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

The OPA notes that North Bay Hydro Distribution Limited is part of the "Group 3" – North/East of Sudbury region for regional planning purposes. At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has been completed for NBHDL's service territory. The regional planning process for the North/East Sudbury region is not anticipated to start until late 2015. With respect to planned REG investments, on page 13 of its Plan North Bay Hydro Distribution Limited indicates that "[b]ased on the evaluation of the distribution system to accept green energy generation connections, no constraints have been identified in the system, preventing the connection of renewable energy generation installations. Therefore, NBHDL is not proposing any capital investments for capacity upgrades on the distribution system to accommodate the applications for the connection of renewable energy generation plant, over the next five years from 2015 to 2019."

Since a regional planning process has not yet commenced for North Bay Hydro Distribution Limited's service territory, the OPA has no comment on the following three items outlined in the Chapter 5 filing requirements, specifically:

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

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

Ontario Power Authority

120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Appendix H – Innovative Report

Innovative Research Group, Inc.
Toronto • Vancouver

Customer Consultation Report

2015 Application Review

November 2014

Prepared for:

North Bay Hydro Distribution Limited
PO Box 3240
North Bay, Ontario
P1B 8Y5

Customer Consultation Report

2015 Application Review

November 2014

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for North Bay Hydro Distribution Limited (North Bay Hydro).

The conclusions drawn and opinions expressed are those of the authors.

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Introduction

About this Consultation

Innovative Research Group Inc. (INNOVATIVE) has been commissioned by North Bay Hydro to help the utility design, collect feedback and document its customer engagement and consultation process as part of the development of North Bay Hydro's 2015 Application Review, which incorporated both capital infrastructure and operational plans.

North Bay Hydro's 2015 Application Review is a key element of its next distribution rate application. The outcome of this application will determine North Bay Hydro's electricity distribution rates for next year – beginning May 2015 through to April 2016 – and will help set the pace for spending over the next 5 years.

The OEB's new "consumer-centric" approach to rate applications contained in the *Renewed Regulatory Framework for Electricity (RRFE)* requires LDCs to demonstrate services are provided in a manner that responds to identified customer needs and preferences[1]. Distributors are required to provide an overview of customer engagement activities that they have undertaken with respect to its plans and how customer needs and preferences have been reflected in the distributor's application. This initiative sought to bring customers directly into the process of finding the right balance between cost and reliability in North Bay Hydro's 2015 Application Review.

This process of identifying and reacting to customer needs and preferences towards North Bay Hydro's system plan development and execution, as it relates to rate applications, is new to all of Ontario's LDCs. There are no established practices and there are a number of options available to engage with customers. The following section explains how we approached this engagement.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is that they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they don't know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking positions on issues that are sometimes controversial. Moreover, many customers simply do not pay attention and remain unaware of particular consultations that they would participate in if they had have been aware.

Running a consultation on the North Bay Hydro's 2015 Application Review has an additional challenge – the lack of familiarity with the distribution system; including how it is funded, regulated and the nature

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.

of its challenges. This is well documented in Ontario Energy Board research and in INNOVATIVE's own experience.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, we developed a process built on three key principles:

1. Use random-sampling research elements to ensure a representative sample of customers are engaged.
2. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
3. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.

Customer Consultation Overview

Based on the principles outline above, INNOVATIVE worked with North Bay Hydro staff to design a multifaceted customer engagement program which included a combination of qualitative and quantitative research elements. This consultation was designed to engage various rate classes and collect feedback on preferences and priorities as they relate North Bay Hydro's 2015 Application Review.

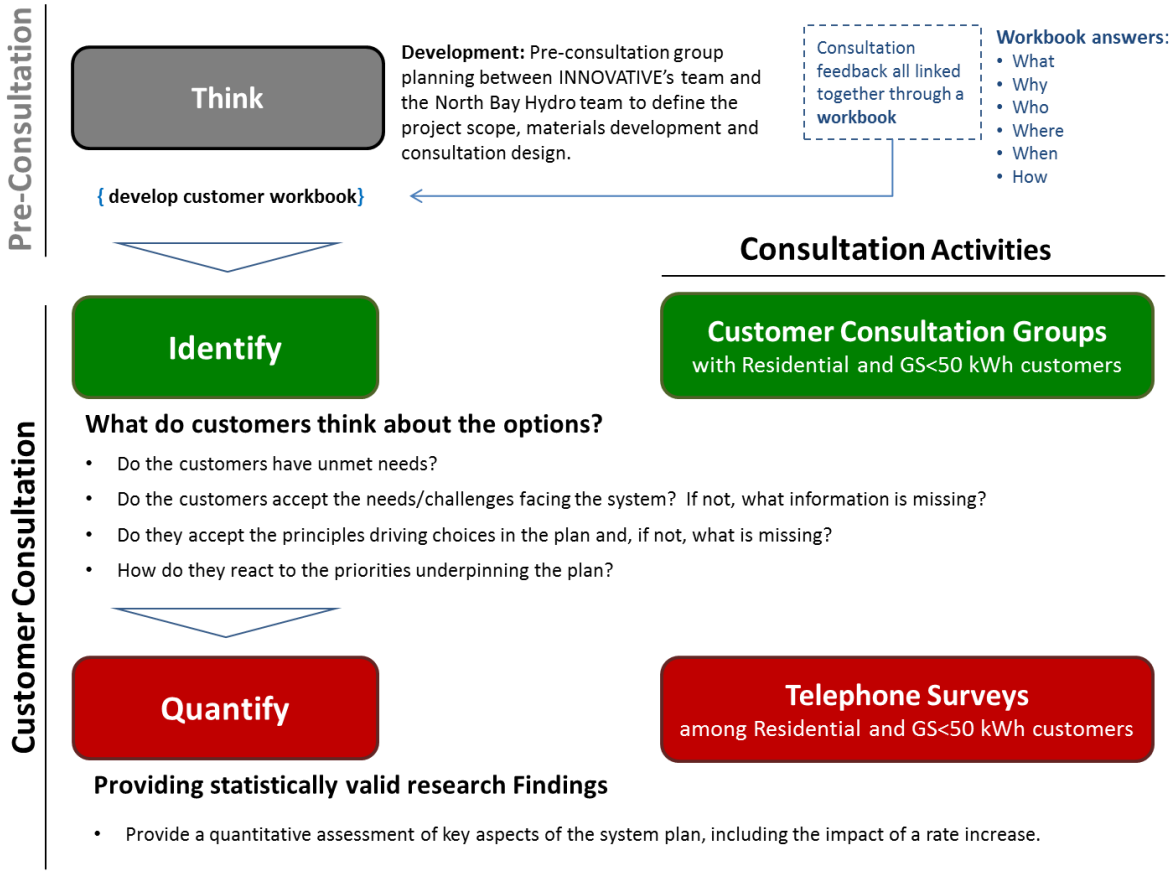
The consultation encompassed two core elements of customer engagement.

1. **General Service and Residential Consultation Groups:** This qualitative phase of the consultation was designed to educate customers, assess their preferences and priorities, gauge reaction to proposed rate changes, and ultimately inform the quantitative phases of the consultation. The groups were randomly recruited and held in North Bay. A workbook was used to provide the participants with core information customers about both the provincial and local electricity system, North Bay Hydro's proposed capital investment and operating spend to maintain system reliability, as well as the rate impact for each respective rate classes. Participants were provided incentives in recognition of their time commitment.
2. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the system plan. Customer lists for both respondent groups were provided by North Bay Hydro and the sample was randomly-selected by INNOVATIVE.

There were three stages in developing and implementing this consultation:

- **Think**: The first stage was to develop the core background material and key questions for the workbook. INNOVATIVE and North Bay Hydro worked together to review the utilities system plan, capital investments and OM&A spending. Potential questions were identified that would allow customers to share their needs and preferences. Then a workbook was developed that would provide the information needed to allow customers with varying levels of knowledge to find answers to those questions.

- **Identify**: The second step was to find out the range of views held by the public regarding the system plan through the more qualitative elements of the process. This included a series of customer discussion groups using randomly recruited samples of residential and GS customers.
- **Quantify**: The third step was quantitative – a randomly recruited telephone surveys of residential and GS customers. Randomly recruited surveys allow for generalizable conclusions that can be applied to the broader population of North Bay Hydro customers. The surveys were developed based on the feedback from the qualitative research.



Workbook Development

As we noted earlier, a key challenge in getting customer feedback on North Bay Hydro's rate application is the lack of knowledge customers have toward Ontario's electricity system and North Bay Hydro's role as the local distributor within the system. North Bay Hydro's proposed distribution system plan, capital investment plan and OM&A budget are all very detailed and extensive documents that uses technical language. Our challenge was to briefly cover these key issues and frame meaningful questions about customer needs and preferences.

The process of developing the consultation workbook began in the summer of 2014. The workbook was divided into key sections that explained North Bay Hydro' electric system, the challenges facing the system, and how North Bay Hydro intended to meet those challenges over time.

The final consultation workbook had five distinct chapters:

1. **What is this Consultation About?** the purpose of the discussion, where the discussion fits in the context of electricity planning in Ontario.
2. **Electricity 101**: how the overall system works and the players involved in operating and regulating the system as it relates to North Bay Hydro's customers.
3. **North Bay Hydro's Grid Today**: a discussion of the structure and key elements of North Bay Hydro's distribution system.
4. **Cost Pressures**: a discussion of the various challenges facing North Bay Hydro's distribution system and an overview of recent and current initiatives to manage the challenges.
5. **What the Plan Means for You**: A section covering the level of planned spending for 2015 by capital investments and OM&A, the expected impact on rates and feedback on priorities, pacing and overall reaction.

Although the proficiency of customers varied, the same basic workbook was used in all qualitative customer engagements. The references to bill impact were varied to reflect the details of that specific rate class (either residential or GS less than 50 kW). As the customer went through the consultation workbook they were prompted with questions relating to system reliability, system challenges, and preferences on the direction of North Bay Hydro's proposed system plan, capital investment and operating spend.

Another key element of the workbook was the questions. In developing the questions, we looked for those that could also work on the telephone, without requiring all of the information in the workbook.

The *needs* questions were the easiest. We started with a basic satisfaction question and then asked an open-ended question about how North Bay Hydro could improve its services. We let customers discuss whatever topics they wanted to with no boundaries. Later in the workbook we probed satisfaction with the number and duration of routine outages and probed the impacts of those outages.

Preferences took a bit more thinking. We were looking for value choices rather than technical issues. Key topics for preferences included:

- What are acceptable outcomes for the number and duration of outages?
- Whether North Bay Hydro had the balance right in its spending priorities and which areas should have more or less priority?
- Whether North Bay Hydro's goals are too high, too low or about right with probes for which are too high and which too low?

The final substantive question asked about the cost of the plan and the outcomes it planned to achieve. Sometimes this questions is asked with a simple support or oppose response scale, but we found that this type of scale does not effectively capture customer responses. Instead, we gave customers three options as well as a "don't know" option:

- The rate increase is reasonable and I support it
- I don't like it, but I think the rate increase is necessary
- The rate increase is unreasonable and I oppose it
- Don't know

The workbook concluded with a final set of five questions to assess the workbook and process itself.

The workbooks can be found in the **Appendix** of this report.

Executive Summary

The following section provides the detailed findings on the needs and the preferences of North Bay Hydro's general service and residential customer base. In this section, we provide a high level overview of North Bay Hydro customers' needs and preferences.

The overview includes feedback from 18 customers who participated in the *qualitative stage* of the consultation where we explored the range of issues related to North Bay Hydro's rate application, as well as feedback from another 605 customers who contributed to the quantitative stage where we documented the incidence of needs and preferences across the customer population.

Customer Needs & Preference

Continued delivery of high quality services

Most North Bay Hydro customers are generally quite satisfied with the job the utility does running the electricity distribution system. This pattern was consistent in both phases of the customer consultation.

Overall Satisfaction across Consultation Activities:

Response	Directional (Focus Groups)		Generalizable (Telephone Surveys)	
	General Service	Residential	General Service	Residential
Very satisfied	4	3	35%	41%
Somewhat satisfied	8	3	53%	42%
Neither satisfied nor dissatisfied	0	0	0	2%
Somewhat dissatisfied	0	0	8%	8%
Very dissatisfied	0	0	2%	5%
Don't know / Refused	0	0	2%	2%
TOTAL	n=12	n=6	n=100	n=505

When we asked what North Bay Hydro can do better to improve services, comments focused on three major areas:

- Lower rates.
- Removal of TOU and debt retirement charges.
- Improvements to reliability or reduced outages.

This paradox of *lower rates* while seeking *service improvements* is the key dilemma the consultation sought to explore and better understand.

The consultation focused deeper on the question of outages. In the qualitative stage, the workbook provided information about the system's current average level of reliability and sought customer feedback on satisfaction with current levels of reliability.

Reliability of service

The qualitative consultation activities spent additional time exploring the impacts of outages on customers, acceptable frequencies, and durations of outages. Those findings are detailed in the following section, in the qualitative phase of the customer consultation.

The telephone surveys built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

While 85% of residential respondents and 78% of GS respondents experienced at least one power outage in the past 12 months, the overall impact on households and businesses was relatively insignificant. Asking respondents to think back to their most recent power outage:

- 68% of residential respondents said the outage caused a *minor inconvenience*, while 23% said it caused *no inconvenience at all*.
- 31% of GS respondents said the outage caused a *minor cost to their business*, while 54% said it *had barely any costs at all to their business*.

When it comes to system reliability, a majority of residential and GS customers want to see continued spending on upgrades and maintenance.

Regarding frequency of outages:

- Almost one-in-four (23%) residential respondents think North Bay Hydro should spend what is needed to reduce the number of power outages and half (53%) think they should spend what is needed to maintain the current level. Only 14% state that North Bay Hydro should accept more power outages in order to keep customer costs from rising.
- General Service customers respond similarly on how to address the number of outages: 29% think that North Bay Hydro should spend what is needed to reduce the number of power outages and 45% say they should spend what is needed to maintain the current level.

Regarding duration of outages:

- Three-quarters (78%) of residential respondents think North Bay Hydro should spend what is needed to either reduce (26%) or maintain (52%) the duration of power outages. Only one-in-six (16%) think that North Bay Hydro should accept longer power outages to keep costs down.
- Similar proportions of General Service respondents think that North Bay Hydro should spend what is needed to reduce (33%) or maintain (46%) the length of power outages. No significant differences arise within region or consumption.

Survey respondents were informed of North Bay Hydro's proposed capital investment required to maintain system reliability and then asked to think about reliability in terms of bill impact.

- Six-in-ten (59%) residential customers and 37% General Service customers believe that North Bay Hydro should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.

When informed that up to an estimated 25% of all power outages among North Bay Hydro customers are caused by wire contact with trees, the policy of establishing a 15 foot tree clearance from either side of overhead power lines is supported by a large majority of both residential (82%) and GS (81%) respondents.

However, when it comes to North Bay Hydro's impact on the city's tree canopy, opinions are mixed between residential and GS customers:

- 56% of residential customers and 37% of GS customers disagree with the following statement: "*while North Bay Hydro's policy of tree trimming and tree removal is designed to lower the number of customer power outages, they're going too far in removing the City's tree canopy*".

Affordable electricity costs

It is true that many customers are feeling a "financial pinch" when it comes to their electricity bills. However, just as many customers are able and willing to pay more if that means maintaining system reliability.

When it comes to the impact on household finances and the bottom line, a number of customers indicate that their electricity bill has a significant impact:

- 57% of residential customers agree that "*The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities*";
- While 63% of GS customers agree that "*The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off*."

Yet, at the same time, when considering the cost of reliable electric service, a majority of customers say they are willing to pay a bit more if that means better service reliability.

- 57% of residential and 52% of GS customers agree that "*I'm [my organization would be] willing to pay a bit more for my electricity if it means better service reliability*."

Furthermore, most claim to be able to pay more for electricity but have concerns about the impact a rate increase will have on others.

- 56% of residential and 63% of GS customers agree that *"I [my organization] can personally afford to pay more for electricity, but I am worried about the impact this will have on others [some of my suppliers and customers]"*.

Finally, when it comes to legacy issues, a large majority support spending more to maintain the local distribution system for future generations.

- 77% of residential and 84% of GS customers agree that "*Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations*."

Assistance to reduce consumption and thereby costs

It's very clear that customers want to see North Bay Hydro help reduce electricity consumption and costs, as revealed by the quantitative component of the customer consultation:

- 83% of residential and 73% of GS customers agree with the statement: "*I think North Bay Hydro should do more to help customers find ways to reduce their electricity consumption and costs*".

Communications through a variety of media including phone, internet, social media, in-person and email

While not tested in the quantitative phase of the customer consultation, a number of customers in the qualitative phase of the consultation suggested that North Bay Hydro invest more in communication and the channels they use to reach customers. This was a particularly salient point when it came to communicating during power outages and letting customers know when power would be restored.

Aside from communicating around power outages, there were mixed opinions among customers when it came to levels of customer service and the perceived associated costs. Some customers suggested that North Bay Hydro's call centre should be staffed "24-7", while others argued that they would be unwilling to pay for that level of service.

Ultimately, when it comes to communications with North Bay Hydro, customers placed a lot of value on their time and having the ability to communicate through their preferred channel.

Business to be customer centric including timely service that solves their problems

Again, while not tested specifically in the quantitative consultation phase, there was certainly an observed directional desire for improved planning, timely service, and communications in the qualitative phase of the customer consultation.

Professional interactions with highly skilled and experienced personnel

As noted in the qualitative phase of the consultations, a number of customers expressed a general concern over a perceived trend in the loss of skilled labour from North Bay to southern Ontario and other jurisdictions and questioned if this was having an impact North Bay Hydro and its ability to maintain the local distribution system.

Elements of this sentiment were subsequently tested in the quantitative phase of the consultation:

- Six-in-ten (59%) residential respondents and nearly half (49%) of GS respondents believe that it is important for North Bay Hydro to retain and attract experienced and qualified workers to operate the system by paying a wage that is competitive but within industry benchmarks.
- Furthermore, 55% of residential customers and 56% of GS customers agree with the following statement: "*Skilled hydro workers are sought out throughout North America and Ontario. If North Bay Hydro doesn't pay the people who maintain our local distribution system a competitive salary, we risk losing the most qualified and experienced hydro workers to southern Ontario".*

It's clear that, in most cases, customers expect the utility to pay a competitive wage to ensure that the system is operated by skilled and experienced personnel.

Proactive communications when there are unplanned outages

It was learned during the qualitative consultation phase that many North Bay Hydro customers – particularly GS customers –place a high premium on proactive communications related to unplanned outages.

While the majority of participants are generally satisfied with the service they receive and find the number of outages to be acceptable – when probed for areas of improvement – many said they would like to see North Bay Hydro provide better communications around power restoration. This is a particularly salient point among GS customers, whose business operations can be seriously affected by power service interruptions. In the event of an outage GS customers need to make decisions based on the information provided by North Bay Hydro to minimize the impact to their bottom-line: i.e. *do they send staff home, cancel a shift of workers, or wait until power is restored?* GS participants suggested that more reliable estimations of when power would be restored, and more communication channels in which to access this information would be helpful.

While improved communications from North Bay Hydro on power restorations was also mentioned by residential customers, the urgency or importance of such process enhancements did not appear as urgent a priority when compared to the GS group.

Customer Reaction to Rate Impacts

Asking people whether they *support* or *oppose* a rate increase puts many participants in a difficult spot. It is clear that many customers have an issue with the idea of "supporting" a rate increase. While they do not *want* or *like* a rate increase, they are often not opposed to a rate increase. In fact, most feel a rate increase is needed. As such, we created a response for these customers: "*I don't like it, but I think the rate increase is necessary"*.

Other participants had no problem in expressing outright support for a rate increase. The statement we provided for them is "*The rate increase is reasonable and I support it*".

When we refer to the combination of these two groups – *I don't like it but it's necessary* and *I support the rate increase* – we refer to the level of "acceptance".

Referring to the generalizable results from the telephone surveys, 73% of residential customers accept North Bay Hydro's proposed rate increase, while 68% of general service customers accept the proposed rate increase. This is in line with the direction observed in subsequent qualitative focus group phase of the customer consultation.

Q: Considering what you know about the local distribution system, which of the following best represents your point of view?

Response	Directional (Focus Groups)		Generalizable (Telephone Surveys)	
	General Service	Residential	General Service	Residential
The rate increase is reasonable and I support it	1	1	20%	25%
I don't like it, but I think the rate increase is necessary	9	3	48%	48%
The rate increase is unseasonable and I oppose it	1	0	28%	25%
Don't know / Refused	1	2	4%	2%
TOTAL	n=12	n=6	n=100	n=505

As seen throughout North Bay Hydro's customer consultation, there is no simple answer to electricity utility spending and investing from the customer's perspective. Rate increases are undesirable, but lower reliability is unacceptable and the need to invest in renewal and spend on maintenance of the distribution system is understood and accepted.

As a result, North Bay Hydro customers reluctantly accept the proposed spending plan and its accompanying rate increase as an unfortunate necessity.

Workbook-based Facilitated Discussion

Customer Consultation Groups
with RS and GS Customers

PURPOSE: To gain qualitative input/ response to proposed system plan from RS and GS < 50 kWh customers and to feed into survey design

Summary

General Satisfaction:

Overall, every participant was satisfied with the service they receive from North Bay Hydro. Even amid some concerns, two-thirds of Residential Service (RS) customers, and one-third of General Service (GS) customers indicated they were '*very satisfied*' with the service they receive from North Bay Hydro.

System Reliability:

All of the residential participants found the number of outages they experienced in the last 12 months to be acceptable. Only two-in-twelve of General Service customers found them to be unacceptable, of which one customer experienced five outages over the course of a year. One GS customer noted that the number of outages was '*very acceptable*' and that their experience with power interruptions at their business was only ever due to extreme weather events, to which North Bay Hydro had little to no control.

Overall, all GS and residential participants were satisfied with the *reliability* and *quality* of electricity services provided by North Bay Hydro.

Areas for Improvement:

While the majority of participants are generally satisfied with the service they receive and find the number of outages to be acceptable – when probed for areas of improvement – many said they would like to see North Bay Hydro provide better communications around power restoration. This is a particularly salient point among GS customers, whose business operations can be seriously affected by power service interruptions. In the event of an outage, GS customers need to make decisions based on the information provided by North Bay Hydro to minimize the impact to their bottom-line: i.e. do they send staff home, cancel a shift of workers, or wait until power is restored? GS participants suggested that more reliable estimations of when power would be restored, and more communication channels in which to access this information would be helpful.

While improved communications from North Bay Hydro on power restorations was also mentioned by residential customers, the urgency or importance of such process enhancements did not appear as urgent when compared to the GS group.

Billing was another area of concern among a number of GS and residential participants. While out of North Bay Hydro's control, the majority of participants from both groups cited that their electricity bills are unclear in regards to what they were being charged for, and where their money was going.

Furthermore, the multiple bills that many GS customers receive is also a concern that was cited in the discussion groups. These bills come in various intervals that make it difficult to manage; sending all the bills together would be far more convenient from a business perspective.

Some felt that the fee collection practices are too rigid and that they don't take individual circumstances into account. One participant expressed frustration that they were held to the same standards as RS customers (e.g. in terms of "grace amount owing"), even though their situations are incomparable.

Concerns with Plan:

Vegetation management was another common concern. While the RS customers had mixed views on this point, the GS customers were united in their concern for the curb appeal of their properties and the broader community in general. Some expressed criticism that there is not enough care or consideration in implementing the strategic removal of trees. The 15ft rule was cited to be detrimental to an area in which the flora is an integral part of the local ambiance.

Social Acceptance of Plan:

Most participants (14 of 18) accepted North Bay Hydro's plan to increase customer rates by the proposed amount; with two saying they support the proposed rate increase and twelve saying they don't like it, but think it is necessary.

Most felt that North Bay Hydro's proposed plan was well presented. Moreover, most participants in the consultation stated that the evidence provided was satisfactory for them to weigh the benefits between maintained reliability and cost implications. A number of them went on to say that North Bay Hydro appears to be acting proactively and seems to be allocating money where it would have the highest and most effective return. Most would agree that North Bay Hydro is managing cost while meeting customer expectations and keeping rates reasonable.

Q: Considering what you know about the local distribution system, which of the following best represents your point of view?

Response	RS	GS	COMBINED
The rate increase is reasonable and I support it	1	1	2
I don't like it, but I think the rate increase is necessary	3	9	12
The rate increase is unreasonable and I oppose it	0	1	1
Don't know	1	1	2
Refused	1	0	1
TOTAL	6	12	18

Methodology

About the General Service and Residential Customer Consultation

INNOVATIVE was engaged by North Bay Hydro to conduct general service and residential customer consultation sessions designed to identify the needs and preferences of consumers as they relate to the utility's proposed spending on the distribution system.

The consultation sessions were held in North Bay on October 9, 2014. A total of 18 general service and residential customers participated in these consultation sessions.

General Service under 50 kW Rate Class	12 participants
Residential Rate Class	6 participants

Recruiting Consultation Participants

General Service customers in the under 50 kW rate class were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General Service customers qualified for the consultation if they managed or oversaw their business' electricity bill. This was to ensure they were at least somewhat knowledgeable of their electricity costs and could have an informed discussion on the impact of the proposed rate increases.

Customer recruitment lists were randomly generated and provided to INNOVATIVE by North Bay Hydro.

An incentive of $100 was provided to all general service and $80 to all residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to review participant feedback and collect verbatim quotes.

Consultation Session Structure

The consultation sessions were structured around the themes contained in the workbook that was developed by INNOVATIVE and North Bay Hydro staff in the fall of 2014.

The workbook themes included the following:

1. What is this Consultation About?
2. Electricity 101
3. North Bay Hydro's Grid Today
4. Cost Pressures
5. What the Plan Means for You

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why North Bay Hydro is seeking feedback from general service and residential customers.

After explaining the purpose of the consultation, hardcopy workbooks were distributed. These acted as a session guide and provided a space for participants to record their answers to the questions contained within.

The facilitator then led the participants through the workbook section by section to ensure they understood the information and to answer any questions they had about the content.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on their answers and what the various issues meant for them or their businesses.

The hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately 2 hours.

Informing the Consultation Process

In addition to identifying customer needs and preferences as they relate to the proposed system plan, feedback collected from this phase of the consultation was used to inform the design of the subsequent telephone survey component of North Bay Hydro's customer engagement program.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section highlights the general feedback from each consultation group.

Consultation Sessions

General Service under 50 kW Rate Class

Customer Experience and Expectation

All participants were satisfied with the quality of service they received from North Bay Hydro; with one third stating they were '*very satisfied*'. Additionally, nine-in-twelve found the number of outages they experienced over the past year to be acceptable.

Improving Service of the Local Distribution System

Communication was the biggest concern, particularly during outages when business owners and managers need to make decisions on how to run their daily operations. One person mentioned that it was almost impossible to get through to the "*1-800 customer service number*" and when they did get through, no one was able to accurately forecast the duration of the outage. They agreed that a more

accessible and accurate estimation would be particularly helpful for business owners and managers. They would appreciate more communication channels to gather information from. One participant suggested a website or mobile app that could be updated remotely by on-site crews.

While the participants were satisfied with the overall service, a few participants had comments pertaining to specific areas that could be improved. Regarding customer service, some participants find it difficult to resolve conflicts. They've had difficulty getting in contact with the proper representative to answer their questions. This frustration is likely the result of the nature of customer complaints, in that conflicts are often beyond North Bay Hydro's ability to offer a resolution.

A few GS customers also expressed frustration with North Bay Hydro's planning process, particularly as it pertains to new connections and system access. One GS customers recounted experiences with miscommunications and poor planning related North Bay Hydro's engineering team. One participant recounts the installation of a new transformer for a new industrial / commercial property development. North Bay Hydro was several months behind in connecting the property to the grid; this in turn delayed the move-in date of a business tenant. The sentiment shared by a few GS participants was that North Bay Hydro does not respect the business community and the impact poor planning can have on their bottom line. Others echoed that North Bay Hydro's engineering department "needs to take a course in customer service" as their communications and attitude towards local business was in some cases seen as "poor".

Another common concern was vegetation management. They felt that the *15ft around the lines* rule needs to be more of a guideline, assessed on an individual basis by a professional capable of evaluating the risks presented by each type of tree. One user stated, "I've suffered five power outages in the last year and every one of them was caused by a falling poplar tree." The consensus was that North Bay Hydro needs to focus on the trees that are problematic (poplar) and not, as one participant put it, "*butcher* every oak/maple that fall within the 15ft of the line."

Some customers receive multiple bills (in some cases over 30). A number of GS customer expressed frustration towards their inconvenient billing cycle where bills came at various times throughout the week. Others asked if North Bay Hydro could work with small businesses to streamline their billing cycle (i.e. all the multiple bills at the end or beginning of the month). This sentiment was shared with GS customers who received multiple bills from the utility (in most cases, landlords who paid the hydro for their tenants). They would like to see consolidated billing (i.e. all invoices at once) and have just one delivery fee.

Capital Investment

The group was divided evenly in their views regarding spending on buildings, equipment, and IT systems. Half of the participants felt that North Bay Hydro needs to be strategic with spending to ensure they have the resources they need to reliably maintain the system, while the other half feels they should find ways to make do with what they already have.

One person stated that the voltage conversion that happened in their neighbourhood helped significantly with the outages, however the problem of foreign contact (i.e. trees and squirrels) remains.

Operating Budget

This group has been the closest the consumer has ever been to any kind of report on how the budget is distributed. Even so, some felt that the break down is lacking in detail. They appreciated learning that bad debt is down, but still had questions regarding what that actually means to North Bay Hydro. For example, they asked "*How are they allocating their resources?*"One participant mentioned how it was great that labour costs are compensated in line with industry standards, but was concerned with what that means compared to the private sector.

North Bay Hydro's Proposed Plan and Rate Impact

All participants felt that North Bay Hydro is planning well for the future. While only one-in-twelve GS participants supports the rate increase outright, nine-in-twelve participants maintain that, given everything they learned about North Bay Hydro's plan, the increase is necessary, even though they don't like any rate increase Furthermore, GS customers appeared to understand the limits of North Bay Hydro's role, as the distributor, and accept that to maintain service, the cost must increase on the distribution portion of their bill.

Regarding the budget, most did not know if they felt that proposed budget was reasonable. They cited that the information provided was not sufficient to determine such a thing.

How Could the Consultation Process be Improved?

Most felt that the amount of content was appropriate and proportionate to the time allotted for the group. A recurring theme was that people would appreciate being given the workbooks 1-2 weeks in advance in order to familiarize themselves with the material and come prepared with questions. One person suggested having a representative from North Bay Hydro present to answer some of the more technical questions.

Residential Rate Class

Customer Experience and Expectation

Overall, all residential customers are satisfied with the level of service they receive from North Bay Hydro. Additionally they all found the number of outages they experienced in a year to be acceptable.

Improving Service of the Local Distribution System

While most are quite satisfied with the services they receive from North Bay Hydro, when asked where the utility could improve services, there were several individual suggestions. One residential consumer expressed frustration as they believe it had been over a year since they applied to be involved in an energy conservation program. No one from North Bay Hydro had been to inspect the property and consult on reducing their consumption nor did they receive a free "energy efficiency" thermostat.

Another, older participant was hesitant to use online billing and felt the utility was trying to encourage him to migrate to this undesirable billing system. On a similar note, another participant was

disappointed that local "drop boxes" have been removed and envelopes were no longer being sent with their hydro bill.

One participant had his "equal billing" changed by several hundred dollars without notice. This caught him financially off guard. He admitted that he did not read all the information included in his bill, stating that this information used to be sent separately.

It was also mentioned that the 2-meter process that allows energy to be collected from residential solar panels is extraneous and the high cost is a deterrent. This person asked for better accessibility and clearer communication on net-metering.

Sending out hydro saving tips with each bill to help customers make informed choices would be appreciated.

Capital Investment

Some participants were concerned with the breakdown of the life expectancy of the pole line infrastructure. They asked about what the life expectancy of the existing poles and wondered whether a plan is in place to replace them in the future.

Operating Budget

Transparency in the budget was deemed important to several participants. They would like transparency. One in particular stated that they considered North Bay Hydro and Hydro One to be the same entity, fraught with lavish spending and mismanaged resources.

North Bay Hydro's Proposed Plan and Rate Impact

All participants felt that North Bay Hydro is planning '*somewhat well*' or '*very well*,' with the exception of one person who '*didn't know*.' They also agreed that the plan covered what they had expected it would.

How Could the Consultation Process be Improved?

All participants stated that they left the session with a much better understanding of North Bay Hydro's role. They found the amount of information appropriate for the allotted time and one participant acknowledged that it was a good explanation of a very complex issue.

Questionnaire Results (Workbook)

The following tables are the tabulations of participant feedback to questions in the hardcopy workbooks, which were returned at the end of each consultation session.

Note: "GS" = general service less than 50 kW customers, while "RS" = residential customers.

1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services North Bay Hydro is responsible for?

	RS	GS	TOTAL
Very well	2	4	6
Somewhat well	3	7	10
Not very well	1	1	2
I don't understand at all	0	0	0
TOTAL	6	12	18

2. Generally, how satisfied are you with the service you receive from North Bay Hydro?

	RS	GS	TOTAL
Very Satisfied	3	4	7
Somewhat satisfied	3	8	11
Somewhat dissatisfied	0	0	0
Very dissatisfied	0	0	0
Don't know	0	0	0
TOTAL	6	12	18

4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services North Bay Hydro is responsible for?

	RS	GS	TOTAL
Very well	3	2	5
Somewhat well	2	9	11
Not very well	1	1	2
I don't understand at all	0	0	0
TOTAL	6	12	18

5. The average North Bay Hydro customer experiences between 1 and 3 power outages per year. Do you recall how many outages you experienced in the past year?

	RS	GS	TOTAL
Once	2	2	4
Twice	1	5	6
Three times	1	1	2
More than three times	2	3	5
Don't know	0	1	1
TOTAL	6	12	18

6. How acceptable were the number of power outages you experienced over the last 12 months?

	RS	GS	TOTAL
Very acceptable	3	5	8
Somewhat acceptable	3	4	7
Not very acceptable	0	2	2
Not acceptable at all	0	0	0
Don't know	0	1	1
TOTAL	6	12	18

7. Overall, how satisfied are you with the reliability and quality of electricity services provided by North Bay Hydro?

	RS	GS	TOTAL
Very satisfied	4	4	8
Somewhat satisfied	2	8	10
Somewhat dissatisfied	0	0	0
Very dissatisfied	0	0	0
Don't know	0	0	0
TOTAL	6	12	18

8. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?

	RS	GS	TOTAL
North Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years	3	9	12
North Bay Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages	1	3	4
Don't know	2	0	2
TOTAL	6	12	18

9. As a company, North Bay Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?

	RS	GS	TOTAL
North Bay Hydro should find ways to make do with the buildings, equipment and IT systems it already has.	0	6	6
While North Bay Hydro should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.	6	6	12
Don't know	0	0	0
TOTAL	6	12	18

10. How well do you feel you understand the cost drivers that North Bay Hydro is responding to?

	RS	GS	TOTAL
Very well	1	2	3
Quite well	3	9	12
Not very well	2	1	3
Not at all	0	0	0
Don’t know	0	0	0
TOTAL	6	12	18

11. How well do you think North Bay Hydro is managing these cost drivers while meeting customer expectations and keeping rates reasonable?

	RS	GS	TOTAL
Very well	1	0	1
Somewhat well	4	9	13
Not very well	0	3	3
Not well at all	0	0	0
Don’t know	1	0	1
TOTAL	6	12	18

12. Now that you have a better sense of the operations of North Bay Hydro, including the cost drivers, do you feel the proposed budget is reasonable?

	RS	GS	TOTAL
Yes	2	1	3
No	1	3	4
Don’t know	3	7	10
Refused / Missing Value	0	1	1
TOTAL	6	12	18

13. How well did North Bay Hydro's plan cover the topics you expected?

	RS	GS	TOTAL
Very well	2	1	3
Somewhat well	3	10	13
No, not very well	1	0	1
Refused / Missing Value	0	1	1
TOTAL	6	12	18

14. How well do you think North Bay Hydro is planning for the future?

	RS	GS	TOTAL
Very well	2	2	4
Somewhat well	3	9	12
Not very well	0	0	0
I don’t know	1	0	1
Refused / Missing Value	0	1	1
TOTAL	6	12	18

15. Considering what you know about the local distribution system, which of the following best represents your point of view?

	RS	GS	TOTAL
The rate increase is reasonable and I support it	1	1	2
I don’t like it, but I think the rate increase is necessary	3	9	12
The rate increase is unseasonable and I oppose it	0	1	1
Don’t know	1	1	2
Refused / Missing Value	1	0	1
TOTAL	6	12	18

Customer Telephone Surveys

Telephone Surveys
among Residential and GS Customers

PURPOSE: To obtain statistically significant quantitative feedback on the proposed system plan spending and assess reaction to customer opinions obtained from the previous research phases

Summary

The following summary highlights the key findings from telephone surveys of 505 North Bay Hydro residential customers and 100 General Service (GS) <50 kW customers:

General Satisfaction

- More than half (61%) of residential customers are familiar with their local distribution system, while General Service customers are slightly less familiar (58%).
- Majority of residential (83%) and General Service (88%) customers are satisfied with North Bay Hydro.
- When asked how to improve service, four-in-ten want cheaper rates (39% RS; 40% GS). A tenth (9%) of residential customers and nearly one-in-five (19%) GS customers said North Bay Hydro could do "nothing/already satisfied".

Electricity Bill Knowledge Summary

- About half of residential (56% unfamiliar) and General Service (49% unfamiliar) respondents are not overly familiar with the breakdown of their electricity bill.

System Reliability

- Over half (57%) of residents and two-thirds of GS respondents (67%) experienced less than two power service interruptions in the past 12 months.
- The most recent outage in the last 12 months lasted less than 15 minutes for plurality of respondents (46% RS; 39% GS) and are minor inconvenience or had barely any cost to business (66% RS; 54% GS)
- About three-quarter of residential (76%) and GS respondents (74%) think North Bay Hydro should either spend what is needed to reduce the number of power outages (23% RS; 29% GS) or to maintain the current level (53% RS; 45% GS).

System Challenges & Priorities

- On infrastructure investment, six-in-ten (59%) residential respondents and nearly four-in-ten (37%) of General Service respondents believe that North Bay Hydro should invest in its aging infrastructure to reduce future outages, even if it means higher bills.
- Two-thirds (63%) of residential customers and half (52%) of General Service customers believe that North Bay Hydro should be wise with its spending on equipment and tools, but they also

think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

- On budgeting for labour costs increase, three-in-five (59%) residential respondents and half (49%) of GS respondents believe that it is important for North Bay Hydro to retain and attract experienced and qualified workers to operate the system by paying a wage that is competitive but within industry benchmarks.
- Majority of the respondents support North Bay Hydro's tree clearance policy (82% RS; 81% GS).

Overall Assessment of Plan

Residential Acceptance: Nearly three-quarter residential respondents (73%) accept the rate increase. A quarter (25%) of the respondents accept the increase willingly ("the rate increase is reasonable and I support it"), and half (48%) of them support the increase reluctantly ("I don't like it, but I think the rate increase is necessary". Less than a third (25%) thinks the rate increase is unreasonable and would not support it.

Top 3 Reasons for Willing Acceptance ***Q: And why do you say that? [Asked of RS respondents who had an opinion on NBH's proposed rate increase]***	
Invest/necessary to maintain/keep up for future	35%
$4.60-$5.00 not a lot of money/can afford	33%
Cost of everything going up	19%
Other	8%

General Service Acceptance: General Service respondents are slightly less supportive of rate increases than residential customers: about seven-in-ten (68%) of organizational respondents accept the proposed North Bay Hydro plan (20% willing acceptance and 48% reluctant acceptance) while slightly more than a quarter (28%) think the rate increase is unreasonable and would not support it.

Top 3 Reasons for Willing Acceptance ***Q: And why do you say that? [Asked of GS respondents who had an opinion on NBH's proposed rate increase]***	
Rate increase is acceptable/affordable	30%
Necessary for long-term investment/infrastructure	25%
Must be necessary/has to be done	20%
Other	5%

Methodology

INNOVATIVE conducted two customer surveys by telephone for North Bay Hydro:

1. A residential customer survey conducted among **505 respondents** between October 21 and 26, 2014; and
2. A general service customer (GS < 50 kW) survey conducted among **100 respondents** between October 21 and 28, 2014.

Participants were randomly selected from customer lists provided by North Bay Hydro (15,576 residential records and 1,731 GS records).

- A sample of 505 residential customers is considered accurate to within ±4.5 percentage points, 19 times out of 20.
- A sample of 100 General Service customers is considered accurate to within ±9.5 percentage points, 19 times out of 20.

The margin of error in both surveys will be larger within each sub-grouping of the samples.

Questionnaire Design

The questionnaires were designed to simulate the journey that respondents in the Workbook-led Consultation Sessions experienced. This included a combination of educating the customer, having customers reflect on their personal experience with their distribution system, and having them make value judgments on trade-offs between system reliability and bill impact.

As part of simulating the "*workbook journey*", the questionnaires were informed by and incorporated feedback from the previous phases of North Bay Hydro's customer engagement. This included sharing both supportive and non-supportive feedback in the survey from previous phases of North Bay Hydro's customer consultation as it related to North Bay Hydro's proposed capital work and the associated rate increase. Wording of questions differed slightly between the Residential and General Service survey – for example, in the preambles the size of monthly bills differed between residential and general service customers – but otherwise remained generally consistent.

The average survey ran at approximately 10 minutes. Both survey instruments can be found at the end of this section of the report.

Fielding the Survey

Residential (RS) Customer Survey:

For the purposes of executing the residential survey, North Bay Hydro provided INNOVATIVE with a confidential list containing **15,576** of their residential customers' contact information.

The contact list included only residential customers with residential landline contact information on file and who had been a customer of North Bay Hydro since at least January 1, 2013. The information contained in the contact list included customer name, home telephone number, home address, service area, and total annual usage between January 1 and December 31, 2013.

Only one customer per household was eligible to complete the residential survey. Survey respondents were screened to certify that only the resident primarily responsible for paying their North Bay Hydro electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household to answer questions about their electricity bill and whether North Bay Hydro's proposed rate increase would have a relative impact on their bill.

Before retiring any randomly selected telephone number from the contact list, 8 attempts were made to reach a potential respondent for each unique telephone number, or until an interviewer received a hard

refusal. Each night a new sample was released from the contact list to replace completed or retired numbers.

North Bay Hydro's residential customers were contacted at their home by telephone between 4pm and 9pm on weekdays; between 10am and 8pm on Saturdays; and between 11am and 8pm on Sundays.

General Service (GS) Customer Survey:

The sample for the GS survey consisted of **1,731** customers drawn from a confidential list provided to INNOVATIVE by North Bay Hydro. GS respondents were screened to ensure they were in charge of managing the electricity bill at their organization.

GS customers were contacted on weekdays between 9am to 4pm.

All fieldwork was conducted using INNOVATIVE's computer-assisted telephone interviewing (CATI) system.

Sample Design

The two surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In both surveys, residential and general customers were divided into quartiles based on annual electricity usage to ensure the sample had a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households.

Residential and General Service Sample Design:

North Bay Hydro customers were divided into quartiles based on annual electricity usage. The following table illustrates the segmentation of the residential and general service customer survey samples by usage quartile.

Customer Type		Total Sample	Low	Medium-Low	Medium-High	High
Residential	Target	500	125	125	125	125
	Actual	505	126	126	125	128
	Difference	+5	+1	+1	0	+3
General Service	Target	100	25	25	25	25
	Actual	100	25	29	22	24
	Difference	0	0	+4	-3	-1

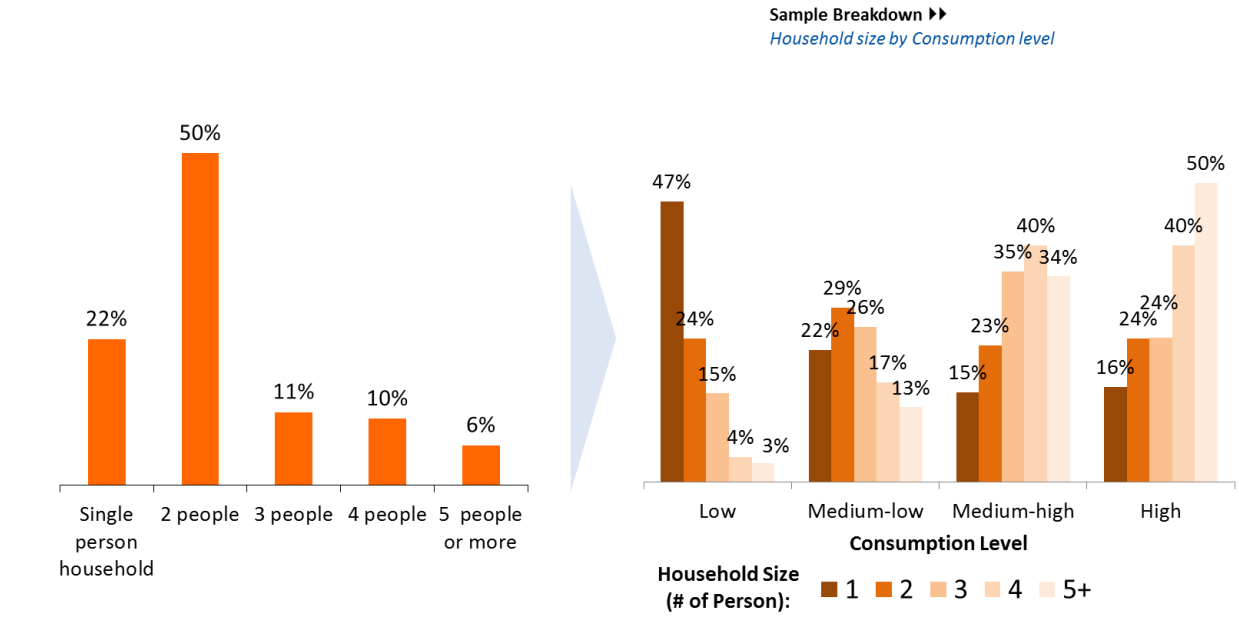
Sample Weights

Weights have not been applied to either the residential or GS data as the stratified random samples are accurate representations of North Bay Hydro's actual customer distribution and type.

Demographic Profiles

The following details the demographic characteristics of respondents who completed the Residential Ratepayer Survey [n=505].

Figure A: Residential Customer Profile

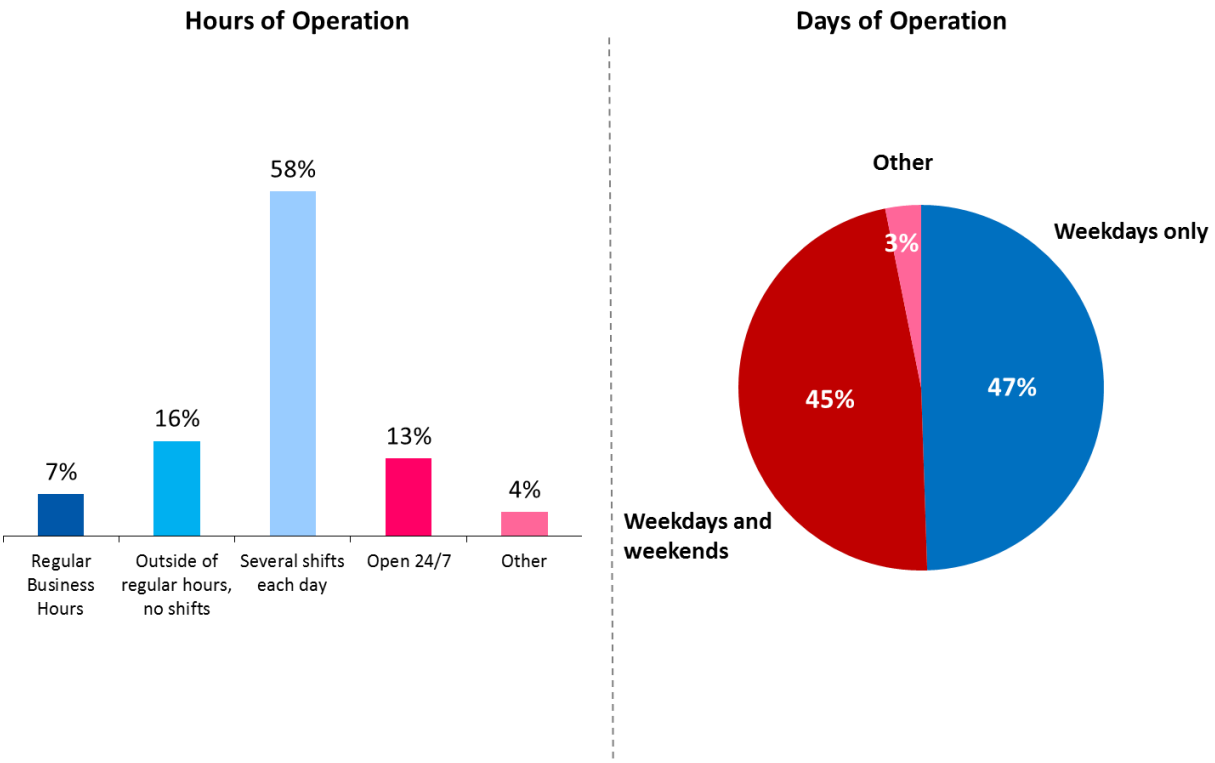


Note: 'Refused' (1%) not shown

Firmographic Profiles

Below are the firmographics of respondents who completed the General Service Ratepayer Survey [n=100].

Figure B: GS Customer Profile



Respondent Feedback

Familiarity and Satisfaction

This section of the workbook explores familiarity and experience with the local distribution system, and satisfaction with North Bay Hydro in running that system. The results for residential customers are presented first, followed by general service (GS) customers.

Familiarity and Satisfaction Summary

- More than half of residential customers (61%) are familiar with the local distribution system, while General Service customers are slightly less familiar (58%).
- A majority of residential (83%) and General Service (88%) customers are satisfied with the job North Bay Hydro is doing.
- When asked how to improve service, a plurality (48% RS; 33% GS) want reduced rates and charges.
- One-in-ten (9%) residential respondents and nearly two-in-five (19%) General Service respondents say North Bay Hydro could do "nothing to improve their service". Some residential (2%) and GS (15%) respondents commended North Bay Hydro on already doing a good job.

Preamble for Familiarity and Satisfaction Section

Prior to answering the questions in the General Satisfaction Section, respondents were presented with a preamble concerning key components of Ontario's electricity system.

The preamble read as follows:

"To start, I'd like to ask you a few questions about the electricity system…

As you may know, Ontario's electricity system has three key components: ***generation***, ***transmission*** *and* ***distribution****.*

- ***Generating stations*** *convert various forms of energy into electric power;*
- ***Transmission lines*** *connect the power produced at generating stations to where it is needed across the province; and*
- ***Distribution lines*** *carry electricity to the homes and businesses in our communities.*

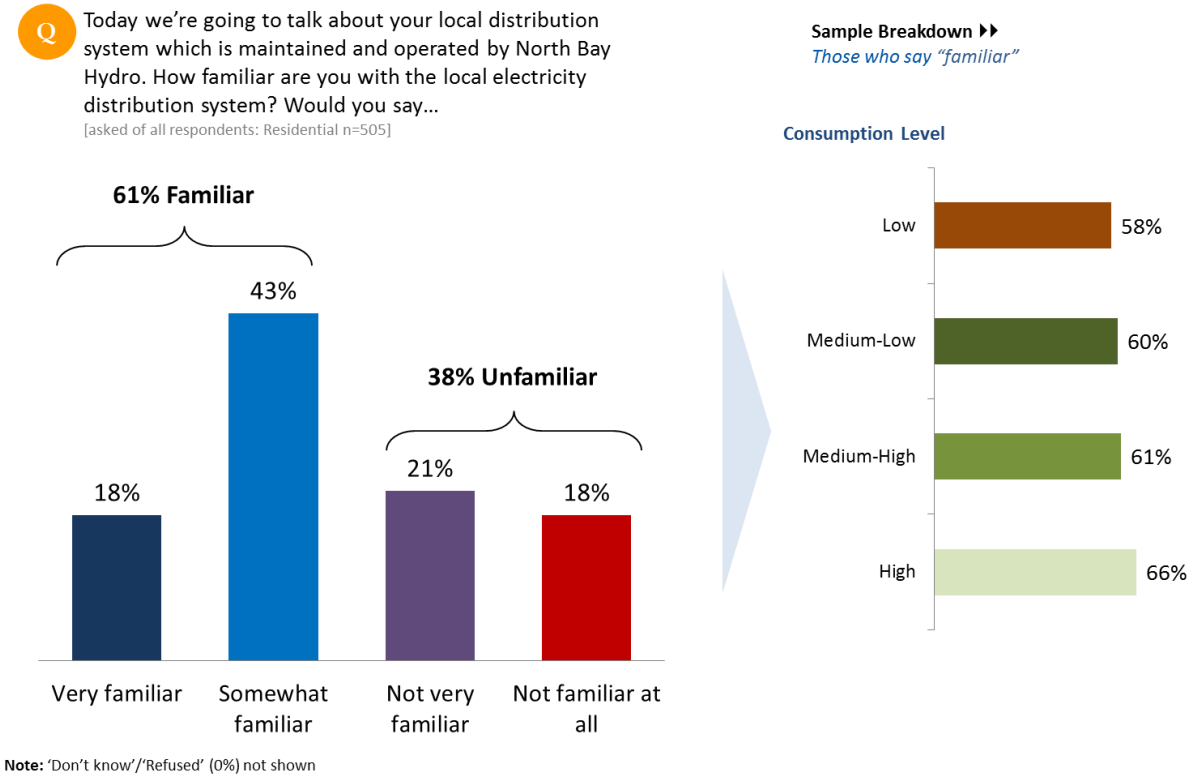
Today we're going to talk about your ***local distribution system*** *which is maintained and operated by North Bay Hydro."*

Familiarity with Local Electricity Distribution System

More than half of residential respondents (61%) are familiar with their local distribution system. Of those who indicated they are familiar, 18% say they are *very* familiar with the system.

- Differences in consumption level are seemingly related to familiarity. High levels of consumption are associated with greater familiarity than low level consumption (66% versus 58%).

Figure RS.1: Familiarity with the Local Distribution System

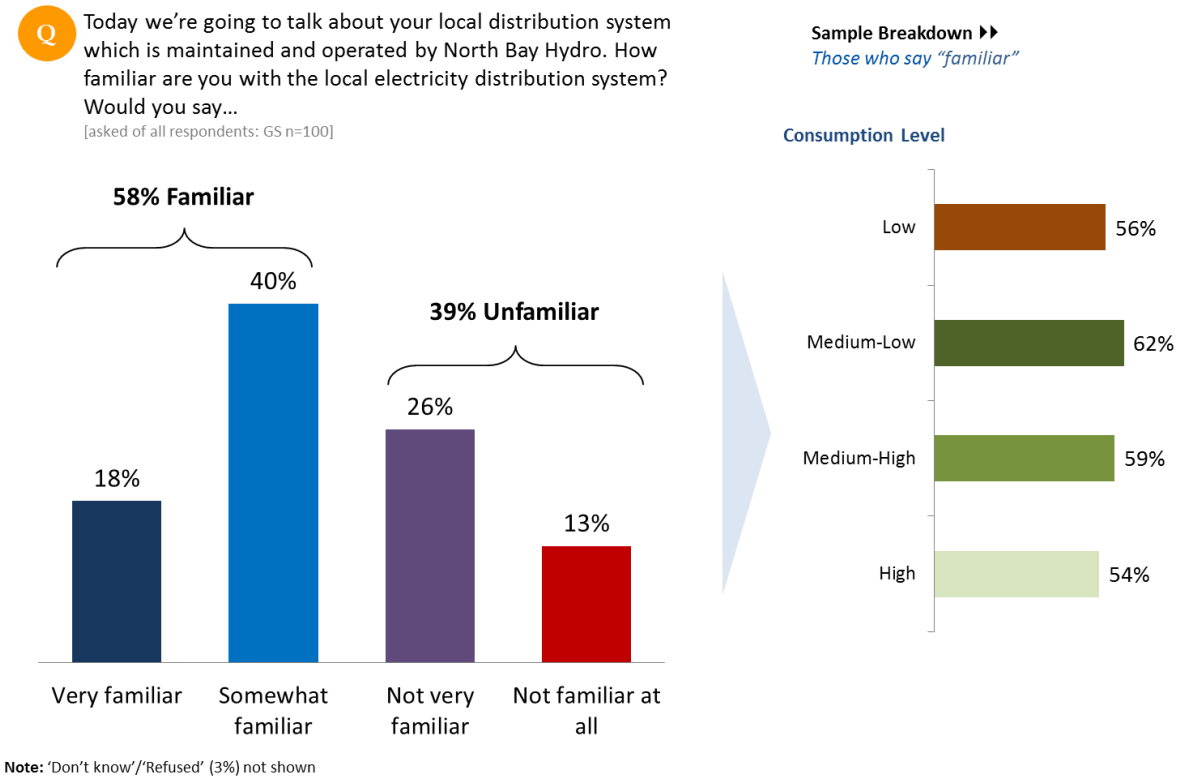


Note: 'Don't know'/'Refused' (0%) not shown

Of the General Service respondents, more than half (58%) are familiar with their local distribution system. Of those who indicated they are familiar, 18% say they are *very* familiar with the system.

- Consumption level does not appear to be a determining factor of respondents' level of familiarity with the system. The difference in familiarity among respondents of different consumption levels is within the margin of error (±10 percentage points) for the sample size of 100.

Figure GS.1: Familiarity with the Local Distribution System



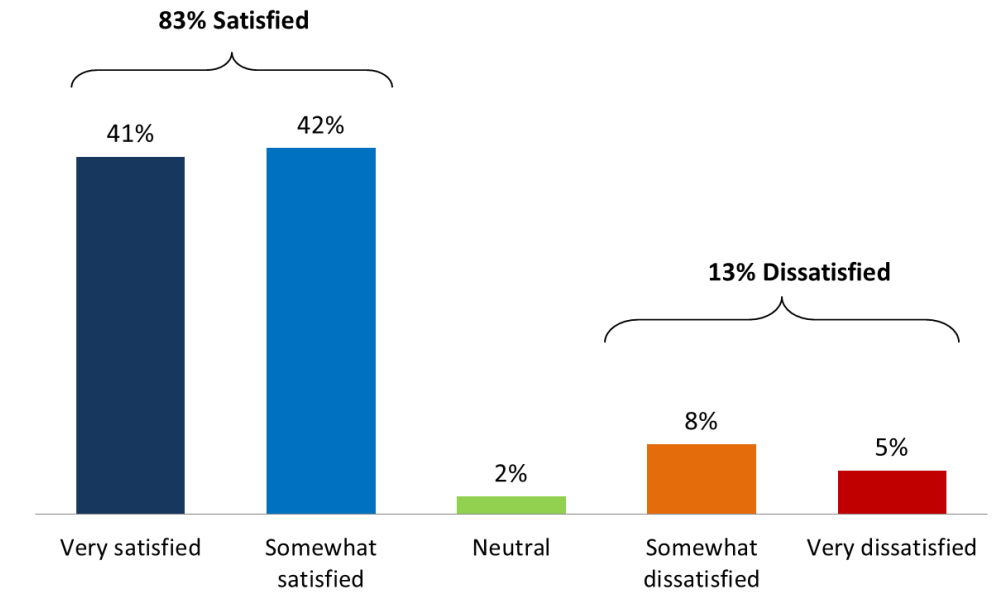
Satisfaction with North Bay Hydro Running the Distribution System

A majority (83%) of residential customers are satisfied with how North Bay Hydro is running their electricity distribution system, with 41% of residential customers responding "very satisfied".

Figure RS.2: Satisfaction with North Bay Hydro

Q Generally speaking, how satisfied are you with the job North Bay Hydro is doing running your local distribution system? Would you say …

[asked of all respondents; Residential n= 505]

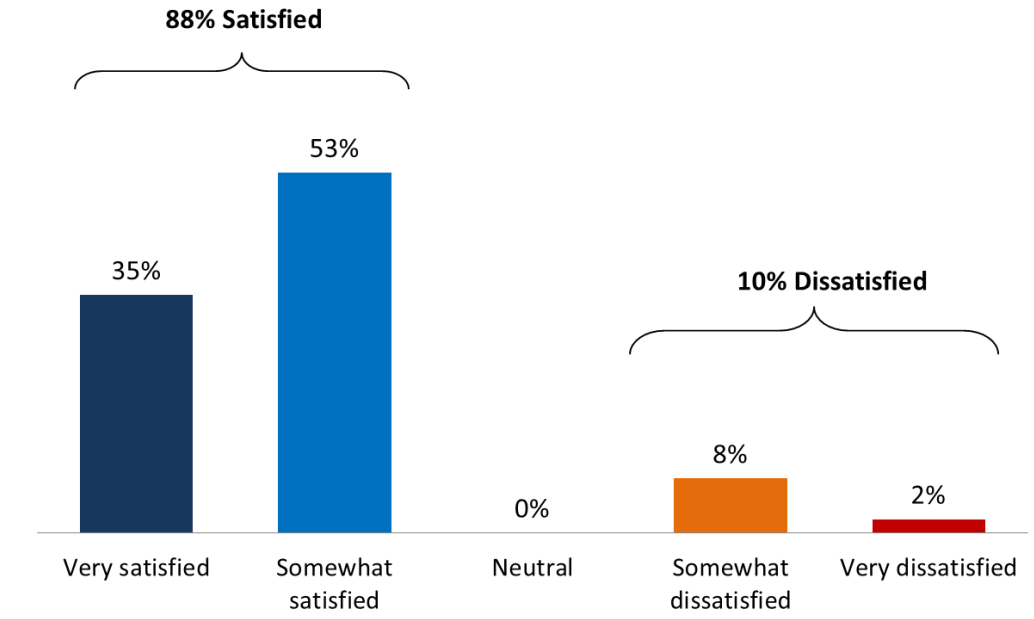


Note: 'Don't know'/'Refused' (2%) not shown

Like residential customers, a majority (88%) of General Service customers are satisfied with the job North Bay Hydro is doing running the distribution system. About one-in-three (35%) General Service customers are very satisfied with North Bay Hydro.

Figure GS.2: Satisfaction with North Bay Hydro

Q Generally speaking, how satisfied are you with the job North Bay Hydro is doing running your local distribution system? Would you say …
[asked of all respondents; GS n= 100]



Note: 'Don't know'/'Refused' (2%) not shown

How to Improve Service

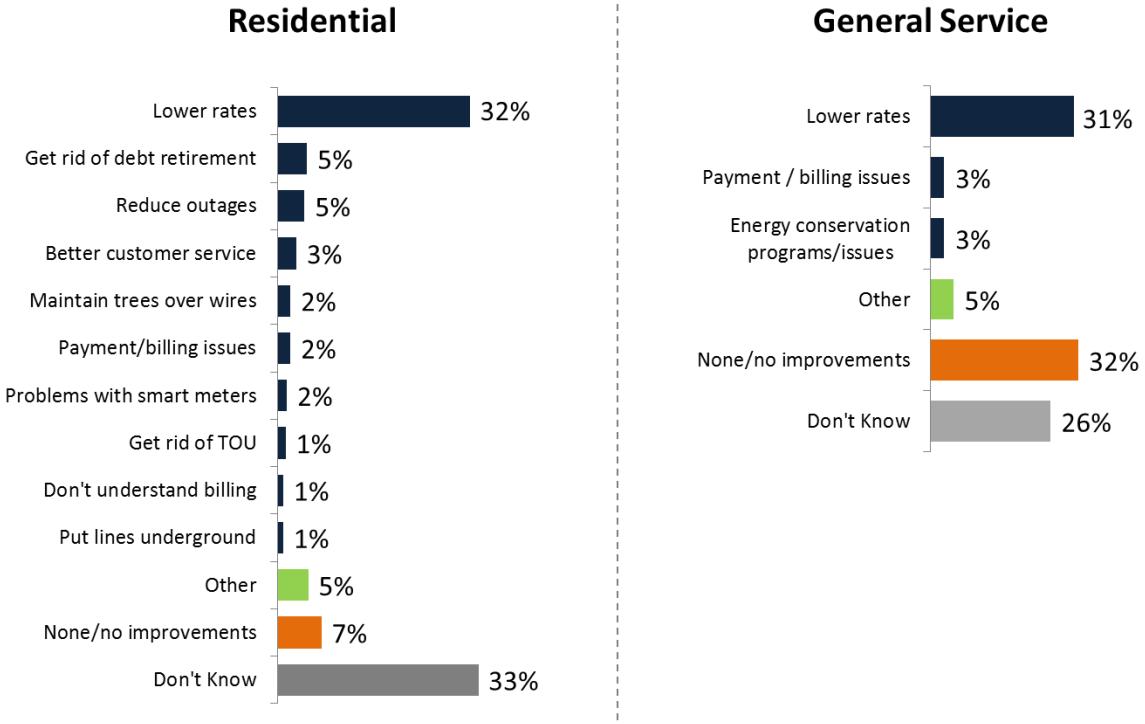
When asked how North Bay Hydro could improve service, a plurality of residential (32%) and General Service (31%) customers suggest that North Bay Hydro could "lower rates".

Other areas for improvement mentioned by residential respondents include "reduce outages" (5%).

Nearly a third (32%) of GS respondents and 7% of residential respondents say North Bay Hydro could do "nothing to improve their service".

Figure RS/GS.3: How to Improve Service

Q Is there anything in particular **North Bay Hydro** can do to improve their service to you (your organization)? [asked of all respondents]



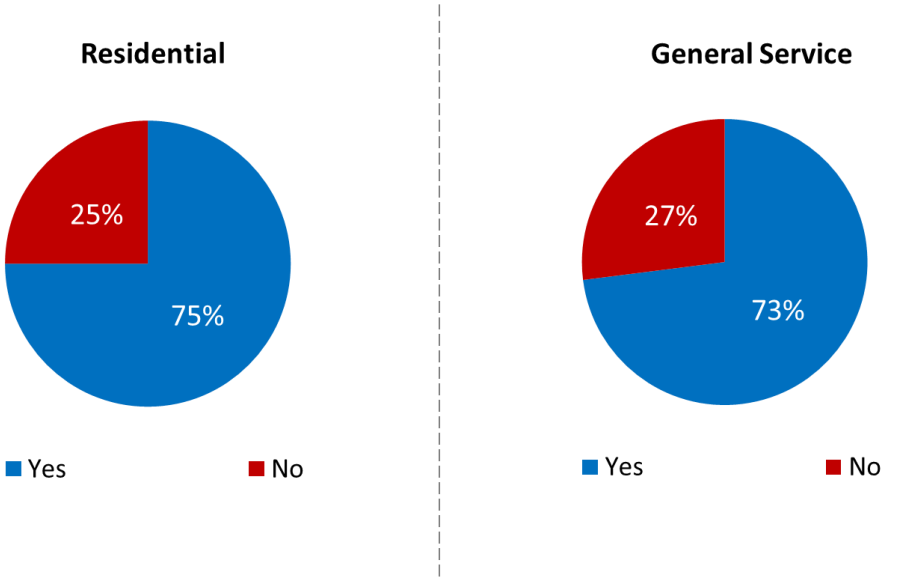
Knowledge of Ownership

About three-quarters of residential (75%) and GS (73%) respondents are aware that North Bay Hydro is owned by the City of North Bay.

- Among residential respondents, the awareness is highest in two-person households, 80% of whom are aware of North Bay Hydro's owner (one: 73%; three:67%; four:73%; five plus: 59%).
- Among GS respondents, the awareness is higher in businesses that operate during regular hours (81%) than businesses that operate outside of regular hours (63%).

Figure RS/GS.4: Knowledge of Ownership

Q North Bay Hydro is 100% owned by the City of North Bay and has an independent board of directors…Before this survey, did you know that North Bay Hydro was owned by the City of North Bay?
[asked of all Residential respondents; n =505; GS respondents n= 100]



Electricity Bill Knowledge

This section explores Residential and General Service respondent perceptions and knowledge of their electricity bill. It specifically focuses on the breakdown of the bill and what portion respondents estimate goes to North Bay Hydro.

Electricity Bill Knowledge Summary

- About half of residential (56% unfamiliar) and General Service (49% unfamiliar) respondents are not overly familiar with the breakdown of their electricity bill.

Preamble for Bill Knowledge & Impact Section

For this component of the survey, respondents were presented with a preamble concerning the breakdown of costs of an electricity bill. The two surveys provided different preambles based on targeted respondents.

The preamble for **residential customers** read as follows:

"I'd now like to talk with you about your electricity bill …

*While some customers pay more and others pay less, the **average residential customer pays about $130 a month** for electricity of **which $30 or approximately 20% goes to North Bay Hydro**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

The **General Service** preamble explained it slightly differently:

"I'd now like to talk with you about your electricity bill …

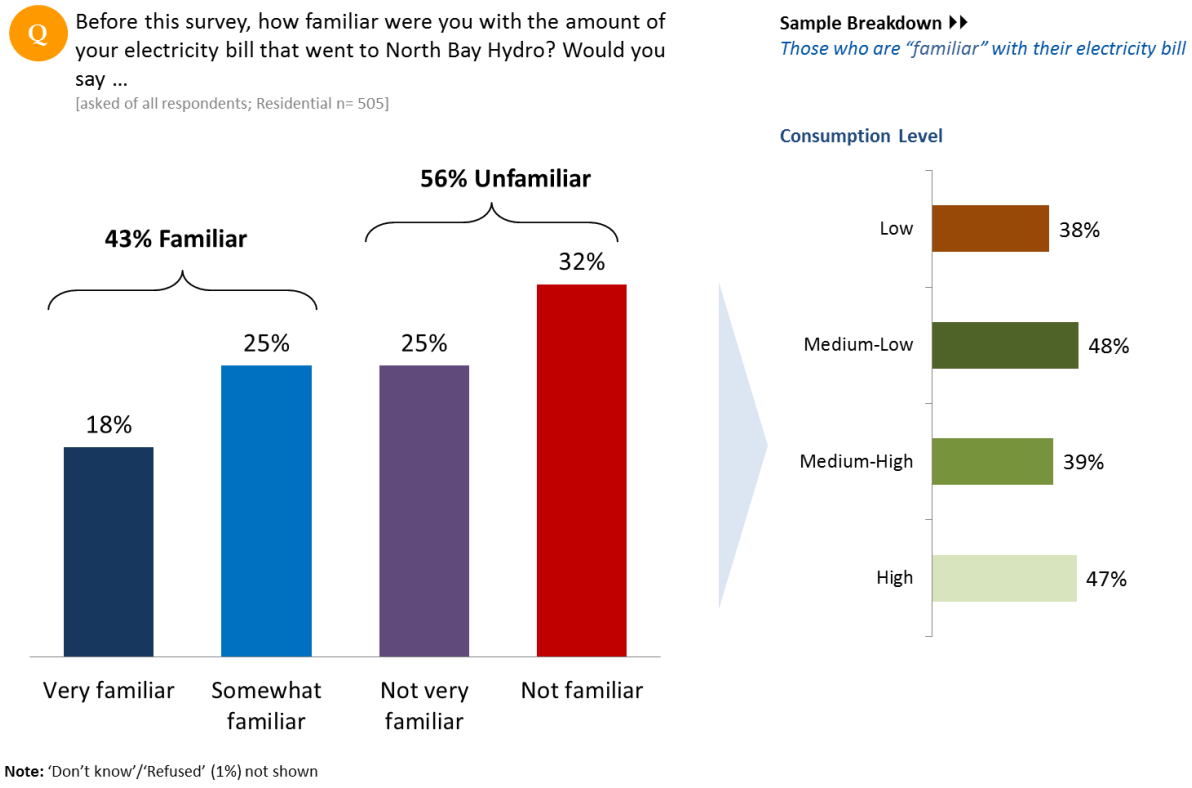
*While some customers pay more and others pay less, the **average small and medium-sized business pays about $315 a month** for electricity of **which $70 or approximately 20% goes to North Bay Hydro**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."*

Familiarity with Share of Bill Going to North Bay Hydro

After the preamble, when asked about the breakdown of their electricity bill, 43% of residential customers stated that they were familiar with the amount of their electricity bill that went to North Bay Hydro.

- Those with high (47%) and medium-low (48%) consumption levels prove more familiar with their bill than the medium-high and low levels (38%).
- Four-person-households (50%) are more familiar with their bills than households of other sizes (one: 38%; two: 44%; three: 37%; five or more: 44%).

Figure RS.5: Familiarity with Share of Bill Going to North Bay Hydro

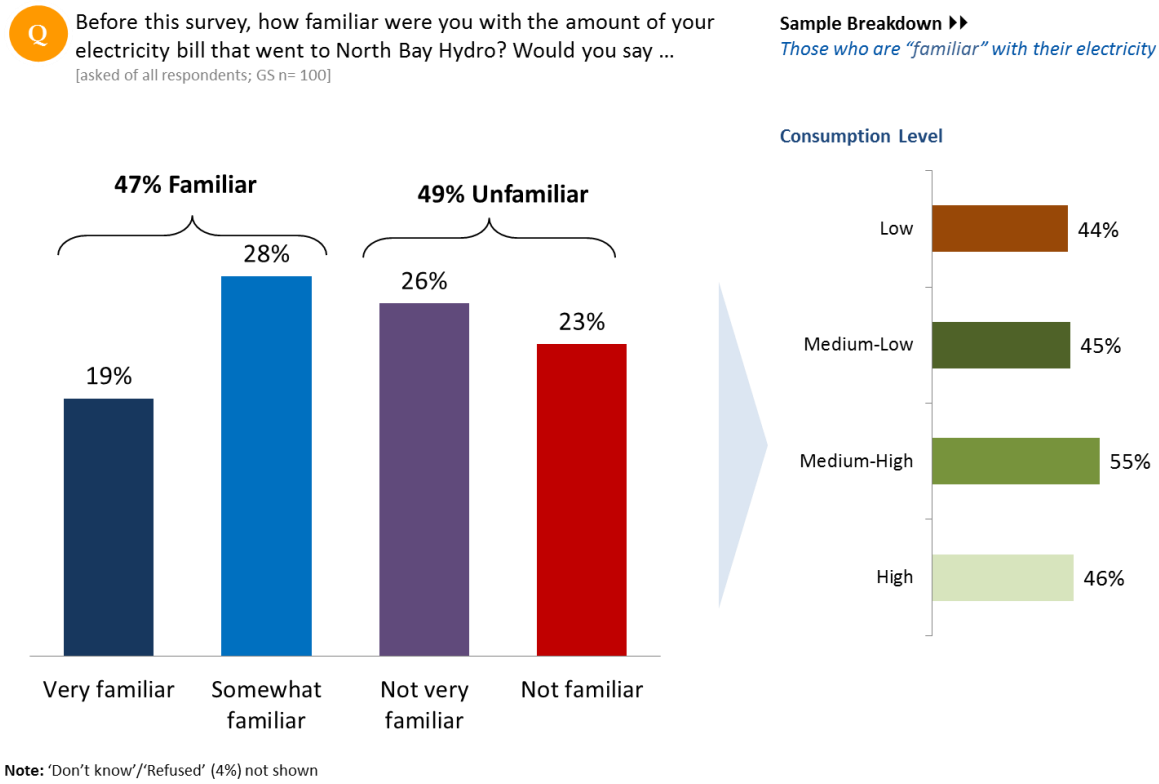


Note: 'Don't know'/'Refused' (1%) not shown

Similar levels of familiarity occur in the GS survey: 47% of respondents say they are familiar with the amount of their bill going to North Bay Hydro, while 49% indicate they are not familiar with how their bill is broken down.

- Organizations consuming medium-high volume (55%) are the most familiar with their electricity bill (Low: 44%; Medium-low: 45%; High: 46%).
- Organizations that operate during regular business hour (53%) are more familiar with their electricity bill than those who operate outside of regular business hours (38%).

Figure GS.5: Familiarity with Share of Bill Going to North Bay Hydro



Note: 'Don't know'/'Refused' (4%) not shown

System Reliability

This section covers the feedback provided by respondents on previous power service interruptions, , as well as the cost of service interruption to General Service respondents. The interruptions discussed were attributed to both weather and non-weather related events. It also discusses perceptions surrounding spending, and reducing the number and length of power service interruptions.

System Reliability Summary

- Over half (57%) of residents and two-thirds of GS respondents (67%) experienced less than two power service interruptions in the past 12 months.
- Among residential respondents who have experienced any power outages in the past 12 months, 46% reported the most recent outage lasted less than 15 minutes and 66% reported the outage was a minor inconvenience.
- Among GS respondents who have experienced any power outages in the past 12 months, 39% reported the most recent outage lasted less than 15 minutes and 54% reported the outage had barely any cost to their business.
- To address the number of outages, nearly a quarter (23%) of residential customers think North Bay Hydro should spend what is needed to reduce the number of power outages and over half (53%) think it should spend what is needed to maintain the current level.
- Three-quarters (74%) of GS customers think North Bay Hydro should spend what is needed to either reduce (29%) or maintain (45%) the length of power outages.

Preamble for Power Service Interruptions

The next five questions focused on how, according to the respondent, North Bay Hydro should address the number of outages. A preamble concerning the average number of power interruptions was provided before the question addressing the number of outages.

The preamble read as follows:

"Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said –not including outages caused by extreme weather – the average North Bay Hydro customer experiences between one and two power outages per year."

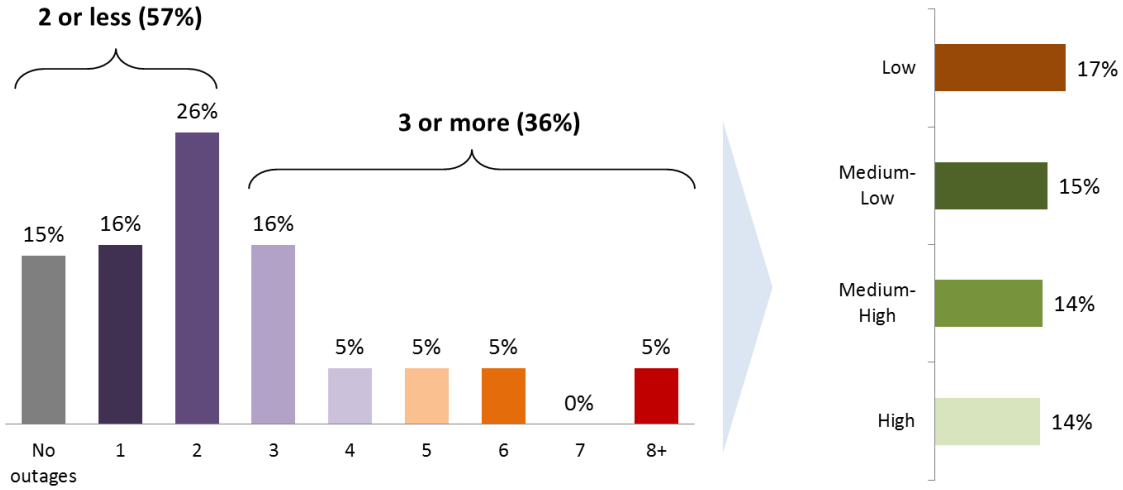
Power Service Interruptions

Among residential respondents, in the past 12 months, one-in-seven (15%) has not experienced any power outage and one-in-three (36%) have experienced more than 3 power outages. Among GS respondents, in the past 12 months, one-in-five (22%) has not experienced any power outage and one-in-four (27%) have experienced more than 3 power outages.

- Residential respondents with the lowest consumption level (17%) are slightly more likely to report no outages (medium-low: 15%; medium-high: 14%; high: 14%)
- GS respondents with the lowest consumption level (32%) are much more likely to report no outages (medium-low: 21%; medium-high: 23%; high: 13%).

Figure RS.6: Power Service Interruptions

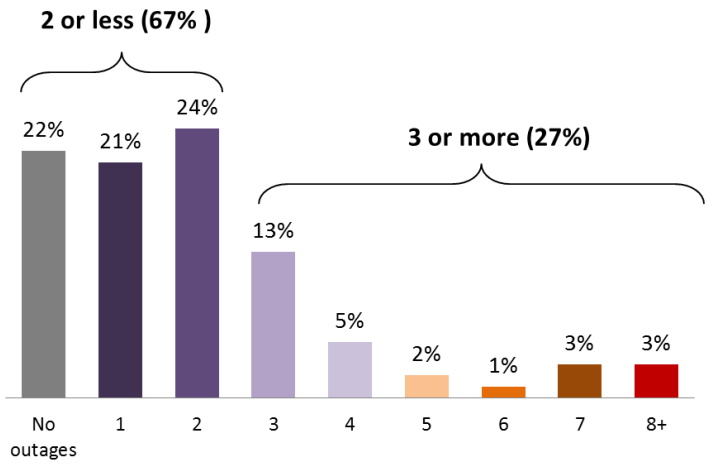
Q Have your organization experienced any power outages in the past 12 months, and if so, approximately how many?
[asked of all respondents; RS n= 505]



Note: 'Don't know'/'Refused' (0%) not shown

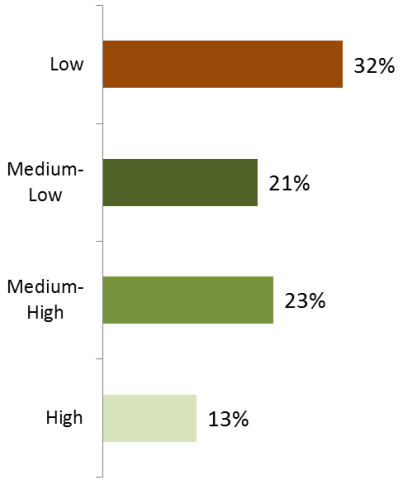
Figure GS.6: Power Service Interruptions

Q Have your organization experienced any power outages in the past 12 months, and if so, approximately how many?
[asked of all respondents; GS n= 100]



Sample Breakdown ▸▸
Those who say "no outages"

Consumption Level



Note: 'Don't know'/'Refused' (2%) not shown

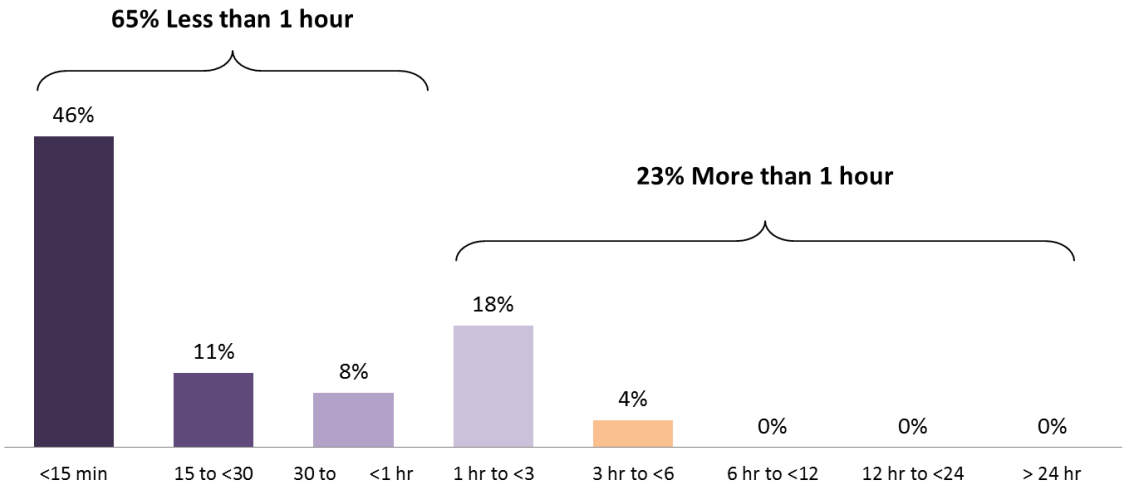
Length of Power Outages

Respondents who reported having experienced an outage in the past 12 months (Residential n=390; GS n=72) were asked two additional questions on the length and impact of the most recent outage.

Among residential respondents, almost half (46%) reported the most recent outage lasted less than 15 minutes. Among GS respondents, two-in-five (39%) reported the most recent outage lasted less than 15 minutes.

Figure RS.7: Length of Power Outages

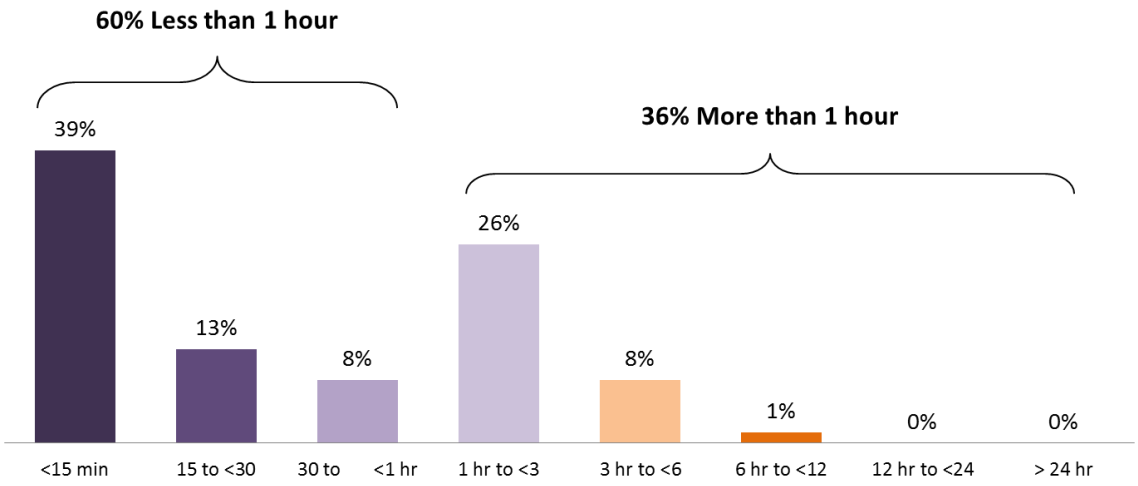
Q And approximately how many minutes did the most recent power outage last?
[asked of respondents who have experienced outage in the past 12 months; RS n= 390]



Note: 'Don't know'/'Refused' (12%) not shown

Figure GS.7: Length of Power Outages

Q And approximately how many minutes did the most recent power outage last?
[asked of only respondents; who have experienced outage in the past 12 months GS n= 72]



Note: 'Don't know'/'Refused' (4%) not shown

Impact of Most Recent Power Outage

When asked about the extent of the inconvenience (for residential respondents) or the cost to business (for GS respondents) caused by the most recent outage, two-in-three (68%) residential respondents reported the outage as a minor inconvenience, whereas one-in-two (54%) respondents reported the outage had barely any cost to his/her business, other than a mild inconvenience.

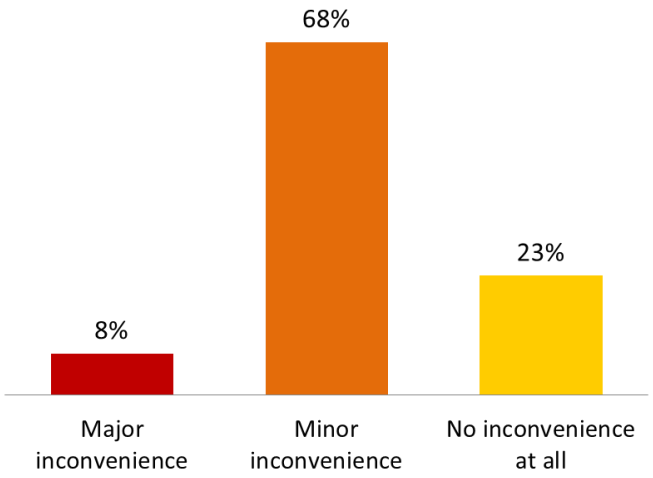
The likelihood of reporting the outage as a "major inconvenience" or "had a significant cost to my business" seemingly increases with level of consumption.

- Among residential respondents, those who consume at the highest level (11%) are most likely to report the outage as a major inconvenience (Low: 3%; Medium-low: 8%; Medium-High: 10%).
- Among GS respondents, those who consume at the highest level (21%) are most likely to report the outage as having a significant cost to his or her business (Low: 6%; Medium-low: 14%; Medium-High: 13%).

Figure RS.8: Inconvenience of Outages

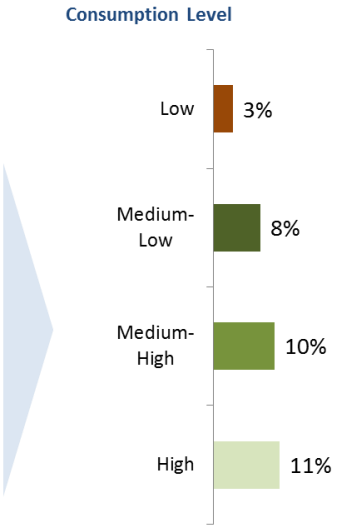
Q Thinking back to the most recent power outage you experienced as a North Bay Hydro customer, would you say the power outage …

[asked of respondents who have experienced outage in the past 12 months; RS n= 390]



Sample Breakdown ▸▸

Those who say "major inconvenience"

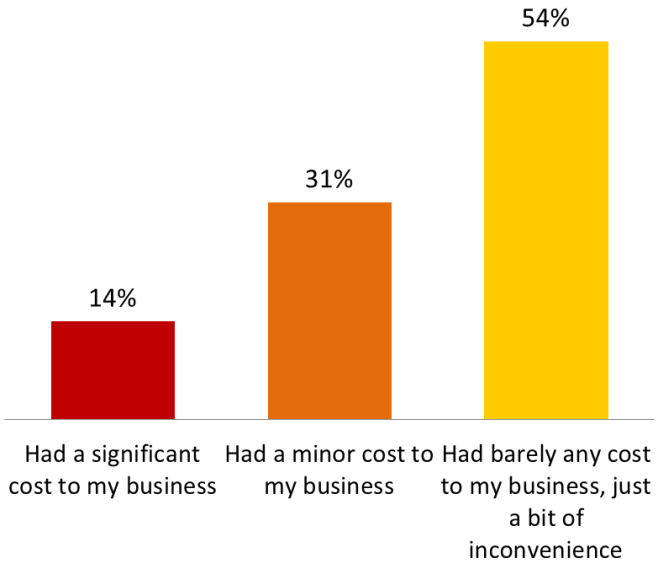


Note: 'Don't know'/'Refused' (0%) not shown

Figure GS.8: Commercial Cost of Outages

Q Thinking back to the most recent power outage you experienced as a North Bay Hydro business customer, would you say the power outage …

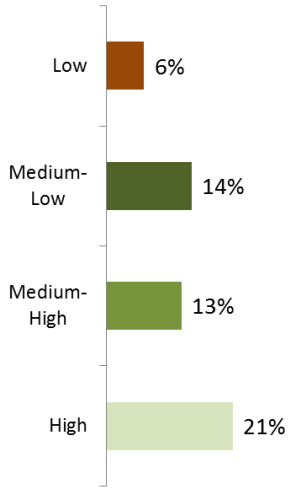
[asked of only respondents; who have experienced outage in the past 12 months GS n= 72]



Sample Breakdown ▸▸

Those who say "major inconvenience"

Consumption Level

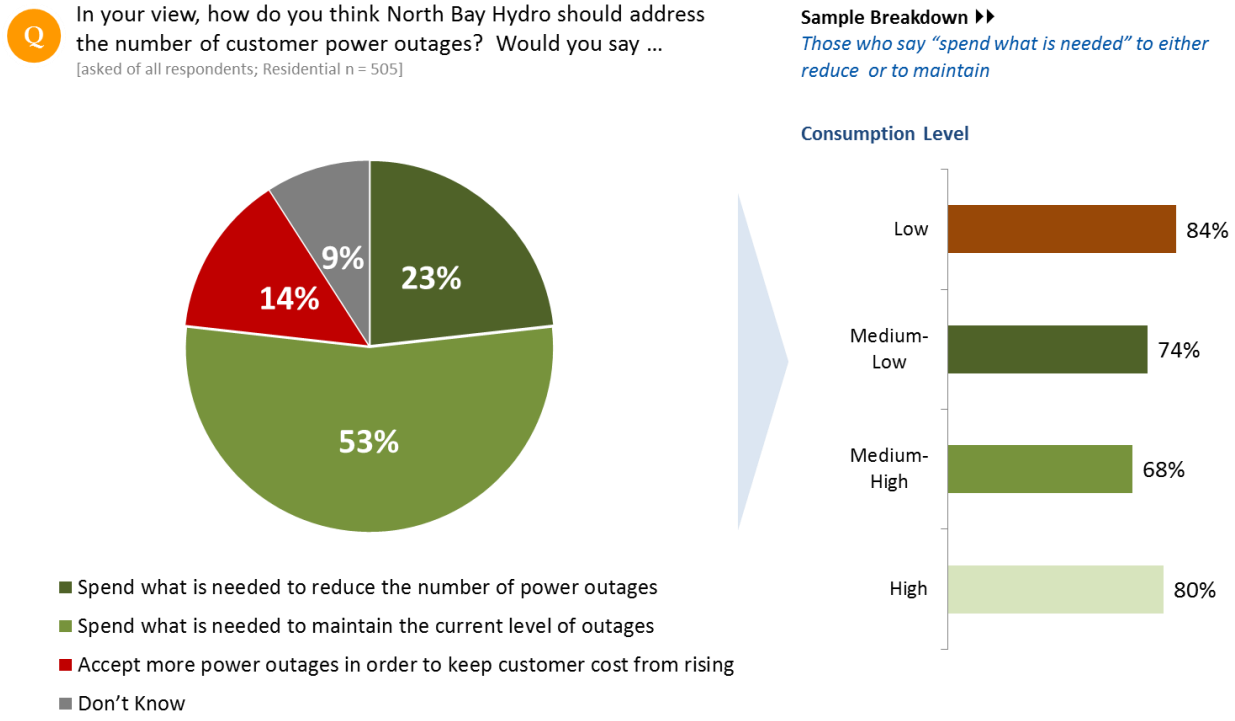


Addressing the Frequency of Service Outages

Almost one-in-four (23%) residential respondents think North Bay Hydro should spend what is needed to reduce the number of power outages and half (53%) think they should spend what is needed to maintain the current level. Just 14% state that North Bay Hydro should accept more power outages in order to keep customer costs down.

- Residents who agree that their electricity bill "has a major impact on their finances" are less likely to want to "spend to maintain" (50%) than those who do not feel their bill has a major impact on their finances (60%).

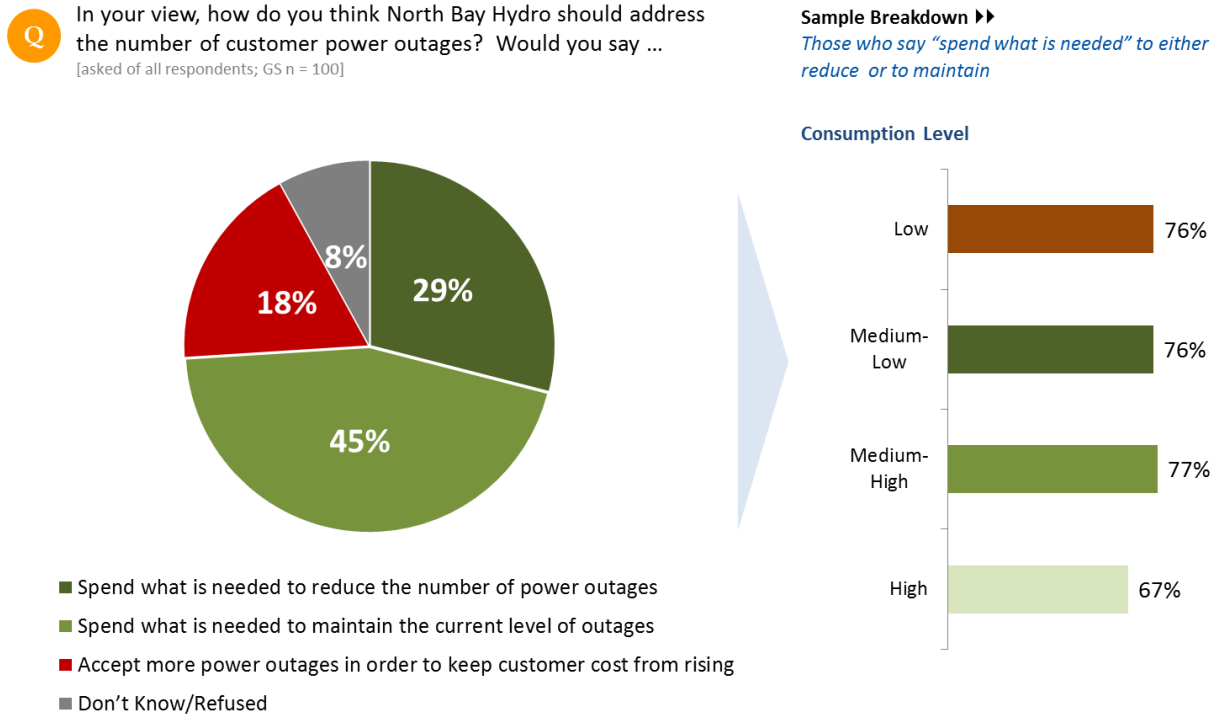
Figure RS.9: Addressing the Frequency of Service Outages



General Service customers respond likewise on how to address the number of outages: 29% think that North Bay Hydro should spend what is needed to reduce the number of power outages and 45% say they should spend what is needed to maintain the current level.

- In terms of consumption levels, GS respondents who consume the most (67%) are the least likely to support the spending (Low: 76%; Medium-low: 76%; Medium-high: 77%).
- GS respondents who agree that their electricity bill "has a major impact on their bottom line" are less likely to want to "spend to maintain" (40%) than those who do not feel their bill has a major impact on their bottom line (52%).

Figure GS.9: Addressing the Frequency of Service Outages



Preamble for Addressing the Duration of Service Outages

Before the follow-up question on how North Bay Hydro should address the length of time without power, respondents were read the following preamble:

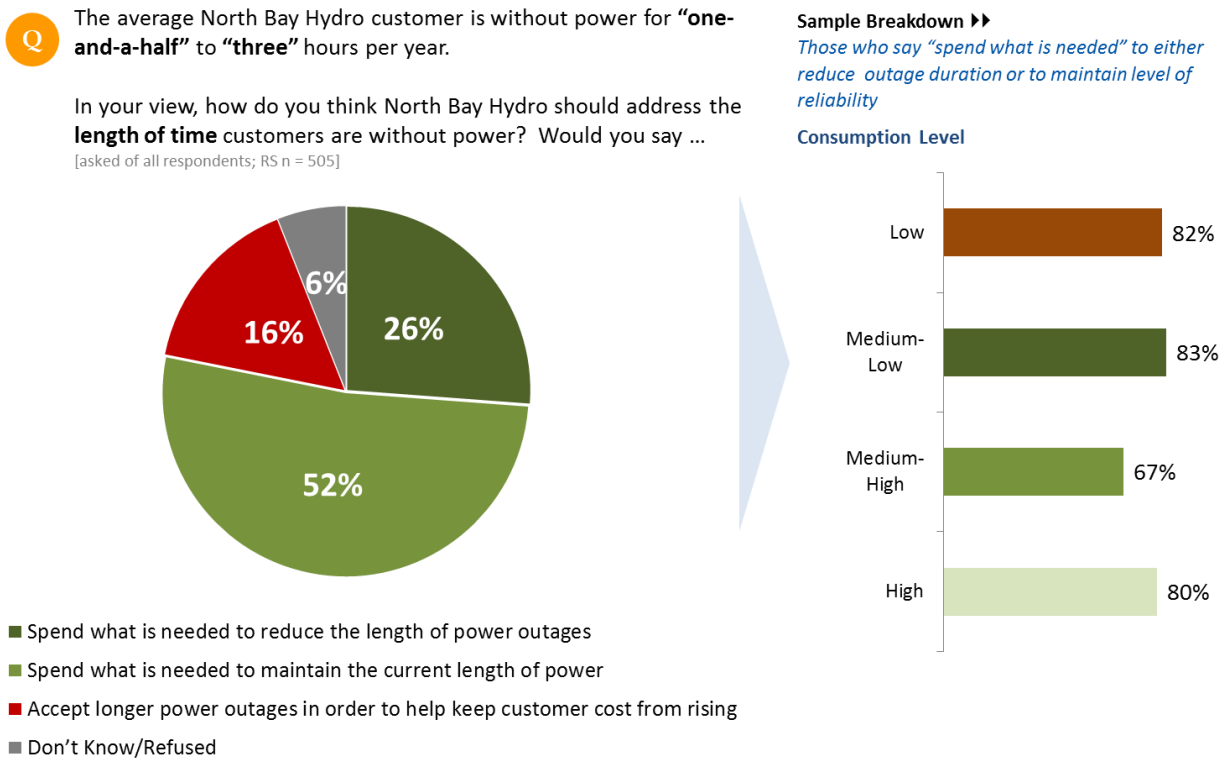
> *"The average North Bay Hydro customer is without power for **one-and-a-half hours** to **three** hours per year."*

Addressing the Duration of Service Outages

Three-quarters (78%) of residential respondents think North Bay Hydro should spend what is needed to either reduce (26%) or maintain (52%) the duration of power outages. Only one-in-six (16%) think that North Bay Hydro should accept longer power outages to keep costs down.

- Residents who say that their electricity bill "has a major impact on their finances" are less likely to want North Bay Hydro to "spend to maintain" (48%) than those unaffected financially by their bill (58%).

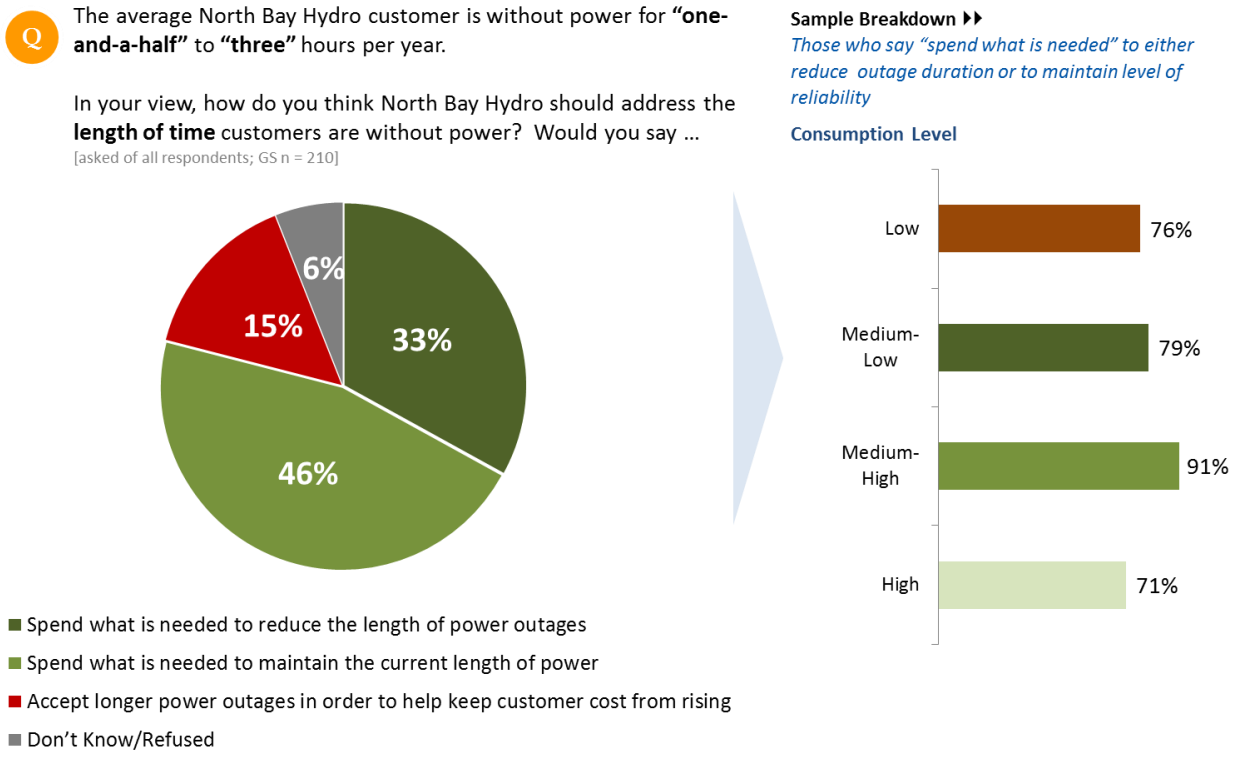
Figure RS.10: Addressing the Duration of Service Outages



Similar proportions of General Service respondents think that North Bay Hydro should spend what is needed to reduce (33%) or maintain (46%) the length of power outages. No significant differences arise within region or consumption.

- GS respondents who consume at a medium-high level (91%) are most likely to support the spending (Low: 76%; Medium-low: 79%; High: 71%)
- GS customers who say that their electricity bill "has a major impact on their bottom line" are slightly less likely to want North Bay Hydro to "spend to maintain" (48%) than those unaffected financially by their bill (58%).

Figure GS.10: Addressing the Duration of Service Outages



System Challenges & Priorities

This section explores respondents' preferences on various aspects of North Bay Hydro's Capital Investment plan and OM&A spending.

System Challenges & Priorities Summary

Investment in Aging Infrastructure

Three-in-five (59%) residential customers and one-in-three (37%) General Service customers believe that North Bay Hydro should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.

- The level of support among residential respondents decreases as consumption level increases. Those who are financially affected by their electricity bill (50%) are less likely to support the investment than those who are not financially affected (71%).
- There is no clear consumption pattern for the GS customers. GS respondents who are affected financially by their electricity bill (32%) are also less likely to support investment in infrastructure than those who are not financially affected (52%).

Investment in Equipment and Tools

Two-thirds (63%) of residential respondents and half (52%) of GS respondents believe that North Bay Hydro should be prudent with its spending, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

- Financial impact of electricity bill is a factor for residential respondents. Those who are struggling with the cost of their bill (57%) are less likely to believe it is important that North Bay Hydro has proper equipment and tools than those who are financially unaffected by the electricity bill (73%).
- Financial impact of electricity bill is not a factor for GS respondents

Budgeting for Labour Costs Increase

Three-in-five (59%) residential respondents and half (49%) of GS respondents believe that it is important for North Bay Hydro to retain and attract experienced and qualified workers to operate the system by paying a wage that is competitive but within industry benchmarks.

- Residential respondents who consume the most (49%) are least likely to support North Bay Hydro paying a competitive wage.
- Residential respondents who are financially affected by their electricity bill (53%) are less likely to support paying a competitive wage than those who are financially unaffected by the bill (67%).
- GS respondents who consume the least (60%) are most likely to support North Bay Hydro paying a competitive wage.

- GS respondents' support for paying a competitive wage is unaffected by the extent to which they are affected financially by their electricity bill.

Tree Clearance Policy

- The policy of establishing a 15 foot tree clearance from either side of North Bay Hydro's overhead power lines is supported by majority of residential (82%) and GS (81%) respondents.

Preamble for System Challenges & Priorities Section

The preamble reads as follow:

"Much of North Bay's electrical infrastructure was built in the 1950s and 60s. While North Bay Hydro believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, North Bay Hydro is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is ***$24 million*** *over the next 5 years.*

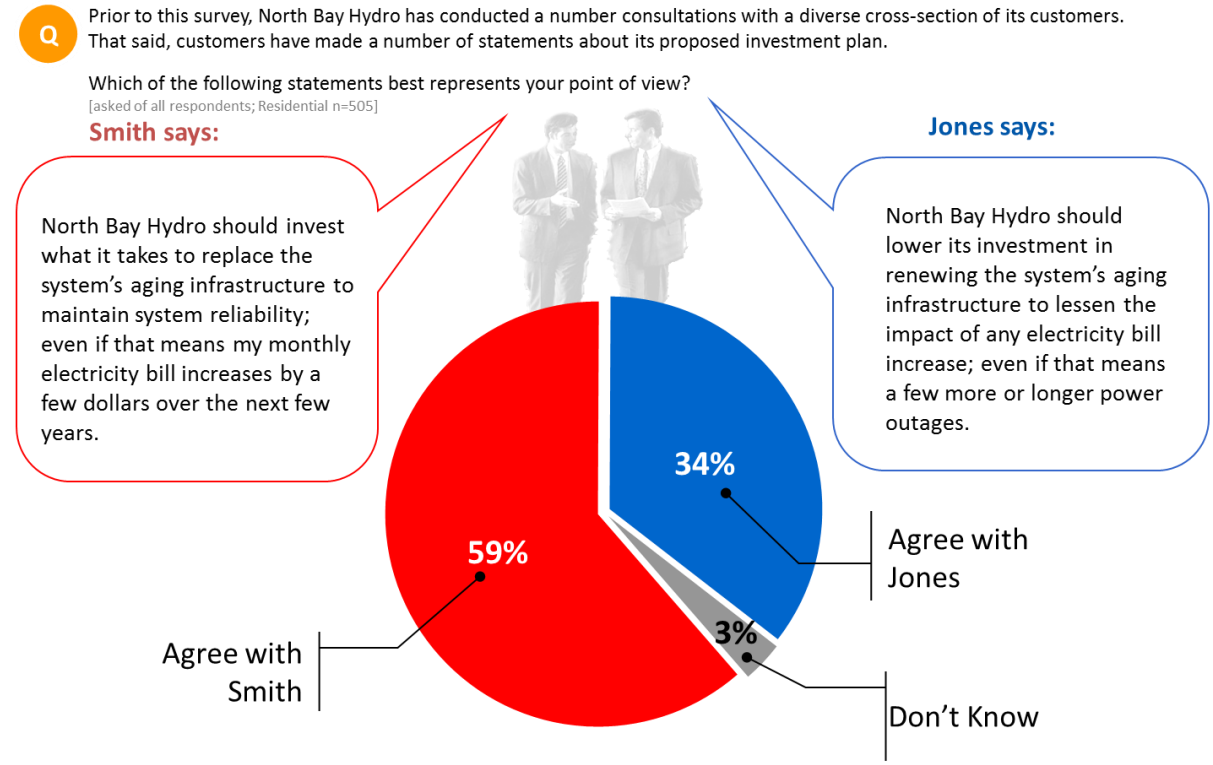
Although this plan will allow North Bay Hydro to make what independent studies suggest are the necessary investments to maintain system reliability, ***it will have an impact on customer bills."***

Investment in Aging Infrastructure

Three-in-five (59%) residential customers believe that North Bay Hydro should invest in aging infrastructure to maintain system reliability, even if it means their bills may increase.

- The level of support among residential respondents decreases as consumption level increases (Low: 63%; Medium-low: 63%; Medium-high: 57%; High: 52%). Respondents who are affected by their electricity bill financially (50%) are less likely to support the investment than those who are not financially affected (71%).

Figure RS.11: Investment in Aging Infrastructure

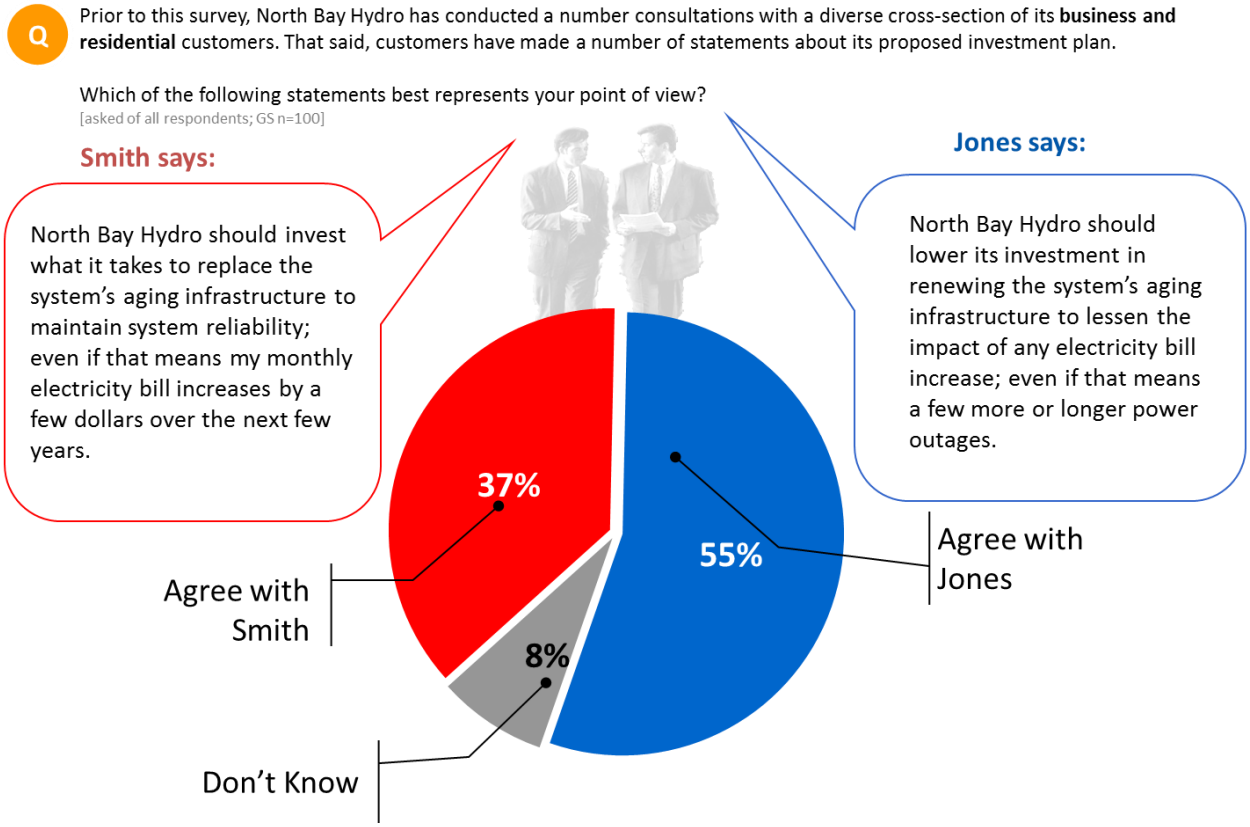


Note: 'Refused' (4%) not shown

As for General Service customers, 37% think North Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, despite a possible bill increase. Slightly more than half (55%) think North Bay Hydro should lower its investment in aging infrastructure, even if that means more outages.

- There is no clear consumption pattern for GS customers. Similar to residential respondents, GS respondents who are financially affected by their electricity bill (32%) are much less likely to support investment in infrastructure than those who are unaffected (52%).

Figure GS.11: Investment in Aging Infrastructure



Preamble for Investment in Equipment and Tools

For the following question on general plant, respondents were read this brief preamble:

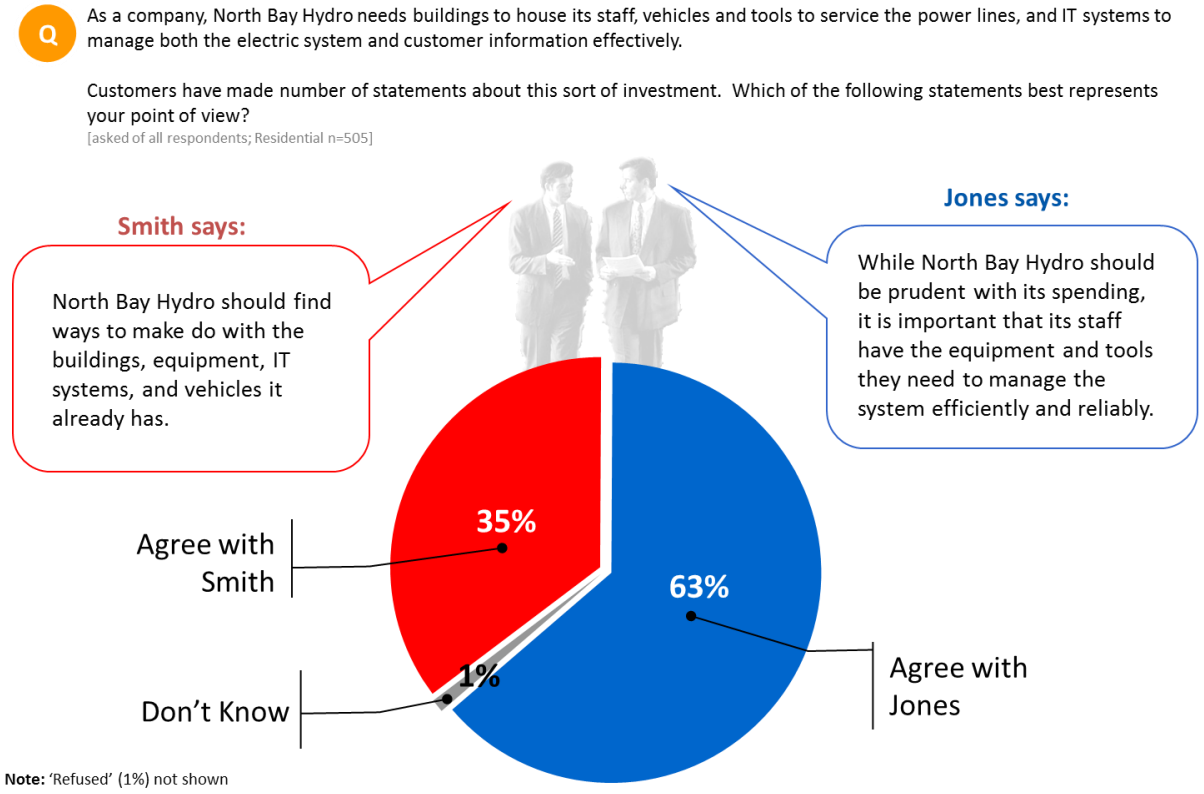
> *"North Bay Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company, North Bay Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information."*

Investment in Equipment and Tools

Two-thirds (63%) of Residential customers believe that North Bay Hydro should be prudent with its spending, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably. One-in-three (35%) think that North Bay Hydro should find ways to make do with the buildings, equipment and IT systems it already has.

- Residential respondents struggling with the cost of their electricity bill (57%) are less likely to believe it is important that North Bay Hydro has proper equipment and tools than those who are unaffected financially by the electricity bill (73%).

Figure RS.12: Investment in Equipment and Tools

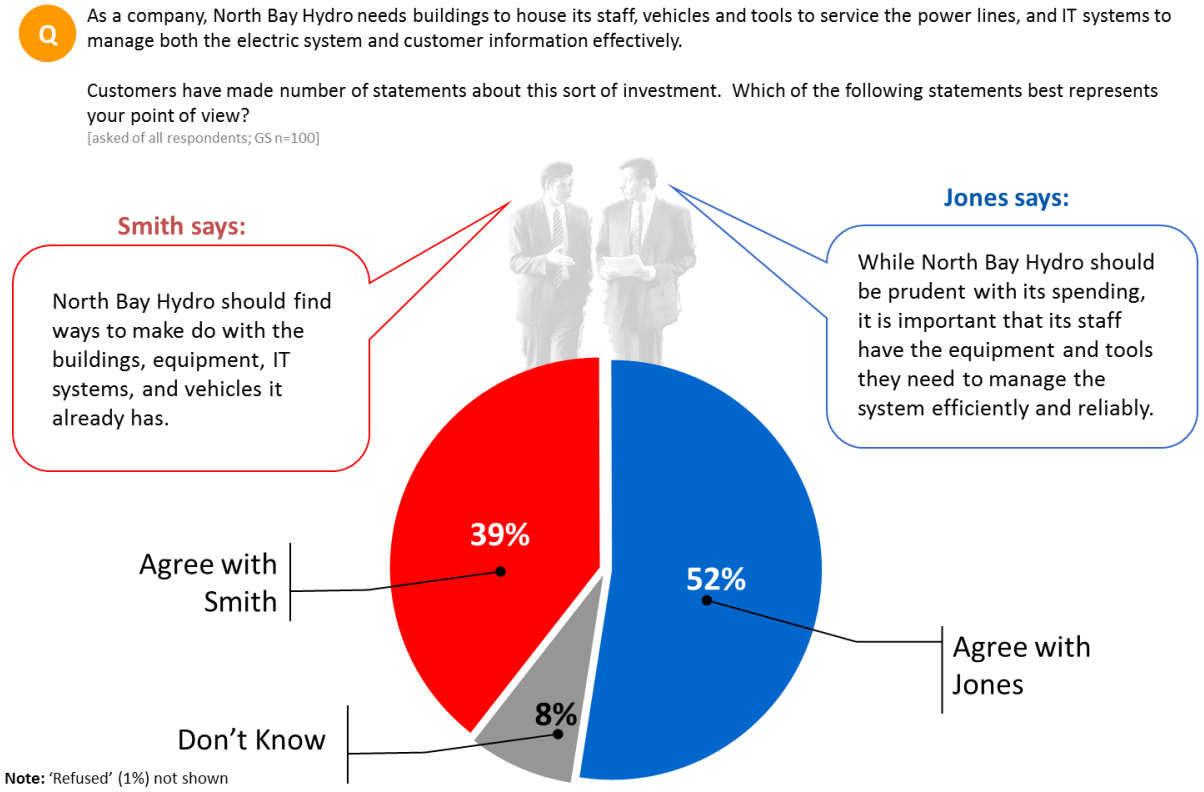


Note: 'Refused' (1%) not shown

Less than two-in-five (39%) General Service respondents believe that, while North Bay Hydro should be wise with its spending, it is important that North Bay Hydro's staff have the equipment and tools they need to manage the system efficiently and reliably.

- The support for investment in equipment and tools is unaffected by the extent to which the GS respondents are struggling with the cost of their electricity bill (52% for those who are struggling and those who are not).

Figure GS.12: Investment in Equipment and Tools



Preamble for Budgeting for Labour Cost Increase

Before the follow-up question on how North Bay Hydro should address labour cost increases, respondents were read the following preamble:

> *"In addition to its capital investment budget, North Bay Hydro also needs to consider its **operating budget** which also has an impact on customer bills. The operating budget pays for the day-to-day costs for managing and maintaining the system, including labour costs, customer services and maintenance."*

Budgeting for Labour Cost Increase

Three-in-five (59%) residential respondents believe that it is important for North Bay Hydro to retain and attract experienced and qualified workers to operate the system by paying a wage that is competitive but within industry benchmarks.

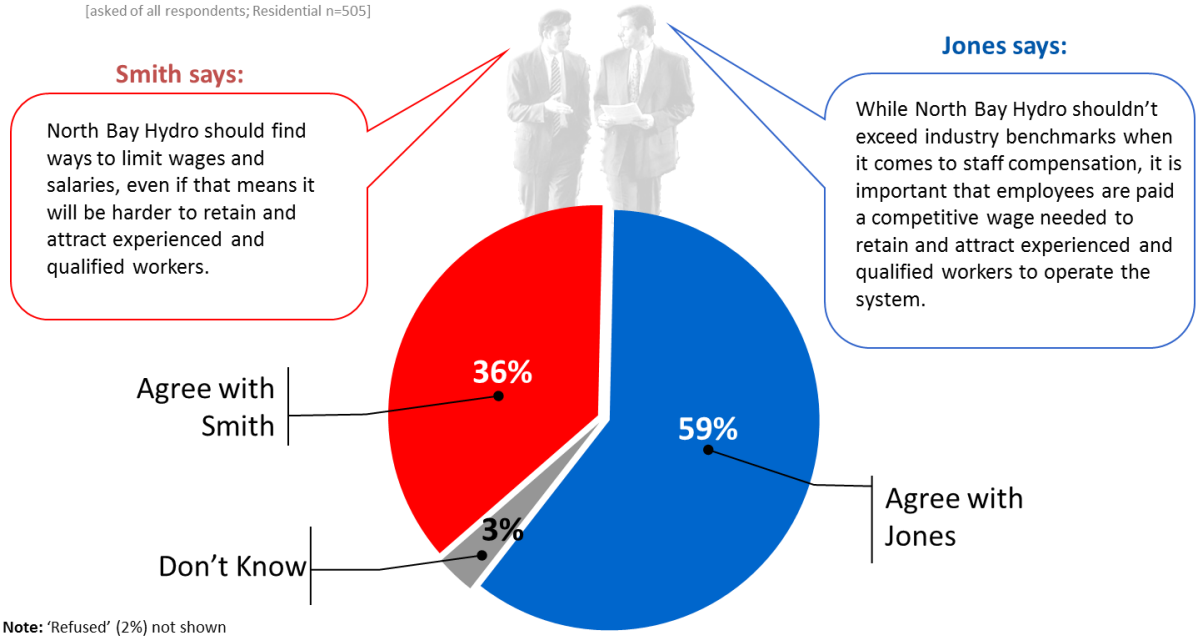
- Residential respondents who consume the most (49%) are least likely to support North Bay Hydro paying a competitive wage. (Low: 65%; Medium-low: 60%; Medium-high: 62%).
- Residential respondents who are financially affected by their electricity bill (53%) are less likely to support paying a competitive wage than those who are financially unaffected by the bill (67%).

Figure RS.13: Budgeting for Labour Costs Increase

Q With an increased workload on staff from growing customer demands, new provincial policies and regulations, as well as operating and maintenance needs of the system, North Bay Hydro's proposed plan would see labour costs increasing next year, in line with industry standards.

Again, customers have made number of statements about this sort of budgeting. Which of the following statements best represents your point of view?

[asked of all respondents; Residential n=505]

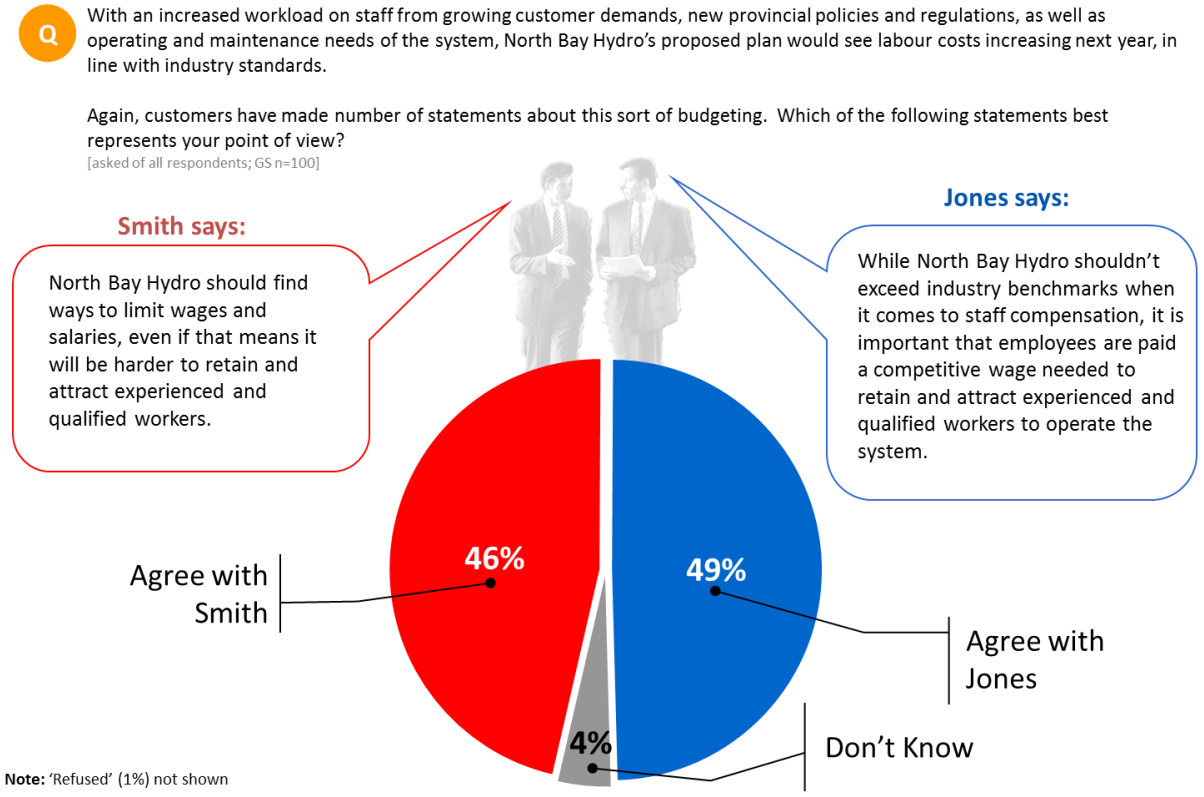


Note: 'Refused' (2%) not shown

About half (49%) of GS respondents believe that it is important for North Bay Hydro to retain and attract experienced and qualified workers to operate the system by paying a wage that is competitive but within industry benchmarks.

- GS respondents who consume the least (60%) are most likely to support North Bays Hydro paying a competitive wage (Medium-low: 48%; Medium-high: 41%; High: 46%).
- GS respondents' support for paying a competitive wage is unaffected by the extent to which they are financially affected by their electricity bill.

Figure GS.13: Budgeting for Labour Costs Increase



Preamble for Vegetation Management Policy

For the following question on tree clearance policy, respondents were read this brief preamble:

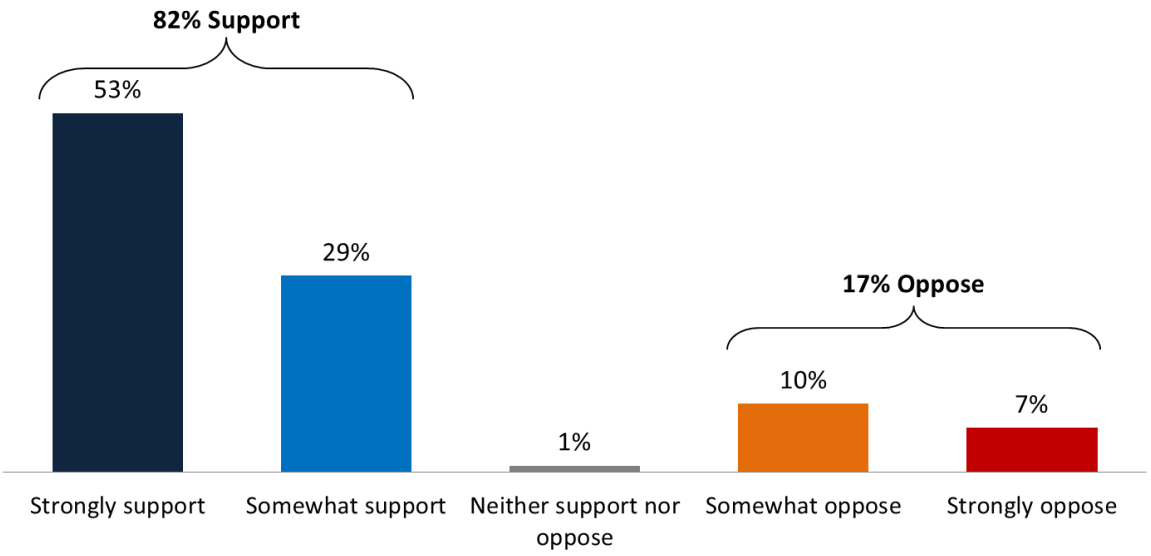
> *"It's estimated that up to 25% of all power outages among North Bay Hydro customers are caused by wire contact with trees. Furthermore, close proximity of branches to wires can pose a risk to the public and North Bay Hydro workers that need to perform maintenance on the system.*
>
> *Due to this reality, North Bay Hydro has recently made it a policy of establishing a 15 foot tree clearance from either side of its overhead power lines."*

Vegetation Management Policy

North Bay Hydro's tree clearance policy received majority support from both residential (82%) and GS (81%) respondents.

Figure RS.14: Vegetation Management Policy

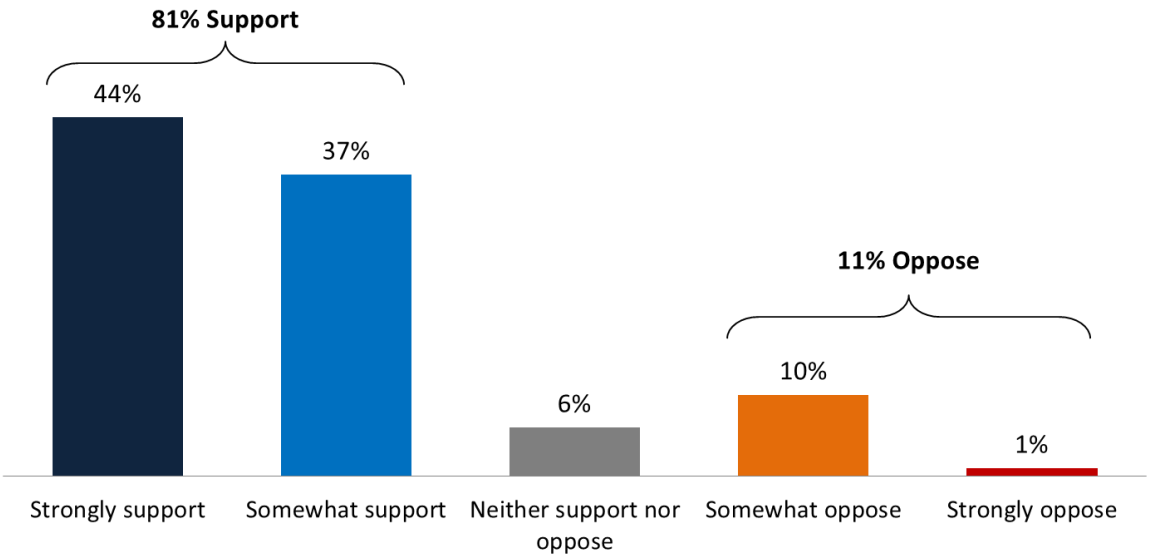
Q Although this policy may have an impact on North Bay's tree line, do you strongly support, somewhat support, somewhat oppose or strongly oppose this policy?
[asked of all respondents; RS n= 505]



Note: 'Don't know'/'Refused' (1%) not shown

Figure GS.14: Vegetation Management Policy

Q Although this policy may have an impact on North Bay's tree line, do you strongly support, somewhat support, somewhat oppose or strongly oppose this policy?
[asked of all respondents; GS n= 100]



Note: 'Don't know'/'Refused' (2%) not shown

Reaction to Previous Customer Consultation Input

This section measures agreement with some of the key opinion statements provided by North Bay Hydro's customers in previous phases of the consultation.

Customer Reaction Statements

Of the 11 customer input statements provided in the questionnaire, the statement with the most support among residential customers is "nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generation".

Among General Service customers, the most supported statement was "we should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal".

The statement with the lowest level of agreement among residential respondents is "while North Bay Hydro's policy of tree trimming and tree removal is designed to lower the number of customer power outages, they're going too far in removing the City's tree canopy".

The statement with the lowest level of General Service agreement is "My organization would be willing to pay a bit more for electricity if it means better service reliability."

Residential Customer Reaction

A majority of residential respondents agree with all of the customer input statements provided in the questionnaire except one: "while North Bay Hydro's policy of tree trimming and tree removal is designed to lower the number of customer power outages, they're going too far in removing the City's tree canopy" (18% strongly agree; 23% agree; 29% disagree; 27% strongly disagree).

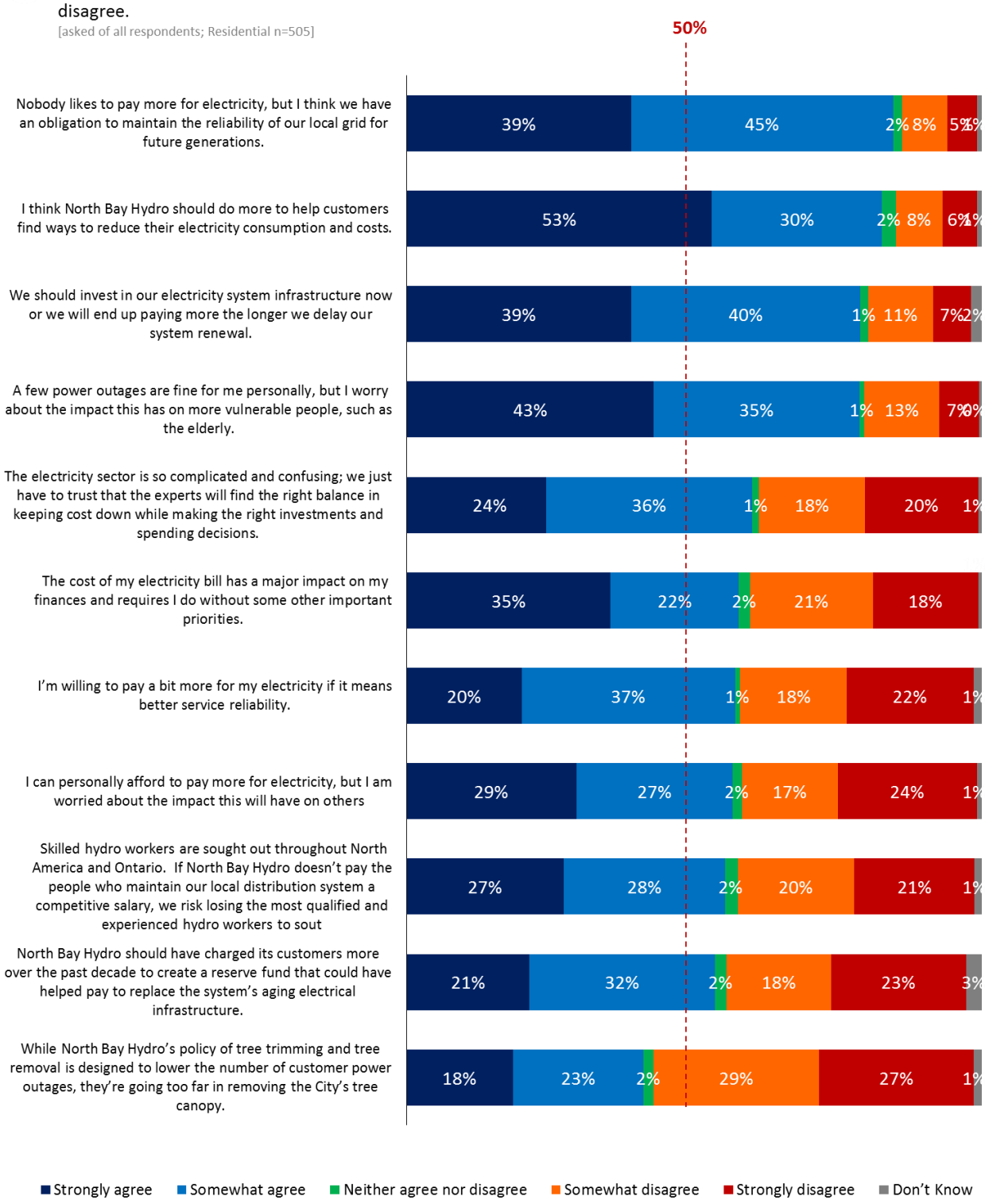
Of the eleven statements put forth to residential customers, two of them have at least 80% support. The statements focus on the future of infrastructure and cost. In the statement with the most support, more than eight-in-ten (84%) agree that "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local grid for future generations" (45% strongly agree).

Slightly fewer (82%) residential customers also agree that "I think North Bay Hydro should do more to help customers find ways to reduce their electricity consumption and costs". This statement elicits strong intensity of agreement (53% strongly agree).

Figure RS.15: Reaction to Customer Input

Q The following statements have been made by customers throughout North Bay Hydro's community consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

[asked of all respondents; Residential n=505]



GS Customer Reaction

Though General Service respondents agree with all eleven statements provided in the questionnaire, none of the statements elicited strong intensity of agreement. The statement that elicited the strongest intensity of agreement is “I think North Bay Hydro should do more to help customers find ways to reduce their electricity consumption and costs” (38% strongly agree).

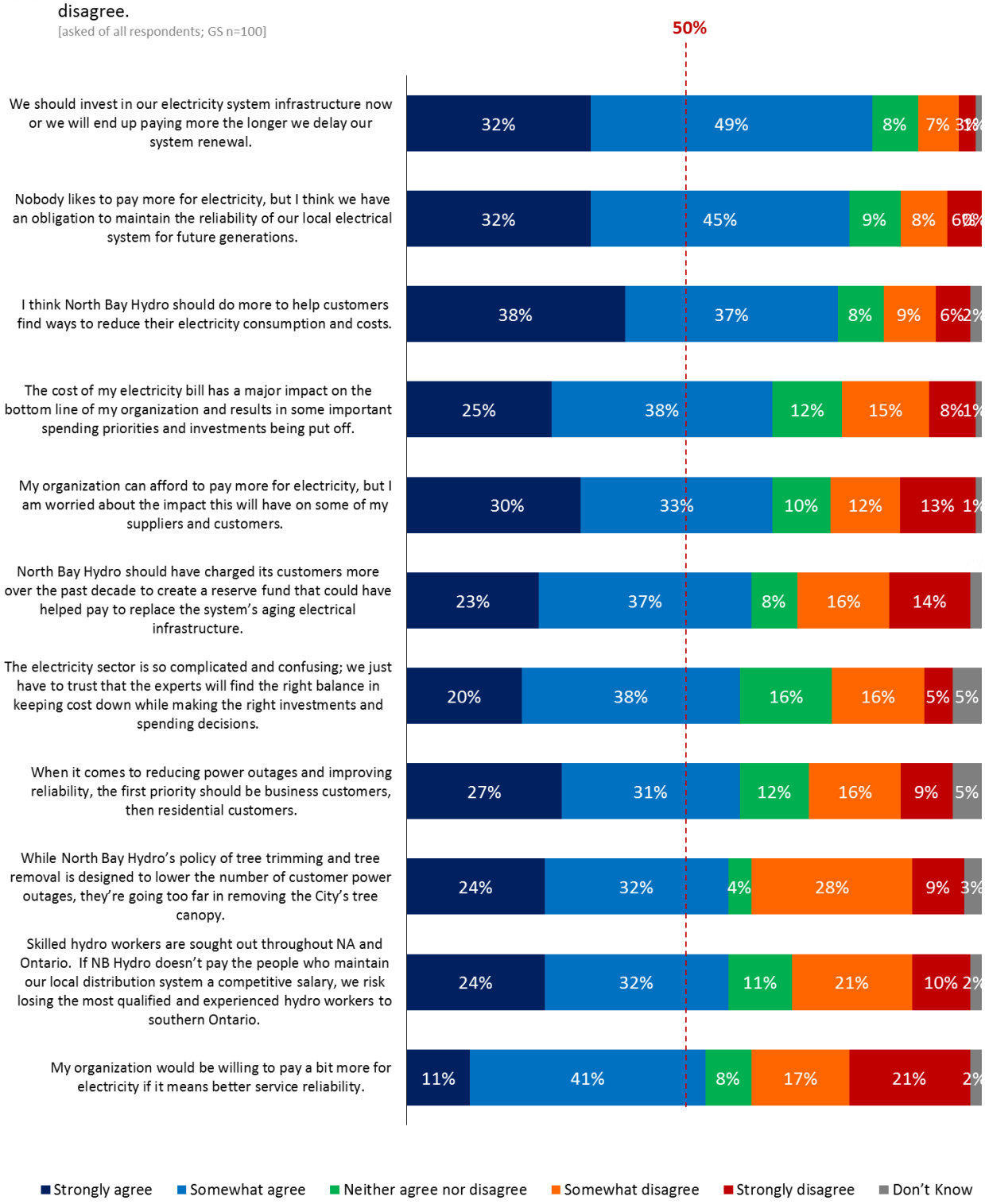
The statement with strongest overall agreement is “We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal”.

The statement that received the second highest level of agreement is “nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations”.

Figure GS.15: Reaction to Customer Input

Q The following statements have been made by customers throughout North Bay Hydro's community consultation process. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

[asked of all respondents; GS n=100]



Assessment of Plan

This section explores the degree of acceptance that North Bay Hydro's customers express for a rate increase. Acceptance is defined as either support for a rate increase or agreeing that it is necessary. This section also explores the underlying reasons for acceptance and opposition to a rate increase, probing more specifically through open-ended questions.

Acceptance of Rate Increase Summary

About three-quarters of residential (73%) respondents accept the rate increase. However, most of these respondents offer reluctant acceptance: they don't like the increase, but feel it's necessary to maintain the grid (48%). Only a quarter (25%) thinks the rate increase is unreasonable.

- Residential customers who feel their electricity bills have a major impact on their finances (64%) are much less likely to accept a rate increase.

General Service respondents are slightly less willing to accept the rate increases than residential respondents: close to seven-in-ten (68%) of organizational customers support the proposed North Bay Hydro plan. Much of that acceptance appears to be reluctant: they "don't like the rate increase, but feel it is necessary" (48%). Slightly more than a quarter (28%) think the proposed rate increase is unreasonable and oppose it.

- GS respondents whose bottom line is affected by the cost of their electricity bill (62%) are less likely to support the proposed rate increase than those who are unaffected (87%).

Financial Flexibility and Level of Acceptance

The level of acceptance differs among respondents depending on the extent to which they are financially impacted by their electricity bill. Among residential respondents who are financially strained, about three-in-five (64%) accept the proposed rate increase. Among residential respondents who are financially flexible, their level of acceptance increased to more than four-in-five (86%).

The change in level of acceptance is similar among GS respondents. For GS respondents whose organizations' are financially strained, 62% accept the proposed rate increase. For those whose organizations' are financially flexible, 87% accept the proposed rate increase.

Reasons why customers accept or oppose North Bay Hydro's proposed DSP:

- In the residential breakdown, those who are most strongly accepting of the rate increase cite "Invest/necessary to maintain/keep up for future" (35%) and "$4.60-$5.00 not a lot of money/can afford" (33%) as their key reasons.
- Those who reluctantly accept the increase cite "don't want to pay more but must be maintained" (34%) as the main reason.
- One-in-two (50%) of those against the rate increase cite "pay too much already" as the reason for their disapproval.

- In the GS breakdown, similar reasons emerge. Those who are most strongly accepting of the rate increase cite “rate increase is acceptable/affordable” as their main reason (30%).
- Those who reluctantly accept the increase cite "must be necessary / has to be done" (19%) as the main reason.
- One-in-five (21%) of those against the rate increase cite "rates already too high" as the reason for their disapproval.

Preamble for Assessment of Plan Section

Prior to the questions given in the Assessment of Plan Section, residential customers were presented with a preamble concerning the breakdown of pricing for North Bay Hydro's 5-year plan:

*According to North Bay Hydro's proposed plan, the total required funding to manage the day-to-day operations and required capital investment is estimated to be **$14.7 million** in 2015.*

- ***53%** of the these funds or approximately **$7.8 million** is budgeted for capital investments required to replace aging infrastructure; to connect new customers to the electricity system; to invest in tools, IT systems, vehicles and facilities needed to manage the electricity system; and for new technologies to make the system more efficient, reliable and safe.*
- ***47%** of these funds or approximately **$7.0 million** of this proposed plan is budgeted for the day-to-day management of the company as a whole, salaries and wages, customer service and on-going maintenance of the distribution system.*

*To fund this plan, **North Bay Hydro** is proposing the **average residential household's rate increase by 92 cents ($0.92)** on the distribution portion of their bill over the next five years. So, by 2019, the average residential household will be paying an **estimated $4.60 more per month** on the distribution portion of its electricity bill.*

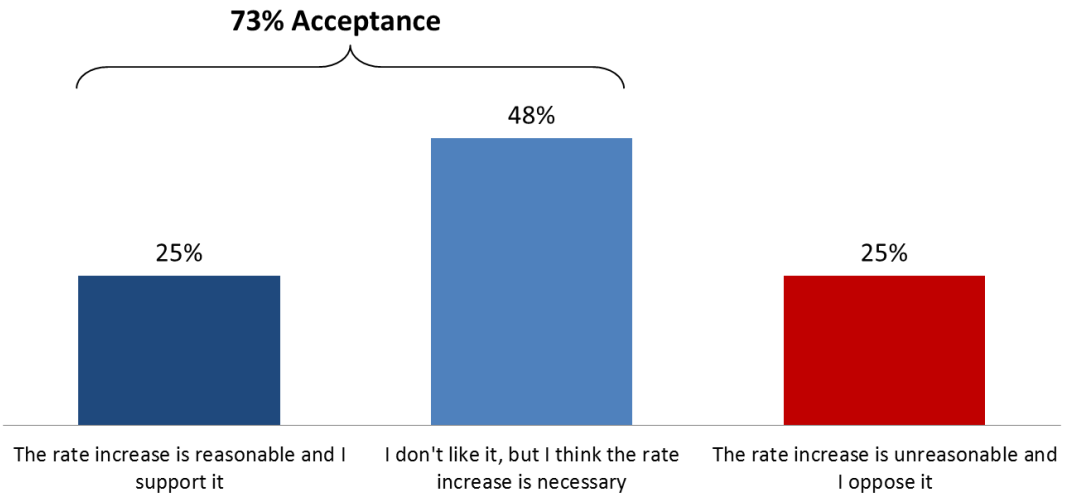
*(Note: in the GS Survey, the two bolded phrases in the last paragraph were replaced with "**average small and medium-sized business' rate increase by $1.10"** and **"estimated $5.49 more per month"**, respectively. The rest of the preamble remained the same for organizational customers.)*

Acceptance of Rate Increase

When residential respondents were asked the "acceptance question" on rate increases, close to three-quarters (73%) agree to the rate increase. One-in-four residential respondents (25%) oppose the rate increase and think it is unreasonable. Close to half of the respondents (48%) don't like the rate increase, but think it is necessary.

Figure RS.16 - Acceptance of Rate Increase

Q Considering the cost of the North Bay Hydro plan, which point of view is closest to your own? Would you say…
[asked of all respondents; Residential n=505]



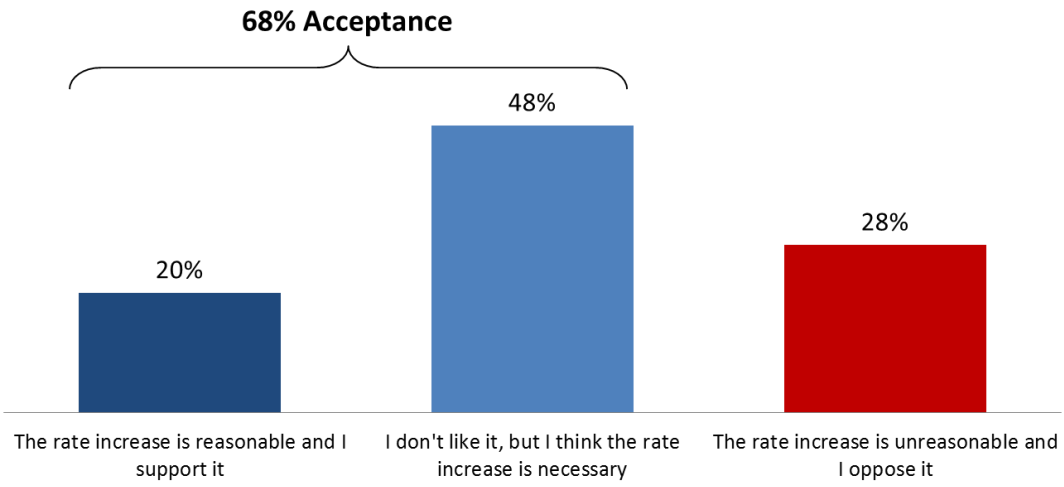
Note: 'Not sure'/'Refused' (2%) not shown

General Service respondents, on the other hand, are slightly less likely to support rate increases: about two-thirds (68%) of GS respondents accept the increase.

As noted with residential respondents, close to half (48%) of GS respondents do not like the proposed rate increase but believe it is necessary. The proportion of GS respondents (28%) that oppose the rate increase is slightly higher than the residential respondents (25%).

Figure GS.16 - Acceptance of Rate Increase

Q Considering the cost of the North Bay Hydro plan, which point of view is closest to your own? Would you say…
[asked of all respondents; GSn =100]



Note: 'Not sure'/'Refused' (4%) not shown

Financial Flexibility and Level of Acceptance

It is expected that the proposed rate increase would have greater financial impact on some respondents than others; consequently, the respondents' level of acceptance for rate increase could differ depending on their level of financial flexibility. That is, the extent to which the cost of electricity bill has on the respondents' personal finances or business bottom line.

For residential respondents whose electricity bill has major impact on their finances and requires them do without some other important priorities, the level of their acceptance for the proposed rate increase (64%) is lower than those whose finances are less impacted by their electricity bill (86%).

Figure RS.17 - Financial Flexibility and Level of Acceptance

	Financially Strained	Financially Flexible
The rate increase is reasonable and I support it	17%	38%
I don't like it, but I think the rate increase is necessary	47%	48%
The rate increase is unreasonable and I oppose it	34%	11%
Overall Level of Support	**64%**	**86%**

For GS respondents whose electricity bill has major impact on their organizations' bottom line and requires them to put off some important spending priorities and investments, the level of their acceptance for the proposed rate increase (62%) is lower than those whose bottom line are less impacted by their electricity bill (87%).

Figure GS.17 - Financial Flexibility and Level of Acceptance

	Financially Strained	Financially Flexible
The rate increase is reasonable and I support it	13%	35%
I don't like it, but I think the rate increase is necessary	49%	52%
The rate increase is unreasonable and I oppose it	35%	13%
Overall Level of Acceptance	**62%**	**87%**

Opinions on Proposed Rate Increase

For residential respondents who chose "the rate increase is reasonable and I support it", 35% hold their position because they believe the investment is necessary for the future. About one-in-three (33%) of the same group of respondents believe the proposed rate increase is affordable.

For residential respondents who chose "I don't like it but believe the rate increase is necessary", 34% hold their position because they believe maintenance is necessary.

For residential respondents who chose "the rate increase is unreasonable and I oppose it", half of them (50%) hold their position because they believe they "pay too much already".

Figure RS.18 – Opinion on Proposed Rate Increase

Q And why do you say that? [Asked of RS respondents who had an opinion on NBH's proposed rate increase]

ACCEPTANCE: INCREASE REASONABLE	% RS
Invest/necessary to maintain/keep up for future	35%
$4.60-$5.00 not a lot of money/can afford	33%
Cost of everything going up	19%
Is going to happen anyway	5%
Good service	2%
Other	8%

n=123

ACCEPTANCE: DON'T LIKE BUT NECESSARY	% RS
Don't want to pay more but must be maintained	34%
Invest/necessary to maintain/keep up for future	14%
Pay too much already	11%
Will cost more down the road if not updated now	10%
Management/employee salaries/bonuses too high	5%
Cost of everything going up	4%
On fixed income/pension	4%
Financial accountability/where's the money going	4%
Need better management	3%
Eliminate/reduce retirement,debt & delivery fees	3%
$4.60-$5.00 not a lot of money/can afford	2%
Other	5%

n=236

NO ACCEPTANCE: INCREASE UNREASONABLE	% RS
Pay too much already	50%
Eliminate/reduce retirement,debt & delivery fees	9%
Management/employee salaries/bonuses too high	9%
Financial accountability/where's the money going	7%
Need better management	6%
On fixed income/pension	6%
Can find other ways to save/reduce costs	5%
Developers should pay for initial costs of new system	2%
Other	7%

n=123

For GS respondents who chose “the rate increase is reasonable and I support it”, 34% hold their position because they believe the rate increase is affordable. One-in-four hold their position because they believe the increase is a necessary long-term investment in infrastructure.

For GS respondents who chose “I don’t like it but believe the rate increase is necessary”, 19% hold their position because they believe maintenance is necessary.

For GS respondents who chose “the rate increase is unreasonable and I oppose it”, about one-in-five (21%) hold their position because they believe the “rates already too high”.

Figure GS.18 – Opinion on Proposed Rate Increase

Q And why do you say that? [Asked of GS respondents who had an opinion on NBH’s proposed rate increase]

ACCEPTANCE: INCREASE REASONABLE	% RS
Rate increase is acceptable/affordable	30%
Necessary for long-term investment/infrastructure	25%
Must be necessary/has to be done	20%
Other	5%
Don't Know / Refused	20%

n=20

NO ACCEPTANCE: INCREASE UNREASONABLE	% RS
Rates already too high	21%
Should find other ways to cut costs	18%
Rising costs will affect my business	14%
No one likes an increase	11%
Don't Know / Refused	36%

n=28

ACCEPTANCE: DON'T LIKE BUT NECESSARY	% RS
Must be necessary/has to be done	19%
No one likes an increase	15%
Rates already too high	15%
Should find other ways to cut costs	10%
Rate increase is acceptable/affordable	8%
Necessary for long-term investment/infrastructure	6%
Other	10%
Don't Know / Refused	16%

n=48

Survey Instruments

Residential Survey Instrument

A. Introduction

Introduction

INTRO
Hello, my name is _____ and I'm calling from **Innovative Research Group** on behalf of **North Bay Hydro**, your local distributor.

Innovative Research Group is a national public opinion research firm. We have been commissioned by **North Bay Hydro** to help them better understand the needs and preferences of its customers.

North Bay Hydro – which distributes electricity to residential and business customers in the City of North Bay– is in the process of developing its **spending and investment plan for the coming year** and wants to hear from customers, like you, to help inform this plan.

Because **North Bay Hydro** is entirely funded by the fees that its customers pay on their electricity bills, it wants to know *how much* or *how little* its customers want it to spend and invest to manage and maintain the local electrical system.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	**ARRANGE CALLBACK**
No – HARD REFUSAL	4	[**Terminate**]

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1	

A2. Have I reached you at your home phone number?

INTERVIEWER NOTE; IF "NO" ASK: May I speak to someone who does live there?

Yes - SPEAKING, CONTINUE	1	[**continue to A3**]
YES - TRANSFERRED – **(GO BACK TO INTRODUCTION)**	2	[**back to INTRO**]
No - NOT AVAILABLE – **(ARRANGE CALLBACK)**	3	[**ARRANGE CALLBACK**]
Refused – LOG **(THANK AND TERMINATE)**	9	[**Terminate**]

A3. Are you the person primarily responsible for paying the electricity bill in your household?

Yes	1	[**continue to A4**]
No	2	[**go to TRANSFER-1**]
Don't know (**DNR**)	98	[**Terminate**]

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

Yes – transferred to electricity bill payer	1	[**BACK TO** *INTRO*]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK**]
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

A4. Can you confirm that your household receives an electricity bill from **North Bay Hydro**?

Yes	1	[**continue**]
No	2	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

B. General Satisfaction & Background Info

We need respondents to think about electricity and the part of the system that North Bay Hydro operates.

B5. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by **North Bay Hydro**.

That said …

B6. How familiar are you with your local electricity distribution system? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Generally speaking, how satisfied are you with the job North Bay Hydro is doing running your local distribution system? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B8. Is there anything in particular **North Bay Hydro** can do to improve their service to you? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

B9. **North Bay Hydro** is 100% owned by the City of North Bay and has an independent board of directors. This voluntary board is made up of members of North Bay's business community and is responsible for overseeing the operations and management of the utility.

Before this survey, did you know that North Bay Hydro was owned by the City of North Bay? [**DO NOT READ LIST**]

Yes	1
No	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C. Bill Knowledge & Impact

I'd now like to talk with you about your electricity bill …

C10. While some customers pay more and other pay less, the average residential customer pays **about $130 a month** for electricity of **which $30 or approximately 20% goes to North Bay Hydro**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to North Bay Hydro? Would you say … [**READ LIST**]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

D. System Reliability

These questions are about getting the respondent to think about their experience with system reliability.

READ PREAMABLE: Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **North Bay Hydro** customer experiences **between one and three power outages** per year.

D11. Have you experienced any power outages **in the past 12 months**, and if so, approximately how many? [**DO NOT READ LIST**]

No outages	0 [**SKIP to D13**]
1 outage	1 [CONTINUE]
2 outages	2 [CONTINUE]
3 outages	3 [CONTINUE]
4 outages	4 [CONTINUE]
5 outages	5 [CONTINUE]
6 outages	6 [CONTINUE]
7 outages	7 [CONTINUE]
8 or more outages	8 [CONTINUE]
Don't know (**DNR**)	98 [**SKIP to D13**]
Refused (**DNR**)	99 [**SKIP to D13**]

READ ONLY IF D11 = 1 thru 8

D12. And approximately how many minutes did the most recent power outage last? [DO NOT READ LIST; select category accordingly]

Less than 15 minutes	1
15 to less than 30 minutes	2 [specify if less than *15 minutes*, if stated "less than 30 minutes"]
30 minutes to less than 1 hour	3
1 hour to less than 3 hours	4
3 hours to less than 6 hours	5
6 hours to less than 12 hours	6
12 to less than 24 hours	7
More than 24 hours	8
Don't know (**DNR**)	98
Refused (**DNR**)	99

D13. Thinking back to the **most recent** power outage you experienced as a North Bay Hydro customer, would you say the power outage …

[READ LIST; ROTATE 1 and 3]

Was a major inconvenience	1
Was a minor inconvenience	2
Was no inconvenience at all	3
Have never experienced an outage with North Bay Hydro (**DNR**)	97
Don't know (**DNR**)	98
Refused (**DNR**)	99

D14. In your view, how do you think **North Bay Hydro** should address the **number** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept **more** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

D15. The average **North Bay Hydro** customer is without power for "**one-and-a-half**" to "**three**" hours per year.

In your view, how do you think North Bay Hydro should address the **length of time** customers are without power? Would you say … **[READ LIST]**

[Rotate response codes 1 and 3]

Spend what is needed to reduce the length of power outages	1
Spend what is needed to maintain the current length of power outages	2
Accept **longer** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

E. System Challenges & Priorities

[PREAMBLE]

Much of North Bay's electrical infrastructure was built in the 1950s and 60s. While North Bay Hydro believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, North Bay Hydro is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is **$24 million** over the next 5 years.

Although this plan will allow North Bay Hydro to make, what independent studies suggest are, the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

System Renewal Question

E17. Prior to this survey, North Bay Hydro has conducted a number consultations with a diverse cross-section of its customers.

That said, customers have made a number of statements about its proposed investment plan. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that means my monthly electricity bill increases by a few dollars over the next few years.	1

Others have said …

North Bay Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any electricity bill increase; even if that means a few more or longer power outages.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

General Plant Question

E18. As a company, North Bay Hydro needs buildings to house its staff, vehicles and tools to service the power lines, and IT systems to manage both the electric system and customer information effectively.

Customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should find ways to make do with the buildings, equipment, IT systems, and vehicles it already has. 1

Others have said …

While North Bay Hydro should be prudent with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. 2

Don't know (**DNR**) 98
Refused (**DNR**) 99

E19. [PREAMBLE]

In addition to its capital investment budget, North Bay Hydro also needs to consider its **operating budget** which also has an impact on customer bills. The operating budget pays for the day-to-day costs for managing and maintaining the system, including labour costs, customer services and maintenance.

Operating Question: Labour Costs

E20. With an increased workload on staff from growing customer demands, new provincial policies and regulations, as well as operating and maintenance needs of the system, North Bay Hydro's proposed plan would see labour costs increasing next year, in line with industry standards.

Again, customers have made number of statements about this sort of budgeting. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should find ways to limit wages and salaries, even if that means it will be harder to retain and attract experienced and qualified workers. 1

Others have said …

While North Bay Hydro shouldn't exceed industry benchmarks when it comes to staff compensation, it is important that employees are paid a competitive wage needed to retain and attract experienced and qualified workers to operate the system. 2

Don't know (**DNR**) 98
Refused (**DNR**) 99

Operating Question: Vegetation Management

E21. It's estimated that up to **25% of all power outages** among North Bay Hydro customers are caused by wire contact with trees. Furthermore, close proximity of branches to wires can pose a risk to the public and North Bay Hydro workers that need to perform maintenance on the system.

Due to this reality, North Bay Hydro has recently made it a policy of establishing a **15 foot tree clearance** from either side of its overhead power lines.

Although this policy may have an impact on North Bay's tree line, do you strongly support, somewhat support, somewhat oppose or strongly oppose this policy?

Strongly support 1
Somewhat support 2
Neither support nor oppose (**DNR**) 3
Somewhat oppose 4
Strongly oppose 5
Don't know (**DNR**) 98
Refused (**DNR**) 99

F. Reaction to Customer Input

Below are the common themes that have come out of the customer focus groups.

The following statements have been made by customers throughout North Bay Hydro's community consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (**DNR**)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (**DNR**)	98
Refused (**DNR**)	99

RANDOMIZE QUESTIONS

Willingness / Ability to Pay

F22. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

F23. I'm willing to pay a bit more for my electricity if it means better service reliability.

Impact of rate increase on others

F24. I can personally afford to pay more for electricity, but I am worried about the impact this will have on others.

Pay Now or Later

F25. We should invest in our electricity system infrastructure **now** or we will end up paying more the longer we delay our system renewal.

Deferring to the experts

F26. The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.

System Reliability

F27. A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.

Labour Costs

F28. Skilled hydro workers are sought out throughout North America and Ontario. If North Bay Hydro doesn't pay the people who maintain our local distribution system a competitive salary, we risk losing the most qualified and experienced hydro workers to southern Ontario.

Vegetation Management

F29. While North Bay Hydro's policy of tree trimming and tree removal is designed to lower the number of customer power outages, they're going too far in removing the City's tree canopy.

CDM

F30. I think North Bay Hydro should do more to help customers find ways to reduce their electricity consumption and costs.

Reserve Fund

F31. North Bay Hydro should have charged its customers more over the past decade to create a **reserve fund** that could have helped pay to replace the system's aging electrical infrastructure.

Legacy

F32. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.

G. Assessment of Plan

G33. PREAMBLE

According to North Bay Hydro's proposed plan, the total required funding to manage the day-to-day operations and required capital investment is estimated to be **$14.7 million** in 2015.

- **53%** of the these funds or approximately **$7.8 million** is budgeted for capital investments required to replace aging infrastructure; to connect new customers to the electricity system; to invest in tools, IT systems, vehicles and facilities needed to manage the electricity system; and for new technologies to make the system more efficient, reliable and safe.
- **47%** of these funds or approximately **$7.0 million** of this proposed plan is budgeted for the day-to-day management of the company as a whole, salaries and wages, customer service and on-going maintenance of the distribution system.

To fund this plan, **North Bay Hydro** is proposing the **average residential household's rate increase by 92 cents ($0.92)** on the distribution portion of their bill over the next five years. So, by 2019, the average residential household will be paying an **estimated $4.60 more per month** on the distribution portion of its electricity bill.

G34. Considering the cost of the North Bay Hydro plan, which point of view is closest to your own? Would you say [**READ LIST**] …
Rotate response codes "1 "and "3"

The rate increase is reasonable and I support it	1
I don't like it, but I think the rate increase is necessary	2
The rate increase is unreasonable and I oppose it	3
Don't know (**DNR**)	98
Refused (**DNR**)	99

Ask only if G34 = 1, 2, 3 or 4

G35. And why do you say that? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

H. Demographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

H36. Counting yourself, how many people live in your household?

1 person	1 **SKIP TO END**
Enter number of people	2---7
8 or more	8
Refused (**DNR**)	99 **SKIP TO END**

Ask only if H36 = 2 thru 8

H37. And how many of them are under 18?

None	0
Enter number of children	1---7
8 or more	8
Refused (**DNR**)	99

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

General Service Survey Instrument

A. Introduction

Introduction

INTRO.
Hello, my name is _____ and I'm calling from **Innovative Research Group**, a national public opinion research firm. We have been hired by **North Bay Hydro** to help them better understand the needs and preferences of its customers.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>	**[skip to A1]**
2) Yes <**transferred to contact**>	**[skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record callback time]**
5) Maybe <**may I ask who is calling?**>	**[skip to GATE]**

NEW. And … can I have their …
First Name _____
Last Name _____
Title/Position _____
Phone Number _____

ASK to be transferred …

- **if transferred → go to A1**
- **if not transferred → Thank & Add to Callback List**

GATE. My name is _____ and I'm calling on behalf of your local electricity distributor, **North Bay Hydro**.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **North Bay Hydro** customer consultation.

1) Yes <**transferred to contact**>	**[skip to A1]**
2) No <**not available**> "When is a good time to callback?	**[record callback time and GO to "NEW"]**
3) No <**not interested in talking**>	**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:
Hello, my name is _____ and I'm calling from **Innovative Research Group**, a national public opinion research firm. We have been hired by **North Bay Hydro** to help them better understand the needs and preferences of its customers.

North Bay Hydro – which distributes electricity to residential and business customers in the City of North Bay– is in the process of developing its **spending and investment plan for the coming year** and wants to hear from customers, like you, to help inform this plan.

Because **North Bay Hydro** is entirely funded by the fees that its customers pay on their electricity bills, it wants to know *how much* or *how little* its customers want it to spend and invest to manage and maintain the local electrical system.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	**[continue]**
No – NOT PRIMARY BILL PAYER	2	**[go to TRANSFER-1]**
No – BAD TIME	3	**ARRANGE CALLBACK**
No – HARD REFUSAL	4	**[Terminate]**

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Just to confirm, does your organization receive an electricity bill from **North Bay Hydro**?

01	**YES**	1	**[continue]**
02	**NO**	2	**[Terminate]**
98	**DK (DO NOT READ)**	98	**[Terminate]**

A3. As part of your job, are you in-charge of managing or overseeing your organization's electricity bill?

Yes	1	[**Continue to A4**]
No	2	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL?[**Return to NEW**]
DK	3	CAN I SPEAK TO THE PERSON WHO MANAGES YOUR ORGANIZATION'S **ELECTRICITY** BILL? [**Return to NEW**]

B. General Satisfaction & Background Info

We need respondents to think about electricity and the part of the system that North Bay Hydro operates.

B4. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your **local distribution system** which is maintained and operated by **North Bay Hydro**.

That said …

B5. How familiar are you with your **local electricity distribution system**? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B6. Generally speaking, how satisfied are you with the job **North Bay Hydro** is doing running your local distribution system? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Is there anything in particular **North Bay Hydro** can do to improve their service to your organization? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

B8**.** **North Bay Hydro** is 100% owned by the City of North Bay and has an independent board of directors. This voluntary board is made up of members of North Bay's business community and is responsible for overseeing the operations and management of the utility.

Before this survey, did you know that North Bay Hydro was owned by the City of North Bay? [**DO NOT READ LIST**]

01	Yes 1
02	No 2
98	Don't know (**DO NOT READ**) 98
99	Refused (**DO NOT READ**) 99

C. Bill Knowledge & Impact

I'd now like to talk with you about your organization's electricity bill …

C9. While some customers pay more and other pay less, the **average small and medium-sized business pays about $315 a month** for electricity of **which about $70 or approximately 20% goes to North Bay Hydro**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to North Bay Hydro? Would you say … [**READ LIST**]

01	Very familiar 1
02	Somewhat familiar 2
03	Not very familiar 3
04	Not familiar 4
98	Don't know (**DO NOT READ**) 98
99	Refused (**DO NOT READ**) 99

D. System Reliability

These questions are about getting the respondent to think about their experience with system reliability.

READ PREAMABLE: Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **North Bay Hydro** customer experiences **between one and three power outages** per year.

D10. Have your **organization** experienced any power outages **in the past 12 months**, and if so, approximately how many? [**DO NOT READ LIST**]

No outages	0 [**SKIP to D13**]
1 outage	1 [CONTINUE]
2 outages	2 [CONTINUE]
3 outages	3 [CONTINUE]
4 outages	4 [CONTINUE]
5 outages	5 [CONTINUE]
6 outages	6 [CONTINUE]
7 outages	7 [CONTINUE]
8 or more outages	8 [CONTINUE]
Don't know (**DNR**)	98 [**SKIP to D13**]
Refused (**DNR**)	99 [**SKIP to D13**]

READ ONLY IF D11 = 1 thru 8

D11. And approximately how many minutes did the most recent power outage last? [DO NOT READ LIST; select category accordingly]

Less than 15 minutes	1
15 to less than 30 minutes	2 [specify if less than *15 minutes*, if stated "less than 30 minutes"]
30 minutes to less than 1 hour	3
1 hour to less than 3 hours	4
3 hours to less than 6 hours	5
6 hours to less than 12 hours	6
12 to less than 24 hours	7
More than 24 hours	8
Don't know (**DNR**)	98
Refused (**DNR**)	99

D12. Thinking back to the **most recent** power outage you experienced as a North Bay Hydro **business** customer, would you say the power outage …

[READ LIST; ROTATE 1 and 3]

Had a significant cost to my business	1
Had a minor cost to my business	2
Had barely any cost to my business, just a bit of inconvenience	3
Have never experienced an outage with North Bay Hydro (**DNR**)	97
Don't know (**DNR**)	98
Refused (**DNR**)	99

D13. In your view, how do you think **North Bay Hydro** should address the **number** of customer power outages? Would you say … [**READ LIST**]

[Rotate response codes 1 and 3]

Spend what is needed to reduce the number of power outages	1
Spend what is needed to maintain the current level of outages	2
Accept **more** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

D14. The average **North Bay Hydro** customer is without power for "**one-and-a-half**" to "**three**" hours per year.

In your view, how do you think North Bay Hydro should address the **length of time** customers are without power? Would you say … [READ LIST]

[Rotate response codes 1 and 3]

Spend what is needed to reduce the length of power outages	1
Spend what is needed to maintain the current length of power outages	2
Accept **longer** power outages in order to help keep customer costs from rising	3
Don't Know (**DNR**)	98
Refused (**DNR**)	99

E. System Challenges & Priorities

[PREAMBLE]

Much of North Bay's electrical infrastructure was built in the 1950s and 60s. While North Bay Hydro believes it has done its best to prolong the life of these assets, today many of these assets are now approaching the end of their useful life and are beginning to pose a threat to system reliability.

As part of its investment plan, North Bay Hydro is proposing a significant infrastructure renewal program. The estimated cost of this system renewal program is **$24 million** over the next 5 years.

Although this plan will allow North Bay Hydro to make, what independent studies suggest are, the necessary investments to maintain system reliability, **it will have an impact on customer bills**.

System Renewal Question

E16. Prior to this survey, North Bay Hydro has conducted a number of consultations with a diverse cross-section of its **business and residential** customers.

That said, customers have made a number of statements about its proposed investment plan. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that means my monthly electricity bill increases by a few dollars over the next few years.	1

Others have said …

North Bay Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any electricity bill increase; even if that means a few more or longer power outages.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

General Plant Question

E.17 As a company, North Bay Hydro needs buildings to house its staff, vehicles and tools to service the power lines, and IT systems to manage both the electric system and customer information effectively.

Customers have made number of statements about this sort of investment. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should find ways to make do with the buildings, equipment, IT systems, and vehicles it already has. 1

Others have said …

While North Bay Hydro should be prudent with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. 2

Don't know (**DNR**) 98
Refused (**DNR**) 99

[PREAMBLE]

In addition to its capital investment budget, North Bay Hydro also needs to consider its **operating budget** which also has an impact on customer bills. The operating budget pays for the day-to-day costs for managing and maintaining the system, including labour costs, customer services and maintenance.

Operating Question: Labour Costs

E19. With an increased workload on staff from growing customer demands, new provincial policies and regulations, as well as operating and maintenance needs of the system, North Bay Hydro's proposed plan would see labour costs increasing next year, in line with industry standards.

Again, customers have made number of statements about this sort of budgeting. Which of the following statements best represents your point of view?
[Read and Rotate statements 1 and 2]

Some customers have said …

North Bay Hydro should find ways to limit wages and salaries, even if that means it will be harder to retain and attract experienced and qualified workers.	1

Others have said …

While North Bay Hydro shouldn't exceed industry benchmarks when it comes to staff compensation, it is important that employees are paid a competitive wage needed to retain and attract experienced and qualified workers to operate the system.	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

Operating Question: Vegetation Management

E20. It's estimated that up to **25% of all power outages** among North Bay Hydro customers are caused by wire contact with trees. Furthermore, close proximity of branches to wires can pose a risk to the public and North Bay Hydro workers that need to perform maintenance on the system.

Due to this reality, North Bay Hydro has recently made it a policy of establishing a **15 foot tree clearance** from either side of its overhead power lines.

Although this policy may have an impact on North Bay's tree line, do you strongly support, somewhat support, somewhat oppose or strongly oppose this policy?

Strongly support	1
Somewhat support	2
Neither support nor oppose (**DNR**)	3
Somewhat oppose	4
Strongly oppose	5
Don't know (**DNR**)	98
Refused (**DNR**)	99

F. Reaction to Customer Input

Below are the common themes that have come out of the customer focus groups

The following statements have been made by customers throughout North Bay Hydro's community consultation process.

For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.

Strongly agree	1
Somewhat agree	2
Neither agree nor disagree (**DNR**)	3
Somewhat disagree	4
Strongly disagree	5
Don't Know (**DNR**)	98
Refused (**DNR**)	99

RANDOMIZE QUESTIONS

Willingness / Ability to Pay

F21. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

F22. My organization would be willing to pay a bit more for electricity if it means better service reliability.

Impact of rate increase on others

F23. My organization can afford to pay more for electricity, but I am worried about the impact this will have on some of my suppliers and customers.

Pay Now or Later

F24. We should invest in our electricity system infrastructure **now** or we will end up paying more the longer we delay our system renewal.

Deferring to the experts

F25. The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.

System Reliability

F26. When it comes to reducing power outages and improving reliability, the first priority should be business customers, then residential customers.

Labour Costs

F27. Skilled hydro workers are sought out throughout North America and Ontario. If North Bay Hydro doesn't pay the people who maintain our local distribution system a competitive salary, we risk losing the most qualified and experienced hydro workers to southern Ontario.

Vegetation Management

F28. While North Bay Hydro's policy of tree trimming and tree removal is designed to lower the number of customer power outages, they're going too far in removing the City's tree canopy.

CDM

F29. I think North Bay Hydro should do more to help customers find ways to reduce their electricity consumption and costs.

Reserve Fund

F30. North Bay Hydro should have charged its customers more over the past decade to create a **reserve fund** that could have helped pay to replace the system's aging electrical infrastructure.

Legacy

F31. Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.

G. Assessment of Plan

G32. PREAMBLE

According to North Bay Hydro's proposed plan, the total required funding to manage the day-to-day operations and required capital investment is estimated to be **$14.7 million** in 2015.

- **53%** of the these funds or approximately **$7.8 million** is budgeted for capital investments required to replace aging infrastructure; to connect new customers to the electricity system; to invest in tools, IT systems, vehicles and facilities needed to manage the electricity system; and for new technologies to make the system more efficient, reliable and safe.
- **47%** of these funds or approximately **$7.0 million** of this proposed plan is budgeted for the day-to-day management of the company as a whole, salaries and wages, customer service and on-going maintenance of the distribution system.

To fund this plan, **North Bay Hydro** is proposing the **average small to medium sized business' rate increase by $1.10** on the distribution portion of their bill over the next five years. So, by 2019, the average **small to medium sized business** will be paying an **estimated $5.49 more per month** on the distribution portion of its electricity bill.

G33. Considering the cost of the North Bay Hydro plan and what it means for your business, which point of view is closest to your own? Would you say [READ LIST] …
Rotate response codes "1 "and "3"

The rate increase is reasonable and I support it	1
I don't like it, but I think the rate increase is necessary	2
The rate increase is unreasonable and I oppose it	3
Don't know (**DNR**)	98
Refused (**DNR**)	99

Ask only if G34 = 1, 2, 3 or 4

G34. And why do you say that? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

H. Firmographics

These last few questions are for statistical purposes only. Again, all of your responses are completely confidential.

H35. Which of the following best describes the **hours of operation** of your business? Would you say … [**READ LIST**]

You are open 24/7	1
You operate several shifts each day, but are not open 24/7	2
You operate during regular business hours only	3
You operate outside of regular business hours, but do not have shifts	4
(**DNR**) Other (please specify): _____	88
(**DNR**) Refused	99

H36. And, which of the following best describes **when your business operates** throughout the week? Would you say … [**READ LIST**]

You operate on weekdays only	1
You operate on weekdays and weekends	2
(**DNR**) Other (please specify): _____	88
(**DNR**) Refused	99

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Workbook Appendix:

North Bay Hydro's 2015 Application Review

2015 Rate Application Review

Residential Customer Consultation Workbook

NORTH BAY HYDRO
Community Power

October 9, 2014

North Bay Hydro is the local distribution company responsible for electricity distribution in the City of North Bay.

With 48 employees, North Bay Hydro operates and maintains a distribution system serving a population of approximately 54,000 with almost 24,000 residential and business customers.

North Bay Hydro is 100% owned by the City of North Bay.

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What's this consultation about?

The purpose of this customer consultation is to collect your feedback on North Bay Hydro's investment and spending plan to maintain the local distribution system over the next year (2015).

North Bay Hydro's goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price. However, there is a balancing act that all utilities must consider when planning for the future: system reliability vs. the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of the electricity distribution system and the spending decisions North Bay Hydro will need to make over the next year. Ultimately, this consultation will help North Bay Hydro ensure alignment between its operational and capital investment plans and customers needs and preferences.

As a North Bay Hydro customer, this is an opportunity for you to tell North Bay Hydro what you think about the plan and the cost implications for you. This is also an opportunity for North Bay Hydro to explain to its customers the challenges in operating and maintain the local electricity distribution system, and more importantly how North Bay Hydro intends to meet those challenges.

To participate in this review, you do not need to be an expert. The workbook explains key parts of the electrical distribution system, the challenges facing the system, North Bay Hydro's recent work to maintain the system, and the company's budgetary plan for the next year.

North Bay Hydro does not expect you to make electrical engineering decisions. North Bay Hydro wants to hear about the electricity issues that matter most to you and whether or not you feel the company's spending and investing priorities seem reasonable.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

What's the process that North Bay Hydro must follow?

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which recently developed a new regulatory requirement for electricity distributors, such as North Bay Hydro, to gather customer preferences on distribution system investments.

North Bay Hydro is funded by the distribution rates paid by its customers. Periodically, North Bay Hydro is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. North Bay Hydro must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

As a customer, how are my interests protected?

North Bay Hydro's evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence, in some cases challenging North Bay Hydro's plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates North Bay Hydro can charge for distribution.

Why is my feedback important?

Your feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when North Bay Hydro files its rate application for 2015. As part of the rate hearing process, the OEB will be reviewing how North Bay Hydro acquired and responded to customer feedback in its planning process.

Rate Application Process

- North Bay Hydro assesses system needs
- **Collect customer needs and preferences**
- Refines plan (where necessary)
- Reports on how plan responds to customer input
- Files plan with OEB
- Interrogatories & OEB rate hearing process
- OEB sets North Bay Hydro's distribution rates

Innovative Research Group Inc. has been engaged by North Bay Hydro to collect participant feedback and will deliver it to North Bay Hydro to assist them in shaping their rate application and distribution system plan.

Consumer feedback on Ontario's electricity system

There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how North Bay Hydro uses your money.

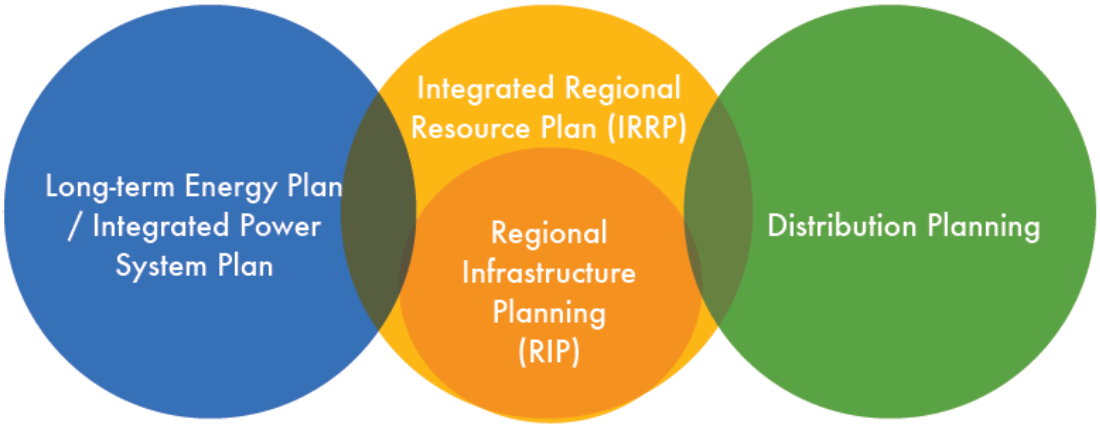
Distribution Planning: This workbook and consultation concentrates on the short-term plan for North Bay Hydro's distribution system over the next year. The graphic below shows the various planning initiatives ongoing across Ontario's electricity system. In addition to the short-term distribution plan being discussed in this workbook, there are other planning initiatives undertaken to ensure that the distribution system maintains reliability and works efficiently for the benefit of customers.

If you're interested in broader medium- and long-term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan: The Ontario Government`s plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website: http://www.energy.gov.on.ca/en/ltep/

Regional Planning: The Ontario Power Authority (OPA) looks ahead to the future electricity needs of your region and how those needs can be addressed through CDM, local generation, and electricity from outside the region. You can follow the OPA`s regional planning process at this website: http://www.powerauthority.on.ca/power-planning/regional-planning

Electricity System Planning in Ontario



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal power generation)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether CDM & local generation options have been considered, in addition to core infrastructure ("wires") solutions.

Distribution Network Planning

Distribution planning involves plans, both near- and longer-term, to ensure the local distribution systems has the adequate infrastructure to meet required reliability and safety standards, and to otherwise meet the needs of customers.

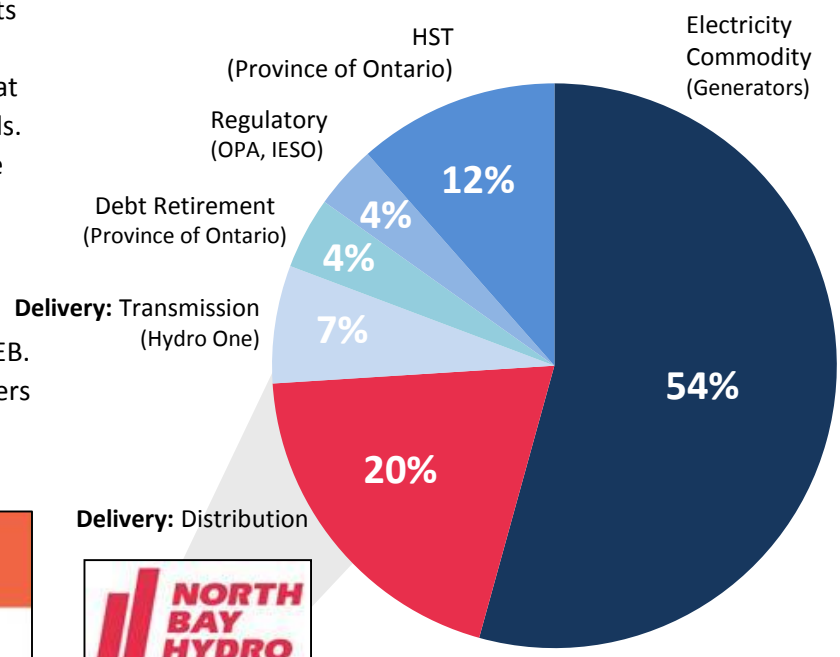
NORTH BAY HYDRO
Community Power

Customer Electricity Bills

Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery" charge on your bill: ***distribution*** and ***transmission***. While North Bay Hydro collects both, it remits the transmission charge to Hydro One. The distribution charges are what North Bay Hydro uses to fund its utility needs. Distribution costs make up about 20% of the typical residential customer's (800 kWh per month) total electricity bill.

North Bay Hydro's distribution rates are subject to the review and approval of the OEB. The revenues collected from customers covers North Bay Hydro's capital investments and operating expenses.

About 20% of the average residential electricity bill goes to North Bay Hydro



MONTHLY BILL STATEMENT
UTILITY

Account Number:
000 000 000 000 0000 0

Meter Number:
0000000

Your Electricity Charges

Electricity	x.xx
300 kWh On-peak @ X.X ¢ /kWh	
300 kWh Mid-peak @ X.X ¢ /kWh	
200 kWh Off-peak @ X.X ¢ /kWh	
Delivery	x.xx
Regulatory	x.xx
Debit Retirement Charge	x.xx
Your Total Electricity Charges	x.xx
H.S.T.	x.xx
Ontario Clean Energy Benefit (-10%)	(-x.xx)
Total Amount	$X.XX

Current monthly distribution charges are approximately **$30** for a typical North Bay Hydro residential customers who consumes 800 kWh in a month.

It is estimated that an additional **$0.92** per month each year or approximately **2.9%** per year will be required over the next five years to operate, maintain, and modernize North Bay Hydro's electricity distribution system.

Electricity Grid 101

Who Does What in Ontario's Power System?

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three components: **generation**, **transmission** and **distribution**.

GENERATION

Generating facilities convert various forms of energy into electric power.

EXAMPLE

Ontario Power Generation
TransCanada Energy Ltd
Bruce Power
Samsung Renewable

TRANSMISSION

Transmission lines connect the power produced at generating facilities to substations.

EXAMPLE

Hydro One

DISTRIBUTION

Distribution lines carry electricity to homes and businesses.

EXAMPLE

North Bay Hydro
Lakeland Power
Greater Sudbury Hydro
Hydro Ottawa

CONSUMERS

Electricity is delivered to homes and businesses.

EXAMPLE

Residential
Commercial
Industrial

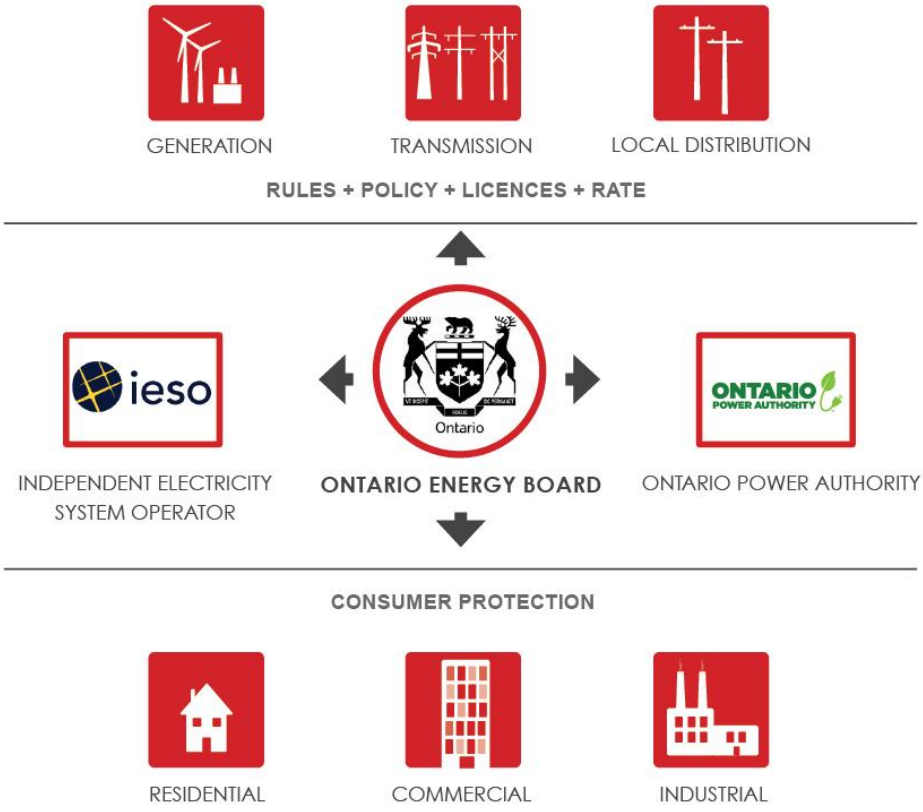
Electricity Grid 101:
How is Ontario's Electricity System Regulated?

Ontario Ministry of Energy:
The Ontario Ministry of Energy sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

Ontario Energy Board:
The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

Ontario Power Authority:
The Ontario Power Authority (OPA) is responsible for medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. The OPA receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.

The Independent Electricity System Operator:
The Independent Electricity System Operator (IESO) is responsible for electricity supply over the short-term. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it.



Customer Feedback

1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services North Bay Hydro is responsible for?
   - ❑ Very well
   - ❑ Somewhat well
   - ❑ Not very well
   - ❑ I don't understand at all

2. Generally, how satisfied are you with the service you receive from North Bay Hydro?
   - ❑ Very satisfied
   - ❑ Somewhat satisfied
   - ❑ Somewhat dissatisfied
   - ❑ Very dissatisfied
   - ❑ Don't know

3. Is there anything in particular that North Bay Hydro can do to improve it service to you?

North Bay Hydro's Grid Today

This section describes the construction of North Bay Hydro's distribution grid including its substations, overhead and underground systems. It also explains the company's historical growth and current electrical infrastructure.

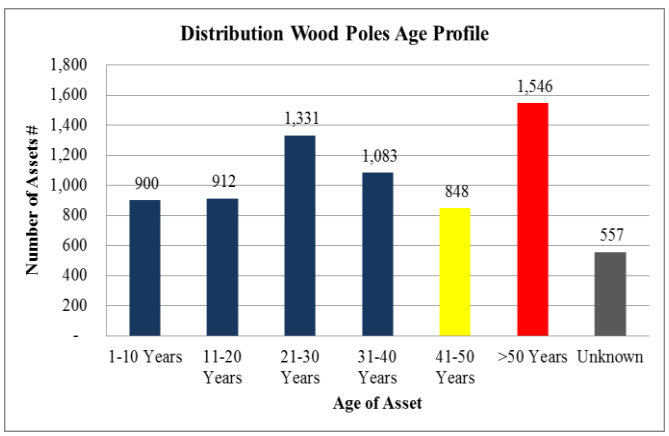
Background on North Bay Hydro's Distribution System

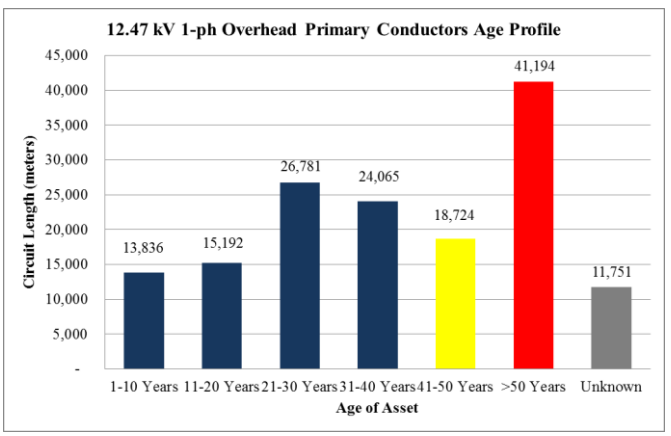
The current distribution system was created from the amalgamation of three different distribution companies in 1968; **Widdifield Hydro**, **West Ferris Hydro**, and **North Bay Hydro**, each of which had their own unique system design standards and distribution equipment.

Of particular concern, the amalgamated North Bay Hydro had three different distribution voltage systems. Due to the inefficiencies and inflexibility of operating such a system, a voltage conversion project, spanning over multiple decades, was undertaken. Converting the system to a single standard would improve voltage regulation, decrease pole line congestion by minimizing number of feeders, lower electricity line loss, improve system security, reliability and operational flexibility. From a long-term perspective, the number of required substations would also be minimized.

Harmonizing the entire system to one distribution voltage standard has been the main driver behind all capital expenditures for the past 20 years. The voltage conversion program has targeted the replacement of some of North Bay Hydro's oldest assets that are at the end of their life, those built in the early to mid-1900's, and allowed conversion of the voltage at the same time. This infrastructure has served the city of North Bay well beyond its expected lifespan and the full conversion to a single standard will be complete by 2017. North Bay Hydro will then turn its attention to replacing the remaining aging assets found in the existing 12kV system; doing nothing will result in service reliability issues.

In May 2014, North Bay Hydro commissioned an asset condition assessment report to document the condition of all major assets. This report will help guide North Bay Hydro's infrastructure spending from 2015 through 2019. The charts below illustrate the age profiles of wooden poles and overhead conductors.

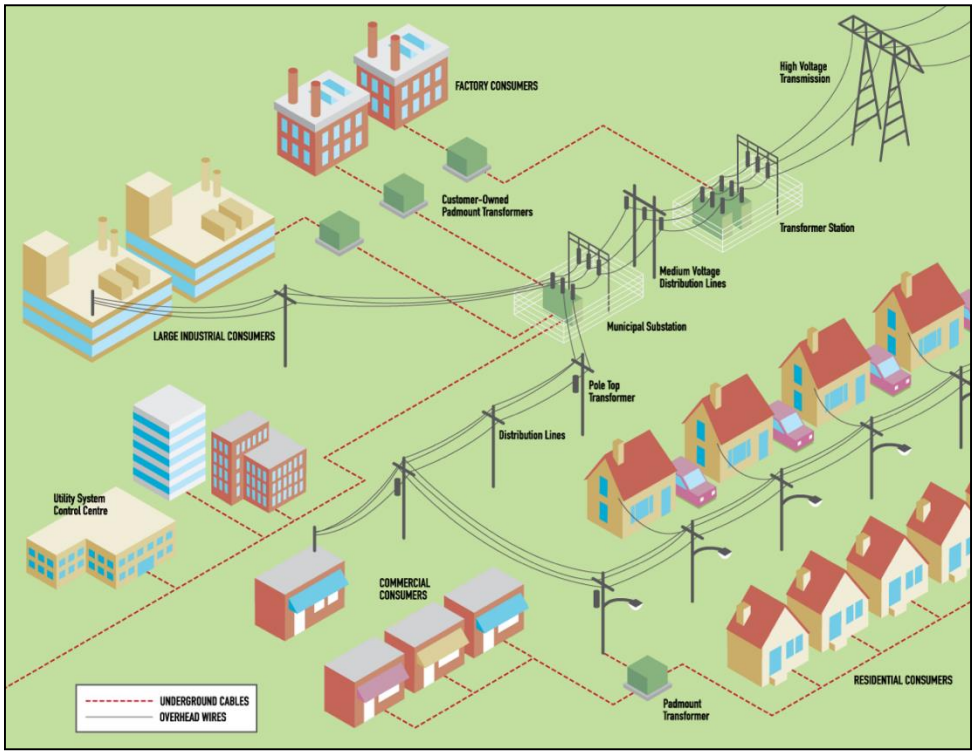




North Bay Hydro's Grid Today

Every distribution system is unique with its own history and challenges. In order to better understand the current North Bay Hydro system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The diagram below and following terms will help guide you through the system.

North Bay Hydro's distribution system is made up of a number of components which work together to transport electricity to homes and businesses across the city.



The system is predominantly made up of overhead wires as opposed to underground cables, largely as a result of the high concentration of Canadian Shield in the area which often makes underground digging cost prohibitive.

The service area served covers approximately 310 square kilometers, of which 270 square kilometers is rural. The distribution network consists of **16 municipal substations**, approximately 511 km of overhead distribution wires and 73 km of underground distribution cables.

North Bay Hydro receives all of its power from **2 transformer stations** which are owned and operated by Hydro One.

Hydro One's Transmission System:

High Voltage Transmission – Connects our distribution system to electricity generating stations across the province.

Transmission Station – Reduces high voltage electricity from transmission lines to medium voltage which is fed into North Bay Hydro's distribution stations.

North Bay Hydro's Distribution System:

Municipal Substations: Municipal substations are a critical element of the electricity distribution system —they are the local hubs from where electricity is distributed to an area. Municipal substations stations contain:

Transformers - Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area.

Feeder Circuits - The wires that connect the transformer station to the broader distribution system in order to deliver electricity to customers.

Breakers - Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of electricity is detected.

Switches - Control the flow of electricity and steer the current to the correct circuits.

North Bay Hydro's Grid Today:
Distribution System

North Bay Hydro's Distribution System:

Overhead System: The overhead system includes the wires that are commonly seen across North Bay Hydro's service area. The voltage of the overhead system can range from 4 kV (4,000 volts) to 12kV.

Wires – There are 511 km of wire that carry electricity across the overhead distribution system.

Poles – Wires are suspended from these, usually wooden (sometimes concrete), poles.

Pole Top Transformers – These transformers are mounted near the top of utility poles and are needed to further step-down the voltage from the lines to the final connection to customers.

Underground System: The underground system includes 73 km of cable, some of which is directly buried and or installed in ducts. At certain intervals, underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

An advantage of underground systems is that they are affected to a lesser extent by extreme weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage it often takes longer to locate and repair a problem compared to overhead wires.

Underground Cables – Convey the electricity in the underground system. Cables that connect the distribution stations and major industrial users to the distribution station are significantly larger than cables used to connect residential neighbourhoods.

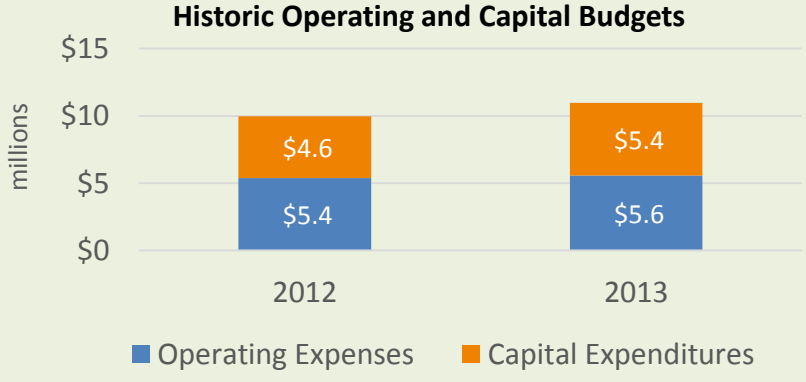
Padmount Transformers – Similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and vault transformers, which are housed in underground chambers.

Paying for the Distribution System?

As anyone who runs their own business would expect, North Bay Hydro manages it spending in two budgets – an operating budget and a capital budget.

North Bay Hydro's **operating budget** covers regularly recurring expenses such as the costs of running service vehicles, the payroll for employees, and the maintenance of distribution equipment and buildings.

Its **capital budget** covers items that, when purchased, do not need to be repurchased for some time and that have lasting benefits over many years. This can include much of the equipment that is part of the distribution system, such as poles, wires and transformers, major computer systems, and vehicles.



Managing the distribution system requires millions of dollars in maintenance, system renewal and running the day-to-day operations. In its last fiscal year (2013), North Bay Hydro's operating expenses and capital expenditure totalled $11.0 million.

Customer Feedback

4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services North Bay Hydro is responsible for?
    - ❑ Very well
    - ❑ Somewhat well
    - ❑ Not very well
    - ❑ I don't understand at all

5. The average North Bay Hydro customer experiences between 1 and 3 power outages per year. Do you recall how many outages you experience in the past year?
    - ❑ Once
    - ❑ Twice
    - ❑ Three times
    - ❑ More than three times
    - ❑ Don't know

6. How acceptable were the number of power outages you experienced over the last 12 months?
    - ❑ Very acceptable
    - ❑ Somewhat acceptable
    - ❑ Not very acceptable
    - ❑ Not acceptable at all
    - ❑ Don't know

7. Overall, how satisfied are you with the reliability and quality of electricity services provided by North Bay Hydro?
    - ❑ Very satisfied
    - ❑ Somewhat satisfied
    - ❑ Somewhat dissatisfied
    - ❑ Very dissatisfied
    - ❑ Don't know

Cost Pressures

From the day-to-day to major storm events, there are a variety of ever-present pressures on North Bay Hydro's operating and capital budget.

Many of these expenditures are items over which North Bay Hydro has little or no control – major storms, and the implementation of Smart Meters, for example.

Other costs are associated with preventative maintenance like replacing aging equipment. Since 2010, North Bay Hydro has undertaken several large scale projects, and more are planned.

Why hasn't North Bay Hydro anticipated the need to fix aging infrastructure?

North Bay Hydro monitors the health of its electric infrastructure very closely. As part of its rate application, it must show the OEB third party audits of the health of its system's assets. These asset health audits help North Bay Hydro prioritize which parts of its system get upgraded or rebuilt first.

Why hasn't North Bay Hydro set aside funds to pay for required upgrades?

The OEB does not allow utilities in Ontario (including North Bay Hydro) to create reserve funds. If reserve funds were allowed, a utility would have to charge customers a premium on their rates to set money aside. Under OEB issued *Cost of Service* licenses, a utility can only charge customers the rate required to run the distribution system at a reliability standard set by regulatory bodies.

Paying for North Bay Hydro's Distribution System: *Capital Investment Drivers*

North Bay Hydro has developed a list of capital investment drivers and proposes investment programs based on these key drivers.

Reliability: There are two main measures of reliability in the distribution system:

1) How often does the power go out?
2) How long does is stay out?

To achieve maintained or improved reliability, projects are developed to improve asset performance and decrease the frequency and duration of power outages.

Service Requests: North Bay Hydro has a legal obligation to connect customers to its distribution system. This includes both traditional demand customers (new homes and businesses) and distributed generation customers (e.g. micro-FIT customers who have contracts to sell electricity back to the grid such as rooftop solar panels). Requests can also include system modifications to support infrastructure development by government agencies, road authorities and developers.

Support Capacity Delivery: Where there are forecasted changes in demand that will limit the ability of the system to provide consistent service delivery or where it is incapable of meeting the demand requirements, new builds or expansion is required. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by new customers served over time.

System Efficiency: To provide customers with the best service possible, there is always a need to improve power outage restoration capability.

Mandated Compliance: Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and other regulations.

Obsolescence:
Asset installations that no longer align with North Bay Hydro's current operating practices or current standards. This can include those assets that:

- are no longer manufactured,
- lack spare parts,
- cannot be accessed,
- lack the ability to have maintenance performed on them,
- have operational constraints or conflicts, which can result in increased reliability and/or safety related risks.

Aging or Poor Performing Equipment: Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

Business Support Costs: North Bay Hydro is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

Paying for North Bay Hydro's Distribution System: *Capital Investments*

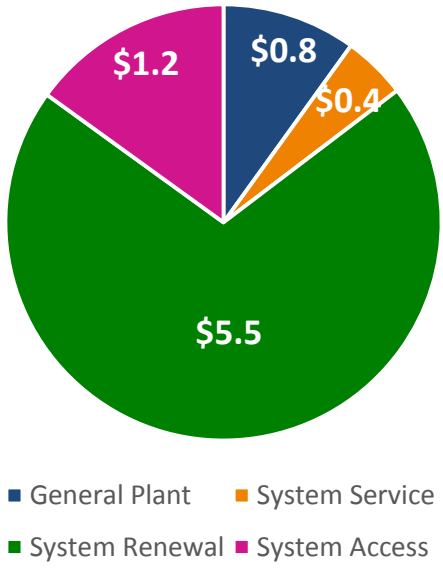
What are the major issues we need to address?

Over the years, North Bay Hydro has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However, North Bay Hydro's key challenge still comes from the need to replace aging equipment.

In 2015, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by North Bay Hydro to be **$7.8 million**.

To assist us in prioritizing what needs to be replaced and by when, North Bay Hydro uses an asset management model to drive replacement decisions. Using the information provided by the asset management model, North Bay Hydro plans for four types of capital investment costs:

2015 Forecasted* Capital Expenditures (millions)



System Access

Definition: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of request

Programs (e.g.): Customer Connections, Relocating assets based on infrastructure needs

System Renewal

Definition: Projects focused on replacing aging equipment in poor condition

Programs (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

System Service

Definition: Primarily consisting of projects that improve system reliability

Programs (e.g.): Automated Switches, better distribution system monitoring equipment

General Plant

Definition: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system

Programs (e.g.): IT, facilities, fleet

*These figures are subject to change upon final rate application submission.

Cost Drivers
Capital Investments

Specific projects that are driving North Bay Hydro's capital investments include:

Aging Infrastructure

- Inventory of assets and asset health to determine what equipment needs to be replaced, and what can safely stay in place until it no longer works.
- An extensive underground rebuild to maintain system reliability.
- The construction of a new substation to replace the current one which is in poor condition, is becoming a safety hazard and is the last substation in North Bay that requires automation.

Day-to-Day Reliability

- The voltage conversion program to bring equipment up to the current single standard, which will result in greater flexibility to respond to local power outages.

New Technology

- North Bay Hydro will be extending SCADA into the new substation – this will control the breakers at the station and allow for remote operation, monitoring and provide access to a vast amount of decision making data. This automation will save on truck rolls and reduce outage times

Required New Equipment

- North Bay Hydro plans to purchase a new "bucket" truck to replace an existing truck that is well beyond it's useful life.

The following five project areas represent approximately 85% of North Bay Hydro's estimated 2015 Capital Investment budget*:

1) Municipal substation rebuild, including new power transformers	
Project Cost	$2,511,617
2) Projected system access demand work: i.e. new connections, upgraded services, road relocations, and new subdivision developments	
Project Cost	$1,109,300
3) Underground system rebuild: Wickstead/Melina Close/Madelena	
Project Cost	$1,247,860
4) Overhead system rebuild: Main St. W/Ferguson/McIntyre	
Project Cost	$938,733
5) Replacement of bucket truck	
Project Cost	$453,285

The remaining 15% of the capital investment plan is earmarked for a number of smaller projects including voltage conversion initiatives and productivity investments such as IT system upgrades.

*These figures are subject to change upon final rate application submission.

Cost Drivers
Operating Expenses

In addition to its capital budget, North Bay Hydro also needs to consider its operating budget which also impacts customer bills.

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this cost driver is North Bay Hydro's tree trimming program, designed to lessen the impact of failing tree branches on power lines.

Labour Costs:
- Increased workload from customer demand, provincial polices and the operating and maintenance needs of the system.
- Annual wage and benefit increases - compensation at North Bay Hydro is in line with industry benchmarks.

Customer Engagement:
- The OEB now requires all local distribution companies to demonstrate that they have consulted customers before applying for a rate increase. North Bay Hydro agrees with this new practice, but these programs add to operating costs.

Business & Strategic Planning:
- Since 2010, there has been an unprecedented amount of change in the electricity sector. Changes are occurring at every level (government, regulatory, municipal) and they impact how North Bay Hydro operates.
- Changing technology offers new applications for efficiency and service improvements.

Smart Meters:
- The Province requires all local distribution companies, including North Bay Hydro, to implement Smart Meters.

IT Systems & Maintenance:
- North Bay Hydro is minimizing IT costs by maintaining existing IT systems. New modules are being added to meet new functional requirements on an as-needed basis only.
- New applications have been implemented for locates, collection processes and to improve customer service on the website.

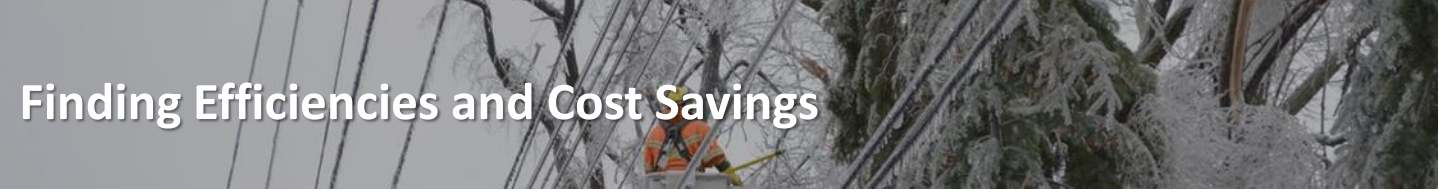
Operational Review:
- North Bay Hydro plans to conduct a formal review of its Engineering and Operations departments.

Vegetation Management:
- 30%-50% of outages are tree related and are a safety hazard.
- A local certified arborist has reviewed North Bay Hydro's service territory and provided an assessment and recommendation based on sound arboricultural advice.
- North Bay Hydro has now made it a policy of establishing 15 feet of clearance from either side of centre line of its overhead circuits
- Based on customer feedback North Bay Hydro will also begin a stump removal and re-greening program within the City.

Change between 2010 Approved Operating Budget and 2015 Request:

2010 OEB Approved Operating Budget*	$5,680,410
Salaries, Wages & Benefits	747,263
Customer Focus:	
Customer Engagement	82,000
Bad Debts	(78,921)
Operations Effectiveness	
Business & Strategic Planning	100,000
IT Systems & Maintenance	97,392
Smart Meters	106,753
Operational Review	208,000
Vegetation Management	346,655
Substation Preventative Maintenance	(171,607)
Other miscellaneous programs	38,301
2015 Request to OEB	**$7,156,244**

*These figures are subject to change upon final rate application submission.



Finding Efficiencies and Cost Savings

To set the context of North Bay Hydro's (NBH) operations, below are some examples of the other things they do on top of construction and maintenance of the physical distribution system.

- In 2010 NBH handled 2,367 underground cable locates and in 2013 this had increased 55% to 3,678.
- In 2013 handled 39,805 telephone calls , a 66% increase from 23,967 telephone calls in 2010.
- Collection work orders have increased 60% - from 1,454 in 2010 to 2,326 in 2013.
- Disconnection notices increased from 9,680 in 2010 to 13,588 in 2013, up 40%.
- 15,000 – 20,000 walk-ins per year.
- Approximately 289,000 bills issued each year.
- 565 trouble calls in 2013.
- Receive over 300 requests from customers for connection to its system or upgrades/changes to existing connections (service spots).

NBH achieves continuous improvement by implementing measures that directly reduce costs, improve productivity and improve levels of service to customers.

Cost Reduction Measures: Examples of some of the cost reduction measures that NBH has implemented are:

- *Just-in-time* delivery of hardware and equipment reduced inventory levels by $340k in 2013.
- NBH purchases its materials through a joint Northern LDC Buying Group to obtain economies of scale. It is estimated NBH saved approximately $70k in products and an additional $45k in freight.
- Substation maintenance activities performed in-house has saved $60k per year in contractor costs and fees.
- A bulk purchase of 3 station transformers made through a competitive purchase process resulted in cost savings of over $25k.

Productivity Improvement Measures: NBH has implemented the following productivity improvement measures:

- NBH has invested and continues to invest in remotely operable SCADA switches to restore power more quickly and reduce the costs of sending a crew to manually operate the switch.
- Investments in new automation technology allowed NBH to handle a 55% increase in the number of locates completed within required timelines.
- NBH re-organized its Customer Accounts operation including consolidating three different job functions into one, introducing standardized work processes and training staff on customer service skills.
- Bill production and printing brought in-house reducing external purchases by $60k per year.

Customer Service Improvements:

- NBH received many requests for paperless billing and began offering an eBilling option in 2012 - paperless billing together with the Customer Portal is leveraging existing technology on the website to make doing business easier for the customer and has resulted in savings of $53k per year in reduced postage, paper and printing costs.
- Based on feedback, a new website design and content was launched with many built-in enhancements including easy to use online forms, focus on conservation information and information on system status. Major un-planned outages are updated on the website and customers are informed that NBH is responding. NBH also uses social media to advise customers on system status.
- NBH is working with local environmental groups to understand whether the current approach to the vegetation management program can be enhanced to improve customer education on the need for tree trimming and removals and how we can work cooperatively to maintain the green canopy of North Bay.

Customer Feedback

8. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
    - ❑ North Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
    - ❑ North Bay Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
    - ❑ Don't know

9. As a company, North Bay Hydro needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
    - ❑ North Bay Hydro should find ways to make do with the buildings, equipment and IT systems it already has.
    - ❑ While North Bay Hydro should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.
    - ❑ Don't know

10. How well do you feel you understand the cost drivers that North Bay Hydro is responding to?
    - ❑ Very well
    - ❑ Quite well
    - ❑ Not very well
    - ❑ Not at all
    - ❑ Don't know

11. How well do you think North Bay Hydro is managing these cost drivers while meeting customer expectations and keeping rates reasonable?
    - ❑ Very acceptable
    - ❑ Somewhat acceptable
    - ❑ Not very acceptable
    - ❑ Not acceptable at all
    - ❑ Don't know

12. Now that you have a better sense of the operations of North Bay Hydro, including the cost drivers, do you feel the proposed budget is reasonable?
    - ❑ Yes
    - ❑ No
    - ❑ Don't know

What North Bay Hydro's Plan Means for You?

In 2015, residential customers with an average monthly consumption of 800 kWh will actually see an estimated decrease of $2.30 per month on the distribution portion of their electricity bills.

Although there is a reduction in the forecasted 2015 rates, this is a reflection of changes to accounting standards rather than a decrease in North Bay Hydro's projected revenue needs.

However, North Bay Hydro's forecasted increase over the next five years may see an average annual increase of $0.92 per month or 2.8% on the distribution portion of the bill for a residential customers with an average monthly consumption of 800 kWh.

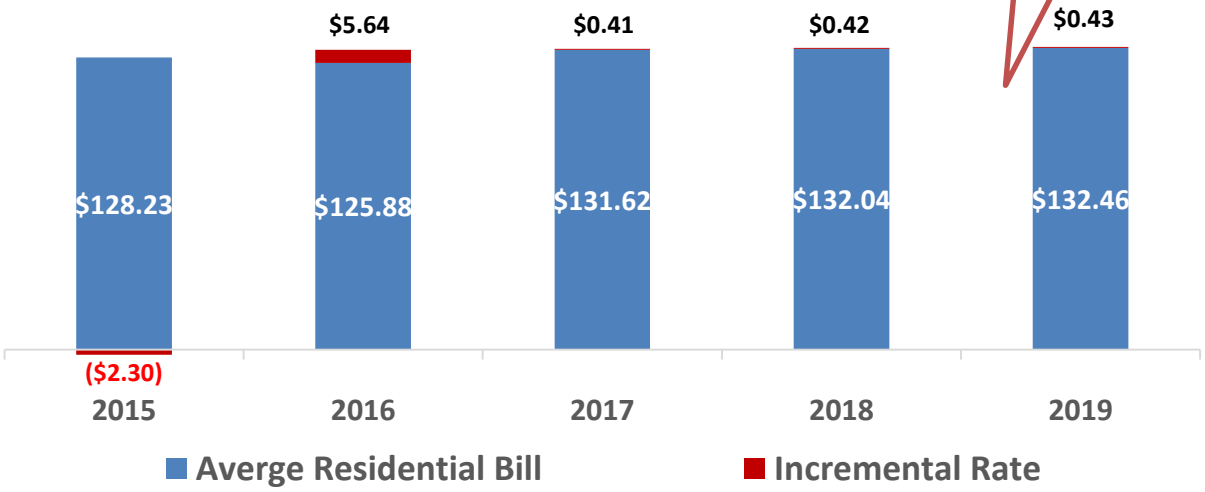
As such by 2019, North Bay Hydro forecasts that the average residential household will be paying an estimated $4.60 more per month on the distribution portion of their electricity bill.

The table below illustrates the 5 year forecasted change in rates.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

Year	Average Residential Bill	Distribution Proportion of bill	Incremental Rate Change	% Change
2015	$125.88	$28.29	($2.30)	-1.8%
2016	$131.62	$33.93	$5.64	4.5%
2017	$132.04	$34.34	$0.41	0.3%
2018	$132.46	$34.76	$0.42	0.3%
2019	$132.89	$35.19	$0.43	0.3%

Estimated average annual increase in monthly bill will be $0.92



Customer Feedback

13. Did North Bay Hydro's Plan cover the topics you expected?

- ❑ Very well
- ❑ Somewhat well
- ❑ No, not very well

If no, what is missing?

14. How well do you think North Bay Hydro is planning for the future?

- ❑ Very well
- ❑ Somewhat well
- ❑ Not very well
- ❑ I don't know

15. Considering what you know about the local distribution system, which of the following best represents your point of view?

- ❑ The rate increase is reasonable and I support it
- ❑ I don't like it, but I think the rate increase is necessary
- ❑ The rate increase is unreasonable and I oppose it
- ❑ Don't know

Final Thoughts

North Bay Hydro values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

Overall Impression: What did you think about the workbook?

Volume of Information: Did NBH provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Distribution Station: These substations are located near to the end-users. Distribution station transformers change the voltage to lower levels for use by end-users.

Feeder Circuit: Is a wire that connects the transformer station to the broader distribution system in order to deliver electricity to customers.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilowatt (kW): 1000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration or operating budget.

Substations: These include transmission stations and distribution stations. They are used to switch generators, equipment, and circuits or lines in and out of a system. It also is used to change AC voltages from one level to another.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Switches: Control the flow of electricity and steer the current to the correct circuits.

Transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

Transformer: Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable).

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

Appendix I – Letter from HONI

Appendix I – Letter from HONI

Hydro One Network Inc.
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15th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

April 2, 2014

Mr. Matt Payne
Manager Engineering
North Bay Hydro Distribution Limited
74 Commerce Cres.
North Bay, Ontario, P1B 8G4

Dear Mr. Payne:

Subject: Regional Planning Status Letter

This letter is in response to your request for a Planning Status Letter. Please note that the province has been divided into 21 regions for the purpose of regional planning. These 21 regions are assigned to one of three groups to prioritize and manage the regional planning process. A map with details about the 21 regions and a list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. (HONI) is the lead transmitter for 19 of the 21 regions.

Your LDC belongs to the North/East of Sudbury region, which is in Group 3.

This letter is to confirm that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) has been developed for the sub-region within the North/East of Sudbury Region affecting North Bay Hydro Distribution Limited. I expect, as per the new process, that Regional Planning for the North/East of Sudbury Region will be initiated in fourth quarter of 2015. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with North Bay Hydro Distribution Limited in executing the new regional planning process.

Please feel free to contact me if you have any questions.

Sincerely,

Ajay Garg, |Manager - Regional Planning Coordination and Transmission Load Connections|
Hydro One Networks Inc.

Cc: Bing Young – Director, Transmission System Development [HONI]
Brad Colden – Manager, Key Accounts Management [HONI]

Appendix J – NBHDL COS 230-05

North Bay Hydro Distribution Limited Conditions of Service	**Number:** NBHDLCOS – 230 – 05 **Issue Date:** June, 2006 **Review Date:** November, 2008
Voltage Guidelines	

1. Preamble

North Bay Hydro Distribution Limited (NBHDL) endeavours to supply a constant, stable *supply voltage* from its *distribution system*. The *Canadian Standards Association (CSA)* provides guidelines for *supply voltage* variation limits.

2. Voltage Criteria

NBHDL maintains *supply voltage* at the *Consumer's* service entrance within the guidelines of *CSA* Standard CAN3-C235-83 (latest edition) Table 3, which allows variations from nominal voltage of:

Nominal Voltage	Voltage Variation Limits			
	Extreme Conditions			Extreme Conditions
		Normal Conditions	Normal Conditions	
Single Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three Phase 4w				
120/208	110/190	112/194	125/216	127/220
240/416	220/380	224/388	250/432	254/440
277/480	245/424	254/440	288/500	293/508
347/600	306/530	318/550	360/625	367/635
Three Phase 3w				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Where *supply voltages* lie outside the indicated limits for *normal operating conditions* but within the indicated limits for *extreme operating conditions*, improvement or corrective action should be taken on a planned and programmed basis. Where *supply voltages* lie outside the indicated limits for *extreme operating conditions*, improvement or corrective action should be taken as soon as practical. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to *supply voltage* levels and duration, etc.

NBHDL shall practice reasonable diligence in maintaining *supply voltage* levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the *transmitter.* NBHDL shall not be liable for any delay or failure in the performance of any of its obligations under this *Conditions of Service* document due to any events or causes beyond the reasonable control of NBHDL, including, without limitation, items indicated in the Force Majeure defined in NBHDLCOS-230-03, Electrical Disturbances.

---------- End of Document ----------

Appendix K – NBHDL COS-230-02

North Bay Hydro Distribution Limited Conditions of Service	**Number:** NBHDLCOS – 230 – 02 **Issue Date:** June, 2006 **Review Date:** November, 2008
Power Quality	

1. Preamble

North Bay Hydro Distribution Limited (NBHDL) endeavors to supply continuous *energy* with no power quality problems. Policies and procedures have been developed to address these issues, including *supply voltage* guidelines and outage notification processes. This section outlines those policies and procedures, as well as indicating the process NBHDL uses for handling voltage disturbances and power quality testing and remedial action.

This section includes conditions under which supply of *energy* to *Consumers* may be interrupted, and may become unreliable or intermittent.

2. Power Quality Testing

In response to a *Consumer* power quality concern, where the utilization of *energy* adversely affects the performance of electrical equipment, NBHDL will perform an investigative analysis on their *distribution system* up to the *ownership demarcation point* to attempt to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

Upon determination of the cause resulting in the power quality concern, where it is deemed a *distribution system* delivery issue and where *good utility practice* are not met, NBHDL will recommend and/or take appropriate mitigation measures. NBHDL will endeavor to take appropriate actions to control power disturbances found to be detrimental to the *Consumer*. If NBHDL is unable to correct the problem without adversely affecting other NBHDL *Consumers*, then it is not obligated to make the corrections. NBHDL will use appropriate industry standards (such as *Canadian Standards Association* or *IEEE* standards) and *good utility practice* as a guideline. If the problem lies on the *Consumer* side of the *distribution system*, NBHDL shall seek reimbursement from the *Consumer* for the costs incurred in its investigation.

3. Prevention of Voltage Distortion on Distribution

Consumers having a non-linear load shall not be connected to NBHDL's *distribution system* unless power quality is maintained by implementing proper

corrective measures such as installing proper filters, and/or grounding. Further, to ensure the *distribution system* is not adversely affected, power electronics equipment installed must comply with *IEEE* Standards. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

4. Obligation to Help in the Investigation

If NBHDL determines the *Consumer's* equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on NBHDL's *distribution system*, the *Consumer* is obligated to help NBHDL by providing required equipment information, relevant data and necessary access for monitoring the equipment.

5. Timely Correction of Deficiencies

If an undesirable *distribution system* disturbance is being caused by the *Consumer's* equipment, the *Consumer* will be required to cease operation of the equipment until satisfactory remedial action has been taken by the *Consumer* at the *Consumer's* cost. If the *Consumer* does not take such action within a reasonable time, NBHDL may *disconnect* the supply of *energy* to the *Consumer.*

6. Notification for Interruptions

Although it is NBHDL's policy to minimize inconvenience to *Consumers*, it is necessary to occasionally interrupt a *Consumer's* supply of *energy* to maintain or improve the *distribution system*, or to provide new or upgraded services to other *Consumers*. NBHDL will endeavor to provide the *Consumer* with reasonable advance notice of planned *energy* interruptions. Notice may not be given where work is of an *emergency* nature, involving the possibility of injury to *Persons* or damage to property or equipment.

However, during an *emergency*, NBHDL may interrupt supply of *energy* to a *Consumer* in response to a shortage of supply of *energy* or to effect repairs on NBHDL's *distribution system* or while repairs are being made to a *Consumer-owned substation.*

7. Notification to Customers on Life Support

Consumers who require an uninterrupted source of *energy* for life support equipment must provide their own *emergency backup* equipment for these purposes. *Consumers* with life support systems are encouraged to inform NBHDL of their medical needs and their available *emergency backup.* These *Consumers* are responsible for ensuring that the medical information they provide NBHDL is accurate and up-to-date. This information is maintained in NBHDL's Customer Information System and supplied to the Operations Department.

With planned interruptions, the same procedure as prescribed in Section 6 above will be observed. For those unplanned *energy* interruptions that extend beyond six hours and the time expected to restore the supply of *energy* is longer than what was indicated by *Consumers* (registered on life support) as their available *emergency backup*, NBHDL will endeavour to contact these *Consumers* but will not be liable in any manner to the *Consumer* for failure to do so.

8. Emergency Interruptions for Safety

NBHDL will endeavour to notify *Consumers* prior to interrupting the supply of *energy*. However, if an unsafe or hazardous condition is found to exist, or if the use of *energy* by apparatus, appliances, or other equipment is found to be unsafe or damaging to NBHDL's *distribution system* or any other *Person*, the supply of *energy* may be interrupted without notice.

9. Emergency Service (Trouble Calls)

NBHDL will exercise reasonable diligence and care to deliver a continuous supply of *energy* to the *Consumer*. However, NBHDL cannot guarantee a supply of *energy* that is free from interruption.

When *energy* is interrupted, the *Consumer* should first ensure that their failure is not due to the opening of a *Consumer*-owned protective device such as a fuse or breaker operating within their installation. If there is a partial power failure, the *Consumer* should obtain the services of an electrical contractor to carry out necessary repairs. If, on examination, it appears that NBHDL's main source of supply of *energy* has failed, the *Consumer* should report these conditions at once to NBHDL by calling the 24 hour phone number outlined in NBHDLCOS-500 Appendix A, Corporate Contacts.

NBHDL operates a trouble-call response, 24 hours a day, seven days a week, to provide service to *Consumers*. NBHDL will initiate restoration efforts as rapidly as practicable.

10. Outage Reporting

Depending on the outage, duration and the number of *Consumers* affected, NBHDL may issue a news release to advise the general public of the outage. In turn, news radio stations may call for information on a 24 hour basis when they hear of an outage.

---------- End of Document ----------

Appendix L – ArborWorks Consulting Report

North Bay Hydro

Tree Trimming Program

Consulting 2014

February 2014

Consultant: Daniel Shepstone, Arborist/ Utility Arborist

ArborWorks Tree Service

Forward

Daniel Shepstone, Certified Arborist and Utility Arborist with the International Society of Arboriculture and the Ontario Ministry of Training, Colleges and Universities Ontario and President of ArborWorks Tree Service created this report at the request of North Bay Hydro. The intention is to provide industry specific knowledge of arboriculture and its application with respect to tree, limb and brush clearances around energized conductors, apparatus, and substations as they relate to community safety, concerns and perspectives.

Considerations with respect to the historical methodologies and current practices have been addressed. Included are recommendations on improving the ability of North Bay Hydro to design, create, manage and apply a best practices tree pruning and vegetative management program for maintaining trees and related vegetation in proximity to, and around utility lines and apparatus.

The document has been created with best intentions for North Bay Hydro application by using Industry Standard references, local geography, local tree species, Federal, Provincial and Municipal legislative requirements.

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C.V. Daniel Shepstone

Utility Pruning –Objectives of the LDC

Industry Standards and Practices

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Conclusion

Introduction

History

Utility line clearing has been a necessary component to any utility distribution company since the establishment of electrical grids and hydro distribution to a community. Overhead utility lines and other important apparatus are found firmly established in many communities. Trees are also a very important contributor to the makeup of our landscapes. Both planted and naturally established trees impact the community and its residents as a whole, surrounding flora and fauna and how safely and efficiently electricity is distributed throughout.

Trees are vitally important to the landscape and the environment. They contribute with carbon reducing capabilities as well as their psychological and sociological impacts on society. It has been recognized since the beginning of civilization that trees, their composition and the manageability of it, is a very important faucet of human evolution and existence.

The theory of Arboriculture has been practiced for centuries. The practice of managing, growing and cutting trees dates back to include the cultivation of fruit and ornamental trees, by the Egyptians, Greeks and Romans. Over time the evolution of society and mankind has made ever-changing demands from the landscape and the environment. These requirements would include land clearing for settlement and civilization, wood cutting for heating, shaping and molding for tools, boats, shelter and other needs. It is recognized that the cultivation of trees and other plants began around the fifteenth century for food, building and other resources.

The preservation of trees in both the urban and rural environment has generated an increasing demand for skilled people, with an intrinsic knowledge of tree biology, mechanics and cultivation principles. These people must have an understanding of the symbiotic nature in which trees and modern society thrive. High-profile recent environmental issues such as harvesting of the rain forests, depletion of the ozone layer, political pressures with respect to interests in natural resources, climate change and carbon foot prints have pronounced effects on the public opinion on the importance of people and trees ability to co-exist in the same environment.

Since the early twentieth century the arboriculture industry as we know it today began to take shape. Credit to industry leaders such as John Davey, F.A. Bartlett, Alex Shigo and many other early researchers for their contributions to the

introduction of research, laboratories and fieldwork dedicated to expanding our knowledge in sciences of tree biology and mechanics. Information derived from their efforts promoted an industry need to promote better public understanding trees, their biology and the importance of their place in the landscapes. More recently technological advances have profoundly increased our ability to not only theorize but to accurately measure the structural integrities and biological reactions of trees and wood fiber.

Arboriculture

In the mid 1800's the term Arboriculture was defined as the cultivation of trees and shrubs *(Collins English Dictionary)*. It wasn't until the mid 1900's that the term was more commonly used in the industry to encompass the cultivation, management and study of individual trees, shrubs and other woody perennials. Arboriculture is both a science and a practice.

The science of arboriculture studies how plants grow and respond to cultural practices and their environments. The practice of arboriculture includes the technique of pruning, removing and climbing trees for that purpose, including fertilization, management, cultivation, pest and disease diagnosis and control with respect to trees and shrubs.

Amenity trees, as opposed to those cultivated for their timber or fruit value are typically the trees tended to through arboriculture practices. Those skilled, knowledgeable and trained in the field of arboriculture are referred to as Arborists. An arborist is a person both in which may study arboriculture and one whom professes at the technique and practices. Early twentieth century, the western societies more commonly referred to an arborist as a 'tree doctor' or 'tree surgeon'.

After a brief introduction of the importance of both trees and utilities and the symbiotic relationship they play in today's societies. We now may reflect on the importance of utilizing appropriate methodologies to ensure safe and reliable hydro distribution while utilizing sound practices of arboriculture to ensure public safety and perception is intrinsically balanced in the community.

About the Author

DANIEL SHEPSTONE

Employment

President and Founder of ArborWorks Tree Service

ArborWorks Tree Service was founded in North Bay in 2005. Daniel has owned and operated the business in Ontario since 1999. Changing from its original establishment as Arbortech Tree Service to ArborWorks in 2004. Daniel has grown the organization to the corporation it is today by using fundamental Arboriculure practices. It is the endeavors of ArborWorks Tree Service to continue as a leader in maintaining and promoting proper tree pruning practices.

Qualifications

Certfied Arborist 2001
Certified Utility Arborist 2010
Ministry of Training , Colleges and Universities, Ontario (licence # 444A - 249381)
International Society of Arboriculture (cert. # ON-0747 AU)

Tree Risk Assessment Qualification
Pacific Northwest Chapter ISA (cert. 1303)

Certified Pesticide Applicator –Exterminator/ Public Works, 2011
IPM Council of Canada

Safety and Awareness for Line Clearing, 2009
Electrical & Utilities Safetyt Association of Ontario

Arboriculutre – Home Study Course, 1999
Bartlett Tree Experts Co.

Annual Training & Seminar Conference in Arboriculture, attendee 1999-2014
International Society of Arboriculture, Ontario Chapter member

Educational Details

Humber College, 1999
Arborist Apprenticeship Program

Sir Sandford Fleming College, 1998

Fish and Wildlife Technician diploma

Police Foundations diploma

Objectives of North Bay Hydro
Tree Trimming Program

North Bay Hydro, not unlike any other utility distribution company is mandated to provide electricity to the community. It must do so in a safe and reliable manner using an exhausting network of electrical apparatus, transmission, and distribution lines within the community. The equipment is engineered using both overhead and underground technologies.

When designing and engineering distribution lines in the community and different environments, consideration with respect to the local vegetation must take place. These include local tree and shrub species, plant hardiness zones, invasive woody plants and shrubs.

Historically tree trimming has consisted of a set of requirements that included specified distances the vegetation must be cut away from the lines. These requirements used terminology that had broad meaning with little scientific consideration to the relations the cutting would do to the plant. This practice provided little opportunity for the plants and the hydro rights-of-ways to develop and be maintained in a favorable manner.

Early tree trimming contracts were drafted with the best interests of the utility and the community in mind. Unfortunately little scientific premise was available to reference with respect to encouraging symbiotic relationships between hydro distribution and local vegetation. As a result, little forethought was put into the vitality of the plants that sustained the cutting and by todays standards improper pruning techniques where used. Today we can refer to scientific journals and appreciate the research that has been published to assist utilities in creating rights-of-ways that encourage appropriate plant and tree species to grow and be pruned that would promote increased public safety, fewer distribution interruptions, extended cycle pruning times and target cycle pruning.

Following are excerpts from the 2014 Vegetation Management Contract including Scope, Technical Requirements and Permission requirements of the contractor.

Scope of the Contract

The services required under the contract consist of supplying labour, equipment and materials necessary to perform tree trimming, brushing and removal of danger trees to provide adequate clearance for North Bay Hydro Distribution Limited (North Bay Hydro) electrical and communication distribution system within the City of North Bay.

TECHNICAL SPECIFICATIONS

General

The importance of trees to mankind in general, and the citizens of North Bay in particular, cannot be overestimated. Not only do trees benefit climatic conditions, but also, from the aesthetic point of view, their contribution is beyond monetary consideration. Trees are encouraged to grow along streets or are planted there to beautify the city and their destruction or unnecessary removal is indefensible.

Desirable as it may be, it is not always practical to locate overhead lines where the pruning of trees for line clearance can be eliminated. It is, however, the established policy of North Bay Hydro to engage skilled foresters and to follow recognized arboricultural practices in line clearing work so that the health and appearance of trees may be maintained to the highest degree that existing conditions will permit.

The purpose of performing line-clearing operations is not only to render power circuits free from tree interference so that they may give uninterrupted service, but also to protect the public against avoidable hazards due to the presence of North Bay Hydro's lines.

In general, ownership to trees will be with the municipality or property owners. In order to maintain good public relations, it is imperative that personnel responsible for line clearing operations notify the adjacent property owners before proceeding with the work. It is also most important that persons arranging for and performing the work conduct themselves in a manner that would promote good public relations.

Specifications

The specifications as follows shall govern all line clearing operation authorized by North Bay Hydro unless they are specifically amended by North Bay Hydro's authorized representative by way of a written addendum issued by the Purchasing Department.

The Contractor must work in accordance with the most recently published Electrical & Utility Safety Association (E&USA) Electric Utility Safety Rules, E&USA Line Clearing Operations Safe Practice Guide 2008, the Ontario Occupational Health & Safety Act and The Utility Work Protection Code.

Permission

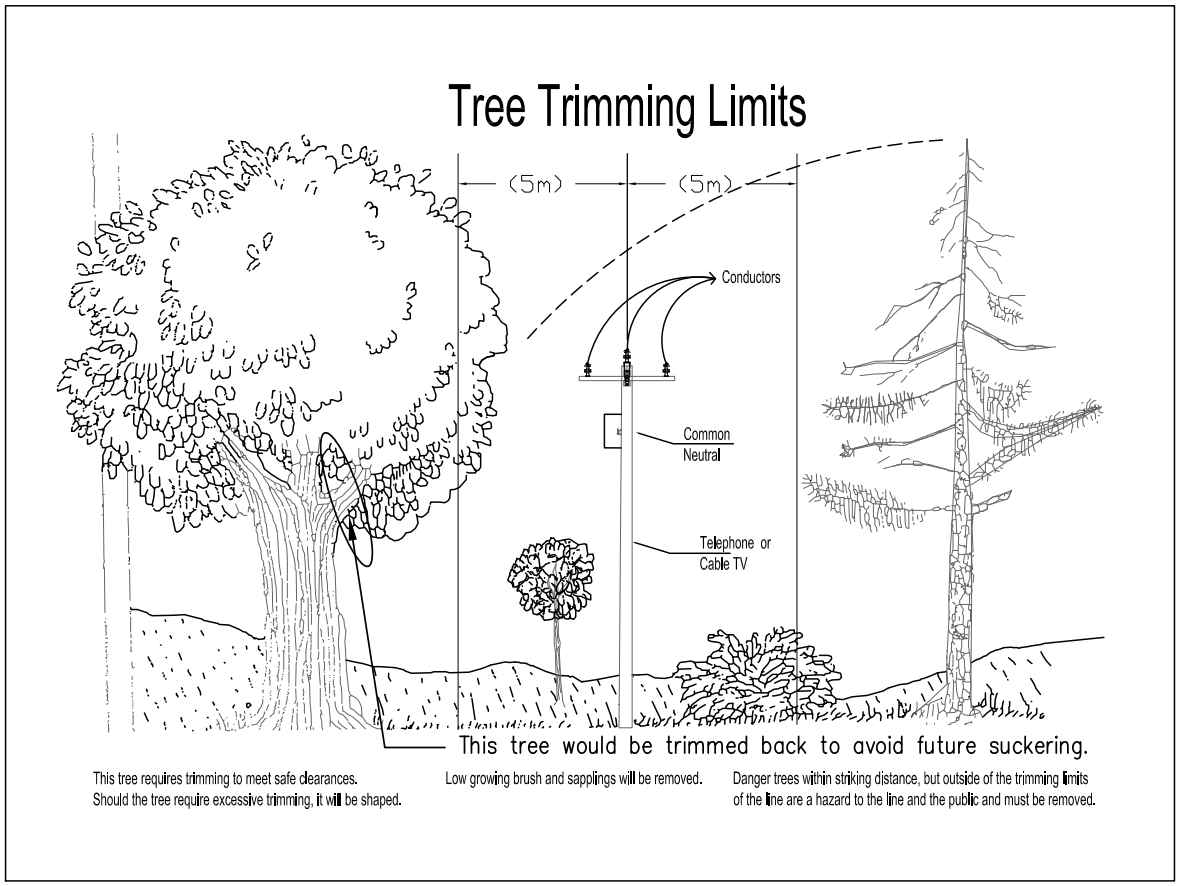
Before any work on trees on private property is commenced, the Contractor shall obtain verbal permission from the owner of that property. If permission is refused the matter shall be referred to North Bay Hydro's authorized representative. If the property owner is not at home, the Contractor shall leave a card provided by North Bay Hydro and shall trim trees on that property only by direction of North Bay Hydro's authorized representative.

North Bay Hydro is investing in a much more robust Forestry program to re-establish the right-of-ways in order to reduce the number and frequency of tree-related power outages. In order to accomplish this goal, North Bay Hydro will contact each customer

<u>to obtain written approval</u> for the Contractor to perform the necessary work on the customer's property. These written permissions will be obtained in advance of the Contractor beginning work in the area.

North Bay Hydro is granted access under "Section 40 - Powers of Entry" under the Electricity Act, 1998 to enter on land on which its distribution system is located to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities used to distribute electricity. North Bay Hydro may enter any land for the purpose of cutting down or removing trees, branches or other obstructions if, in the opinion of North bay Hydro, it is necessary <u>to do so to maintain the safe and reliable operation of its distribution system</u>.

<u>Sound judgment shall be exercised in the appraisal of the value of the trees to the community, especially with regard to sound mature trees considered to be landmarks of historic interest</u>.



The objective of North Bay Hydro is to improve the clearance between the utility lines and the trees in certain proximity, therefore reducing the amount tree contacts made with hydro equipment that cause interruptions in service.

The intentions of the 2014 contract are to address the concerns of the utility while making statements that would implement appropriate arboriculture practice to meet the industry standards. Throughout are highlighted terms and statements that have been incorporated to address more recent concerns.

Some of the utility concerns identified in the contract are with respect to:

- Inappropriately qualified personnel managing and performing duties required to perform the contract
- Identification that standards for practice are available and shall be performed
- Historically poor methodologies and practices performed hinder current opportunities to maintain and manage aging trees
- Positions of liability following poor practice or recognition of land use and tree ownerships
- Definition that the program will inherently be reclamation of rights-of-ways, differentiating from past maintenance practices

Performance and Personnel

Tree pruning has become a very intense, complicated and costly proponent for hydro distribution companies.

Throughout history, as we know utility networks have become increasingly vast and ever aging. Vegetation management considerations have developed professional people that are dedicated, trained and skilled in very specific faucets of the utility distribution industry. Recognized are those who are skilled in the management of trees and vegetation in relation and proximity to the utility equipment.

Here are readily used terms in vegetation management:

- *Skilled Foresters: one who is skilled in forestry or in charge of a forest.*

The term Forester inaccurately defines the position that is inherently desired for charge of this vegetation management contract.

More accurately, a vegetation control program with respect to utility lines in a combination of urban and rural settings has been identified as a program that shall be managed by one who is skilled in Arboriculture:

- *Arborist: one who is engaged in the profession of arboriculture who, through experience, education and related training, possesses the competence to provide for or supervise the management of trees and other woody plants.*

In Ontario the skill of arboriculture is a recognized trade with the Ministry of Training, Colleges and Universities. This profession is broken down into two delineations: Arborist and Utility Arborist:

- *Utility Arborist: a person who undertakes any work required to prune or clear vegetation in proximity* to energized electrical equipment, structures and conductors or who in the course of utility line clearing operations, prunes, falls or removes trees which could come into contract with energized power lines. (*Proximity is defined as a distance of three meters or less from a primary conductor with a voltage of 750 volts or greater.)*

An experienced Arborist or a Utility Arborist whom has the skill sets and knowledge required to readily identify trees and make recommendations, adhering to appropriate standards to successfully manage trees in relative proximity to utility lines after consideration to all concerning and superfluous factors surrounding the tree, the environment, the community and the utility.

<u>Arboriculture</u> is primarily focused on individual woody plants and trees maintained for permanent landscape and amenity purposes, by arborists, for the enjoyment, protection, and benefit of human beings.

Industry Standards

Utility Distribution and Vegetation

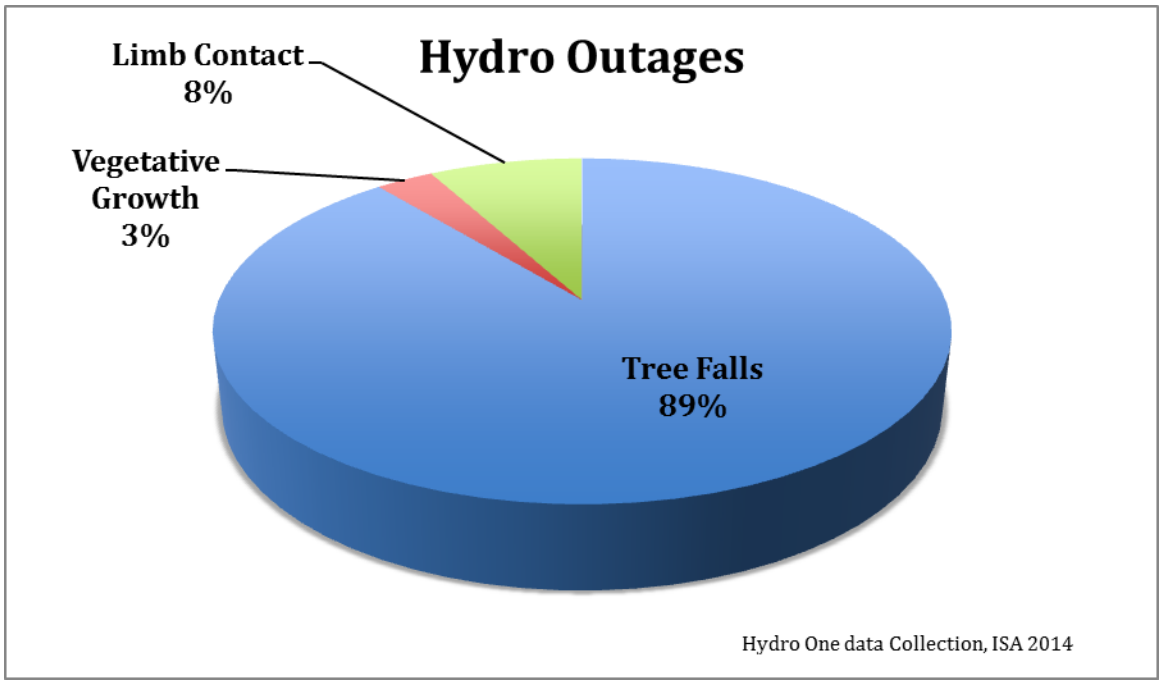
Trees must co-exist with the modern communities and utility distribution methods. Overhead and underground space is becoming a precious commodity in growing communities. With this in mind human accommodation, transit, other utilities, trees and hydro distribution equipment must compete for the same space.

Green industries, climate change, renewable power, reduced carbon emissions are all focuses on ensuring that while performing business in an safe and efficient manner, there is also consideration for the longevity and limited maintenance requirements of both the facility being engineered and its affects on the vegetation and environments surrounding it.

Tree and utility systems most commonly compete for overhead space with overhead power lines, street lights, transformers, poles, guys and other apparatus above ground. Not so typical interference comes from competition between trees and utility equipment below ground installations.

Root systems are an extensive and elaborate interconnecting system that occupies a significant area of the soil near the trunk of the tree. Generally below ground issues occur during the utility building phase. If professional consultation is not taken place prior to the installation of underground services significant tree health and structural concerns may result. Liabilities concerning safety, including the damage the tree roots sustained during construction comparatively to the remaining ability of the tree to maintain stability and not fall over. Health concerns, including tree decline or death following construction. Both structure and tree health, are vitally important considerations taken into account in planning and preconstruction meetings. It is common for 'Arborist Reports' to accompany engineering packages when proposing new line construction.

Overhead competition is the focus of concern for majority of tree and utility conflicts. According to recent Hydro One data collection most distribution interruptions occur in three ways; Tree falls, Vegetative growth, Limb contact. The data presented indicated that 89% of outages were as a result of tree falls or failures and only 8% from limb contact and 3% of outages as a result of general vegetative growth.



Pruning

Trees being the most common source of hydro distribution interruptions, and the demand for greener communities promote regulation and standard practices for appropriate tree care and utility pruning methods with best interest in both the utility and the ideal green community.

Throughout North America, utility pruning has become a profession of its own. Guidelines in the United States of America, the American National Standard, ANSI Standards have recognized standards of practice that would best facilitate tree care operations, including safety practices, pruning methods, vegetation clearance requirements and apply those to best practices for electrical utility rights-of-ways.

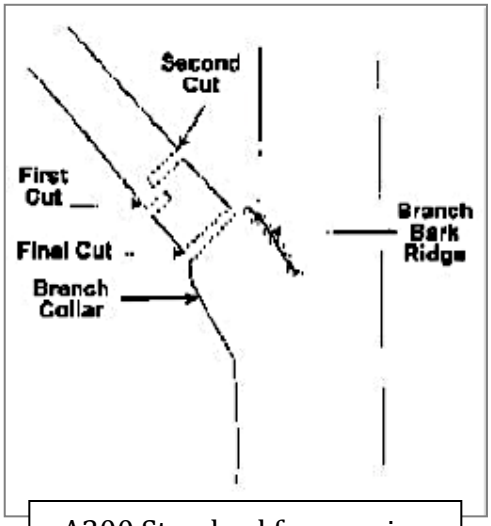
ANSI-A300 is a standard for pruning and management of trees, shrubs and other woody plants. The ANSI standards are intended to provide Federal, Provincial, Municipal and private entities recognized standards when developing policy. In Canada the ANSI standards are readily referenced during operations while maintaining compliance with regulations including Occupational Health and Safety Act, the Electrical Utility Safety Rules and surrounding regulations.

By far the best way to maximize the benefits of trees and maintain appropriate utility and vegetation clearances is to plant trees where they will not interfere or conflict with the utility equipment. Unfortunately many factors do not permit this as

a viable maintenance practice. The ANSI-A300 recognizes that not all trees will be located in a space suitable for its size and proximity to street, sidewalks, building and other parts involved in infrastructure growth and development, including utility service lines and rights-of-ways.

A variety of terms have been defined in the ANSI standards that encourage a balance for optimal tree growth and benefits while adequately discouraging vegetative growth, failures and other related concerns, biologically and structurally that occur with poorly maintained trees. The terms have been adopted from published scientific literature.

Research has shown that trees respond to injury or disease with specific biological reactions. Historically, utility trimming has been superficial in its attempts to maintain appropriate vegetative clearances. Today's methods are tremendously more proactive in managing the vegetation as a known biological presence with predictable reactions.



A300 Standard for pruning and removing branches

Tree trimming, or pruning as it currently is referred to provides an opportunity to assess the species, age, condition and location of the tree and appropriate pruning practices utilized to facilitate longer periods required pruning. Utility companies generally refer to the frequency pruning and vegetative controls on the lines and rights-of-ways as cycles, or cycle pruning.

In general, cycle pruning is conducted between three and eight years in a predetermined geographical area. Urban environments often do not facilitate extended cycle times due to the influence the general public has on maintaining tree canopy as a part of urban life. Urban trees influence society through heating and cooling benefits, carbon reducing qualities, human psychological health benefits and so on.

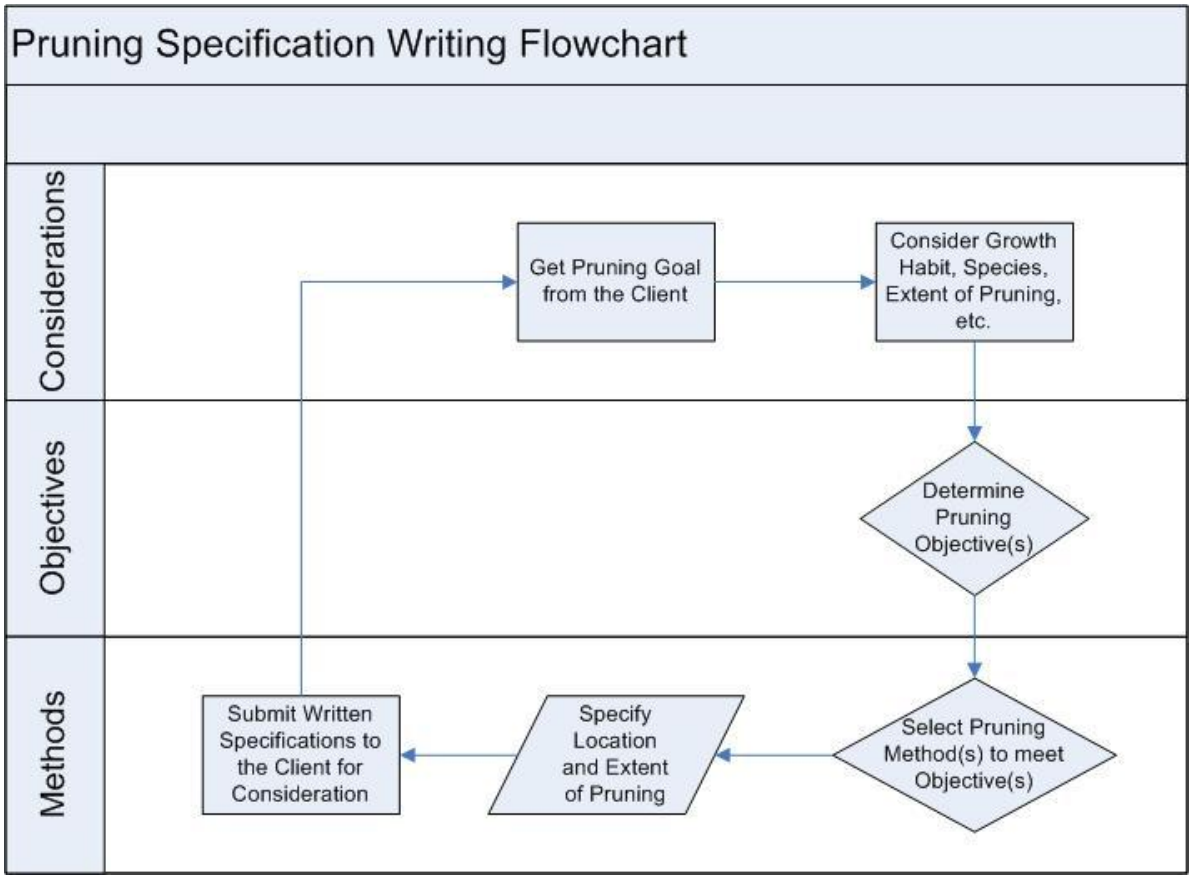
Removing trees completely may extend cycle times in rural environments. The use of mechanical, chemical and cultural control methods will also reduce required the frequency of pruning and brushing operations.

A best practice management approach would be to balance short and long cycles, through the use of tree inventories and technology to identify areas in which more

frequent pruning is required, essentially target pruning. Focusing resources on areas of high profile more often and ensuring compliance with current practice to promote an apparently controlled environment in which trees and utility service may share overhead space.

Pruning of trees and shrubs in compliance with the ANSI-A300 standards and its application to vegetation management for electrical utility rights-of-ways is an integral management consideration when designing a vegetation control and maintenance program. Combinations of sound inventory, practice and management techniques are proven strategies to improve safe and reliable utility distribution in urban and rural environments.

ANSI-A300 standard for writing pruning specifications:



Topping and heading cuts created the rapid regeneration of limbs

Past Practice

Historically utility trimming was the removal of vegetative growth within certain distance from conductors and related apparatus. This theory in practice only created heading, stubbing and topping cuts.

a part of a tree, limb or leader, at a specified distance or
or trunk. This approach to pruning was very counter productive to the ultimate goal. The original cutting provided the clearance required, however the advantageous growth that resulted from the cutting created regeneration of the very weak, rapidly growing limbs that would quickly interfere with the utility lines.

Current Practice

Appropriate pruning practice performed in compliance with the ANSI A300 standard will incorporate the use of proper pruning cuts and directional pruning opportunities to avoid excessive epicormic response. This provides the tree to continue growing, allowing taller canopy with proper clearance, sustained for longer periods between pruning.

Directional pruning using proper pruning cuts directing existing limb material away from the utility and preventing undesirable rapid limb growth response

Vegetation Control

Vegetation management is defined not only through the practice of pruning and removing trees and limbs, but it refers to the removal and prevention abilities of the management plan to reduce unwanted vegetative growth below and in proximity too hydro lines, in and around substations and apparatus.

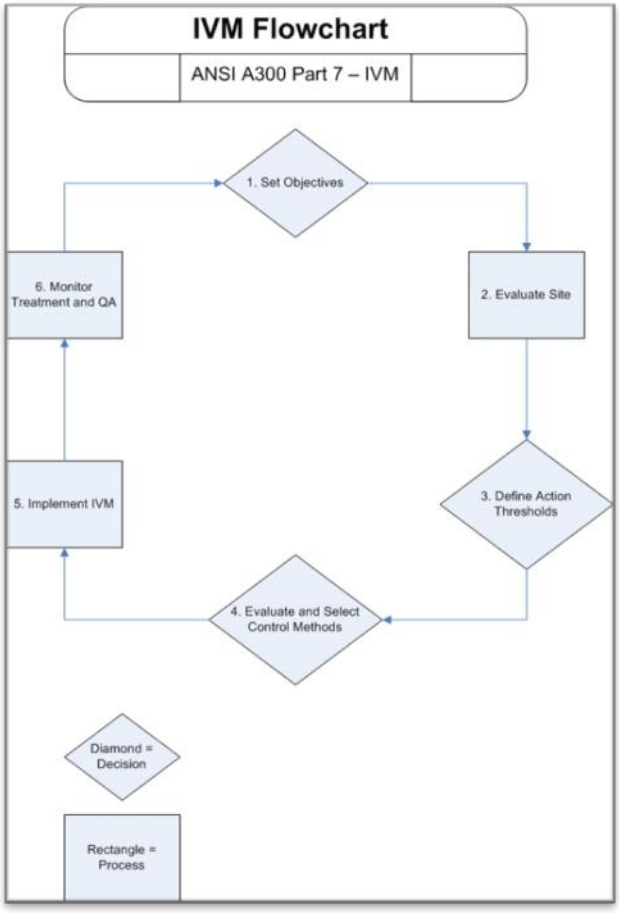
Vegetative management plans should incorporate a variety of control techniques.

- Manual: cutting of brush through the use of hand operated tools
- Mechanical: cutting and removal of underbrush through the use of equipment mounted saws, mowers, or other devices
- Chemical: use of herbicides, growth regulators or other pesticides to prevent the regeneration of undesirable plant species.
- Cultural: control the regeneration and growth of undesirable plant species through the establishment of compatible, stable plant communities or the use of crops, pastures, mulching, or other managed landscapes
- Biological: the use of plants, animals, insects or pathogens to regularly attack or remove undesirable plant species from growing to excessive height and diameter.

An Integrated Vegetation Management plan should take into consideration action thresholds, control methods used, maintenance cycles, geographical locations to be managed, resources available, local regulations and ongoing quality assurance the program will be applied according to the appropriate standards.

Stubbing limb cuts creating excessive regeneration and significant interference

Attached is the flow chart that makes up part of the ANSI-A300 standard that is recognized practice to account for appropriate planning, management, implementation and monitoring of an IVM program.



Control Methods

Several control methods are recommended for the cutting, removal, reduction and reduced regeneration properties. It is always necessary to consider multiple methods to create a successful 'brush' management plan.

The cutting and removal of brush has been an effective but cyclical repetition of removing regenerated and new seeded species that pose inherently interference and encroachment issues on rights-of-ways. Manual operation of saws and hand held mowers can be a slow and costly option, although readily available. Substitutes to manual cutting are mechanical and chemical methods.

Biologically when a perennial plant, including trees and shrubs are cut at the base or low on the trunk, the rizhosphere is left undisturbed. In this organic layer of soil contains the root systems of all terrestrial plants, trees and shrubs. Following the cutting and removal of the stem of the tree or shrub the root systems pushes this biological reactionary system that produces epicormic growth, a flush of newly rapidly growing shoots.

The new shoots that a plant produces are determined by the amount of energy reserves stored in the root system. Epicormic growth may be produced the during the same growing season or at the beginning of the next growing season. To combat this biological response in plants the three methods of brush removal should be considered during one cutting season:

- ✓ Mechanical Control
- ✓ Chemical Control
- ✓ Cultural Control

Mechanical Control

Mechanical brush removal or control is an effective method of cutting the unwanted plant, immediately converting the stem and branch material into shredded or chipped biodegradable material that is left on site assisting in discouraging regeneration of unwanted plant species. Mechanical mulching or brushing machines are effective methods for cutting the plant at the base and extending into the soil, the rizhosphere, disturbing, by cutting and removing root systems leaving little opportunity for the plant to regenerate.

Chemical Control

Herbicide - Understanding, Recommendation and Application

What is a Herbicide

Herbicide is mixture of chemical or biological agents and inert additives that are designed to control the growth and reproduction of vegetative materials.

Any herbicide is referred to as part of the pesticide families. The active ingredient to any herbicide is the chemical or biological component to the mixture that actually interrupts the growth potential of the vegetation it is trying to control.

Herbicides are produced to control vegetation in many different ways. Some herbicides are active upon contact, systemically or through osmosis. Some are applied pre-plant emergent or post plant emergent. They can be applied to the foliage, stem or root of a plant, as well as applied to the soil in which the plant grows. There are several qualified methods of applying the herbicide. Depending on the way you wish to control the vegetation will contribute to a decision on how it should be applied. Some methods used are foliar spraying, stem spraying, stem injection, cut-stump contamination or basal bark spraying.

If the decision to use a herbicide is chosen to be the best course of action for the control of the vegetation, then considerations must be made as to what herbicide would be best suited to the needs of the control purpose, the methods available to apply it, the environment surrounding the vegetation including soil types and surrounding developments. Public perception and legislation must also be considered. Herbicides must be registered for use in Canada, and classified by both Federal and Provincial governments.

Legislation - Federal

The Federal Government of Canada, through Health Canada has an extensive registration system that must be completed by the registrant of the product (pesticide) prior to its use in Canada. The Pesticide Management and Research Association of Canada (PMRA) are responsible for Registering and classifying the pesticides at the federal level. Once the product has been registered for use a label is attached to the product that supplies the applicator with extensive information of the toxicity of the product, its direction for use, what it is registered to control and much more information.

After a product receives federal registration it falls to provincial legislation for further regulations on its use.

Legislation - Provincial

In April of 2010 the Government of Ontario chose to implement new legislation governing the use of pesticides in Ontario. It further classified pesticides provincially and implemented a ban on many federally registered products, eliminating their use for cosmetic purposes within the province.

Currently we have 11 classes of pesticides in Ontario. The important information to be aware of is that pesticides in class 2 to 4 are for commercial purposes and can only be applied by licenced exterminators. Class 9 pesticides are banned active ingredients; they are manufactured of synthetic materials and cannot be applied for cosmetic purposes. Class 11 pesticides are deemed to be 'organic' and are registered for use by licenced applicators for control of pests, including unwanted vegetation for cosmetic purposes, and used in domestic products.

In Ontario, pesticides that contain class 9 active ingredients may be used by Industrial Vegetation exterminators for use on a public work, which includes a utility, but its use has to be under the direction of an Integrated Pest (Vegetation) Management Plan, drafted by an Ontario accredited Integrated Pest (Vegetation) Management person.

Integrated Pest (Vegetation) Management - IVM

Integrated Pest (Vegetation) Management is a decision making process that encompasses the entirety of the project to be completed including the environment, any prevention methods and alternatives to chemical control.

Provincial legislation requires that all public works must use licenced Industrial Vegetation exterminators, and accredited IPM persons to assess, recommend, apply and manage the application of a herbicide on a public work in efforts to control undesirable vegetation.

Method of Application

When considering a method to apply a herbicide considerations including access to the site, land usage, soil types, water bodies and public perception should all be taken into account.

Evaluating and Reporting

As part of the IPM process, a monitoring program has to be developed. It is part of the Pesticide Act, Ontario Regulation 63/09 that the public work be diligent in maintaining records of the pesticide usage throughout the year.

It is part of the regulation that the annual reports be drafted in accordance to Regulation 63/09. S.25 (4). and be kept at the head office of the public work and produced to the provincial Director or any member of the public, free of charge upon request.

Cultural Control

Cultural Control is the effective use of compatible plant materials to discourage the growth and regeneration of undesirable plants. Utility rights-of-ways should consider the use of wild grasses and forbs that can easily be seeded post mechanical mulching, and in combination with chemical controls.

WILD GRASSES AND FORBS TO CULTURALLY CONTROL UNWANTED PLANT MATERIAL IN A UTIILTY R.O.W.

Observations: North Bay Hydro Cycles

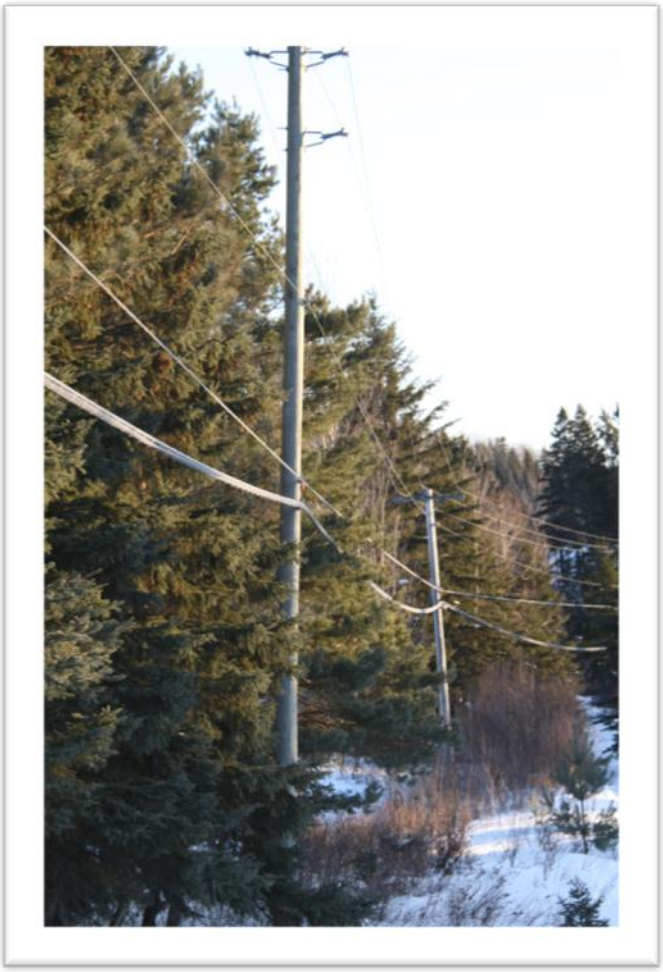
Observations have been made to identify the amount of work required to meet current contract specifications comparatively to past practice.

Overview of Cycles

Cycle 1A

Description: Consists of Hwy 11 North corridor, including College Drive, Cedar Heights, Larocque Road and the area surrounding McKeown Avenue most often referred to as Thibeault Terrace.

The concentration of work is not accessible through conventional bucket truck mean and considered to be off road*, with a majority of the work consisting of complete tree removal in close proximity to primary lines.



Hwy 11 is extensively overgrown and requires significant resources to reclaim appropriate clearances. Thibeault Terrace is an urban residential area with relatively extensive network of overhead lines. This area requires significant pruning improvements.

Cycle 1B

Description: Consisting partly of Hwy 11 North corridor and the roads extending to the east, including the airport and Golf Course Road area.

A significant amount of the work is roadside accessible, with a

segment of back lot sections. Work is estimated to be extensive with relative equal amounts improved pruning methods to remove existing stub cut and topped trees in combination with complete tree removal. Mechanical and chemical brush control is recommended for rural residential and back lot locations.

Cycle 1C

Description: Consisting mainly of urban and rural-residential streets including Airport Hill and its resident streets, Tower Drive, Lees Rd and Smith Rd.

Majority of the area is roadside accessible requiring more extensive pruning and some removals. Airport Hill is a compilation of mature deciduous trees with opportunity to maintain significant tree canopy with proper assessment and implementation of crown elevation and restoration pruning techniques. An area identified as one overhanging limbs may be acceptable in some locations.

Approximately half of Tower Drive, Northmount, Smith and a segment of Lees Road is extensively overgrown and will require significant clearance improvements.

Cycle 1D

Description: Consists of Carmichael Drive, Four Mile Lake Road, Chadbourne Drive and Widdifield Station Road.

This area is overgrown by coniferous species, specifically balsam, spruce and red pine. The cycle has a combination of on and off road accessible lines. Back lots should have mechanical and chemical control, roadside lines require extensive tree removal to reclaim rights-of-ways.

Cycle 2 A through D

Description: Cycle 2 is grouped into one area because it consists of the most developed area; residential, commercial and industrial spaces. In general the disbursement of trees in this cycle is consistent throughout, only sparse in the immediate downtown core. The area includes from John Street west along the waterfront and out Main Street West to Hwy 17, north to O'Brien Street and part of Trout Lake Road.

Vegetation continuously in contact with high voltage repeatedly burning off new growth stunting limbs under phase

Cycle two is the oldest part of the city, the oldest street trees are observed presenting the opportunity for tree and human, utility and tree conflicts and overall concerns. Field data identified extensive improper and outdated pruning methods resulting in current vegetation and utility contacts through rapid regeneration of limbs (suckers and water sprouts).

The cycle is mostly roadside accessible with some overgrown residential back lot areas. Cycle 2 has an extensive network of older trees that require significant restoration pruning and where pruning is too extensive and the regeneration of advantageous growth would result, removal is recommended.

Cycle 3A and 3B

Description: Consists of Wallace Heights down Lake Heights and Sage including the Birch Haven area to the southeast of Trout Lake.

This area was effectively pruned to current standards in 2012. Significantly less work required in upcoming cycles in this area.

Cycle 3C

Description: Peninsula Road, North Shore Road and tributaries.

Cycle pruning with more current methods was pursued in 2011. The proximity of hydro lines is greatly improved from methods dating back pre-2011 contract. Clearances are currently at minimum distances; pruning cuts are generally made in compliance with ANSI-A300 standards but many areas were not pruned or missed through out the cycle. In addition it appears little to no attention was placed on

pole, guy, secondary and triplex clearances creating extensive overgrowth in these areas.

Mechanical and chemical controls are recommended. This area has a significant stand of large white and red pine species with overhanging limbs on West Peninsula road that should be regularly monitored for broken and hanging limbs over the conductors.

New contract requirements outline minimum right-of-way clearances, therefore certain lines may require more resources applied to enlarge the existing rights-of-ways.

This photo identifies that the pruning performed on this stand of immature red pine in cycle 3C has been performed using proper arboriculture. The trees will not regenerate quickly to interfere with the conductors, however the clearances do not meet the requirement of the 2014 Vegetative Management Contract technical specifications.

Cycle 3D

Description: Hwy 63 corridor from Trout Lake to Songis Road including Daly's Rd and Feronia Road areas.

The Hwy 63 corridor is of accessible only with off-road areal devices and manual tree climbing technique. This area is lined with an extreme amount of overgrown mature and immature coniferous trees, balsam, spruce and pine. The trees are overhanging and under growing, limbs topped and stubbed off, neglected brush by definition has permitted the under growing vegetation to become small and large trees under lines. Vegetation is currently burning** in this area and must be removed. The cycle requires significant reclamation work to attain necessary line clearances.

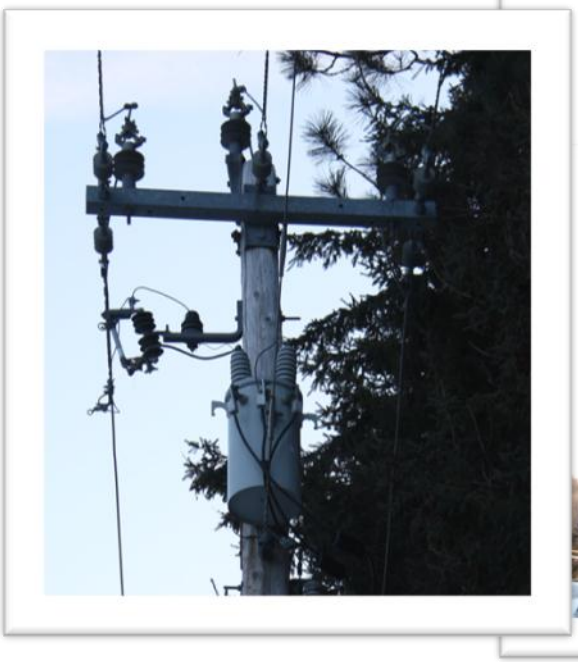
Cycle 4

Description: West Ferris, all roads and back lots south of John Street between Hwy 11 and Lake Nipissing to the South boundary of North Bay.

This cycle was completed in 2013, specification for clearances attained where performed in compliance with the current requirements laid out in the 2014 Vegetation Management Contract. Approximately three streets and all back lots were not completed in that cycle year. In anticipation that the remaining work will be completed prior to the scheduled cycle pruning, in theory the cycle will consists of less work than recently performed.

Data was collected in this cycle estimating a hypothetical reflection of work required at time of the next cycle. The pruning practices performed throughout the cycle have been performed in compliance with the current contract requirements using proper arboriculture. Assumptions can be made that opportunity for epicormic and advantageous growth will result in certain areas, but overall the hydro lines and rights-of-ways have been restored to appropriate clearances.

Extensive overgrown conifers in contact with primary phase conductors and transformer



Cycle Observations Results

Each of the four cycles are broken into four additional segments, 'A' through 'D'. Within each cycle area the, degrees of work necessary to provide hydro and vegetative clearance requirements as per the current cycle contract requirements were documented. Comparatively the amount of work performed during past practice, or cycle pruning performance was estimated to the amount of work necessary to complete the cycle using the current contract requirements.

Past work performance were estimated by utilizing old contract technical requirements, observations made of heading, stubbing and topping cuts, distances from tree trunks to center of conductors, diameter of regenerated growth (both water sprouts and coppice growth).

In addition to making observation of past practice, tree species and local plant hardiness zone information was taken into consideration. This information is valuable when determining:

- The overall vigorousness of the tree species
- The compartmentability properties of the tree to compartmentalize decay
- The epicormic response of the tree species
- The hardiness of the plant
- The invasive properties of the plant
- The expectation or potential for invasive pest or disease

With this information future planning can be managed with a proactive response to anticipate the reaction of the tree to the pruning methods utilized.

The information was collected using a scale of 1 through 5.

Scale:

1. Significantly less work required than previous contract requirements
2. Slightly less work required than previous contract requirements
3. The same amount of work required as previous requirements
4. More work required than previous requirements
5. Significantly more work required than previously contract requirements

In 2013 cycle two zone was carefully examined, more observation was performed and documented for the amount of work required to provide the clearances outlined in the 2014 Vegetative Management Contract.

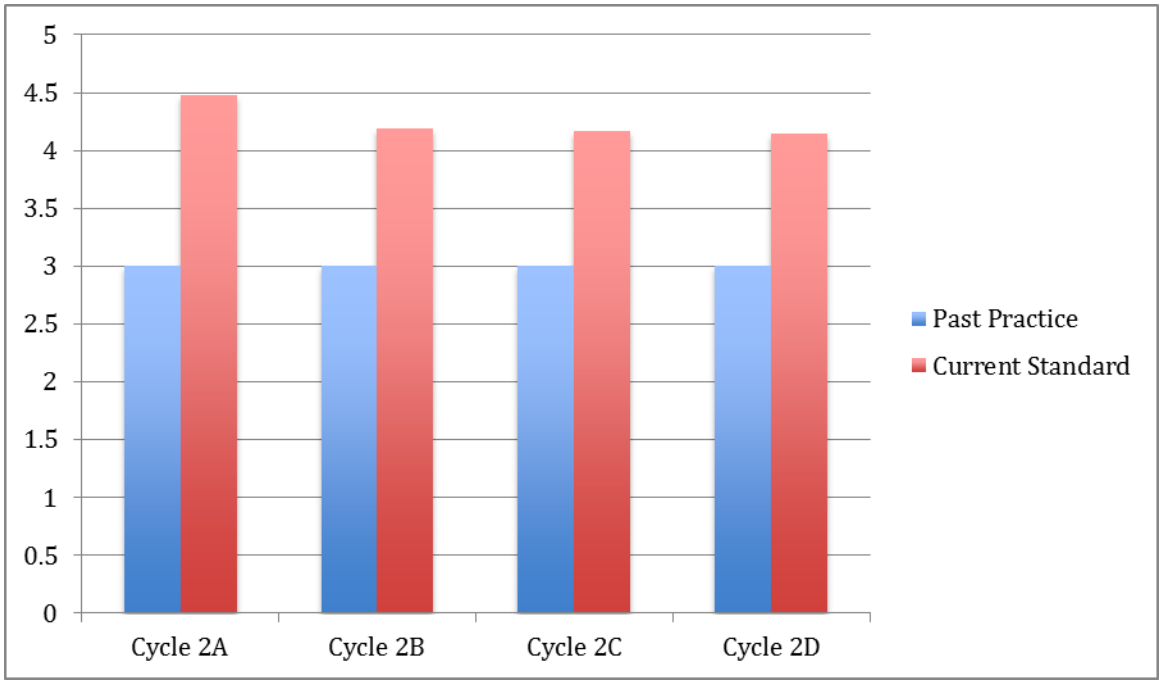
These observations were compared against the amount of work observed in the past cycle contract requirements. The information was documented using the same scale for comparative degrees of work required.

Using cycle two as an extrapolated base line of the work requirements for current and future work requirements as per technical requirements of the 2014 Vegetation Management Contract, results can be therefore be applied to Cycles One, Three and Four through sampling of the respective cycles as a representation of the whole.

Cycle 2 field data compiled scores:

2A	**4.48**
2B	**4.19**
2C	**4.17**
2D	**4.14**

Average Cycle 2 Score: 4.25



Note: Cycle 2 results are a compilation of scores with consideration incorporated in the data as to the geological, physical, topographical and technical aspects of the overall cycle. Cycle 2 consists of mostly urban and sub-urban areas accessible by utility bucket trucks (road side) with a significant number of deciduous trees.

The information derived from this data indicates that the current amount of work required to complete Cycle 2 is approximated to be 35% higher than during the last time the cycle was completed.

The results of cycle 2 can therefore be assumed to be relative to the amount of work increased for other cycles completed under the similar contractual requirements.

In addition to cycle 2 findings, sample plots from cycle One, Three and Four were conducted.

Cycle 1 field data compiled scores:

1A, B, C, D collectively 4.85

Therefore the amount of work required to complete cycle 1 would be between 35% and 47% greater than the work performed to previous contract requirements. (Please refer to increased work with relation to *Field Observation –Area of Increased Vegetative Control*.)

Cycle 3 field data compiled scores:

3A, B, C, D collectively 3.93

Therefore the amount of work required to complete cycle 3 would be between 29% and 35% greater than the work performed to previous contract requirements. (Please refer to increased work with relation to *Field Observation –Area of Increased Vegetative Control*.)

Cycle 4 field data compiled scores:

4A, B, C, D collectively 4.06

Therefore the amount of work required to complete cycle 4 in 2013 was between 31% and 35% greater than the work performed to previous contract requirements.

However, section 4 was not complete as per the 2014 distributed cycle map area. The exceptions were:

Section 4A was only completed on the south side of the overpass, west of Main St. Excluding all areas identified on older Cycle maps including Judge, Worthington and that area.

Section 4D, River Bend Road, Decaire Road, parts of Booth Road, Ferris Drive, Lamorie and the underbrushing on the back lots between substations were left incomplete and not done.

(Please refer to increased work with relation to *Field Observation –Area of Increased Vegetative Control*.)

Cycle 4 field data (Note: Cycle 4 completed 2013, some roads not complete)

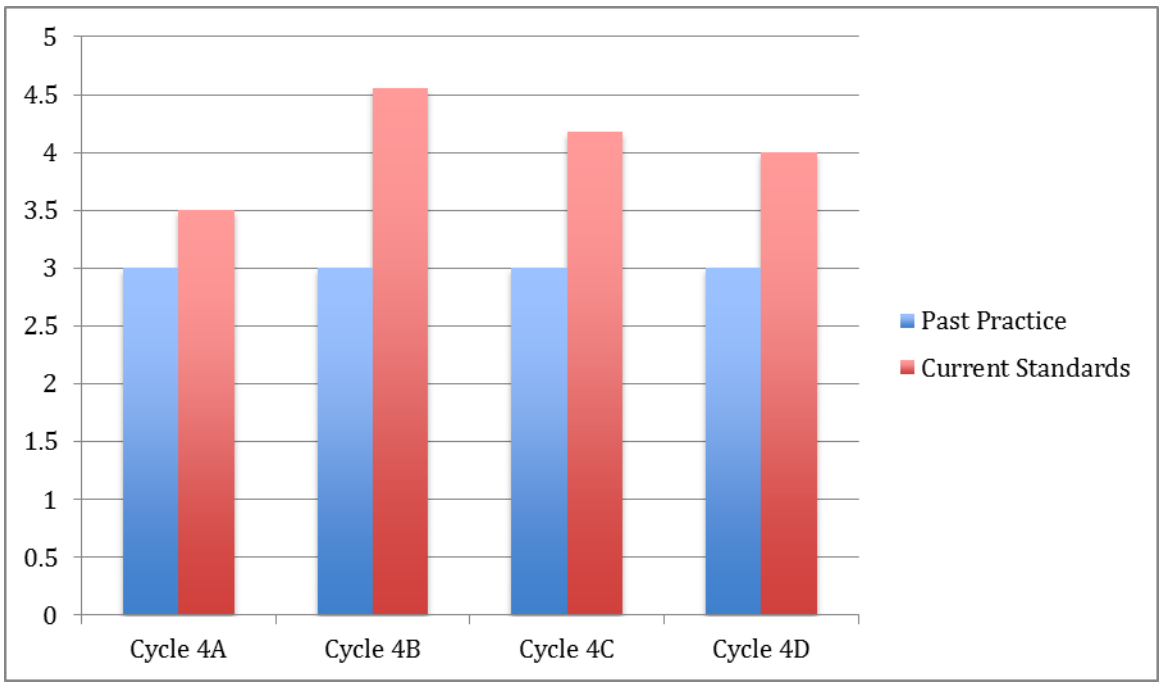
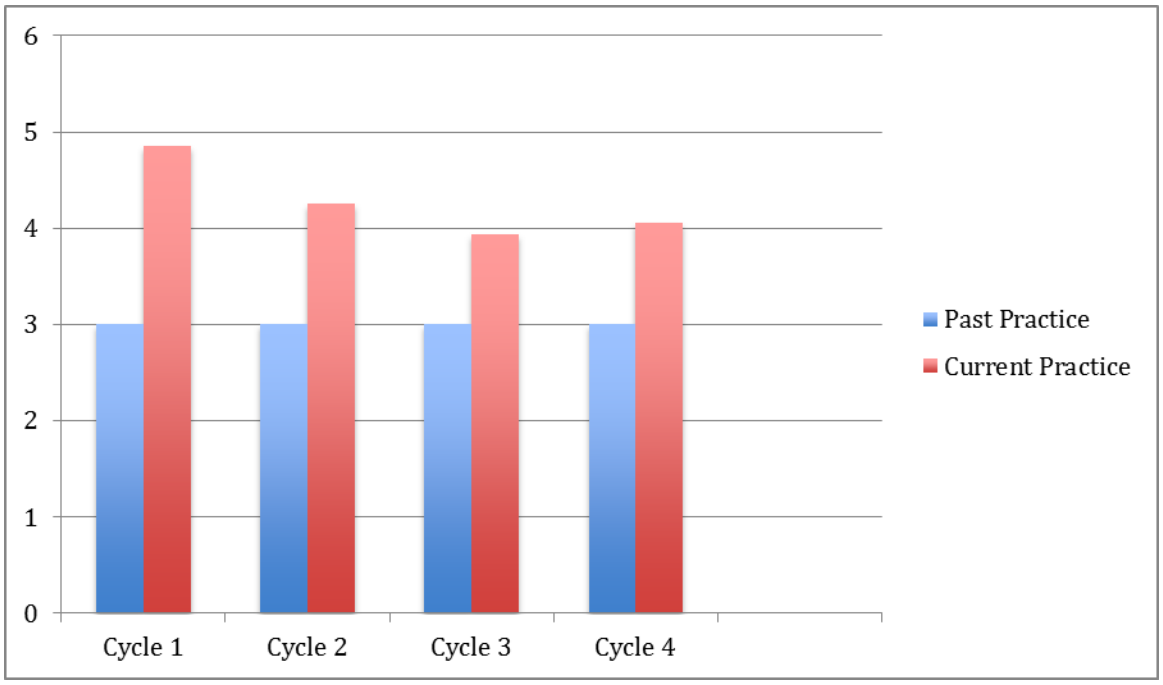


Illustration of Cycle Average Comparisons



Projections are made using comparative data derived from a mostly urban and sub-urban area (Cycle 2).

Field observation – Areas of Increased Vegetative Growth

Throughout the field data collection certain cycle areas require significantly more resources than other areas to reclaim the rights-of-ways. In attempting to make estimations on the amount of resources required to complete the work to current standards some approximations had been made to Cycle One, Three and Four. The estimated percentages of work required were based on mixed sample plots of urban, sub-urban and rural areas within these cycles.

In consideration of the amount of resources to apply to these cycles increased resources, presumably there above the listed percentages will be required in the following areas:

Cycle 1:

- Four Mile Lake Road
- Chadbourne Drive
- Carmichael Drive
- Widdifield Station Road
- Tower Drive
- Smith Road
- Northmount Road
- Lees Road
- Hwy # 11
- Larocque Road

Cycle 3:

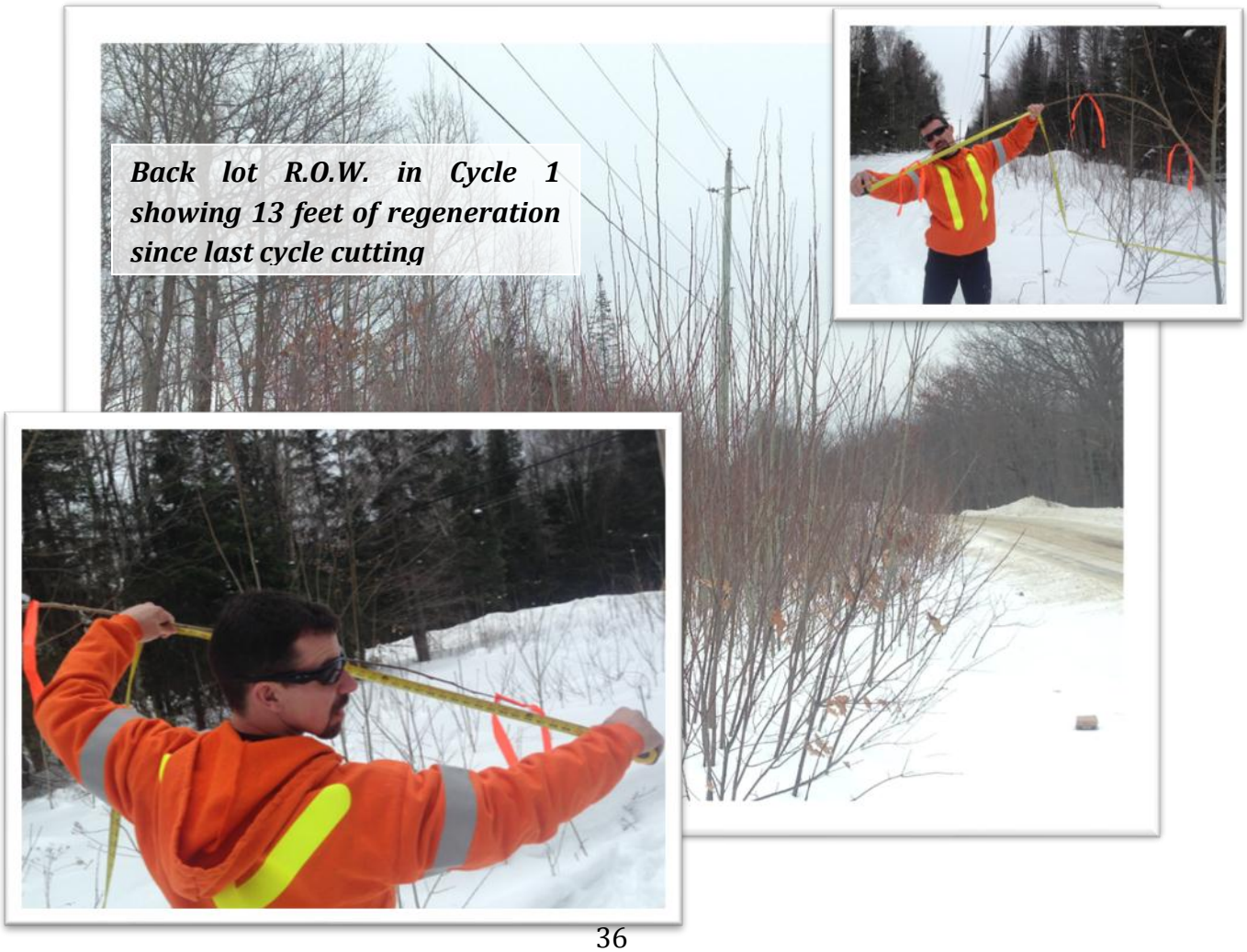
- Hwy #63
- Feronia Road
- Peninsula Road

The areas listed will require significantly more resources in comparison to the overall identified areas in cycle two. In these particular areas the tree line, or vegetative growth is growing from under or nearly under the conductors.

Four Mile Lk Rd – Single phase primary line with mature and semi-mature spruce and balsam trees growing around conductor

Areas in which the vegetation is growing so close to the conductors and related equipment there is no opportunity to prune the trees. With past practice allowing trees to continue to grow in close or very close proximity to the lines it allowed the trees to grow taller in certain areas and larger in diameter in other areas. These trees will require complete removal to reclaim appropriate clearances. Complete tree removal will result in:

- ⇒ Increased workers to complete the task
- ⇒ Larger equipment to process the cut materials
- ⇒ Increased volume of debris, chips and wood to transport and dispose of
- ⇒ Increased customer service and education with respect to private lands
- ⇒ Increased monitoring, supervision, permits and utility disruptions (possible shut down requirements)
- ⇒ Larger work zones resulting in more traffic interference and roadside operations (additional signage, permits and traffic control)



Back lot R.O.W. in Cycle 1 showing 13 feet of regeneration since last cycle cutting

Conclusion

Utility tree trimming operations are increasingly scrutinized by public, political and legislative opinion and regulation. The ideal overhead utility distribution system would allow for no tree or other interfering vegetation within a certain distance to the lines for the safe and uninterrupted distribution of service. Unfortunately nature encodes hidden checks and balances within the environments to prevent our idealistic once establishing, never maintaining rights-of-ways approach required for the ideal situation.

In consideration of the balance required between maintaining appropriate and regulated vegetation clearance for regularly uninterrupted hydro distribution and a green community we must apply what we know about tree biology and cultivation to manage to the best of our abilities.

Regulation provides us with the set of clearances required around conductors and related electrical apparatus. Our understanding of tree biology and cultivation provides us with a standard for best practice to establish and adequately maintain vegetation on a cyclical schedule.

In best practice, proper arboriculture ensures that we can adequately cut a tree limb at a particular location to direct its energy reserves in promoting future growth in the direction we want while discouraging epicormic growth response. This provides the opportunity to utilize certain existing mature trees to provide canopy within a certain proximity to hydro lines.

The utility rights-of-ways established by North Bay Hydro have been examined and estimations on the amount of resources or work required to adequately reestablish these areas, to provide a standard of vegetative clearance, that would satisfy regulation, provide safe and relatively uninterrupted service have been made. This report finds that the overall condition of the rights-of-ways requires significant rehabilitation and restorative work. The practices that have been maintained in the past are out dated causing vegetation and utility conflicts in a large percentage of the city.

Cycle's one and three require a significantly more amount of work with respect to reclaiming rights-of-ways. The area is a rural residential with a low number of residence. The trees species in the area are comprised mostly of balsam fir, spruce and pine. These are regularly observed species in the cycle that have been

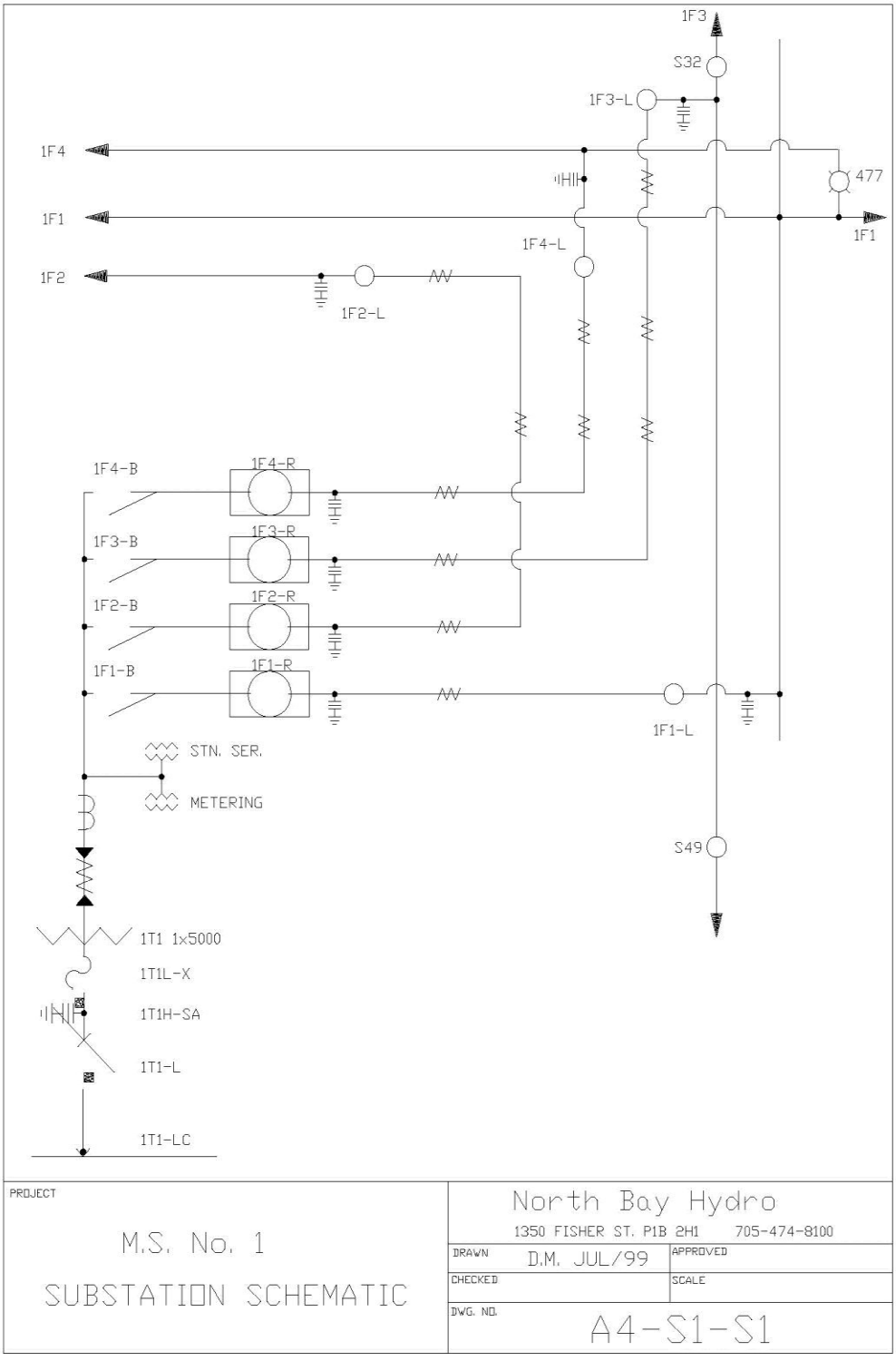
permitted to grow under and nearly under the conductors. This cycle area will require a large number of trees to be removed. Pruning these trees will only defer the growth problem to a later date. The appropriate clearances will not be attained, and these trees will inevitably require removal. The longer the trees are permitted to grow in proximity to the lines, as they are currently will result in increased hydro distribution disruptions from limb and trunk failures until they are removed. The trees will also incrementally require increased resources to remove them as they grow in diameter and height.

Integrated vegetation management techniques provide a mixed opportunity to control regeneration of cut vegetation through root disruption and chemical applications. Best management practices require a combination of methods be applied in one management plan. The use of manual and mechanical cutting techniques in combination with chemical and cultural controls have proven to reduce regeneration and lowered resources in maintaining rights-of-ways. In preparation of an effective integrated vegetation management plan field reports that accurately reflect the condition of the right-of-way, accessibility of the right-of-way, the vegetation to be managed and appropriate control measures should be performed. Appropriate and effective Integrated Vegetation Management would substantially reduce the cyclical use of resources to combat vegetation regeneration.

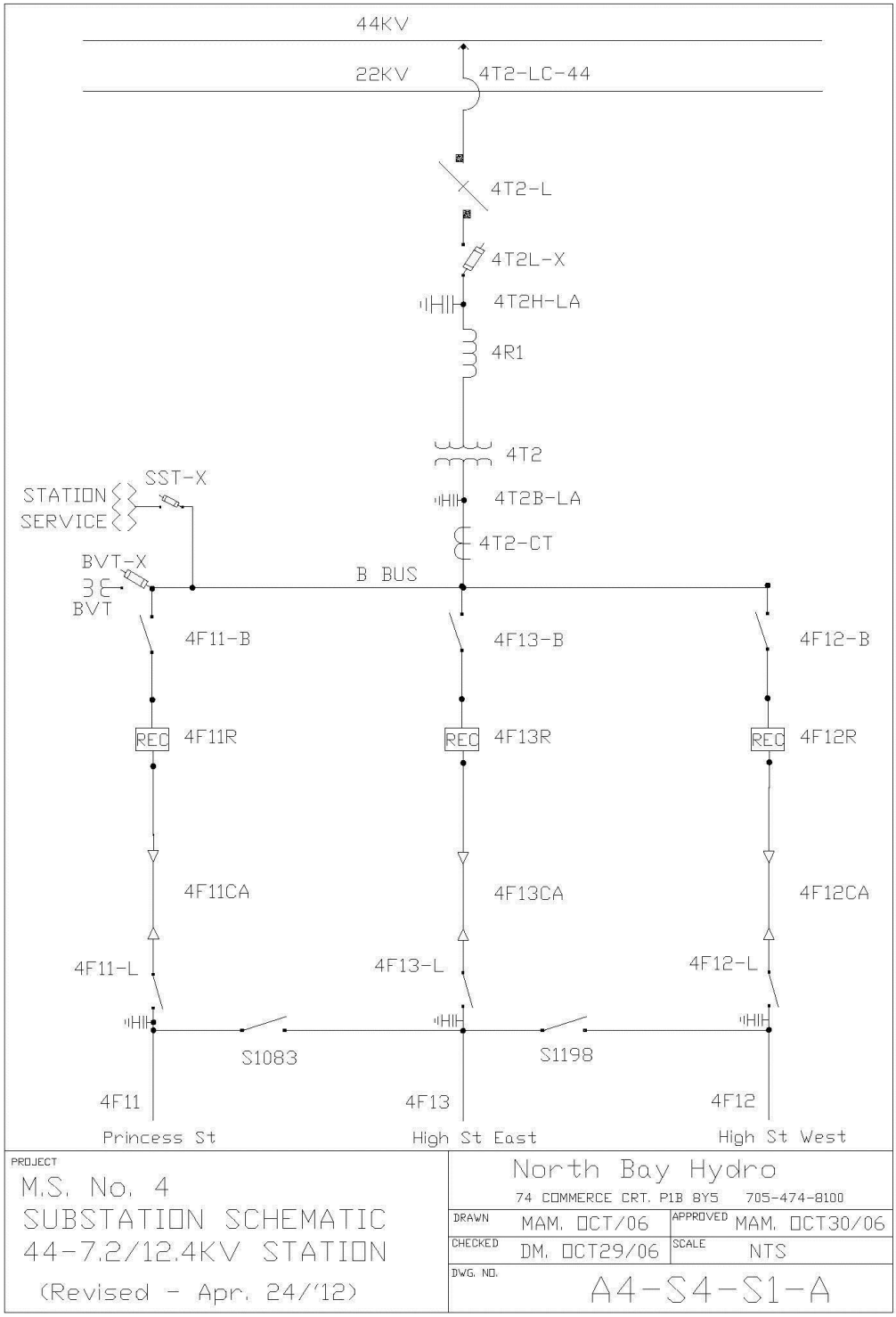
*off road- an area in which standard forestry bucket truck units cannot access due to the location of the hydro line and the terrain.
**burning- when parts of a tree make contact with energized conductors resulting in the vegetation being burned off

Appendix M – Station Single – Line Diagrams

Appendix M – Station Single – Line Diagrams

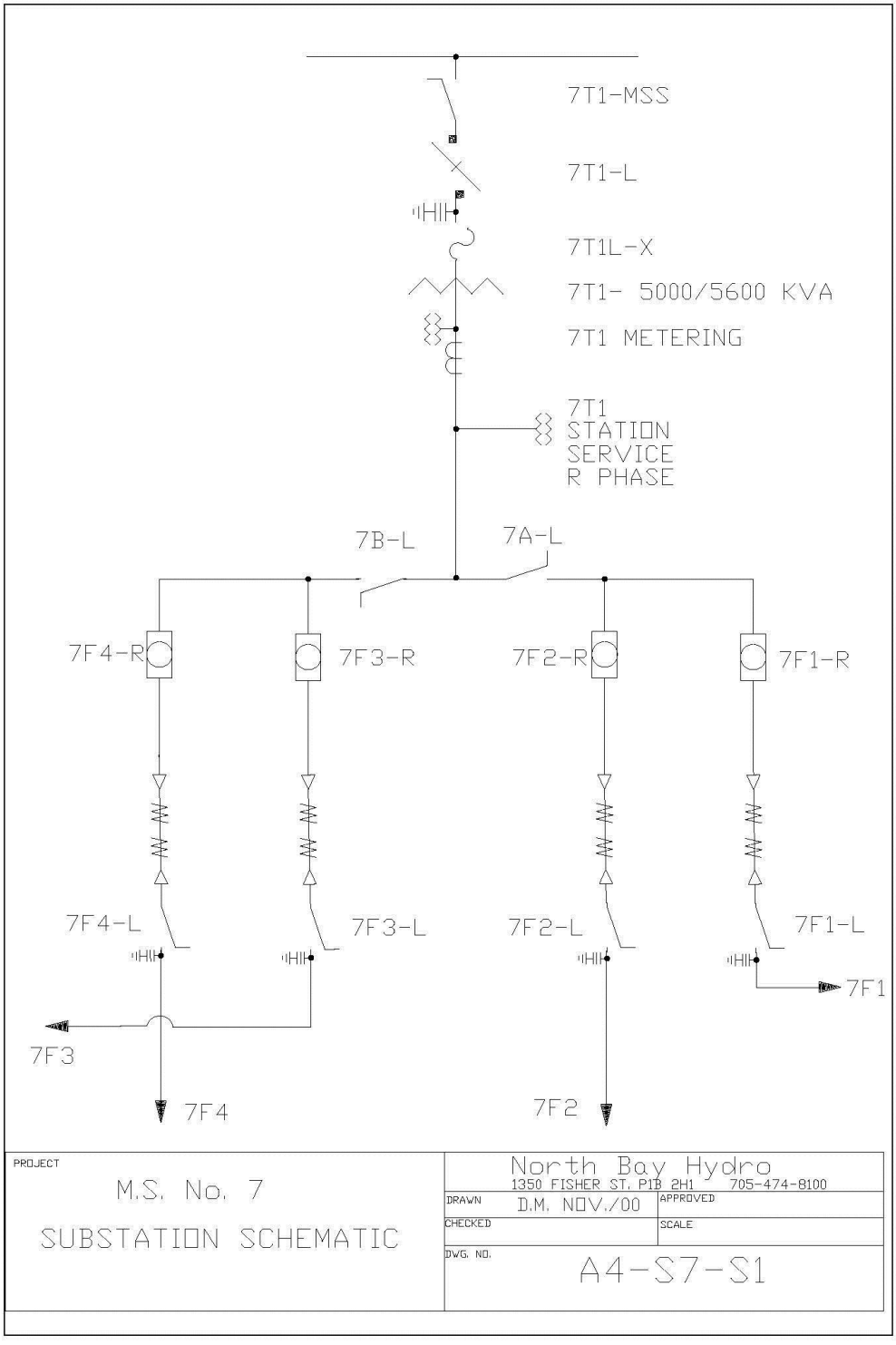


Appendix M - Figure 1: MS1 Single-Line Diagram

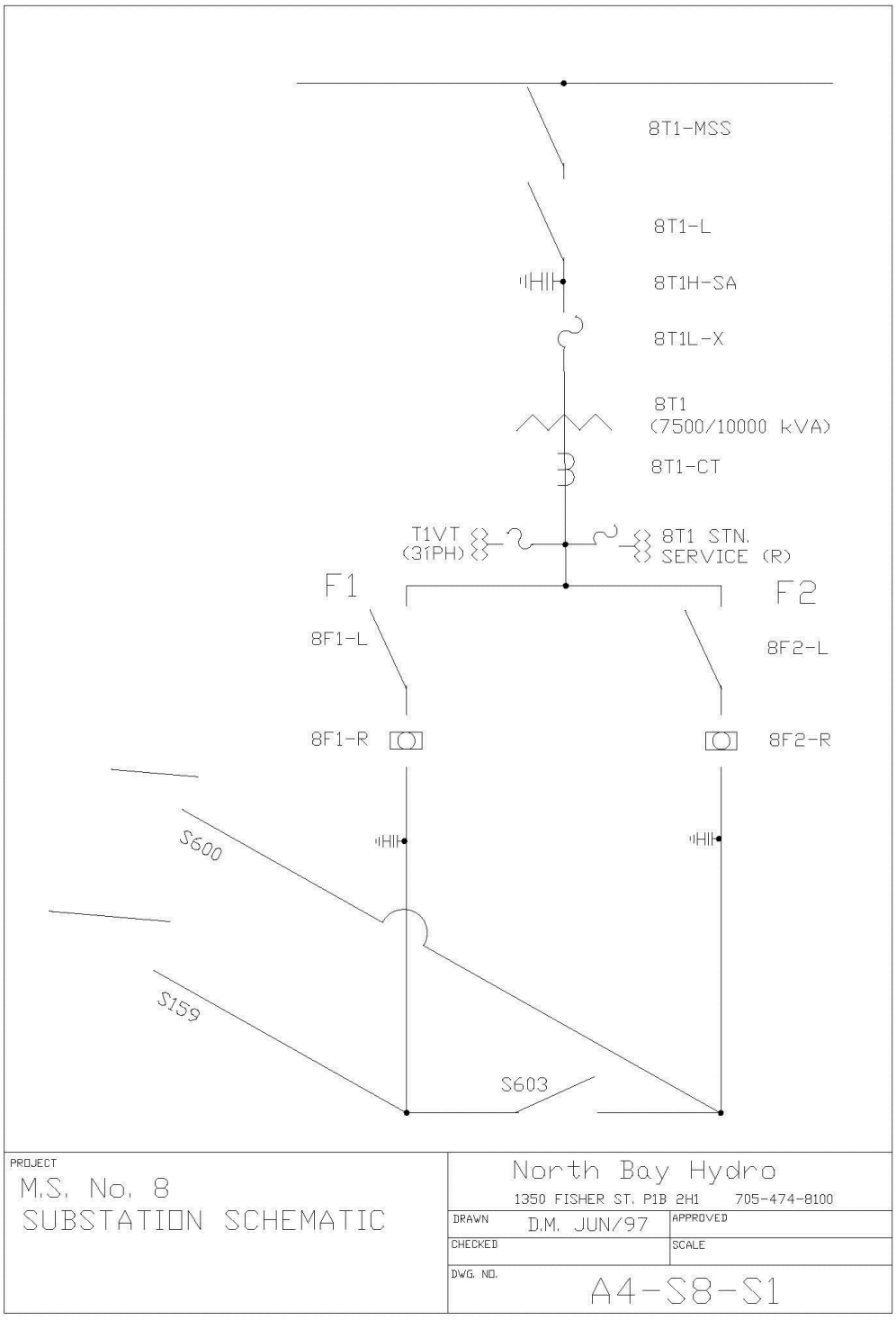


Appendix M - Figure 2: MS4 Single-Line Diagram

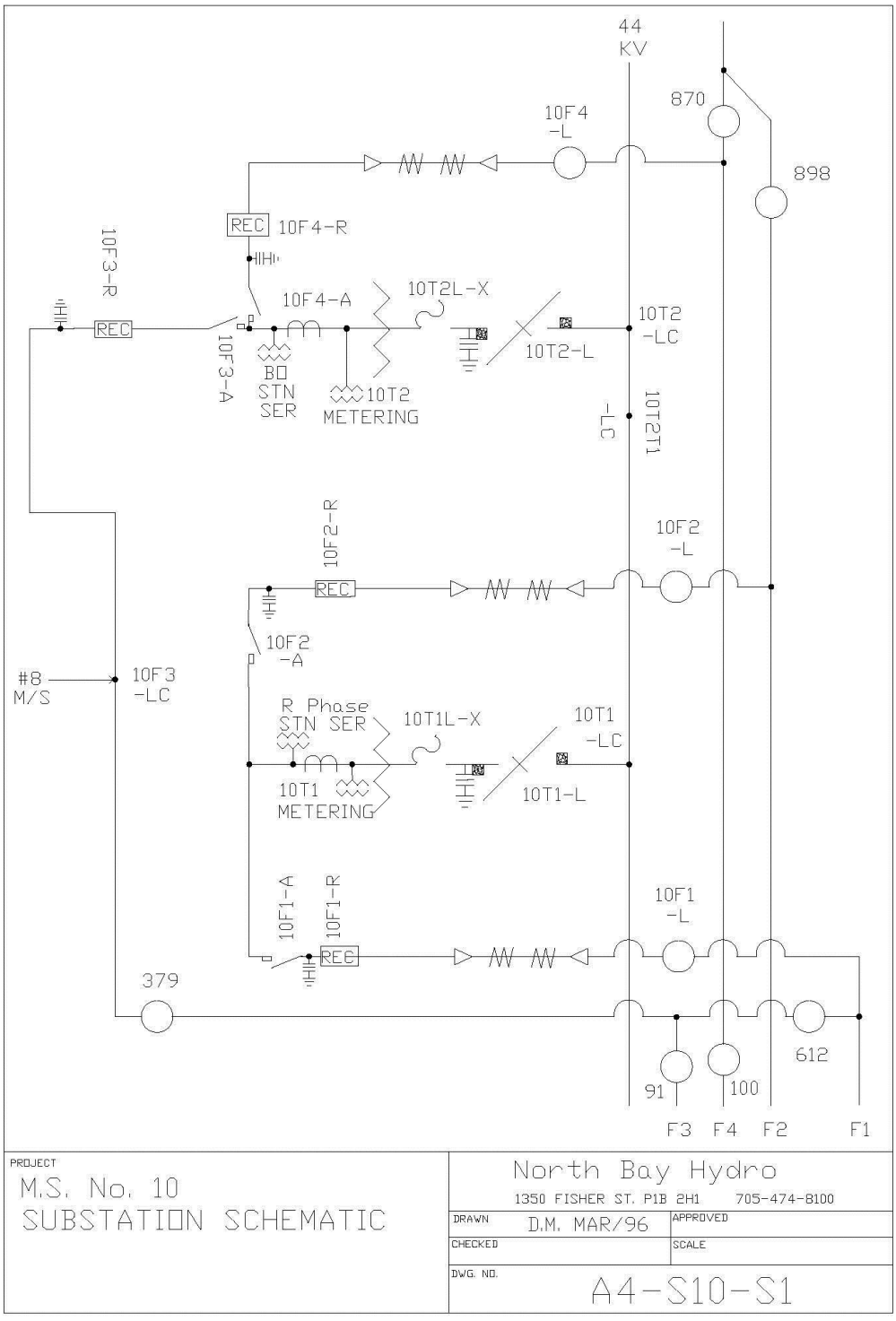
Appendix M - Figure 3: MS9 Single-Line Diagram



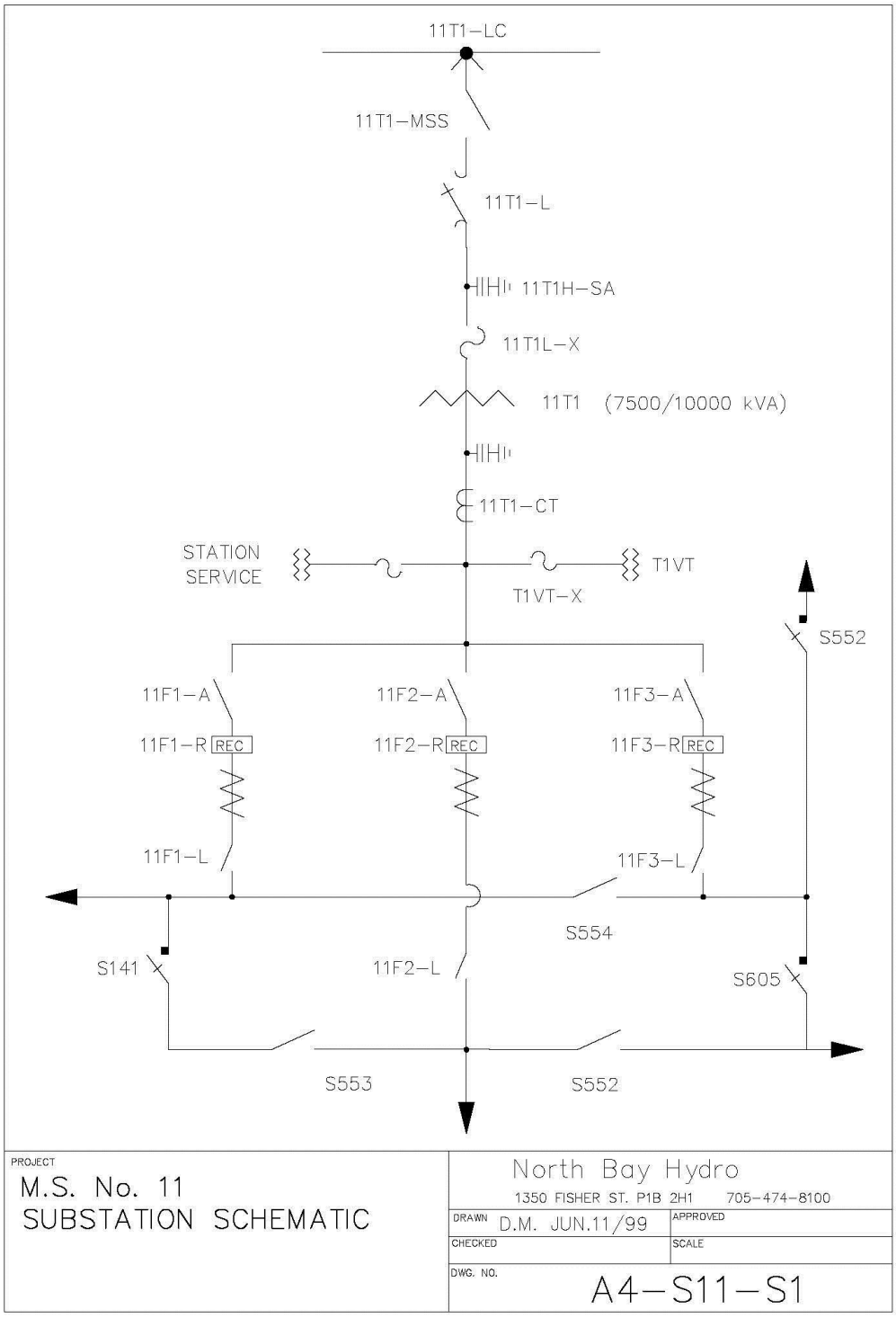
Appendix M - Figure 4: MS7 Single-Line Diagram



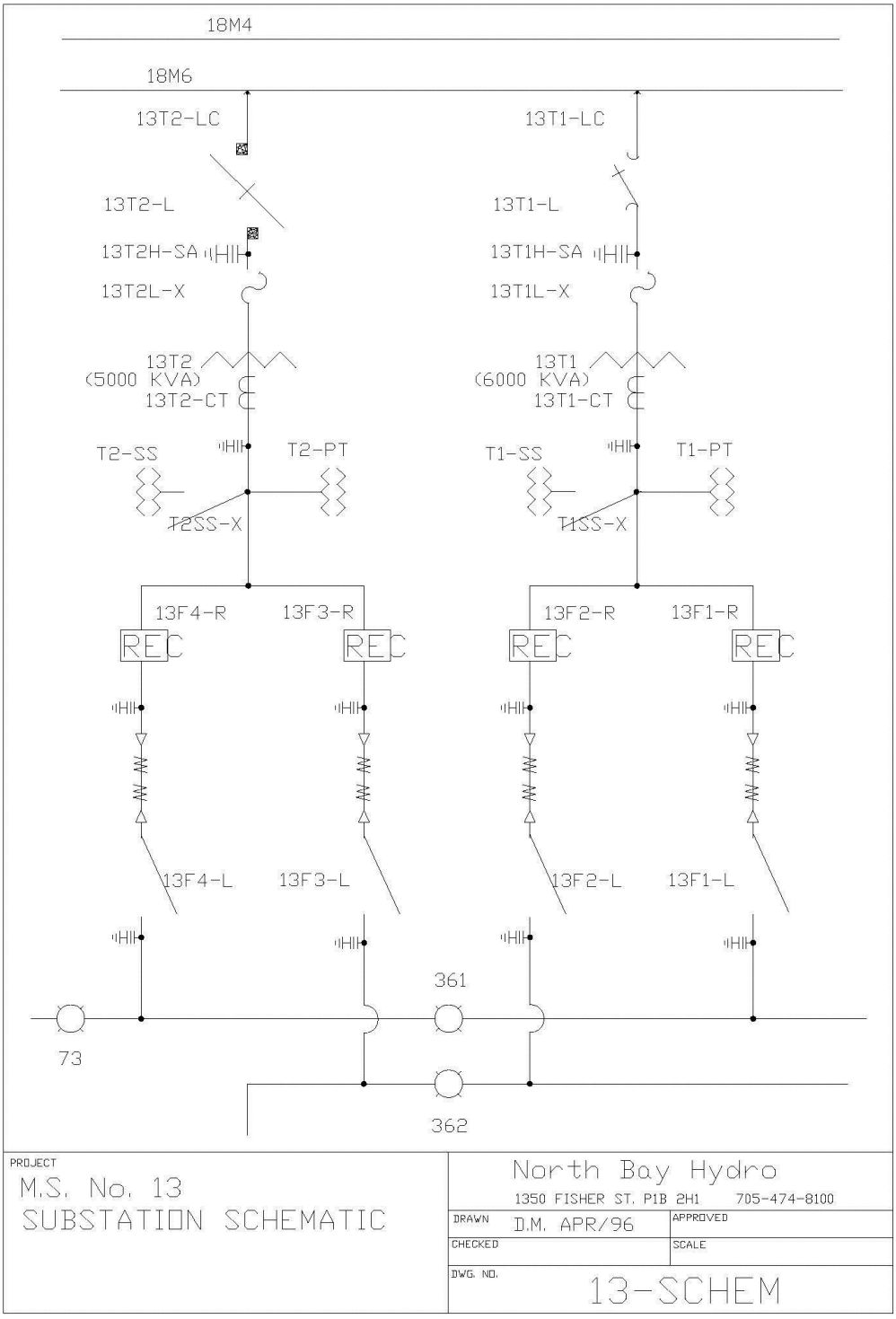
Appendix M - Figure 5: MS8 Single-Line Diagram



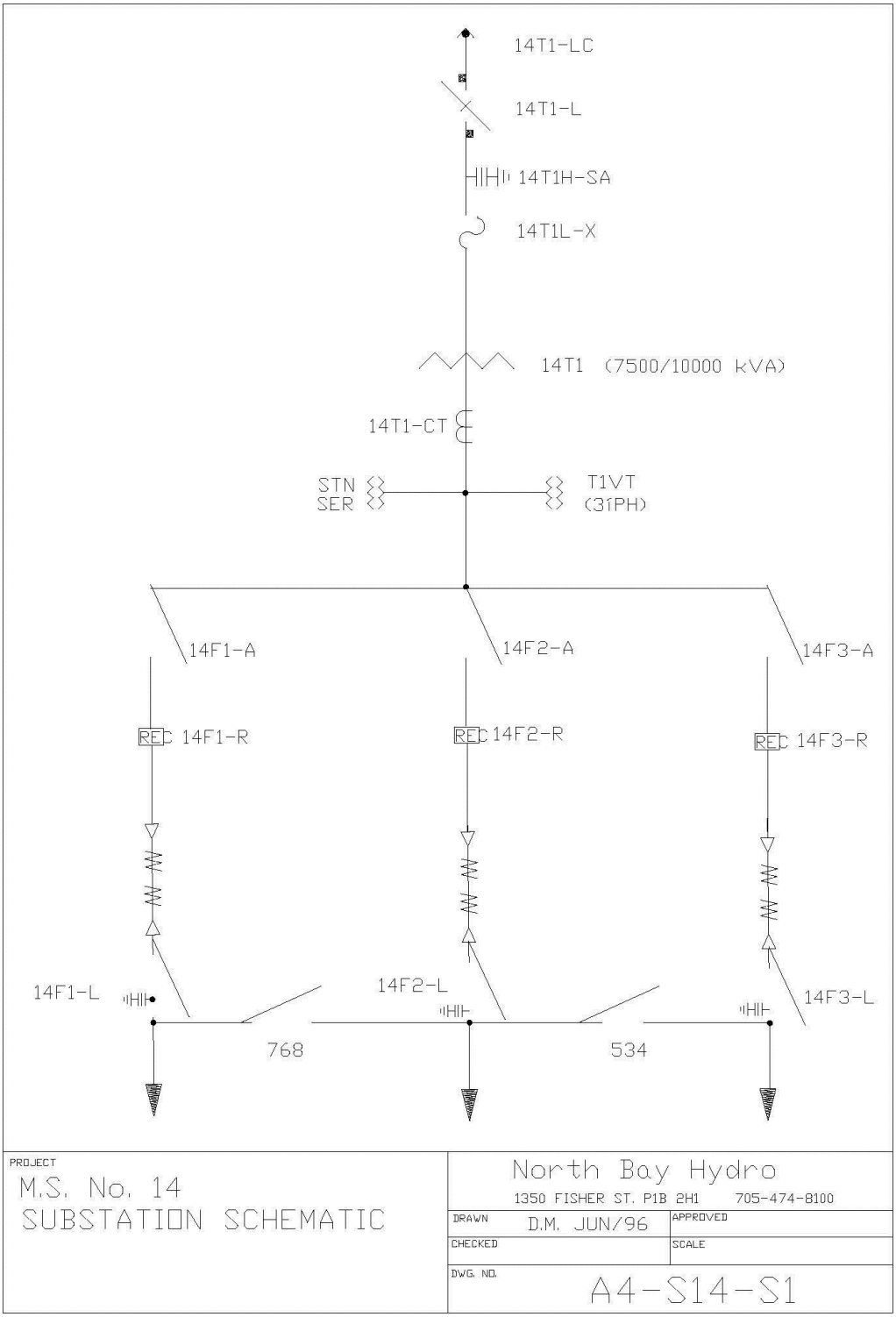
Appendix M - Figure 6: MS10 Single-Line Diagram



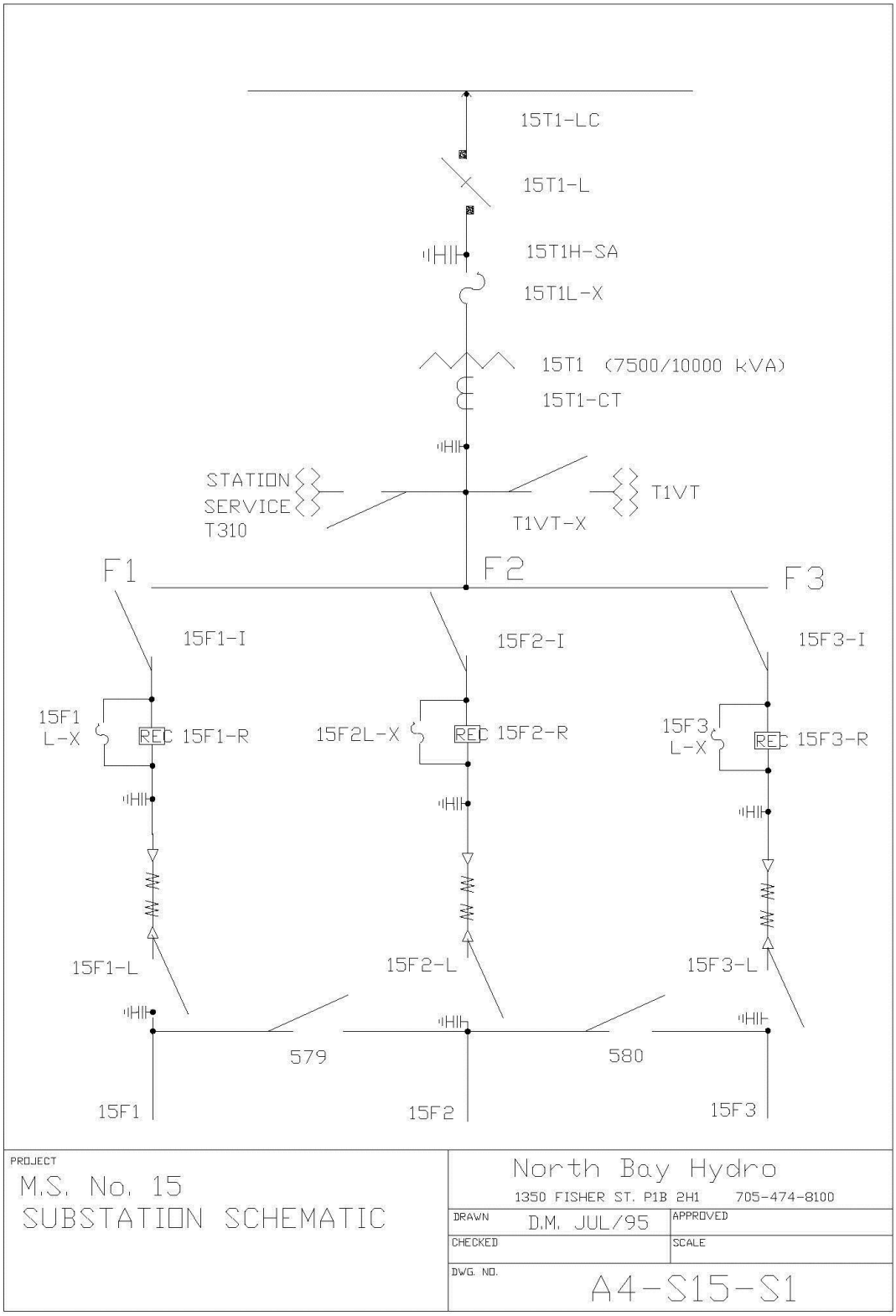
Appendix M - Figure 7: MS11 Single-Line Diagram



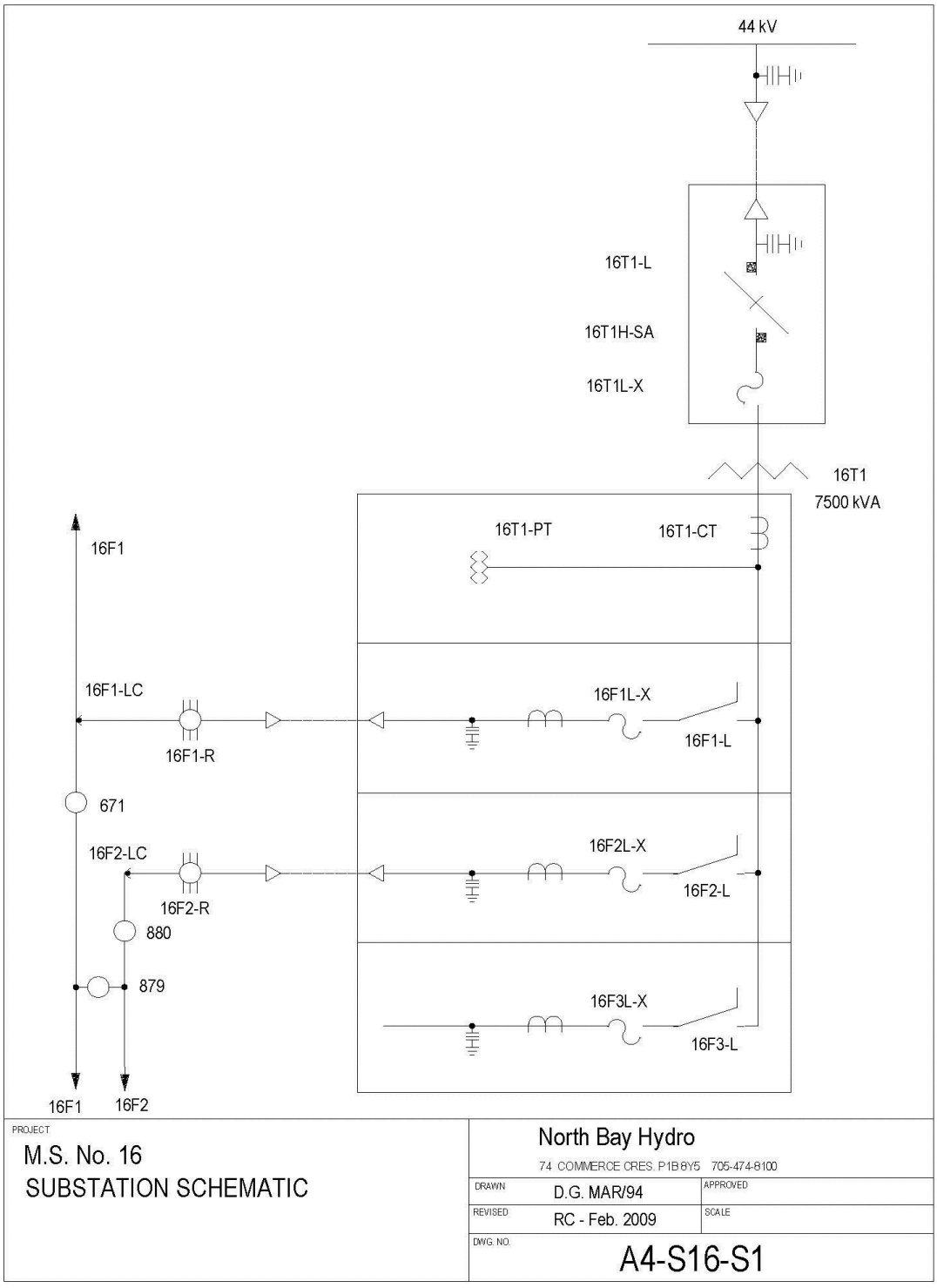
Appendix M - Figure 8: MS13 Single-Line Diagram



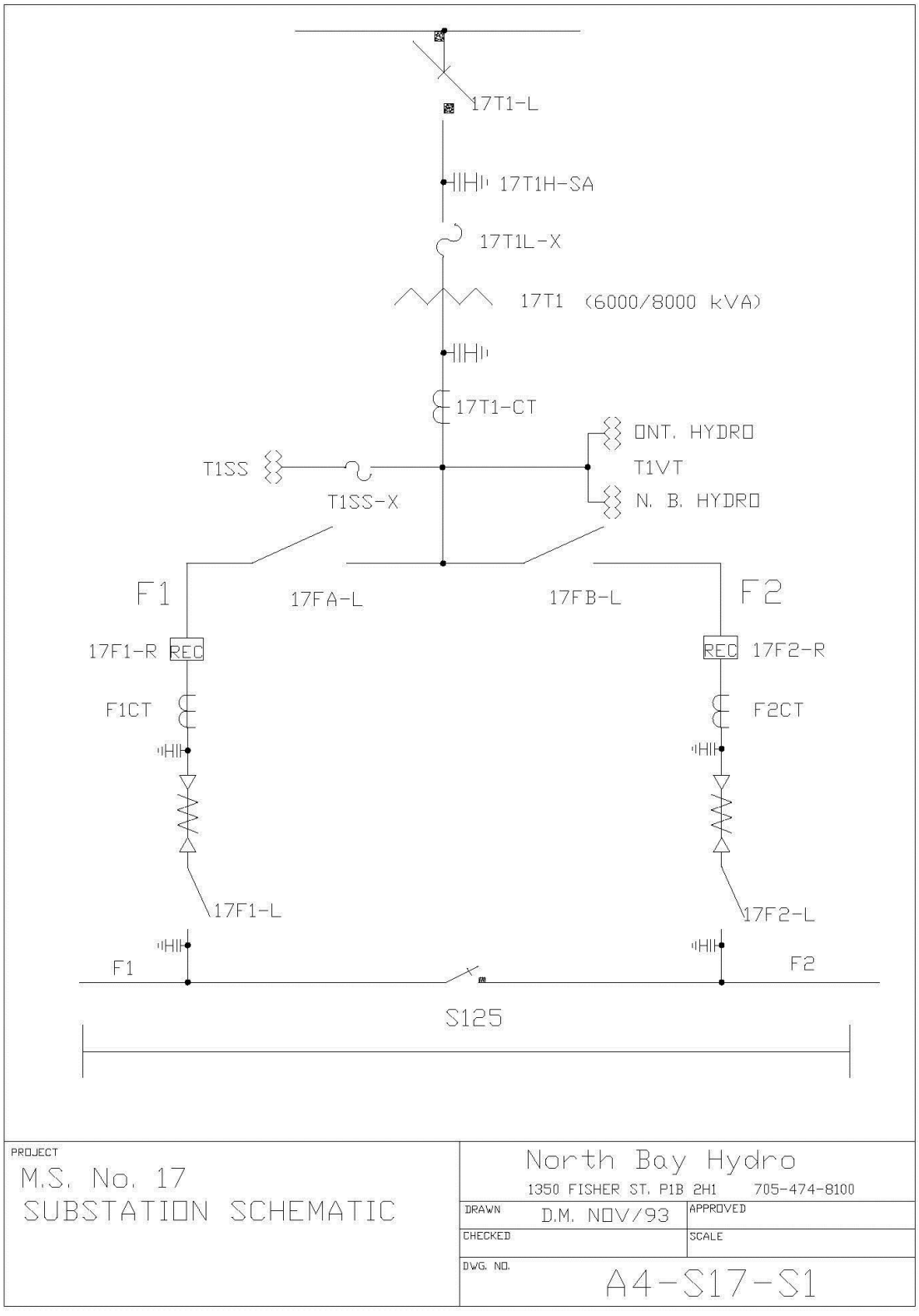
Appendix M - Figure 9: MS14 Single-Line Diagram



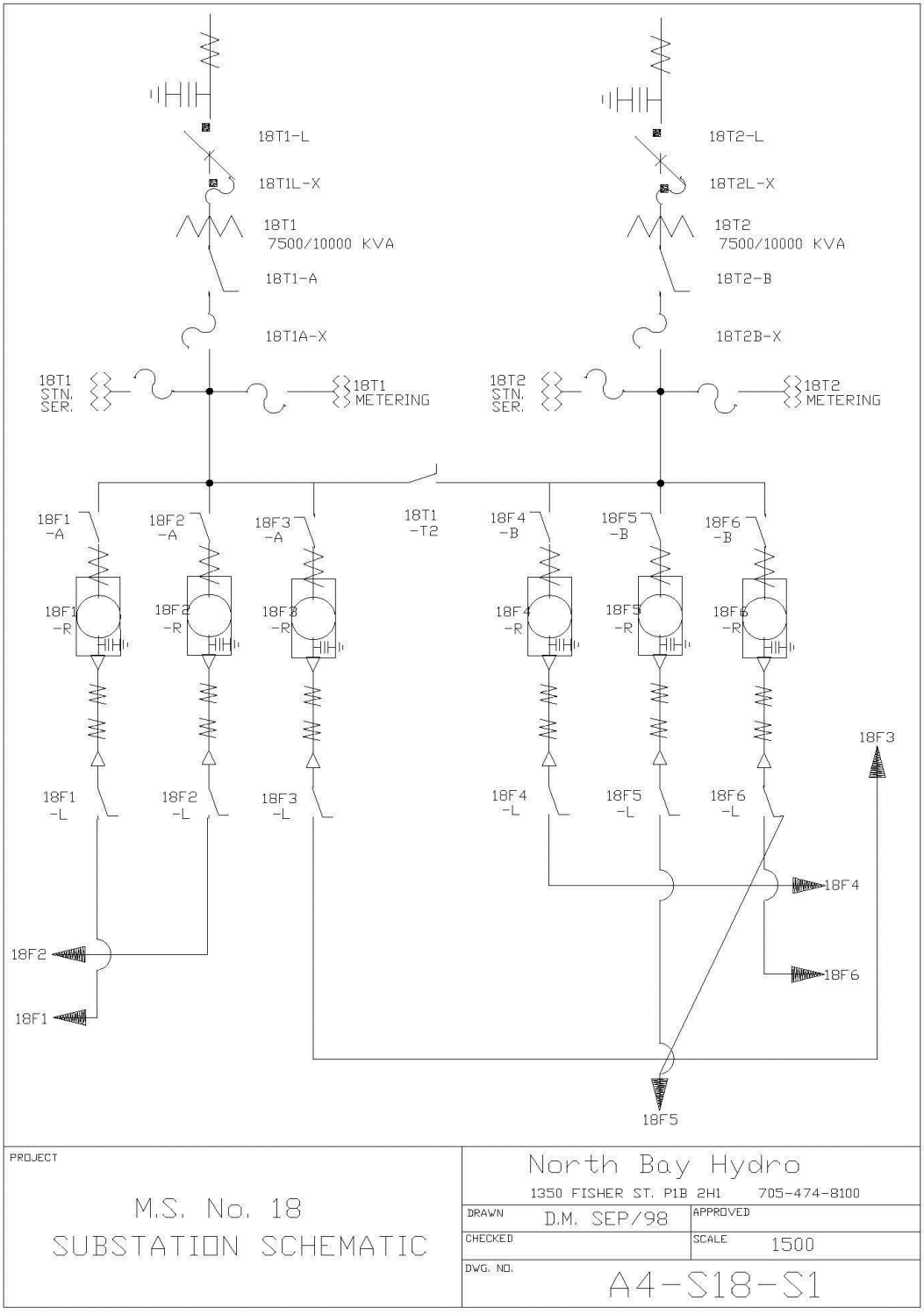
Appendix M - Figure 10: MS15 Single-Line Diagram



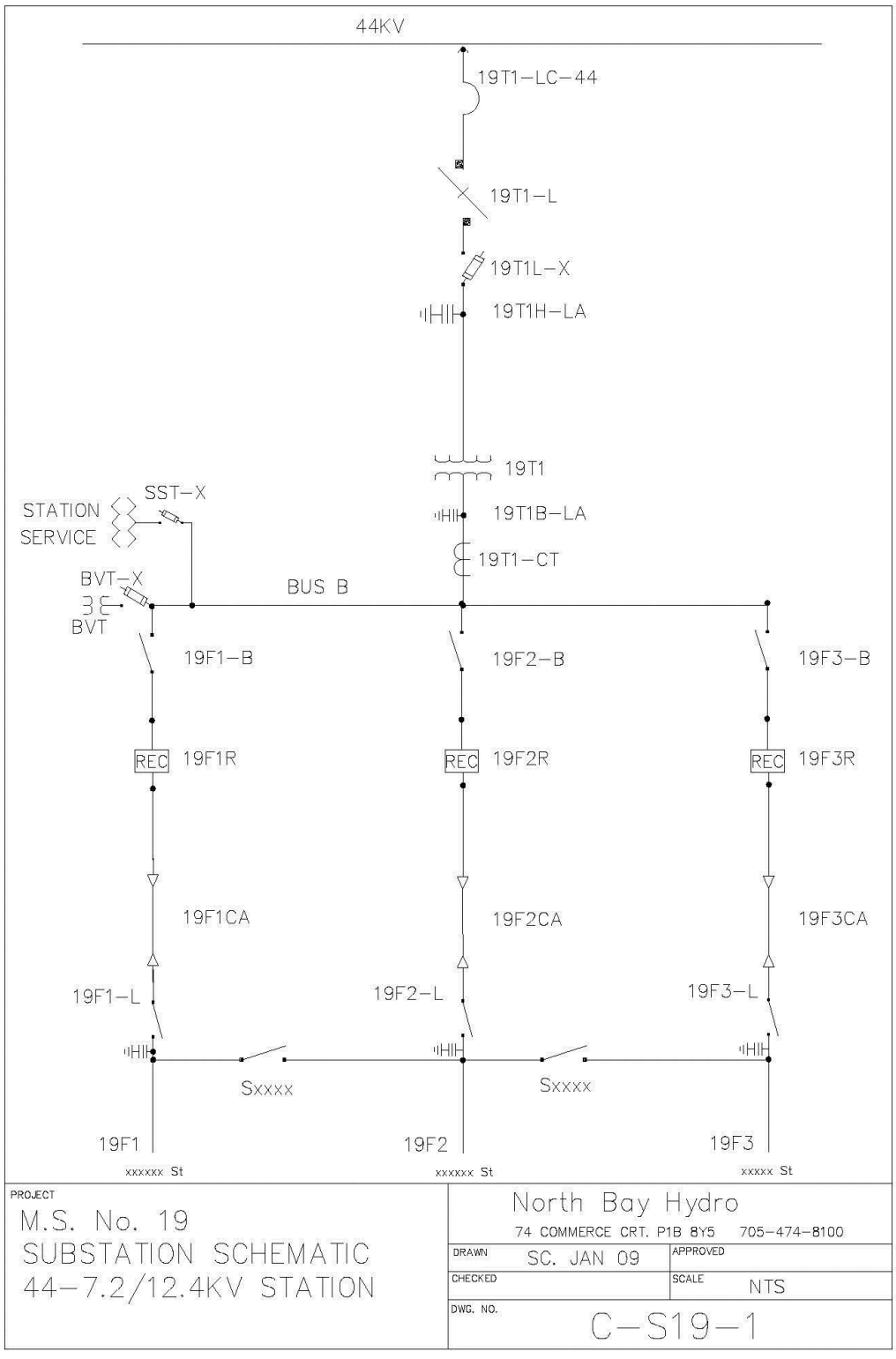
Appendix M - Figure 11: MS16 Single-Line Diagram



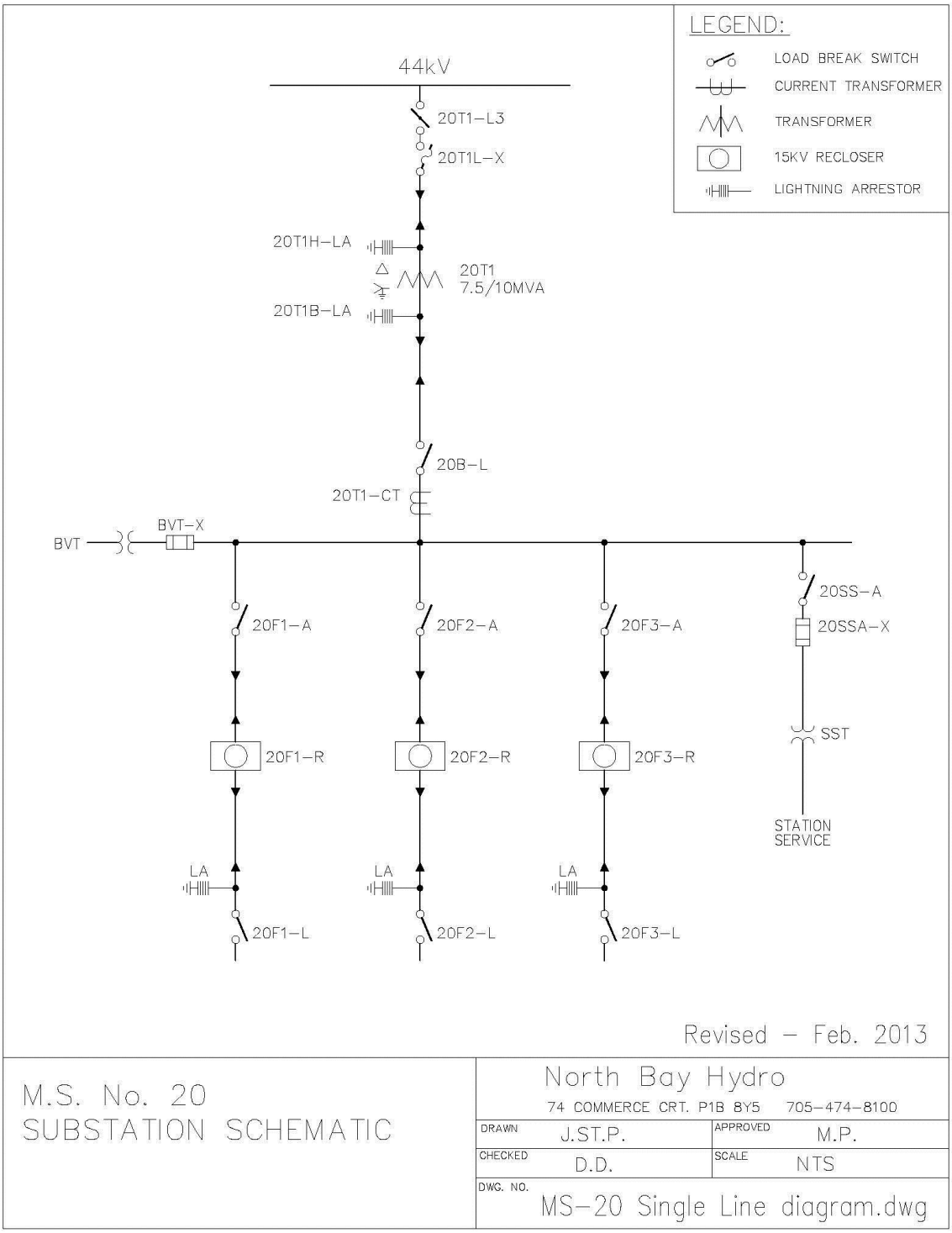
Appendix M - Figure 12: MS17 Single-Line Diagram



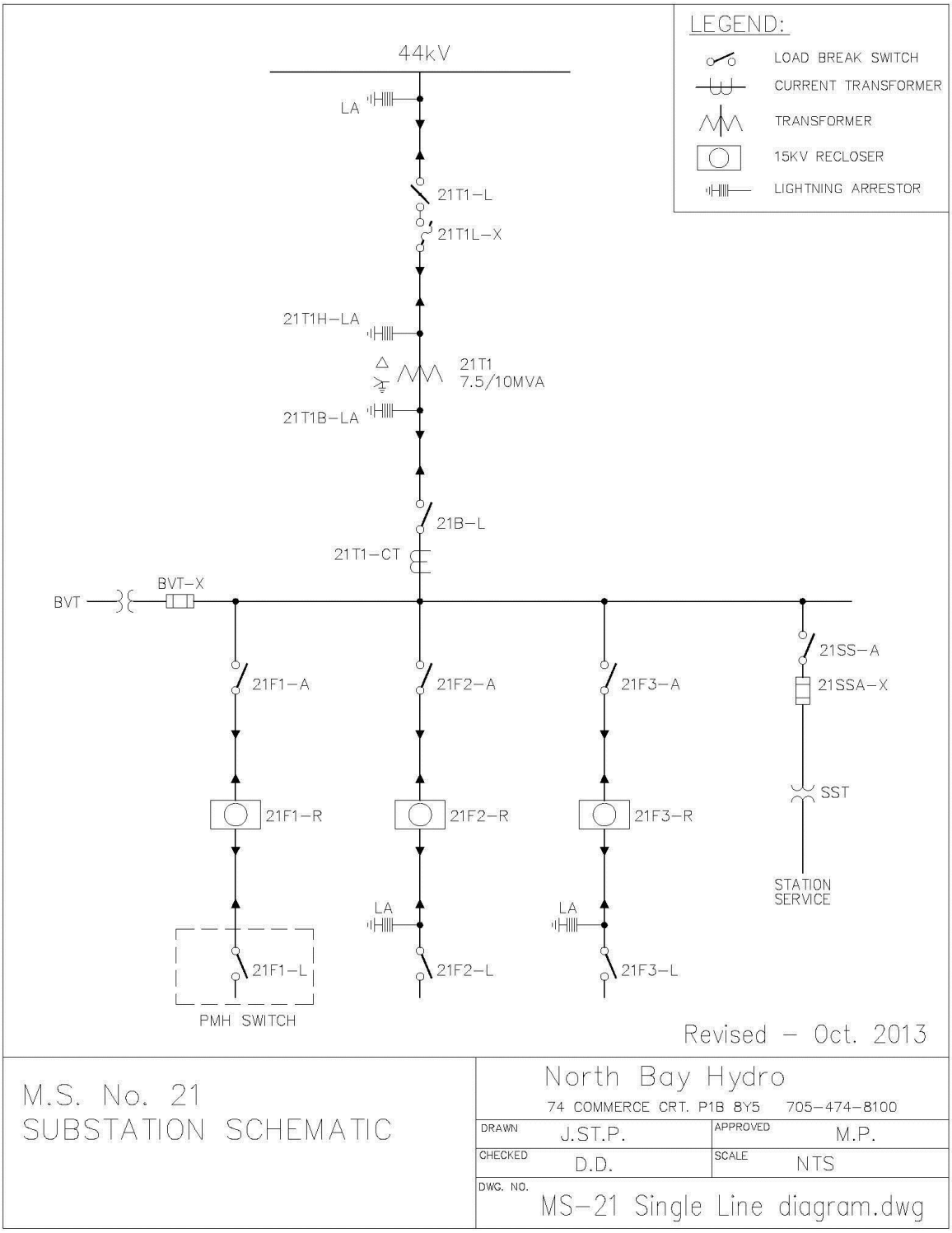
Appendix M - Figure 13: MS18 Single-Line Diagram



Appendix M - Figure 14: MS19 Single-Line Diagram



Appendix M - Figure 15: MS20 Single-Line Diagram



Appendix M - Figure 16: MS21 Single-Line Diagram

Appendix N - Tree Trimming Areas

North Bay

Urban Area

2000

A1-02-21

1A 1B 1C 1D 2A 2B 2C 2D 3A 3B 3C 3D 4A 4B 4C 4D

SCALE 0 800 1600 3200 4800

C.F.B.

AVR ST.
DUSFORD RD.
GUELPH ST.
KINGSTON CRES.
MARCH ST.
MARSTON CRES.
MARRIOTT ST.
NORTHOLT RD.
PARKER AVE.
PRINCEDALE PL.
QUEENSTON ROW
ROYAL CRES.
STANMORE DR.
TAUNTON RD.
UXBRIDGE AVE.
WINDSOR CRES.

R:\drawing\city plan\streetnaming.dwg

Appendix O – Util-Assist Report

util-assist | Solutions. Simplified.

April 17, 2014

Metering Capital Plan for North Bay Hydro

Util-Assist Inc.
www.util-assist.com

355 Harry Walker Parkway North, Unit 4
Newmarket, ON L3Y 7B3
t. 905.952.0477
f. 905.952.3479

util-assist | Solutions. Simplified.

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Section 1: Executive Summary

As part of their planning, and to meet the OEB's requirements for 5-year capital plans, North Bay Hydro Distribution Ltd. (NBHDL) contracted Util-Assist to document their Metering Capital Plan. As part of this planning process, regulatory requirements were considered, including the proposed amendments to the Distribution Service Code (DSC) which will have an impact of all Ontario Local Distribution Companies (LDCs) and the manner in which General Service (GS) customers are metered and billed. While these proposed amendments do not include reclassification of customers, there are possible impacts to the metering strategy and the business processes associated with the billing of customers currently residing in the GS>50 kW through GS<500 kW rate classification.

The proposed strategy transitions NBHDL from the traditional – and manual – metering and billing process, to one that embraces technology and leverages existing infrastructure for a more automated process that is expected to result in lower costs and increased data being available for analysis. This will lead to other business process improvements commonly realized through Smart Meter – and indeed Smart Grid – installations.

The 5 year capital plan (which also captures operating costs over a 10 year period), will result in the replacement of more than 300 meters. The total cost – including meters and installation and maintenance costs – is expected to be approximately $665,436.34, represented by a Net Present Value of $598,775.75.

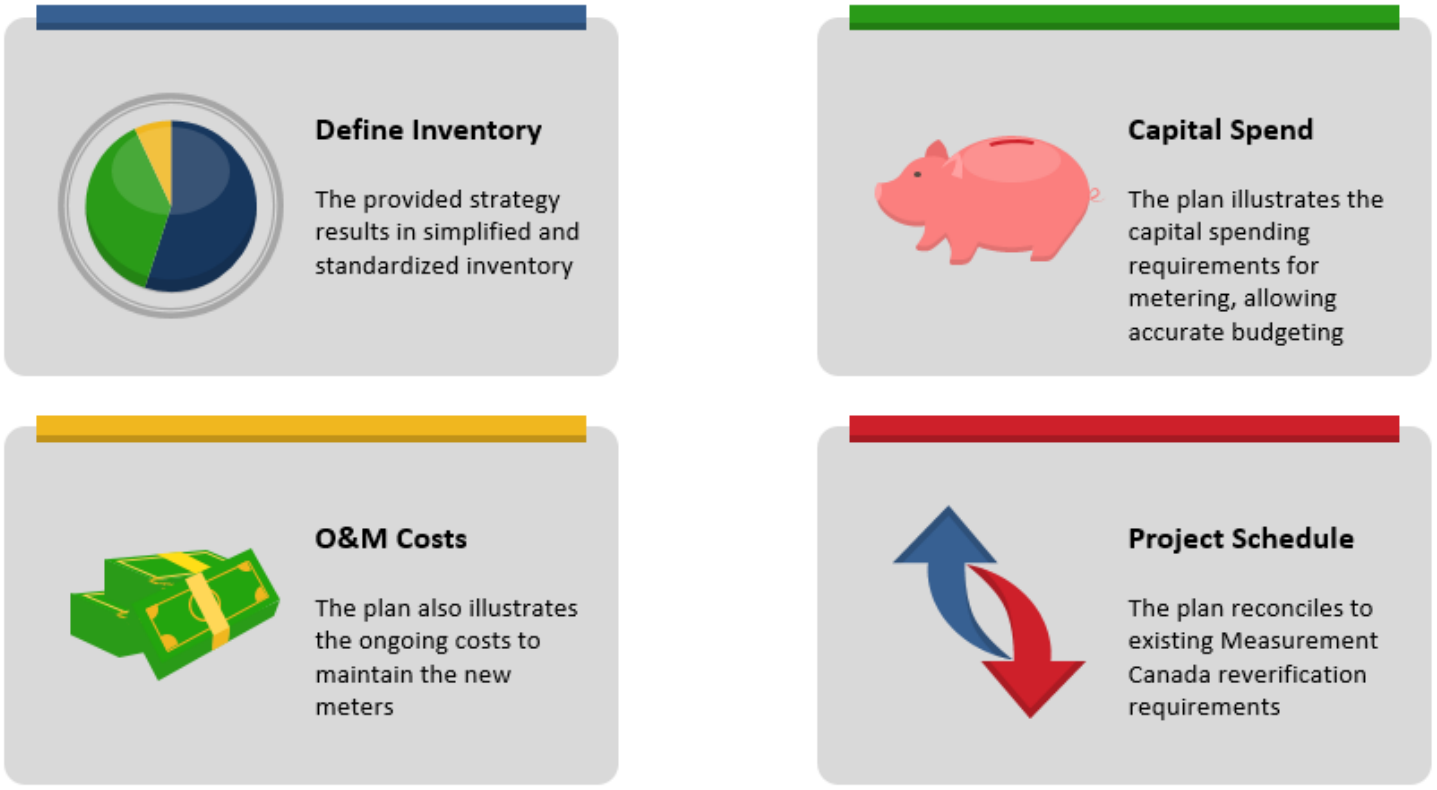


Figure 1: Util-Assist has helped to define requirements and plan deployment of new technology so that NBHDL's implementation will meet future requirements for Smart Grid deployment

Section 2: Introduction

2.1 Regulatory Requirements

The Ontario Energy Board utilizes a "renewed regulatory framework for electricity" which provides "alignment between a sustainable, financially viable electricity section and the expectations of customers for reliable service at a reasonable price." The OEB has used this approach because it believes that "emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."[1]

With regards to setting rates, the OEB have asked distributors to file 5-year capital plans to support their rate applications. This 5-year metering plan will support this goal by providing NBHDL with documentation to support their planned capital expenditures for metering technology. Metering technology is a critical consideration, as it is enabling technology for multiple objectives which the OEB have used to guide their policy development. As listed in the OEB Act[2], objectives include:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

With objectives that include promoting conservation and demand management, the implementation of a Smart Grid, and the promotion of renewable energy, we see that there are opportunities to leverage the existing Smart Meter network to cost effectively implement metering technology to accomplish these objectives.

2.2 Sensus Smart Meter Network

NBHDL has successfully deployed the Sensus metering system to satisfy the provincial Smart Meter Initiative, and have met their requirements for time-of-use (TOU) billing. With these significant milestones behind them, they can now turn their attention to better leveraging this network to improve business processes and implement cost savings measures beyond what was required of the Smart Meter Initiative. The following functionality is available within the existing AMI network, allowing NBHDL to optimize processes:

- Implementing Enhanced Supervisory Message (ESM) meters in an effort to replace MV-90 meters
- Deploying encryption across existing meter population
- Implementing upgraded metering technology to enable CDM programs
- Deploying Remote Disconnect meters to enhance efficiencies
- Using real time alarm / event notification to enhance outage and restoration management

[1] The "Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012" is referenced within this introductory paragraph
[2] *Ontario Energy Board Act, 1998* (the "OEB Act")

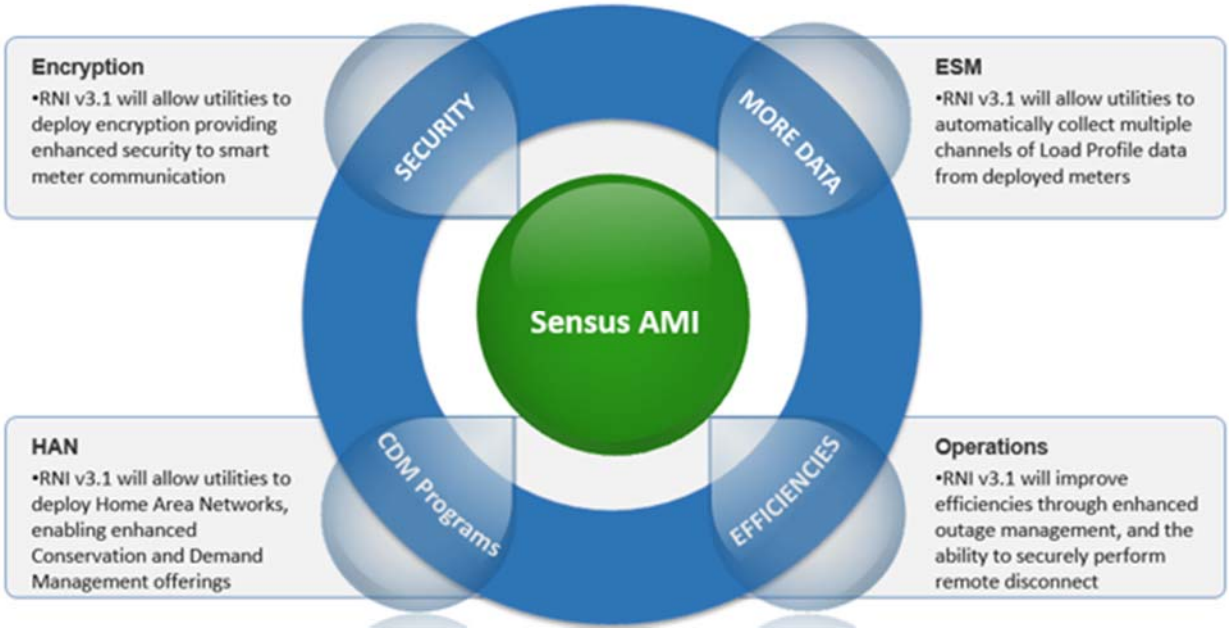
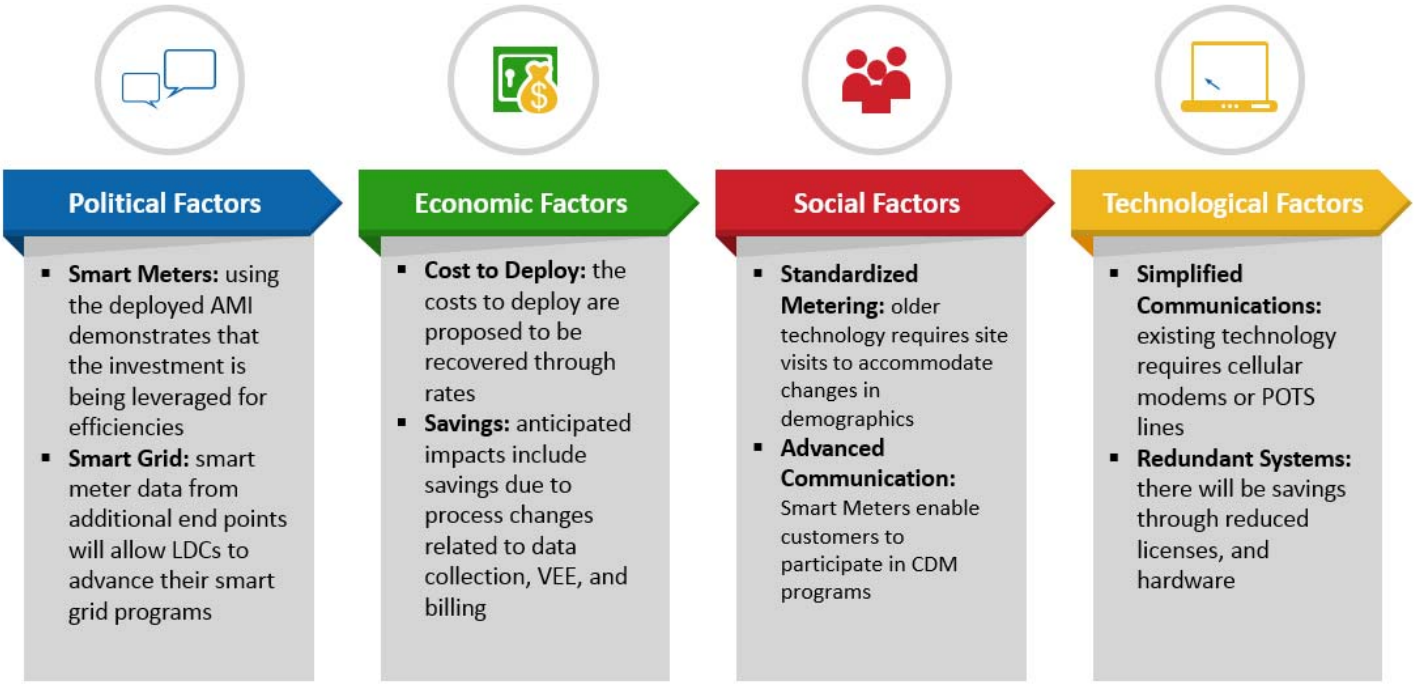


Figure 2: Overview of RNI v3.1 enhancements

2.3 Proposed Amendments to the Distribution System Code (DSC)

In January 2014, the OEB proposed amending the Distribution System Code to require distributors to install MIST meters on any "installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW." This would in effect create two categories of customers for the LDC: customers that require TOU metering where the monthly demand is less than 50 kW, and customers that require MIST metering where the monthly demand is



greater than 50kW. In today's environment only customers with demand greater than 500 kW are required to have MIST meters installed.

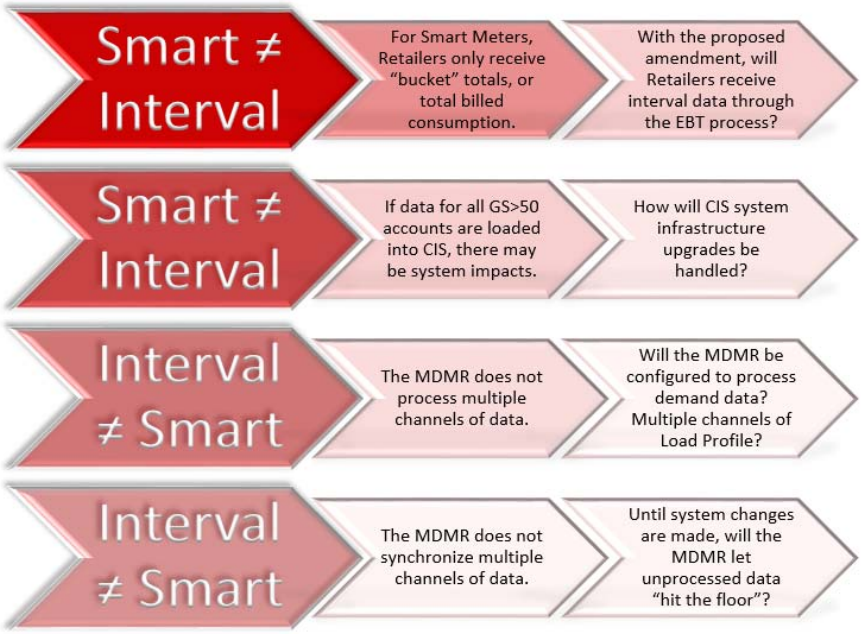
As per the OEB's proposed amendment, the LDC is "expected to seek recovery of the costs for the MIST meter installations through rates with the costs allocated to the applicable customer rate classes."

Per the proposed amendment, the OEB "expects that distributors will install interval metering systems that communicate through the distributor's Advanced Metering Infrastructure installed as part of Ontario's smart meter initiative."

As a result of the regulatory requirements to provide 5-year planning for capital investments, the advancements of the existing smart meter technology, and the OEB's expectation to use the smart meter technology to begin collecting meter data for use in the billing of additional rate classes, NBHDL has created this Metering Capital Plan[3].

2.3.1 Some Unanswered Questions

At this point, the amendment to the DSC is a proposal, with the OEB requesting feedback from utilities on the perceived impacts of this proposal. It is reasonable to assume that most, if not all, utilities would support this amendment based on the desire to make better use of the existing AMI infrastructure. By installing AMI meters on customer rate classes that are currently metered by technology that requires either manual meter reading or additional communications costs, such as cellular modems or POTS phone lines, there are easy to capture cost savings by transitioning to smart meters. Other cost centres that are reduced or eliminated include software licensing costs for what would become redundant metering systems, reduced training requirements and simplified business processes that would result from moving to a single system for collecting data, performing VEE, and storing meter data for subsequent billing and settlement functions. In addition to these cost savings, there are improved customer service programs made available through the automated data collection process, such as Web presentment of consumption information, which is not available to customers today that are metered by electromechanical meters. In addition to the customer service benefits, the LDC will realize benefits through the ability to include all meters in such important analysis efforts as Transformer Loading reports which can lead to enhanced Asset Management programs.



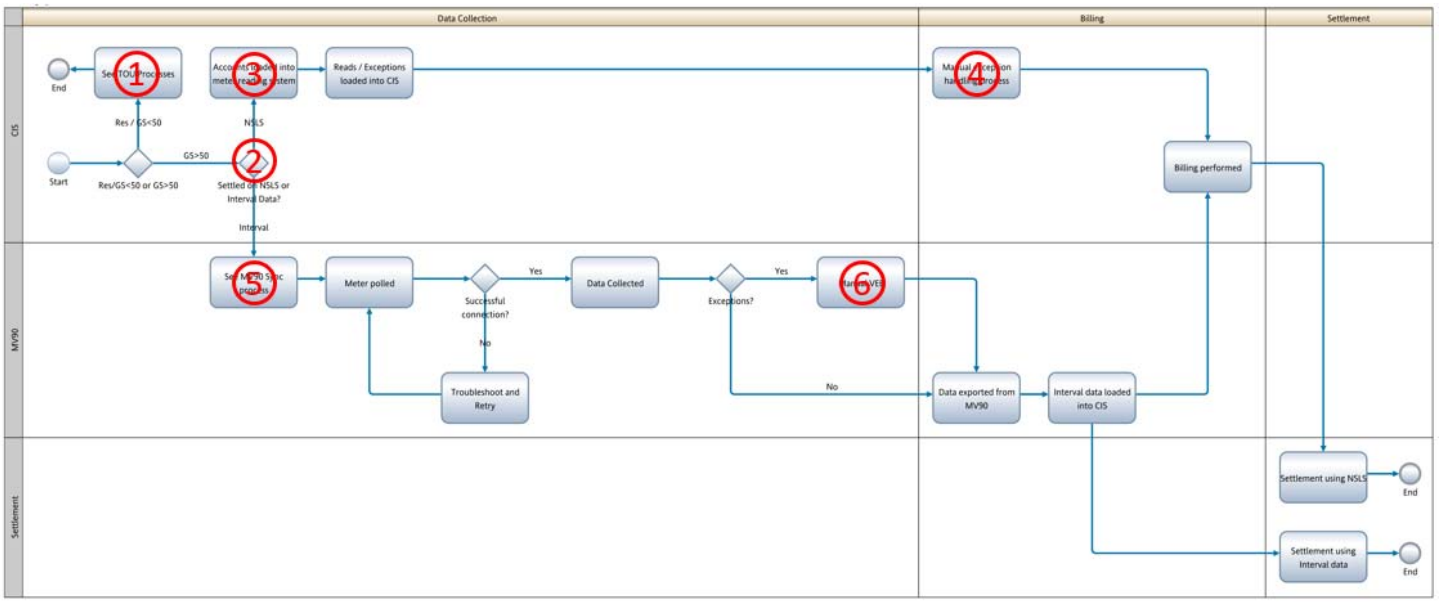
While the benefits are easily recognizable, there are some risks identified which have not been fully explained at this early stage.

One way of comparing the risks with the benefits is by examining – at a very high level – the differences in business processes that might arise through the proposed changes.

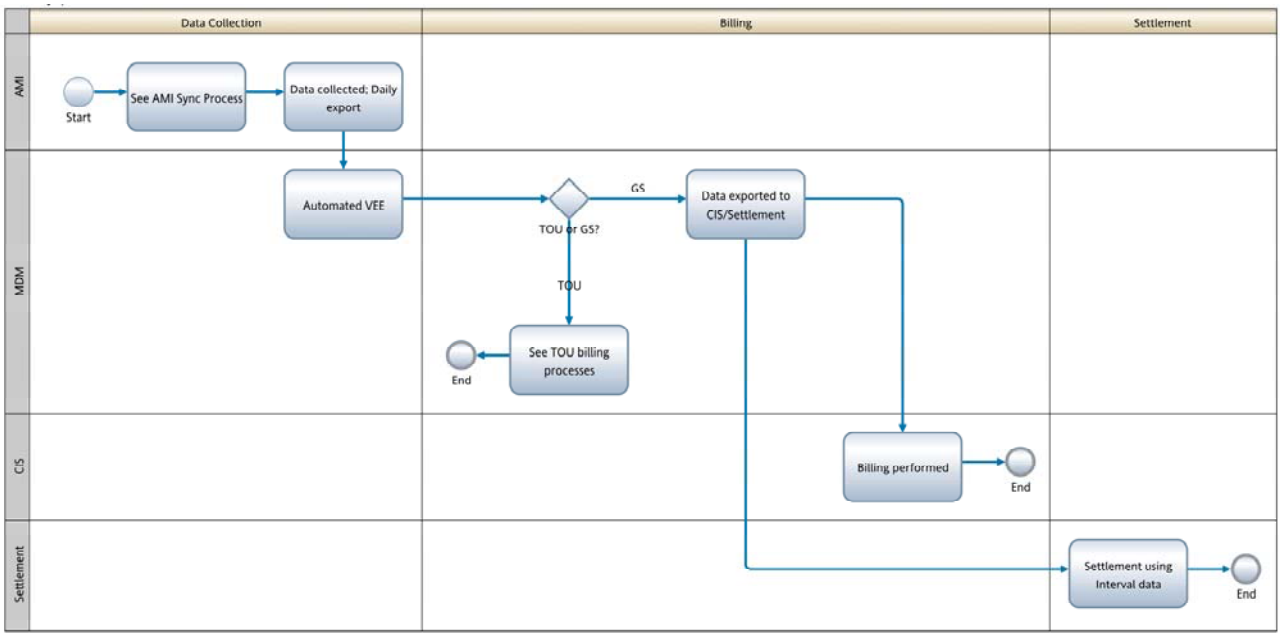
[3] NBHDL currently has 221 meters whose seal expired in 2014 and 2015; the cost of implementing an interim solution for these meters has been deemed cost prohibitive. An interim solution would require the procurement of additional meters which would not have met the long term requirements of NBHDL, requiring added inventory management, non-standard processes for data collection and VEE, etc. – concerns which are all resolved through the holistic approach captured by this Metering Capital Plan.

2.3.2 Current Business Process for GS>50 Meters

The following business process diagrams illustrate – at a high level – the possible impacts of the proposed changes to the DSC. A few process boxes have been highlighted for discussion, as the proposed amendments will provide some advantages in this complex process, but also some possible risks that will need to be identified for future discussion.



2.3.3 Proposed Business Process for GS>50 Meters



It should be noted that these diagrams were not developed based upon any interview process with NBDHL staff, they are meant only to diagrammatically illustrate that the proposed amendments do provide some business process efficiencies, and also that there are components to these complex processes that have not yet been "vetted" or discussed as part of the amendments.

In comparing the two processes, it is apparent that the second diagram is simpler in nature, requiring fewer steps and fewer "decision" boxes or divisions in the process. This is because under the proposed amendments, effectively all meters in the NBHDL "fleet" will be managed under the same business processes for synchronization and data collection, and all billing processes can be automated in nature, differing only in the interfaces used. In the first diagram we have highlighted a few boxes, in order to show where in the existing process some of these differences are seen.

1. See TOU Processes

- Smart meters require Synchronization with AMI, and MDM products, which then facilitate billing processes which are automated in nature. The existing processes for GS>50 also require processes for managing synchronization related information and billing processes are more manual in nature – many processes are required in the existing environment.

2. Settled on NSLS or Interval?

- In the existing process, different settlement processes are required for GS>50 meters as the data that is collected for some meters is done via the MV90 system which includes hourly (or more granular) information which is settled differently than meters which are read manually and only monthly reads are available for the billing and settlement process.

3. Accounts loaded into manual meter reading system

- In the existing process, many GS>50 meters are read manually, for which NBDHL incurs higher costs for data collection and exception handling than would otherwise be required using the AMI system and processes.

4. Manual exception handling process

- In the existing process, any exceptions for manually collected data would require additional truck rolls to resolve, possibly resulting in delays to the billing process.

5. See MV90 Sync Process

- As opposed to the TOU Synchronization process, the existing Sync process for MV90 meters is much more manual in nature.

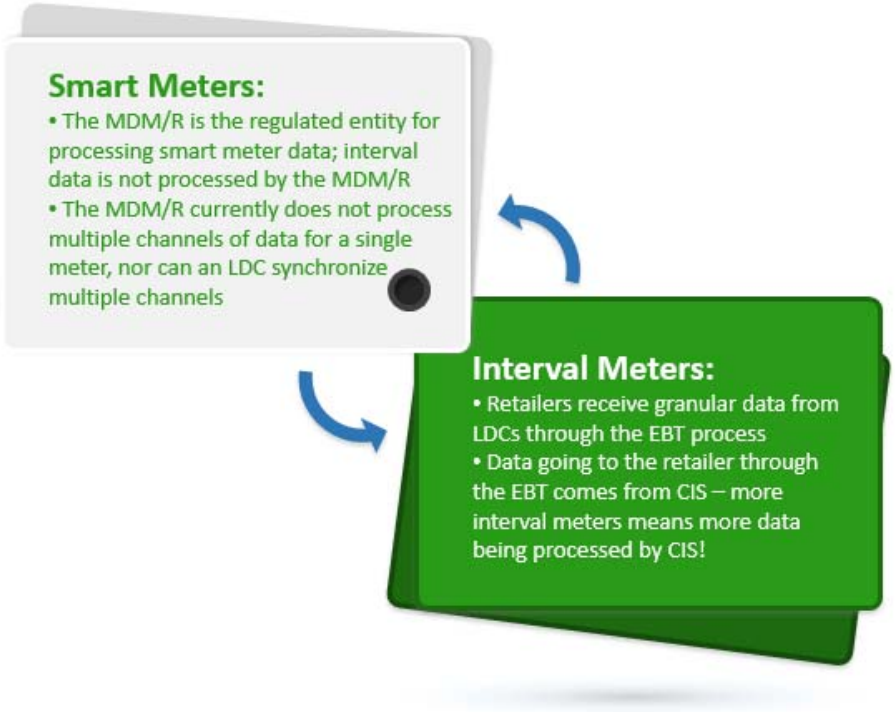
6. Manual VEE

- As opposed to the automated VEE process using an MDM system, the existing VEE process for MV90 meters is much more manual in nature.

What the processes do not capture are the risks that are highlighted in the diagram in Section 2.3.1 "Some Unanswered Questions." We provide some additional verbiage here to better explain these items, so that NBDHL can ensure that future communication from the regulators provides information to answer these questions.

2.3.4 2009 Amendments to the Retail Settlement Code (RSC)

In January 2009, the OEB amended the Retail Settlement Code, in order to clarify that through the "metering evolution period end date" LDCs were to consider smart meters differently than interval meters. While it is true that under many definitions of interval meters, smart meters would qualify as interval meters, for the purposes of settlement with retailers, utilities should consider the two types of meters separately. This amendment provided clarity because if Smart Meters were considered interval meters, the rollout of Smart Meters for TOU billing through the MDM/R could have affected the settlement process – an unintended consequence of the Smart Meter Initiative. By providing this clarity, the OEB was specifying that no changes to the existing EBT structure or process would be required, and that the "issue of third parties (retailers and others) access to data from the MDM/R and the data exchange between distributors, retailers and the MDM/R"[4] would be handled through future consultation.



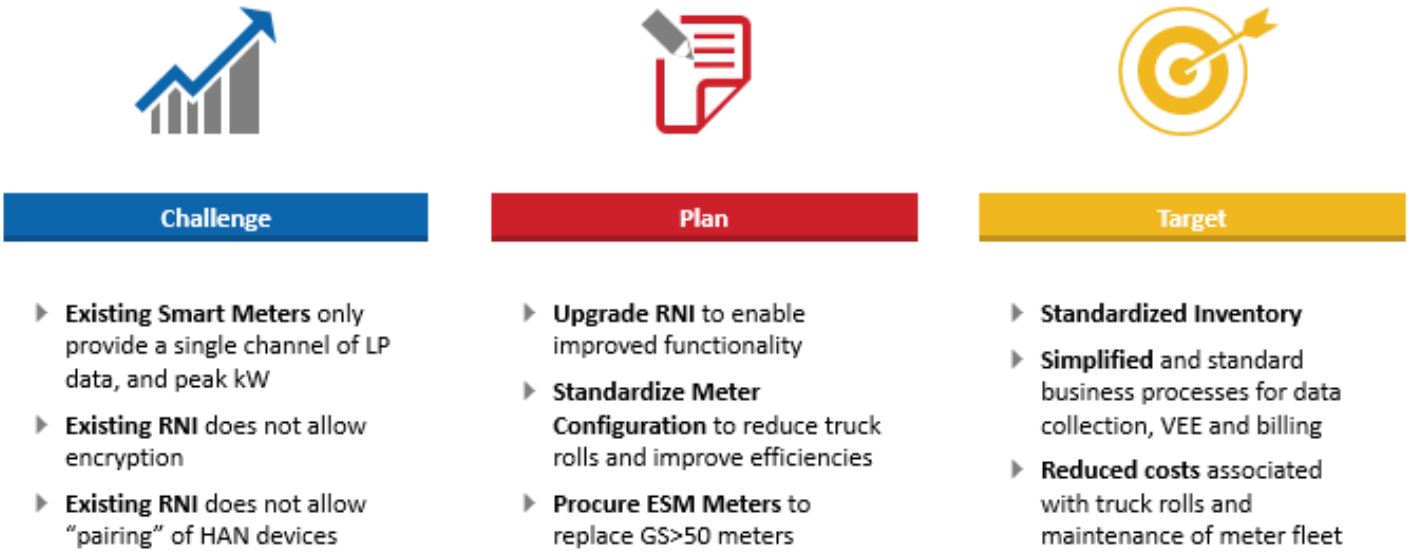
[4] Notice of Amendment to a Code, Amendments to the Retail Settlement Code, Board File No.: EB-2008-0297; January 8, 2009.

Section 3: Sensus Technology

3.1 RNI Upgrade

The Regional Network Interface (RNI) is the Sensus head-end system (the Advanced Metering Control Computer (AMCC)). The RNI version used by NBHDL through 2013 is version 2.2.4 which is what the vast majority of the province has also been using during this time. There are some limitations to this version, which have precluded NBHDL from implementing additional technology to better leverage their smart meter investment:

- For shared RNIs[5], the real-time event and alarm data that Sensus provides over MultiSpeak, is not able to be properly parsed for each utility. For any utility on a shared RNI that does subscribe to the MultiSpeak alarm/event information, alarm/event information from all utilities would be received. This would be problematic for any integrated systems.
- For utilities on a shared RNI, version 2.2.4 does not allow for encryption to be deployed.
- For meters measuring multiple channels of Load Profile data, the network (i.e., over the air) was not able to collect more than kWh load profile information.
- For utilities considering Home Area Network (HAN) projects or pilots, which required the ability to "pair" devices over the AMI network, version 2.2.4 only allowed "bottom up" pairing[6].



[5] Sensus, as a cost sharing and savings model, provides data collection services and is able to implement hardware in a shared services model. NBHDL purchased their hardware as part of the D-9 group of utilities, and all D-9 Sensus utilities share the same head-end system, with smart meter data being kept private and secure.

[6] Pairing devices refers to the ability to "authorize" communication between the AMI meter and a HAN device, such as a smart thermostat, or In Home Display (IHD). The "pairing" process is the authorization of one device's communication module to communicate with another device's communication module. "Bottom up" pairing is when this process is conducted onsite using handheld tools, while "top down" pairing is the ability to perform this function remotely, as with the AMI network.

Sensus is now ready to move their customers from v2.2.4 to v3.1. This upgrade will allow their customers to overcome the challenges listed above; the ability to deploy this functionality will result in the following possible business process enhancements:

- The ability to collect real-time event and alarm data will allow utilities to begin enhancing their outage management processes. While some utilities have improved their outage management by using the AMI data, integration to downstream systems facilitating automated processes has not yet been practical.
- The ability to deploy encryption across their meter populations will allow utilities to deploy remote disconnect meters with added security.
- The ability to collect multiple channels of load profile data will allow utilities to begin using the AMI network to collect data for more customers than just residential or GS<50 rate classes.
- The ability to perform "top down" pairing will allow utilities to deploy HAN projects/pilots with an increased ability to support customer calls, questions or concerns.

3.1.1 Sensus Technology Enhancements / Information

3.1.1.1 What are ESM Meters?

Existing Sensus Smart Meters record and transmit data using what is referred to as the Supervisory Message (SM). The Supervisory Message is a "packet" of information that is constructed on the Communication Module, which is separate and apart from the metrology of the meter. The configuration (to some degree) of the Communication Module is not under Measurement Canada seal, while the metrology of the meter does exist "under seal." This means that once configured, the metrology components cannot be changed without breaking the seal and resealing the meter after the programming is reconfigured.

ESM refers to meters which use an "Enhanced Supervisory Message." The ESM message is also transmitted by the Communication Module; however, the information in the packet is collected from the ANSI tables which exist under the seal within the metrology of the meter. Whereas with the SM, the "interval data" is constructed by having subtracting top-of-hour register reads to create delta values, when ESM is used, the utility is acquiring true load profile data from the ANSI tables.

Utilities need to be aware that there are limitations to what the ESM meters can provide over the air, using the AMI network communication. In some cases, the meters themselves are capable of measuring more channels of load profile data than the ESM message is capable of transmitting. This report will highlight the capabilities of the ESM message as it relates to the available meters so that NBHDL can understand the true capability of the AMI system in delivering the required data.

With the SM, the packet of information that is transmitted contains the most recent top-of-hour register read, some number (on average approximately 11) of delta values which represent interval values, the kW peak demand since last reset and some event/alarm information. With the ESM message, the packet contains the register read, kW peak demand since last reset and some event/alarm information as with the SM, but the ESM packet contains true load profile data for multiple channels (if configured) acquired from the ANSI tables, as well as snapshot reads.

3.1.1.2 What are Snapshot Reads?

Snapshot reads, are readings that are taken at the time that the ESM message is being transmitted. They are instantaneous values. Snapshot reads can be configured for phase voltage, phase current, phase W, peak kW, but not peak kVa.

While there is a limitation to the number of load profile channels that ESM can provide, the snapshot reads do provide some value for engineering analysis, and hence we see an advantage to using AMI meters as replacements to the existing meter population – the data will be acquired regularly and stored by the ODS for analysis.

3.1.1.3 TOU and ESM

All ESM meters must be configured for TOU. The customers in the rate categories that are candidates for replacements may not be billed TOU; however, the meters will be recording TOU and therefore, the meters act as an enabler, allowing NBHDL to provide some additional information to their customers if considered advantageous.

3.1.1.4 What is Auto-Push?

Existing meters or ESM meters can have auto-push configured which is a function that results in a once-daily transmission by the meter that contains the TOU registers, and the peak kW and kVa demand for the meter (since last reset). Any new meters purchased by NBHDL can have Auto-Push enabled without additional cost in order to take advantage of the added functionality[7].

3.2 Technology Strategy: Transition Existing Meters to AMI

As NBHDL considers their 5 year Metering Capital plan, many of the ideas discussed thus far should be considered. The strategy proposed by Util-Assist is centered on the idea of moving towards AMI metering solutions for as many customer rate classes as is possible with the meters that are currently available. In the v3.1 environment it becomes possible to transition from meters that require site visits to gather information for billing and analysis to meter solutions that allow the automated data collection of measured quantities that satisfy the billing requirements.

3.2.1 Benefits of AMI capable meters

The following benefits of utilizing AMI capable meters are listed for consideration by NBHDL:

- **Standardization of Meter Inventory:** Standardization of meter types will simplify the inventory management process. In today's environment, with multiple meter types, as metering requirements evolve, site visits are required to change meters.
- **Standardization of Synchronization Process:** In today's environment, there is a formal sync process for IESO MDM/R TOU billed customers, and then different business processes for establishing the billing process for other rate classes. Using the AMI network will allow standardization of processes which will reduce training requirements and simplify troubleshooting when problems occur.
- **Standardization of Data Collection Process:** In today's environment, IESO MDM/R TOU billing customers are collected using AMI infrastructure, while other rate classes may be manually read and others collected via dedicated phone lines or cellular modems. Considering the data collection costs, as well as the administration of

[7] Should NBHDL determine that auto-push would provide benefits for meters currently deployed, auto-push can be configured using FlexNet utility through a site visit. Benefits include acquisition of kVa demand (for example).

multiple business processes to facilitate billing, will contribute to a positive business case for the solution which leverages existing infrastructure and business processes.

- **Available Data:** With the AMI solution, billing quantities are collected automatically, eliminating the more expensive data collection costs for manually-collected data. In addition to the billing information, the AMI solution does provide alarm/event information and instantaneous reads for some quantities that are useful from an engineering analysis perspective. By using the AMI then, the LDC is able to make use of existing business processes (i.e., available for use with deployed AMI meters) that improve asset management (e.g., transformer loading), the ability to ensure "Conditions of Service" are met (e.g., high/low voltage reporting), improved outage and restoration management, and volt/VAR optimization.
- **Enhanced Services:** By using AMI meters that collect granular load profile information, existing – or new – customer service offerings such as Web presentment of usage data becomes possible.
- **Conservation and Demand Management:** An enhanced service that requires special consideration; by using the AMI network, these rate classes can be included in any CDM programs that are currently restricted to customers with technology that is compatible with the AMI network, such as Zigbee communication to In Home Display devices, load shedding programs managed via AMI radio communication, etc.
- **Security (Encryption):** With v3.1, the deployment of encryption becomes practical. This would give NBDHL confidence that a standard level of security is deployed across the majority of their meter population.

A Metering Capital Plan which embraces the use of the AMI network allows NBHDL to take advantage of these benefits – some of which will be realized through optimized internal processes, and some of which enable enhanced customer service.

3.2.2 Develop a New "Standard" Specification for Residential Meters

With the imminent ability to encrypt the network, providing the desired level of security for deploying remote disconnect meters, the incremental cost of these meters should be considered alongside the cost of a truck roll.

With the HAN functionality that becomes available with RNI v3.1, the incremental cost of a Zigbee communication board should be considered alongside the CDM programs that NBHDL could begin to offer their customers.

With these options in mind, NBHDL could consider creating a new standard for their residential meters. All new meters could be purchased with the Zigbee boards and remote disconnect switches. Purchasing these meters does not imply "stranded assets." The new meters could be deployed strategically:

- Residential meter replacements will continue to occur due to the failure of assets. On average, NBHDL replaces 10 meters per month, an annual average of 120 or more (somewhat weather dependent). As these meters are replaced, they could be replaced with the new standard, if no other residential smart meters were available. Having this meter in place will eliminate the possibility of a truck roll, should the account ever request participation in a CDM program requiring Zigbee communication, or disconnect for any reason.
- For accounts where non-payment disconnect service orders are assigned, replace the old meter with the new specification during the disconnect process. This saves the truck roll for the reconnect and any future disconnect/reconnect processes, as well as provides the customer with the ability to join any CDM programs that require Zigbee communication with the home. Generally speaking, a single truck roll will cover the incremental cost of the remote disconnect switch, so the reconnect process saves NBHDL the money for the switch, and any subsequent truck rolls to this premise contribute to a positive business case. In addition, the old meter can be re-used for the replacement of non-functioning TOU meters, where there is no expectation for future disconnects.

- For customers that request participation in CDM programs, a meter replacement will be required,[8] so replacing the meter with the Zigbee-enabled meter with remote disconnect switch provides security against any future truck rolls to the premise.

3.2.3 Develop a New "Standard" Specification for Commercial Meters

As seal periods expire, NBHDL will need to replace meters. Now that the Sensus network provides the opportunity to collect multiple channels of load profile data over the air, there is opportunity to leverage the existing Smart Meter network as the communication backhaul for multiple classes of customers. In addition to using the Sensus system for communication – and therefore eliminating the cost of phone lines for MV90 meter –this strategy also reduces the requirement for outsourced data collection and validation services

In addition to the cost savings, having a standard meter specification simplifies the procurement, inventory management process, and the training of field staff as it relates to meter programming.

A result of this transition is that NBDHL will be making a capital investment in technology, which should result in a reduction in spending on operations and maintenance. This is because meter types like what have been labelled as "kVa" meters in our analysis are meters that physically meter a single quantity – in this case kVa demand. When one application no longer requires this type of metering, and another customer is found that does require the metering, truck roll costs are incurred to move meters around in order to re-use assets and minimize the costs required to purchase meters. The transition being proposed will result in a reduced need for the efforts involved in managing inventory, and organizing field staff for the re-deployment of existing assets. The following strategy will simplify this model by utilizing meters with functionality that will apply to multiple rate classes, reducing the need for expensive truck rolls as accounts change hands.

[8] Assuming that NBHDL embraces Zigbee-enabled CDM programs.

Section 4: Available Meters

The benefits of a strategy that leverages the existing AMI infrastructure has been detailed from a technology perspective. In addition to the standardization of inventory and the positive business process implications that result from using AMI, there are also regulatory considerations that result from the OEB's stated goals for enabling "behind the meter" applications to increase customer service applications, as well as the proposed amendments to the Distribution Service Code, which would result in the deployment of metering technology suitable for billing commercial class customers using data collected via the AMI infrastructure.

This section will provide additional detail on the functionality that becomes available with v3.1 of the RNI, for the purpose of comparing existing meters with those that are available for use on the existing AMI network.

4.1 Single Phase Applications[9]

Existing residential (and GS<50) smart meters can be used to collect kWh and peak kW data. For this meter population then, single phase iCon-A meters, can be used. There are a couple of considerations:

- Strictly speaking, the interval data that is collected by the supervisory message, is interval data that has been created by subtracting consecutive register reads. This is, technically speaking, different than acquiring true load profile data from the ANSI tables within the meter. The current meters do not access the ANSI tables that contain the load profile data – true load profile data is created by counting pulses; a cumulative total.
- In order to reliably collect the kW peak demand, NBDHL would be advised to activate the auto-push function. The auto-push function will deliver kW and kVa peak demand in a single message delivered after midnight each morning. The meter is configured to push this message out between either midnight and 4 a.m. or midnight and 8 a.m. (i.e., these are the common configurations; the setting is configurable). This setting would be created through collaboration with Sensus to ensure the highest reliability of the data collection process.

For applications where more data than kWh load profile and kW/kVa peak demand are required, new meters will be required. With v3.1, purchasing ESM meters is now possible. With the standard Supervisory Message (SM) the packet contains the most recent "top-of-hour" register read, approximately 11 hours of delta values (effectively interval data, derived by subtracting consecutive "top-of-hour" register reads, as each hour passes), the peak kW demand (since last reset), voltage information (min/max/average calculated over an hour long sample period) and some alarm/event information. This information is all maintained on the communication board. In contrast, the ESM packet contains information that is acquired from the ANSI tables that exist under the metrology "seal." While the SM could only create messages with a single channel of load profile data, the ESM packet is capable of carrying multiple channels of load profile information, in addition to the other quantities which are also found in the SM (peak kW, voltage, alarm/event information, etc.).

However, if this information meets the requirements, there is an advantage to using these meters, as the inventory management, synchronization processes and data collection functions are all standardized.

[9] For the purposes of this document, Sensus AMI meters refers to any meter that is deployed with a Sensus communication module, which allows meter data to be collected over the AMI network. For residential meters, NBHDL has deployed Sensus meters with Sensus communication modules, and for General Service customers, NBHDL has deployed Elster and GE meters with Sensus communication modules. For convenience, these will all be referred to as Sensus meters.

NOTE: Util-Assist provides information throughout this document that can be used to create a "holistic" strategy for the AMI technology solution. It is understood, however, that the more specific requirement for this document is pertaining to GS>50 meters. Information in some previous sections regarding single phase metering is provided for NBHDL's benefit, so that the impacts of the new RNI upgrade are well understood, not solely for polyphase applications, but also for their single phase TOU meter population. The following sections concentrate more specifically on the polyphase applications, and the suggested migration path to strategically transition NBHDL from the existing non-smart meters, to technology which can provide benefits beyond the automated collection of billing information.

Polyphase Applications

Existing (i.e., non-ESM) smart meters can be used to collect kWh and peak kW data. For this meter population then, polyphase A3RL meters can be used. There are a couple of considerations:

- The interval data that is collected by the supervisory message is interval data that has been created by subtracting consecutive register reads. This is different than acquiring true load profile data from the ANSI tables within the meter. The current meters do not access the ANSI tables which contain the load profile data – true load profile data is created by counting pulses; a cumulative total.
- In order to reliably collect the kW peak demand, NBDHL would be advised to activate the auto-push function. The auto-push function will deliver kW and kVa peak demand in a single message delivered after midnight each morning. The meter is configured to push this message out between either midnight and 4am or midnight and 8am (i.e. these are the common configurations, the setting is configurable). This setting would be created through collaboration with Sensus to ensure the highest reliability of the data collection process.
- If NBDHL requires more data than is able to be collected through the SM and auto-push functions, then ESM functionality can be used. When selecting ESM meters, NBDHL should understand that new meters will be required. Existing meters cannot be reprogrammed for use. This is because there are firmware requirements that result in the need for new meters.

4.2 Polyphase Meters Available with Sensus Communication Modules

The following chart shows the polyphase meters that are currently available with Sensus communication modules, making them candidates for use in the NBDHL strategy, as the strategy is centered on meters that can be used with the deployed AMI infrastructure.

Meter	SM	Auto-Push	ESM	SnapShots	Harmonics
Elster A3RL	✓	✓	✓	✓	✗
Elster A3RAL	✓	✓	✓	✓	✗
Elster A3QL	✓	✓	✓	✓	✓
GE kV2c	✓	✓	✗	✗	✗

In the chart above:

- SM = Supervisory Message; includes kWh register reads, intervals, voltage and some alarm/event information
- Auto-push = provides the peak demand since last reset for kW and kVa (assuming the meters are properly configured)
- ESM = Enhanced Supervisory Message; includes true Load Profile information for multiple channels, voltage, snapshot reads and some alarm/event information
- Snapshots = Instantaneous reads taken at the time of ESM transmission, included as part of the ESM transmission
- Harmonics = advanced metering measurements

4.2.1 Note Regarding Harmonics

It is important to understand that while the A3QL meter is capable of measuring harmonics, at this time the AMI network is not capable of collecting the data. For the purposes of installing meters for collection of information via the AMI infrastructure in order to realize the cost benefits of eliminating truck rolls, and ancillary communication technologies such as phone lines and/or cellular modems, the A3QL meter should *not* be considered an option at this time.

Said differently, the A3QL does provide a viable metering option for NBDHL if there are installations that require the measurement of harmonics; however, these installations should be performed with the understanding that additional information will not be collected over the network.

The A3RAL and the A3QL are both 4 quadrant meters, and from the data collection perspective, the AMI network is capable of collecting the identical information from *both* the A3RAL and the A3QL. For this reason, combined with the understanding that the A3RAL is a more cost-effective meter given the functionality, the A3QL meter is not considered in the following deployment strategy which is constructed around the installation of meters which meet the requirements regarding the Unit of Measure that is required for billing.

4.2.2 GE Meters with Sensus Communication Modules

The GE kV2c meter is the only meter available that is suitable for 600V applications. Unfortunately, the GE meter is not yet Measurement Canada approved for ESM. Therefore the only application that NBDHL can install GE meters on (assuming the goal is to collect data over the AMI network), is an application where kWh interval data and kW and kVa peak demand are all that is required for billing. Existing meters can be used to collect this data for these applications; however, a truck roll will be required to configure the meter for auto-push to collect the kVa peak demand.

4.2.2.1 Risk Identified for 600V Applications

This class of customer is identified as a risk with the strategy being proposed, since the GE kV2c meter cannot be used for ESM. Utilities looking to use the Sensus AMI network to collect ESM data, will need to wait for Measurement Canada approval, which is expected sometime in 2015. If NBDHL has meters where seal expiry requires meter replacement before then, NBDHL will need to determine a strategy.

Section 5: Proposed Replacement Meters

5.1 Existing Meters

NBHDL provided Util-Assist with a CIS extract which provided Meter Inventory information for analysis. The following table shows a summary of meter counts alongside the billing requirement:

Category	Billing UOM	Meter Count	Metering Requirement for Customer Class
A	kVa	5	Measuring kVa demand is the only function performed by these meters. The meters are moved (physically) to address requirements. In the future these meters would be made redundant by a strategy which would see a single meter that fulfills the requirements of multiple physical.
B	kWh	52	These non-smart meters are installed at locations which were previously GS>50. These customers no longer meet the requirements for this rate class, and Smart Meters have been ordered for installation.
C	kWh-kW	256	A single channel of Load Profile data along with a monthly peak kW demand meets the current billing requirement. The suggested strategy will result in meters which measure multiple channels of Load Profile; polyphase AMI meters which measure 1 channel of Load Profile do not exist.
D	kWh-kW-kVa	128	To replace the meters currently being used for this rate class, measurement of two load profile channels (kWh, kVah) is required. A3RAL meters are suggested for this class of customer. In addition to load profile data the monthly peak for both kW and kVa is required for billing.
E	kWh-kW-kW77 -kVa-kVa77	93	The Metering requirement for this class of customer is identical to Category D, with the added requirement that the load profile information is used to determine a peak demand value for kW and kVa for between the hours of 7am and 7pm. Util-Assist would suggest working with the ODS provider to fulfill this requirement through an existing billing interface.
	Total:	534	

5.2 Category A (kVa Meters)

As per the chart above, measuring kVa demand is all that these meters are required for. In the strategy being proposed, kVa demand would be a function that is available in multiple meters that can be collected via the Sensus AMI network:

Available Meters			
A3RL ✓	A3RAL ✓	A3QL ✓	GE kV2c ✓

Assuming that the installations are polyphase in nature, the A3RAL would be suggested as the replacement for this meter type. While the A3RL meter will meet base requirements, the price difference between A3RL and A3RAL meters is not significant. However, the benefits associated with simplified inventory management, and the saved costs from reduced truck rolls to move meters as customers change rate classes, is considered significant, and therefore the A3RAL meter is suggested.

In contrast, a metering strategy which does not include the use of the AMI as the communication medium would need to include (for example) costs associated with data collection infrastructure (i.e. modems and phone lines) and the integration work required to move the acquired data into the existing business processes for VEE and billing.

5.3 Category B (kWh Meters)

As per the chart above, measuring kWh is all that these meters are required for. In the strategy being proposed, multiple polyphase meters are available that can be collected via the Sensus AMI network:

Available Meters			
A3RL ✓	A3RAL ✓	A3QL ✓	GE kV2c ✓

Again assuming that the installations are polyphase in nature, and that more data than kWh would benefit the LDC, the A3RAL would be suggested as the replacement for this meter type. Again, while the A3RL meter will meet base requirements, the price difference between A3RL and A3RAL is justified by the simplified inventory management, and the saved costs from reduced truck rolls to move meters as customers change rate classes.

5.4 Category C (kWh-kW meters)

Per the chart above, the metering requirements will be met by the A3RAL meters. In addition to meeting the current billing requirements, when configured for ESM the meter will provide more meter data than is required for billing by providing the snapshot reads that can be configured. By collecting and storing this data in the ODS for analysis, NBDHL will begin to realize the same benefits as for their residential meter population; benefits such as standardized sync processes, standardized data collection, standardized VEE and a single storage system allows NBDHL to begin developing advanced analytics (i.e., transformer loading reports, high/low voltage, etc.).

Available Meters			
A3RL ✓	A3RAL ✓	A3QL ✓	GE kV2c ✓

5.5 Category D (kWh-kW-kVa meters)

For this meter population, Util-Assist proposes using A3RAL meters. If NBDHL wants to measure both kWh and kVah for this customer class, and if there are customers where both the delivered and received energy is required, then four channels of load profile data will be required. That configuration would require four channels of load profile, and the A3RAL is the most cost-effective meter provided by Sensus that can accommodate those requirements. In addition to meeting the current billing requirements, when configured for ESM the meter will provide more meter data than is required for billing by providing the snapshot reads that can be configured.

Available Meters			
A3RL ✓	A3RAL ✓	A3QL ✓	GE kV2c ✗

5.6 Category E (kWh-kW-kW77-kVa-kVa77 Meters)

For this meter population, Util-Assist proposes using A3RAL meters. If NBDHL wants to measure both kWh and kVah for this customer class, and if there are customers where both the delivered and received energy is required, then four channels of load profile data will be required. That configuration would require four channels of load profile, and the A3RAL is the most cost-effective meter provided by Sensus that can accommodate those requirements. In addition to

meeting the current billing requirements, when configured for ESM, the meter will provide more meter data than is required for billing, by providing the Snapshot reads that can be configured.

Available Meters			
A3RL ✓	A3RAL ✓	A3QL ✓	GE kV2c ✗

5.7 MV-90 Metering

While the scope of this report is to provide a strategy for NBHDL's GS>50 meters, Util-Assist has endeavoured to provide a holistic approach by providing information regarding single phase meters, such as the suggestion to create a standard meter specification for future orders that includes remote disconnect and Zigbee communication modules to maximize the value of the AMI network by minimizing future truck rolls. Likewise, for MV-90 metering, we believe that NBHDL should consider using Sensus AMI meters for any rate class – including those metered by MV-90 meters today – for which the data required can be effectively collected.

Available Meters			
A3RL ✗	A3RAL ✓	A3QL ✓	GE kV2c ✗

If NBHDL can modify the business processes that exist today for MV-90 metered accounts such that Sensus AMI meters will meet the requirements[10], there is the potential for further cost savings. For example: with an average annual cost of more than $10,000, there is financial incentive to further explore the possibility of eliminating the requirement for the MV-90 system by replacing existing MV-90 meters with Sensus AMI.

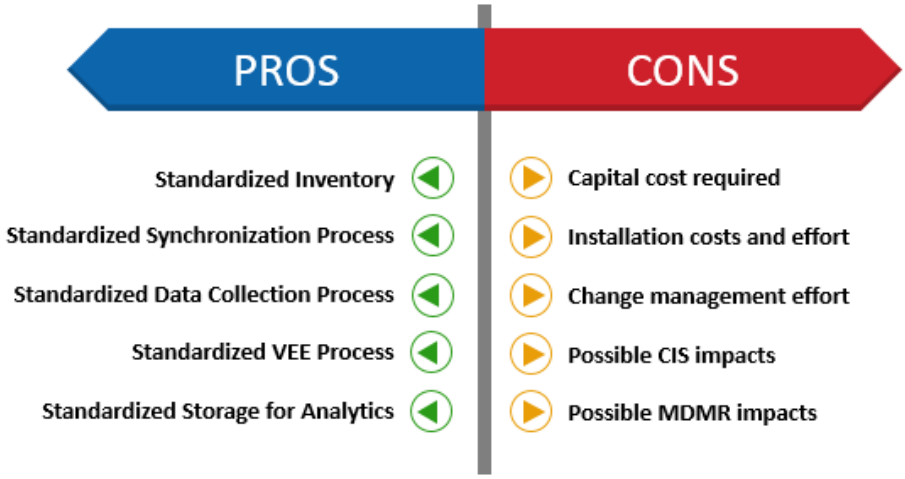
Costs	2012	2013
License / Data Collection	$ 6,223.07	$ 6,409.77
Training	$ 4,000.00	$ 4,000.00
Total:	$ 10,223.07	$ 10,409.77
Average Annual Cost:	**$ 10,316.42**	

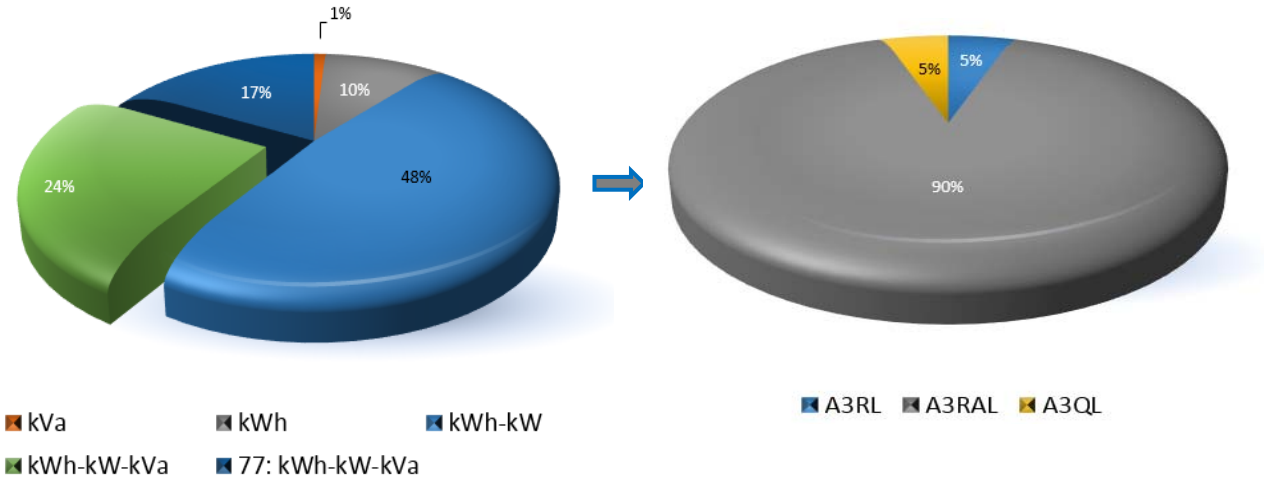
[10] Requirements would include effective data collection, provision of data to CIS for billing, provision of data to settlement systems, and any other back office functions that MV-90 currently fulfills.

5.8 Summary

For the existing polyphase metering applications, Util-Assist suggests transitioning to the A3RAL meters, which can be collected over the Sensus AMI network and with the v3.1 RNI upgrade, will be capable of collecting more data than the currently deployed meters, allowing NBHDL to leverage existing infrastructure to implement simplified processes for additional rate classes.

One of the business drivers is the simplified inventory management process that will result from this endeavour. The following diagram demonstrates how several different types of meters are currently being managed and that through this smart meter deployment, the number of meter types will be reduced, while the business process management of information will be simplified at the same time.





In reality, the pie chart on the right could be simplified even further as Util-Assist is suggesting only A3RAL meters for the GS>50 meters captured by the chart showing the existing meter population. We have, however, incorporated into this chart the possibility that NBHDL may choose to purchase a small percentage of A3QL meters in the event that some additional information such as the measurement of harmonics is required.[11] NBHDL does have a small number of installations that are currently metered by ION meters – an advanced metering solution. As the GS>500 meters were not in the scope of this report, some meters and their existing requirements were not investigated in depth. While it is felt that the A3 meters can solve the majority of NBDHL's general service metering requirements, there may be a need to retain some higher end metering products, which is captured by the A3QL "slice" of the total meter population.

[11] We have also captured the fact that a small number of A3RL meters have already been deployed.

Section 6: Detailed Analysis of Proposed Transition

6.1 Assumptions Made During the Analysis

Within the analysis, the following assumptions were made:

Provincial Tax	HST has NOT been included in the calculations.
Warranty	An average cost for the meter types is calculated to estimate warranty costs.
Meter Failure	A conservative estimate of 0.75% failure is used to generate some ongoing costs.
Maintenance	In addition to meter failures, 1% of meters are expected to require site visits.
Reverification	Costs for MC reverification have NOT been added, as this is a current cost.
Network	NO additional costs for TGBs are anticipated at this time (pending contract).
Upgrades	Costs to upgrade 211 meter bases to 3 element installation is included.
Inflation	A 2.5% per year increase in costs (labour, meters) is included in the calculations.

6.2 Costs for Meters

Util-Assist contacted both Elster and Sensus for budgetary pricing for the A3 meters with Sensus communication modules. Preliminary/budgetary pricing information indicates that NBDHL would benefit from a competitive procurement process.

The A3QL price may require confirmation; the Elster quotation includes iterative pricing, and the pricing for the A3QL may not include 4 quadrant metering. Util-Assist's suggestions around using the A3RAL as opposed to the A3QL are based upon the idea that both meters provide 4 quadrant metering and that the Sensus communication of information does not include any of the power quality measurements provided by the A3QL.

The average total price is calculated by applying the average meter price to the different meter categories in addition to the installation costs for each meter, and then dividing by the total meters.

By applying the average cost for each meter[12] to the metering requirements and the average install cost to the metering requirements, we can see the total estimated costs for the metering requirements:

[12] Util-Assist has provided pricing for both A3RL and A3RAL meters. However, averages are calculated using A3RAL meters only.

Meter	Sensus Cost/Mtr	Elster Cost/Meter	Average Price
A3RL	$424.00	$425.00	$424.50
A3RAL	$583.00	$534.92	$558.96
A3QL	NA	$438.40	$438.40
Average Total Price		$731.45	

Meter Costs			
Category	Cost/Mtr	Quantity	Cost
A	$558.96	5	$2,794.80
B	$558.96	52	$29,065.92
C	$558.96	256	$143,093.76
D	$558.96	128	$71,546.88
E	$558.96	93	$51,983.28
	Total:	534	$298,484.64

	Category	KYWS Covert to 3EI	KWPS Covert to 3EI	Electronic Meter Work
Test Block	Material	$85.90	$85.90	$42.95
Box	Material	$500.00	0	0
Mounting of Box & Conduit by	Contractor	$170.00	0	0
Metering Config. Repair Time	Labour	$432.00	$432.00	$432.00
Miscellanous Material	Material	$23.70	$23.70	$23.70

6.3 Seal Expiry (the "Meter Change Schedule")

The following table shows a summary of meter counts by the seal expiry date:

Deployment Schedule								
Category	<2015	2015	2016	2017	2018	2019	>2019	Checksum
A	2			2		1		5
B	43	9						52
C	14	138	60	42		2		256
D	35		16	10	23	44		128
E	7	1	2	10	21	52		93
Total:	101	148	78	64	44	99	0	534

6.4 Costs per Year

By applying the average cost per meter to the "meter change schedule" we can determine the meter costs per year:

Meter Costs By Year								
Billing UOM	<2015	2015	2016	2017	2018	2019	>2019	Checksum
A	$1,117.92	$0.00	$0.00	$1,203.88	$0.00	$632.41	$0.00	$2,954.21
B	$24,035.28	$5,156.41	$0.00	$0.00	$0.00	$0.00	$0.00	$29,191.69
C	$7,825.44	$79,064.89	$35,235.44	$25,281.43	$0.00	$1,264.82	$0.00	$148,672.03
D	$19,563.60	$0.00	$9,396.12	$6,019.39	$14,190.71	$27,826.13	$0.00	$76,995.94
E	$3,912.72	$572.93	$1,174.51	$6,019.39	$12,956.73	$32,885.42	$0.00	$57,521.71
Total:	$56,454.96	$84,794.23	$45,806.07	$38,524.08	$27,147.44	$62,608.78	$0.00	$315,335.57

6.5 Electric Meter Asset Strategy Summary

Electric Meter Asset Strategy Summary	Meters TOTAL	Meters Total NPV
Meter Capital Investments		
Electric Meters & Modules	$321,642.28	$292,470.74
Installation Costs - Regular Labour	$76,765.94	$69,803.61
AMI Network Infrasctrucutre (TGB's)	$0.00	$0.00
AMI Head End System Infrastructure (RNI)	$0.00	$0.00
Meter Base Repair - Material	$64,949.11	$60,660.75
Meter Base Repair - Contractor	$14,912.40	$13,928.92
Meter Base Repair - Labour	$92,975.04	$86,843.30
Cost of Funds on Capital	$0.00	$0.00
MDM / ODS Capital Investments		
Hardware	$0.00	$0.00
Software	$0.00	$0.00
Integration (Configuration & Training)	$0.00	$0.00
CIS / Customer Service Capital Investments		
Hardware	$0.00	$0.00
Software	$0.00	$0.00
Integration (Configuration & Training)	$0.00	$0.00
Total Capital Costs	**$571,244.77**	**$523,707.32**
Average Capital Cost Per Meter	**$1,069.75**	**$980.73**
Average Cost Per Meter Per Month (Based on 15 Year)	**$5.94**	**$5.45**
AMI O&M		
Maintenance	$29,107.95	$22,721.72
Labour to Run System	$3,715.03	$2,933.28
MDM / ODS O&M		
Maintenance	$0.00	$0.00
Labour to Run System	$0.00	$0.00
CIS / Customer Service O&M		
Hardware Maintenance	$0.00	$0.00
Software Maintenance	$0.00	$0.00
Labour to Run System	$0.00	$0.00
Finance / Corporate Services & Other O&M		
Cost of Funds on Capital (Total = sum over 10Yrs on a 20Yr Loan)	$61,368.59	$49,413.42
Total O&M Costs Based on NPV	**$94,191.57**	**$75,068.42**
Average O&M Cost Per Meter Per Month	**$1.470**	**$1.171**
Total Costs Per Meter Per Month (Based on 10 Yrs)	**$7.413**	**$6.620**
Totals	**$665,436.34**	**$598,775.75**

Annual rate to recover costs	**$88.96**	**$79.44**

Electric Meter Asset Strategy Summary				
	<2014	2015	2016	
Meter Capital Investments				
Electric Meters & Modules	$57,584.06	$86,490.12	$46,722.19	$3
Installation Costs - Regular Labour	$13,743.51	$20,642.48	$11,151.12	$
AMI Network Infrasctrucutre (TGB's)	$0.00	$0.00	$0.00	
AMI Head End System Infrastructure (RNI)	$0.00	$0.00	$0.00	
Meter Base Repair - Material	$12,242.94	$30,461.32	$12,440.37	$
Meter Base Repair - Contractor	$2,810.96	$7,003.59	$2,858.61	$
Meter Base Repair - Labour	$17,525.65	$43,665.59	$17,822.69	$1
Cost of Funds on Capital	$0.00	$0.00	$0.00	
MDM / ODS Capital Investments				
Hardware	$0.00	$0.00	$0.00	
Software	$0.00	$0.00	$0.00	
Integration (Configuration & Training)	$0.00	$0.00	$0.00	
CIS / Customer Service Capital Investments				
Hardware	$0.00	$0.00	$0.00	
Software	$0.00	$0.00	$0.00	
Integration (Configuration & Training)	$0.00	$0.00	$0.00	
Total Capital Costs	**$103,907.12**	**$188,263.10**	**$90,994.99**	**$7**
Average Capital Cost Per Meter				
Average Cost Per Meter Per Month (Based on 15 Year)	**<2014**	**2015**	**2016**	
AMI O&M				
Maintenance	$39.00	$98.56	$697.83	$
Labour to Run System	$0.00	$68.72	$173.65	$
MDM / ODS O&M				
Maintenance	$0.00	$0.00	$0.00	
Labour to Run System	$0.00	$0.00	$0.00	
CIS / Customer Service O&M				
Hardware Maintenance	$0.00	$0.00	$0.00	
Software Maintenance	$0.00	$0.00	$0.00	
Labour to Run System	$0.00	$0.00	$0.00	
Finance / Corporate Services & Other O&M				
Cost of Funds on Capital (Total = sum over 10Yrs on a 20Yr Loan)	$1,128.37	$2,823.16	$3,738.69	$4
Total O&M Costs Based on NPV	**$1,167.37**	**$2,990.44**	**$4,610.16**	**$**
Totals	**$105,074.50**	**$191,253.53**	**$95,605.15**	**$7**

Section 7: Summary

7.1 Conclusion

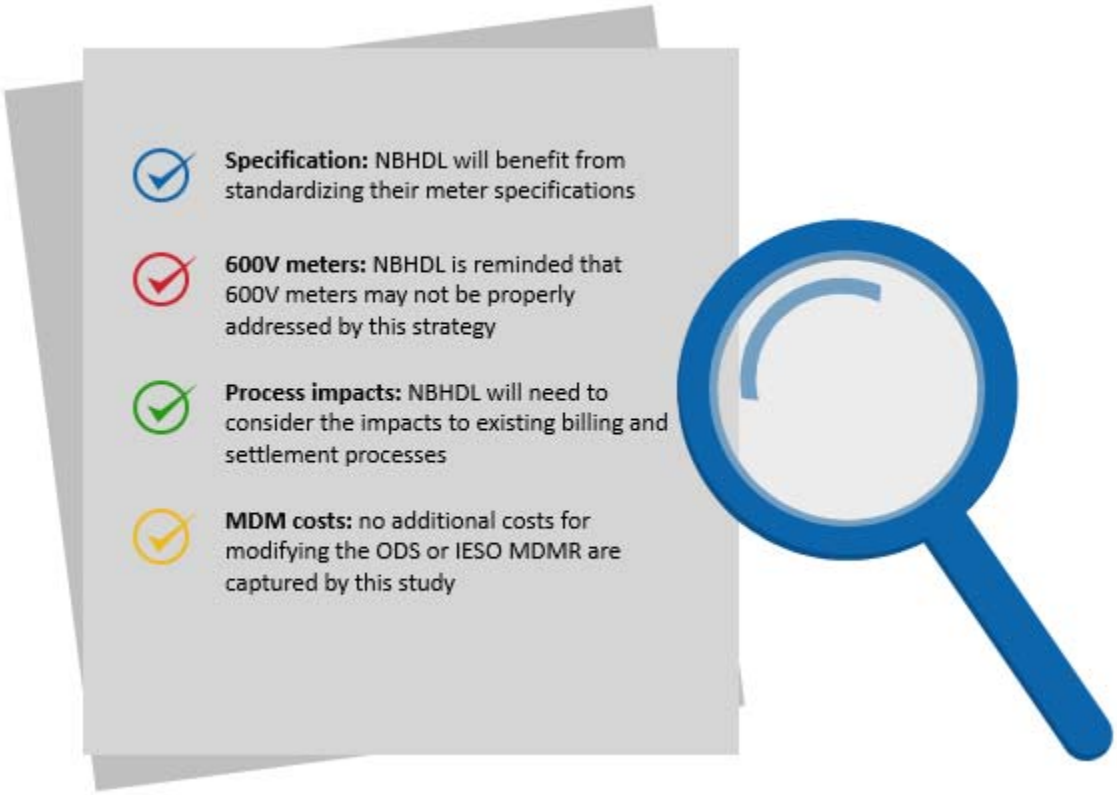
Util-Assist has provided a Metering Capital plan that considers the functionality of existing meters, the possibilities available through system upgrades, and the requirements placed upon utilities by the regulators in order to create a holistic approach to replacing metering assets over the next five years.

The assessment includes analysis of the financial impacts to this strategy by capturing the costs of the meter assets as well as the labour required to initially install the upgraded meters and the ongoing costs to maintain the new meters.

The proposed plan will meet the needs of the regulators[13] as well as the future plans for NBHDL's Smart Grid by leveraging the AMI infrastructure to collect information from smart meters – smart meters deployed across the existing residential *and* general service populations. Through this holistic approach, the operational benefits already witnessed across the residential population will begin to be realized for the additional rate classes. Business processes for the synchronization of systems and the VEE of meter data will be simplified by standardizing the meter population to one in which the data can all be collected by a single system.

7.2 Discussion Points

NBHDL will want to consider some of the points raised through this document as they begin to implement this strategy for their General Service population.



[13] This is a reference to the proposed amendments to the DSC as discussed in Section 2.3 of this strategy document.

Appendix P – Capital Projects Table

Appendix P – Capital Projects Table

- list of projects and descriptions for the forecast period (with total capital cost of material capital expenditures)

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
System Renewal:							
Transformer Purchases - Various Jobs	353,556	306,734	167,495	154,512	262,330	284,135	1,528,761
Major Betterment Projects							
Mercer Drive	293,011	3,255	165	-	-	-	296,431
O'Brien Street - 44kV Line Extension	210,978	-	-	-	-	-	210,978
Norman Avenue	13,779	2,296	-	916	286,402	-	303,393
Birch's Road - move 12kV to new pole line	3,156	232,480	32,287	1,251	-	-	269,175
Bond Street	-	-	-	61	142,287	-	142,348
Giroux Street	-	-	-	198,603	3,631	-	202,234
Turret Complex - Madelena	-	-	-	105	-	529,572	529,678
Turret Complex - Melina Close	-	-	-	105	-	293,306	293,411
Turret Complex - Lake Heights	-	-	-	210	190,380	-	190,590
Turret Complex - Wickstead	-	-	-	105	-	436,521	436,626
Voltage Conversion Projects							
Timmins & Nipissing - Upgrade Polelines for MS19	165,703	-	-	-	-	-	165,703
King Street West	-	-	-	959	167,431	-	168,390
Duke Street	111,138	103,747	-	-	-	-	214,885
Victoria Avenue	12,649	140,365	6,925	-	-	-	159,938
Queen Street, including 3PH	-	1,285	1,870	856	146,132	-	150,143
Sixth Avenue	-	65,079	234	-	-	-	65,312
Old Callander Road	-	34,240	712,070	(2,452)	-	-	743,858
Graham Drive	-	141,589	80,380	12,988	-	-	234,958
Drew Street	-	5,669	133,864	94,589	-	-	234,121
6F4 Area - Preparation for Voltage Conversion	-	-	43,382	56,580	-	-	99,963
Cassells Street	-	-	9,229	141,990	-	-	151,219
MS # 5 - 22kV & Primary Removals	73,519	35,317	37	-	-	-	108,873
Worthington Street	305,617	562,246	93,460	4,606	1,817	-	967,746
NB TS Egress - including Angus	-	245,370	17,324	-	-	-	262,694
Angus Street	-	-	184,627	49,089	-	-	233,716
6F1 - Conversion							
Brookes Street	-	-	-	363	62,811	-	63,174
Hardy Street	-	-	-	251	90,935	-	91,187
Maher Street	-	-	-	242	96,357	-	96,599
Laurier Street	-	-	-	83,311	-	-	83,311
Franklin Street	-	-	-	1,287	223,400	-	224,688
McGaughey Street	-	-	5,350	132,323	365	-	138,039
Hammond Street	-	-	10,544	187,745	52,271	-	250,560
Metcalfe Street	-	-	651	43,373	356,859	-	400,883
Chippewa Street	-	-	-	189,177	-	-	189,177
MS21 Egress Work	-	-	-	112,820	365	-	113,184
Fourth Avenue	-	-	-	1,400	-	147,188	148,588
Fifth Avenue	-	-	-	639	-	154,232	154,871
Fraser South - 12kV	-	-	-	-	-	116,034	116,034
McIntyre Street	-	-	-	1,050	-	452,969	454,019
Ferguson Street	-	-	-	-	636	278,780	279,416
First Avenue	-	-	-	-	814	136,126	136,941
Regina Street	-	-	-	-	785	81,248	82,032
Main Street West	-	-	-	-	422	215,217	215,639
Sherbrooke Street	-	-	-	-	-	112,822	112,822
Second Avenue	77,510	113	126	-	-	-	77,748
Pinewood Voltage Conversion - Civil & Prep	1,571,932	2,913	7,050	-	-	-	1,581,895
Pinewood Voltage Conversion - Electrical	1,140,594	217,726	18,053	-	-	-	1,376,374
Minor Betterment Projects	69,504	89,896	120,395	251,724	86,676	106,591	724,787
Porcelain Switch & Insulator Replacement	65,164	21,694	100,696	8,900	101,671	-	298,125
Asset Management	40,290	182,290	1,986	27,752	24,066	-	276,383

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
System Renewal:							
Distribution Substation Construction							
MS# 19 - Replacement MS# 5	68,468	60	20,191	-	-	-	88,718
MS# 20 - Replacement MS# 12	68,599	2,058,742	40,126	-	-	-	2,167,467
MS# 21 - Replacement of MS# 6	-	-	73,962	1,312,184	31,907	-	1,418,052
MS# 22 - Replacement of MS# 9	-	-	-	-	679,396	1,781,297	2,460,693
Distribution Substation Improvements & Rehabilitation							
MS# 8	194,134	14,480	-	-	-	-	208,615
MS# 14	7,819	160,718	104,375	-	-	-	272,911
MS# 15	-	-	-	-	226,416	-	226,416
MS# 16	-	-	9,492	798,829	84,376	-	892,696
Distribution Substation Transformers							
8T1 Failure - December 2008 - Insurance Proceeds	(92,392)	-	-	-	-	-	(92,392)
17T1 Failure - October 2010	62,526	262,229	25,727	333	-	-	350,815
13T2 Failure - October 2011	-	-	186,034	11,568	-	-	197,602
MS# 1 - Transformer Replacement - T1	-	-	-	-	278,506	-	278,506
MS# 13 - Transformer Replacement - T1	-	-	-	-	-	271,470	271,470
Distribution Substation SCADA							
SCADA - implementation of new radio system for SCADA	-	-	2,835	1,440	368,822	-	373,097
Misc. Projects <$65k on individual project basis*	347,505	164,621	102,806	115,251	200,640	71,897	1,002,721
Sub-Total, System Renewal	**5,164,759**	**5,055,154**	**2,313,746**	**3,997,037**	**4,168,904**	**5,469,405**	**26,169,004**
System Service:							
Highway 11 North - Voltage Regulator Installation & Metering Upgrade	-	-	90,347	-	-	-	90,347
Copeland St. - 44kV Loadbreak Switches	64,600	-	-	-	-	-	64,600
IESO Meter Installations - 44kv Metering							
Bond St., O'Brien St., 15M1/15M2 for NBTS Conversion to 44kV	137,585	103,671	3,344	1,831	-	-	246,432
Meters Installs and Upgrades - Smart Meters	111,423	100,945	43,439	62,040	15,000	15,000	347,848
Capital Infrastructure Modernization	-	-	533	263	148,141	199,213	348,151
Misc. Projects <$65k on individual project basis*							
Meters	38,028	33,544	2,760	41,352	10,000	10,000	135,683
Substations, SCADA and Misc. Projects	22,475	51,185	39,757	9,986	22,822	15,735	161,962
Major & Minor Betterment Projects	22,380	371	20,726	25,655	9,349	9,851	88,332
Feeder Conversion Projects - 5 Individual Projects <$65k/project*	-	-	-	-	1,467	123,445	124,912
18F1, 18F2, 18F3, 7F2, and 1F1							
Sub-Total, System Service	**396,490**	**289,717**	**200,907**	**141,128**	**206,779**	**373,245**	**1,608,267**
System Access:							
Transformer Purchases - Various Jobs	93,439	156,988	187,612	115,377	106,872	95,113	755,401
Major Betterment Projects							
Aerospace Park - 44kV & 12kV Line Extension	-	-	496,321	9,125	-	-	505,446
Voodoo Cres. - 12.5kV and 44kV Line Extension	-	-	130,919	83,482	-	-	214,401
Minor Betterment Projects	292,314	207,132	268,941	288,086	198,147	230,102	1,484,722
Bell FSA Project	-	-	-	459,691	744,212	-	1,203,903
Primary Services Projects	46,683	121,508	137,329	198,663	135,952	217,820	857,955
Gormanville Rd - OPP 44Kv Service & Other 44Kv Work	-	78,298	74	-	-	-	78,372
Aerospace Park - Condo Development	-	-	7,833	182,307	-	-	190,140
100 Chippewa West - Memorial Gardens	-	-	-	92,019	-	-	92,019
Thompson Park - New Primary Service	-	-	-	81,213	-	-	81,213
Secondary Services	299,563	404,425	288,463	204,301	361,792	249,365	1,807,908
Subdivisions	108,129	109,429	71,948	104,729	110,975	100,973	606,183
Road Relocations Projects					103,218	212,218	315,436
Algonquin Ave. - Cassels x Copeland	246,094	164	-	-	-	-	246,258
Front St. - McLeod x Second	161,830	-	-	-	-	-	161,830
Main St.	-	48,408	184,610	6,307	-	-	239,326
John St.	-	-	90,053	177	-	-	90,230
Misc. <$65k on individual project basis*	35,207	182,131	158,671	33,060	39,699	38,112	486,879
Sub-Total, System Access	**1,283,260**	**1,308,483**	**2,022,775**	**1,858,535**	**1,800,867**	**1,143,704**	**9,417,624**

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2015 - Total Forecast	Total by Project
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	
System Renewal:							
General Plant							
Building & General Office Upgrades, including Furniture	12,656	13,858	63,237	11,532	71,116	26,300	198,699
HVAC System	-	-	4,200	148,769	149,427	-	302,396
Generator	-	-	-	-	166,800	-	166,800
Customer Service Entrance & Department Renovation	-	154,297	149,443	-	-	-	303,740
Operations Facility Upgrades - Garage, Yard, Driveway & Warehouse	-	-	17,800	3,945	126,995	36,652	185,392
Fleet Replacement - Bucket Trucks, Radial Boom Devices & Trailers	-	289,661	137,946	12,207	100,063	370,000	909,877
Fleet Replacement - Vehicles < 3 Ton*	64,703	73,801	116,478	49,094	53,000	145,000	502,076
Work Equipment	27,751	66,985	21,427	74,019	47,000	46,151	283,332
Servers, PC, Other Hardware*	18,783	162,087	181,608	7,832	80,600	126,500	577,409
Software	22,620	69,045	88,089	116,066	172,211	21,000	489,030
Sub-Total	**146,512**	**829,735**	**780,227**	**423,463**	**967,211**	**771,603**	**3,918,751**
Contributed Capital							
Contributed Capital from Customers	(905,001)	(464,129)	(675,928)	(1,061,939)	(1,128,077)	(503,987)	(4,739,061)
Sub-Total	**(905,001)**	**(464,129)**	**(675,928)**	**(1,061,939)**	**(1,128,077)**	**(503,987)**	**(4,739,061)**
Miscellaneous	-	-	-	-	-	-	-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**7,253,969**	**36,374,585**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*	-	-	-	-	-	-	-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**7,253,969**	**36,374,585**

**Starred items above (for the 2015 Test Year) are not justified through a capital project summary. Despite the fact that these line items exceed the materiality threshold, they are comprised of a series of individual items that do not exceed the materiality threshold. Each of these items are reviewed and approved or denied on an individual item by item basis during the annual budgeting process with the exception of projects driven by customer demand (for example minor betterment projects). As such, NBHDL has not prepared bucket sum capital summaries for any of these grouped capital expenditures as the individual items in each bucket are immaterial.*

Appendix Q – Material Capital Project Summaries

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	Turrent Complex - Wickstead	16
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	Fifth Avenue Rebuild - Cassells x Wyld	26
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	McIntyre Street Rebuild - Cassells x Wyld	37
	Ferguson Street Rebuild - Princess x First	43
	First Avenue Rebuild - Fisher x Regina	48
	Regina Street Rebuild - Second x Oak	53
	Main Street West - Nipissing x Murray	57
	Sherbrooke Street Rebuild - Second x Oak	64
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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	Transformers - System Renewal			
Investment Category	System Renewal			
Project Description	This project represents the investment into distribution transformers, both overhead and underground, throughout the given year. All new transformers are brought into inventory and are included in the overall PP&E gross assets, they do not then begin to appreciate until put into service. Transformers are then assigned to different projects as required, some System Renewal, some System Access. This specific summary will deal with the System Renewal assignments. For clarity, the capital expenditures sought in this project are specific to transformers that will be put into service in 2015.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$284,135		
	Customer Contribution	$0		
	Net Capital	$284,135		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	not applicable		
	Customer Load (peak KVA)	not applicable		
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	31/12/2015		
	Expenditure Timing	Q1:	25%	$71,034
		Q2:	25%	$71,034
		Q3:	25%	$71,034
		Q4:	25%	$71,034
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The timing of transformer purchases is based on inventory levels and the renewal projects that materialize over the given year. In the System Renewal category purchases are made to cover transformer needs for the following demand sub-categories: minor betterments, voltage conversion, and major betterments. Risks involve lead times, and the award of transformer purchases to one manufacturer. The risk is mitigated by monthly transformer meetings to discuss inventory levels, inventory levels having set minimums and the fact that NBHDL belongs to a consortium for transformer purchases, making sharing of transformers an option as a last resort.			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $353,556 2011: $306,734 2012: $167,495 2013: $154,512 2014: $262,330			

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Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The requirement for transformers in all System Renewal projects.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Planned and unplanned renewal projects that require transformation.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	Transformers investments are made on an as needed basis.

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2015 Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Transformers are an integral part of the system, and investments in them are required in order to facilitate rehabilitation of the system. NBHDL, as a member of the North Easterm District Buying Consortium ("NEDBC"), tenders the procurement of transformers on a 5 year contract, and therefore purchasing alternatives are basically nonexistent over the contract.

Safety (5.4.5.2.B.2)

The purchase of transformers for renewal work does not directly address safety concerns. The actual installation of the transformers under planned and unplanned capital jobs from time to time will address transformers in poor condition and in turn may eliminate safety issues.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to the purchase of transformers.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with the successful transformer manufacturer is a daily function, from the administration of the contract, to the actual ordering and receiving of transformers, the relationship with the vendor is very important in ensuring inventory levels are always kept up to meet demand work. Tremendous coordination takes place in the award of the contract by the utilities that make up the NEDBC.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to Transformer projects.

Economic Development (5.4.5.2.B.5)

Not applicable

Environmental Benefits (5.4.5.2.B.6)

Not applicable

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CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

Category-specific requirements - System Renewal (5.4.5.2.C.a.)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

Transformer purchases are made as required, in the case of System Renewal, the transformers purchased are used to replace failed assets and/or assets that are obsolete and therefore the purchases are in line with optimization policies.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

All transformers purchased are new and therefore are in very good condition, which is expected as they are in the first year of their useful life. The new transformers will be used to replace failed assets or obsolete assets.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

This is not applicable to transformer purchases.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

This is not applicable to transformer purchases.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

This is not applicable to transformer purchases.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

This is not applicable to transformer purchases.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

Transformers are ordered when required, the purchasing of transformers is not a project, but an investment into equipment to be used as part of System Renewal projects.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

Transformer purchases have no affect on system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

Transformer purchases do not address reliability or safety factors.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

Transformers are purchased to maintain inventory and as required for system renewal projects. This section is not applicable to transformer purchases.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

This is not applicable to transformer purchases.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Project Name	**Turret Complex - Madelena**		
Investment Category	System Renewal		
Project Description	The Madelena project consists of the design and construction of new underground high voltage and low voltage infrastructure to replace existing backlot poles and underground secondary infrastructure supplying a large townhouse/condo type development located on Madelena Drive.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$529,572.00	
	Customer Contribution	$0.00	
	Net Capital	$529,572.00	
	O&M Costs (if applicable)	$0.00	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	117	
	Customer Load (peak kVA):	204.6	
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering June 2015 - Civil Construction by Contractor July 2015 - NBH Construction	
	Expected In-Service Date	Oct-15	
	Expenditure Timing	Q1: 5% 26478.6 Q2: 16% 84731.52 Q3: 67% 354813.2 Q4: 12% 63548.64	
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	There a few risks involved with the project. The first risk occurs from the requirement of completing the design by end of Q1, on this specific and two (2) other similar underground projects, so that the jobs can be tendered and awarded to a contractor as one package by the time the ground is free of frost and ready for underground work to commence. If this timeline is missed, there is the possibility that contractor pricing will increase due to lack of availability, or contractors will not be available whatsoever. This difficulty will be mitigated by proper planning and resource assignments. The second risk involves ensuring all that three (3) underground projects be issued as one cohesive package to ensure best possible and most competitive pricing. This will also be mitigated by proper planning and resource assignments. The third risk involves constructability issues. The townhouse/condos are 60 years old and working around existing underground infrastructure, hydro, gas, water, sewer will be extremely difficult. Depending on the difficulty this may affect timelines and increase costs. This will be mitigated by having the entire development area located to aid in design and having test holes possibly dug in areas with high congestion to confirm the feasibility of the designs.		

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2015 Material Capital Project Summary

Comparative Information	A comparable project in scope, size, and design to the Madelena project is the Pinewood Backlot Elimination - Phase 6 – Civil and Electrical project which involved the elimination of backlot poles and the installation of new HV and LV servicing in the city road allowance. The structure of the Madelena project will be modeled after the Pinewood project where the engineering is done upfront, then the a civil contractor is hired to install the civil infrastructure and then NBHDL completes the project by installing the electrical infrastructure. The timing of the Madelena project will also follow the timing of the Pinewood project, where civil construction starts immediately after the winter thaw to ensure the project can be completed by year end. Pinewood – Phase 6 (Civil and Electrical) 2010: $273,827 + $144,278 = $418,105 The costs differ due to the number of services included in the Madelena project, but the Pinewood project illustrates the magnitude of dollars for this type of work.
(5.4.5.2.A.fifth bullet)	
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment and therefore capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver is underground servicing that has reached it's end of life and is causing substantial O&M costs in the form of underground failures.
Related Objectives/Performance Targets	NBHDL objective 3 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Source of justification is the summary of the associated O&M costs caused by the failures and the ACA Report which indicates a significant need for underground infrastructure replacement.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver is the elimination of backlot poles and substandard secondary servicing (all servicing is tapped of one main conductor, causing a number of weak connection points in the main conductor and in the event of failure of the main conductor a number (up to 15 units) of customers experience a lengthy outage.
Related Objectives/Performance Targets	NBHDL objectives 1 and 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The source of justification is the NBHDL longstanding practice or procedural goal of eliminating backlot plant and the knowledge of substandard servicing design that is causing increased O&M costs.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. This project ranked #2 of 13 projects as identified by the Prioritization Matrix prepared as part of this DSP. Given the condition of the asset, and the significant impact this project has on O&M costs, this is the second project required by the NBHDL Capital Expenditure Plan. This, along with the specific ranks of all System Renewal projects, is further explained in Section 4 of the DSP. To ensure the elimination of significant O&M costs related to this area, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The new design will involve new loop fed primary underground supplies, which allows for improved restoration capability in the event of cable failures, as two options for supply will always be available. Overhead related primary disturbances (weather, rodents, and trees) will also no longer be a risk to system operation as the high voltage lines supplying the developments will be placed underground. This project will have a direct contribution to the reduction of O&M costs due to the number of repairs required on an annual basis to the existing underground infrastructure.
Net benefits to customers	Customers will benefit directly from increased reliability in the townhouses, as well as aesthetic benefits from the removal of unsightly backlot poles and equipment. The project will also reduce O&M spending which is a benefit to all customers.
Impact on reliability performance	Although there are a number of secondary cable faults each year, they normally only affect 5 to 15 customers at a time. Given the low number of affected customers, the overall contribution to system reliability performance is quite low. This System Renewal project should eliminate underground secondary cable faults for the first 15-20 years after installation. On top of that all servicing will be individual feeds, so in the event of a secondary cable fault only one customer will be affected instead of 5 to 15.

Project Alternatives

The ACA Report (at page #77) clearly identifies the low voltage servicing involved with this project is in need of immediate replacement. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL has decided to address this starting in 2015. NBHDL decided to identify underground replacement projects that provided immediate payback to customers and this project was one of them.

The added benefit to replacing the existing end of life underground low voltage cabling is it allows for the elimination of a backlot poleline via the installation of new underground high voltage cabling. NBHDL considered several alternatives to achieve the replacement of the underground cabling involved with this project including: i) leaving the underground supply in its current state (the 'do nothing' option); ii) replacing the underground low voltage servicing and replacing the backlot poleline with a new backlot poleline that supplies the area; and, iii) replacing the underground low voltage servicing and replacing the backlot poleline with underground high voltage cabling.

i) The current underground low voltage servicing is 50 years old and is contributing significantly to annual O&M costs. Leaving the plant as is will continue, if not increase, the trend with respect to O&M costs, and will continue to impact the reliability to the customers fed from the servicing negatively. This option is therefore not feasible.

ii) Renewal of both the underground cabling and the backlot poleline is an option, but not a practical one for NBHDL's current needs. The low voltage servicing must be addressed but rebuilding the poleline in the backlot would be contrary to NBHDL's goal of eliminating all backlot poles. It is also impractical to install poles and equipment back in a location that is currently not easily accessible and is an identified concern for customers. Rebuilding in the backlot is also a more costly initiative, as current day construction equipment cannot be utilized due to lack of access (i.e. climb poles instead of work on them from a bucket truck). This lack of access requires an increase in the labour component and contractor costs. The difficulty and significantly higher costs under this alternative make it unfeasible for the purpose of the DSP.

iii) The final option, and the option decided on by NBHDL, is the replacement of the underground low voltage servicing and the replacement of the backlot poleline with new front lot underground high voltage cabling . As mentioned earlier, NBHDL has determined that the low voltage servicing has to be replaced. This is due to the fact that the assets are currently at end of life, built under a design methodology that hasn't been used in 30 plus years, and contribute significantly to annual O&M costs. A major advantage to eliminating the backlot poleline is that trenching is already being completed for the low voltage servicing and therefore the high voltage underground cabling is implemented at a much lower cost due to the utilization of the same trench. A second advantage is the removal of 9 backlot poles, 6 backlot transformers, and 622m of backlot overhead primary from the asset base that no longer require maintenance or repair. And lastly, it helps NBHDL work towards the goal of eliminating all backlot plant. Given these advantages, both practically and financially, NBHDL has elected this option three for the project.

Safety (5.4.5.2.B.2)

Safety is not a driver for the project, although the elimination of backlot plant is always a benefit to overall safety as backlot infrastructure is commonly impeded, and much more difficult to maintain. Access issues have the potential to lead to non-standard approaches to work or work methods that are not commonly practiced. Backlot plant can also hide hazards as the poles and equipment are not easily visible to NBHDL staff or the general public.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this project is in the middle of the service territory. Regional Planning is also not applicable to this project as capacity is not changing. The project will involve a lot of coordination with the individual condo/townhouse owners, both from a design and construction standpoint. It will also involve disruption to a number of customers in the form of excavation in and around their homes. Planning and communication will be critical to minimize the inconvenience of the required disruptions.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new infrastructure will be built to current day standards, which will allow for adaptability in the future, however at this time there are no plans to enable future technological functionality. The project is also not addressing future operational requirements.

Economic Development (5.4.5.2.B.5)

The work will be contracted out and may provide temporary economical benefit in the form of employment. Aside from the construction of the project it is simply the renewal of existing servicing and therefore does not represent an opportunity for Ontario economic growth.

Environmental Benefits (5.4.5.2.B.6)

Environmental benefits are not driving the project, however, with the elimination of backlot poles, comes the elimination of tree trimming around said poles and therefore provides back a space for greening (i.e. trees can be planted back in this area when the polelines are removed). NBHDL has found that this can be a benefit, particularly in a residential area.

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The underground low voltage servicing is well past it's useful life and has consequently been repaired numerous times. This will continue to drive O&M costs if not addressed. The associated poleline that feeds the low voltage servicing is 40 plus years old and also well past its useful life. Both assets require immediate replacement and it is NBHDL's practice to relocate backlot polelines to road allowances upon renewal.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

Asset condition is very poor for the underground low voltage servicing and poor for the back lot poleline. Both of these designations are expected as the assets are past their typical life cycles.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

117 Residential Customers are impacted by the project, however failures typically only involve 5-15 customers at a time.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative impacts are not available (reliability statistics by station or feeder are not available). However, from NBHDL's knowledge of the system, some of the customers in this area experience far worse reliability than the average customer.

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SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

This project will have a high impact to the customers serviced by the existing plant planned for replacement. The impact will also be high for all customers, as the replacement of the plant will eliminate significant annual O&M costs. The project will also remove electrical apparatus from back yards, improving the private space enjoyed by the customers. Risk is low, as safety is not a major driver, and although reliability will be improved it will only be improved to the 117 customers impacted by the project.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

This project provides great value to the 117 customers impacted, in the form of increased reliability and the elimination of backlot plant. The reduction of annual O&M costs that will gained from the project is also of high value to all other customers.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on any other projects planned over the forecast period. The replacement of the assets in this project are in line with the recommendations of the ACA report and make up a "normal" capital plan for NBHDL (ability of current resourcing and comparable to CAPEX spending in previous years). The project ranked 2 of 13 planned projects for the 2015 capital program and therefore will be a high priority for NBHDL.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be a major impact to system O&M costs. The renewal of this area will eliminate approximately $5,000.00 annually from O&M costs. If this project is not implemented, the O&M costs will continue perpetually on the same or at an increasing trend. This is not acceptable and the project must be completed within the 2015 capital investment plan.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

From a system perspective, there will not be a material change to reliability statistics because of the project. That said, the 117 customers impacted directly by the project will see a large improvement to reliability. Safety is not a major driver for the project, however as mentioned above, it will lower the risks of safety related issues through the elimination of a backlot poleline and underground servicing that fails constantly.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked 2 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations.

The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and achievement of the goal of eliminating backyard plant.

The cost of the project is affected by the following: potential increases in contractor costs due to availability; limited access for backyard asset removals; and costs of the underground work associated.

Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in the loss of benefits associated with backyard plant elimination as well as allowing O&M costs for 2015 to increase due to the age of the assets.

The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would result in further reliability issues for the customers residing in the complex. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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Project Name	**Turret Complex - Melina Close**		
Investment Category	System Renewal		
Project Description	The Melina project consists of the design and construction of new underground high voltage and low voltage infrastructure to replace existing backlot poles and underground secondary infrastructure supplying a large townhouse/condo type development located on Melina Drive.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$293,306.00	
	Customer Contribution	$0.00	
	Net Capital	$293,306.00	
	O&M Costs (if applicable)	$0.00	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	73	
	Customer Load (peak kVA):	292.9	
Project Timing	Start Date	January 2015 - Engineering	
		June 2015 - Civil Construction by Contractor	
		July 2015 - NBH Construction	
(5.4.5.2.A.third bullet)	Expected In-Service Date	Oct-15	
	Expenditure Timing	Q1: 9%	$26,397.54
		Q2: 15%	$43,995.90
		Q3: 64%	$187,715.84
		Q4: 12%	$35,196.72
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	There a few risks involved with the project. The first risk occurs from the requirement of completing the design by end of Q1, on this specific and two (2) other similar underground projects, so that the jobs can be tendered and awarded to a contractor as one package by the time the ground is free of frost and ready for underground work to commence. If this timeline is missed, there is the possibility that contractor pricing will increase due to lack of availability, or contractors will not be available whatsoever. This difficulty will be mitigated by proper planning and resource assignments. The second risk involves ensuring all that three (3) underground projects go out as one cohesive package to ensure best possible and most competitive pricing. This will also be mitigated by proper planning and resource assignments. The third risk involves constructability issues. The townhouse/condos are 60 years old and working around existing underground infrastructure, hydro, gas, water, sewer will be extremely difficult. Depending on the difficulty this may affect timelines and increase costs. This will be mitigated by having the entire development area located to aid in design and having test holes possibly dug in areas with high congestion to confirm the feasibility of the designs.		

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Comparative Information	A comparable project in scope, size, and design to the Melina Close project is the Pinewood Backlot Elimination - Phase 7 – Civil and Electrical project which involved the elimination of backlot poles and the installation of new HV and LV servicing in the city road allowance. The structure of the Melina project will be modeled after the Pinewood project where the engineering is done upfront, then a civil contractor is hired to install the civil infrastructure and then NBHDL completes the project by installing the electrical infrastructure. The timing of Melina project will also follow the timing of the Pinewood project, where civil construction starts immediately after the winter thaw to ensure the project can be completed by year end. Pinewood – Phase 7 (Civil and Electrical) 2010: $175,895 + $103,272 = $279,167
(5.4.5.2.A.fifth bullet)	
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment and therefore capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver is underground servicing that has reached it's end of life and is causing substantial O&M costs in the form of underground failures.
Related Objectives/Performance Targets	NBHDL objective 3 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Source of justification is the summary of the associated O&M costs caused by the failures and the ACA Report which indicates a significant need for underground infrastructure replacement.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver is the elimination of backlot poles and substandard secondary servicing (all servicing is tapped of one main conductor, causing a number of weak connection points in the main conductor and in the event of failure of the main conductor a number (up to 15 units) of customers experience a lengthy outage.
Related Objectives/Performance Targets	NBHDL objectives 1 and 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The source of justification is the NBHDL longstanding practice or procedural goal of eliminating backlot plant and the knowledge of substandard servicing design that is causing increased O&M costs.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. This project ranked #5 of 13 projects as identified by the Prioritization Matrix prepared as part of this DSP. Given the condition of the asset, and the significant impact this project has on O&M costs, this is the fifth project required by the NBHDL Capital Expenditure Plan. This, along with the specific ranks of all System Renewal projects, is further explained in Section 4 of the DSP. To ensure the elimination of significant O&M costs related to this area, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The new design will involve new loop fed primary underground supplies, which allows for improved restoration capability in the event of cable failures, as two options for supply will always be available. Overhead related primary disturbances (weather, rodents, and trees) will also no longer be a risk to system operation as the high voltage lines supplying the developments will be placed underground. This project will have a direct contribution to the reduction of O&M costs due to the number of repairs required on an annual basis to the existing underground infrastructure.
Net benefits to customers	Customers will benefit directly from increased reliability in the townhouses, as well as aesthetic benefits from the removal of unsightly backlot poles and equipment. The project will also reduce O&M spending which is a benefit to all customers.
Impact on reliability performance	Although there are a number of secondary cable faults each year, they normally only affect 5 to 15 customers at a time. Given the low number of affected customers, the overall contribution to system reliability performance is quite low. This System Renewal project should eliminate underground secondary cable faults for the first 15-20 years after installation. On top of that all servicing will be individual feeds, so in the event of a secondary cable fault only one customer will be affected instead of 5 to 15.

Project Alternatives

The ACA Report (at page #77) clearly identifies the low voltage servicing involved with this project is in need of immediate replacement Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL has decided to address this starting in 2015. NBHDL decided to identify underground replacement projects that provided immediate payback to customers and this project was one of them.

The added benefit to replacing the existing end of life underground low voltage cabling is it allows for the elimination of a backlot poleline via the installation of new underground high voltage cabling. NBHDL considered several alternatives to achieve the replacement of the underground cabling involved with this project including: i) leaving the underground supply in its current state (the 'do nothing' option); ii) replacing the underground low voltage servicing and replacing the backlot poleline with a new backlot poleline that supplies the area; and, iii) replacing the underground low voltage servicing and replacing the backlot poleline with underground high voltage cabling.

i) The current underground low voltage servicing is 50 years old and is contributing significantly to annual O&M costs. Leaving the plant as is will continue, if not increase, the trend with respect to O&M costs, and will continue to impact the reliability to the customers fed from the servicing negatively. This option is therefore not feasible.

ii) Renewal of both the underground cabling and the backlot poleline is an option, but not a practical one for NBHDL's current needs. The low voltage servicing must be addressed but rebuilding the poleline in the backlot would be contrary to NBHDL's goal of eliminating all backlot poles. It is also impractical to install poles and equipment back in a location that is currently not easily accessible and is an identified concern for customers. Rebuilding in the backlot is also a more costly initiative, as current day construction equipment cannot be utilized due to lack of access (i.e. climb poles instead of work on them from a bucket truck). This lack of access requires an increase in the labour component and contractor costs. The difficulty and significantly higher costs under this alternative make it unfeasible for the purpose of the DSP.

iii) The final option, and the option decided on by NBHDL, is the replacement of the underground low voltage servicing and the replacement of the backlot poleline with new front lot underground high voltage cabling . As mentioned earlier, NBHDL has determined that the low voltage servicing has to be replaced. This is due to the fact that the assets are currently at end of life, built under a design methodology that hasn't been used in 30 plus years, and contributes to annual O&M costs. A major advantage to eliminating the backlot poleline is that trenching is already being completed for the low voltage servicing and therefore the high voltage underground cabling is implemented at a much lower cost due to the utilization of the same trench. A second advantage is the removal of 17 poles, 12 of which are backlot, 5 backlot transformers, and 680m of backlot overhead primary from the asset base that no longer require maintenance or repair. And lastly, it helps NBHDL work towards the goal of eliminating all backlot plant. Given these advantages, both practically and financially, NBHDL has elected this option three for the project.

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Safety (5.4.5.2.B.2)

Safety is not a driver for the project, although the elimination of backlot plant is always a benefit to overall safety as backlot infrastructure is commonly impeded, and much more difficult to maintain. Access issues have the potential to lead to non-standard approaches to work or work methods that are not commonly practiced. Backlot plant can also hide hazards as the poles and equipment are not easily visible to NBHDL staff or the general public.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this project is in the middle of the service territory. Regional Planning is also not applicable to this project as capacity is not changing. The project will involve a lot of coordination with the individual condo/townhouse owners, both from a design and construction standpoint. It will also involve disruption to a number of customers in the form of excavation in and around their homes. Planning and communication will be critical to minimize the inconvenience of the required disruptions.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new infrastructure will be built to current day standards, which will allow for adaptability in the future, however at this time there are no plans to enable future technological functionality. The project is also not addressing future operational requirements.

Economic Development (5.4.5.2.B.5)

The work will be contracted out and may provide temporary economical benefit in the form of employment. Aside from the construction of the project it is simply the renewal of existing servicing and therefore does not represent an opportunity for Ontario economic growth.

Environmental Benefits (5.4.5.2.B.6)

Environmental benefits are not driving the project, however, with the elimination of backlot poles also comes the elimination of tree trimming around said poles and therefore provides back a space for greening (i.e. trees can be planted back in this area when the polelines are removed). NBHDL has found that this can be a benefit, particularly in a residential area.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The underground low voltage servicing is well past it's useful life, and has been repaired numerous times. This will continue to drive O&M costs if not addressed. The associated poleline that feeds the low voltage servicing is 40 plus years old and also well past its useful life. Both assets require immediate replacement and it is NBHDL's practice to relocate backlot polelines to road allowances upon renewal.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

Asset condition is very poor for the underground low voltage servicing and poor for the back lot poleline. Both of these designations are expected as the assets are past their typical life cycles.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

73 Residential Customers are impacted by the project, however failures typically only involve 5-15 customers at a time.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative impacts are not available (reliability statistics by station or feeder are not available). However, from NBHDL's knowledge of the system, some of the customers in this area experience far worse reliability than the average customer.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

This project will have a medium to high impact to the customers serviced by the existing plant planned for replacement. The impact will also be high for all customers, as the replacement of the plant will eliminate moderate annual O&M costs. The project will also remove electrical apparatus from back yards, improving the private space enjoyed by the customers. Risk is low, as safety is not a major driver, and although reliability will be improved it will only be improved to the 73 customers impacted by the project.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

This project provides great value to the 73 customers impacted, in the form of increased reliability and the elimination of backlot plant. The reduction of annual O&M costs that will gained from the project is also a moderate value to all other customers.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on any other projects planned over the forecast period. The replacement of the assets in this project are in line with the recommendations of the ACA Report and make up a "normal" capital plan for NBHDL (ability of current resourcing and comparable to CAPEX spending in previous years). The project ranked 5 of 13 planned projects for the 2015 capital program and therefore will be a high priority for NBHDL.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be a moderate impact to system O&M costs. The renewal of this area will eliminate approximately $1,000.00 annually from O&M costs. If this project is not implemented, the O&M costs will continue perpetually on the same or at an increasing trend. This is not acceptable and the project must be completed within the 2015 capital investment plan.

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Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

From a system perspective, there will not be a material change to reliability statistics because of the project. That said, the 73 customers impacted directly by the project will see a large improvement to reliability. Safety is not a major driver for the project, however as mentioned above, it will lower the risks of safety related issues through the elimination of a backlot poleline and underground servicing that fails constantly.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked 5 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations.

The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and achievement of the goal of eliminating backyard plant.

The cost of the project is affected by the following: potential increases in contractor costs due to availability; limited access for backyard asset removals; and costs of the underground work associated.

Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in the loss of benefits associated with backyard plant elimination as well as allowing O&M costs for 2015 to increase due to the age of the assets.

The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would result in further reliability issues for the customers residing in the complex. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Turret Complex - Wickstead**		
Investment Category	System Renewal		
Project Description	The Wickstead project consists of the design and construction of new underground high voltage and low voltage infrastructure to replace existing end of life, poor conditioned underground high voltage and low voltage infrastructure supplying a large townhouse/condo type development located on Wickstead Avenue.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$436,521.00	
	Customer Contribution	$0.00	
	Net Capital	$436,521.00	
	O&M Costs (if applicable)	$0.00	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	92	
	Customer Load (peak kVA):	308.5	
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering June 2015 - Civil Construction by Contractor July 2015 - NBH Construction	
	Expected In-Service Date	Oct-15	
	Expenditure Timing	Q1: 5% $21,826.05 Q2: 16% $69,843.36 Q3: 67% $292,469.07 Q4: 12% $52,382.52	
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	There a few risks involved with the project. The first risk occurs from the requirement of completing the design by end of Q1, on this specific and two (2) other similar underground projects, so that the jobs can be tendered and awarded to a contractor as one package by the time the ground is free of frost and ready for underground work to commence. If this timeline is missed, there is the possibility that contractor pricing will increase due to lack of availability, or contractors will not be available whatsoever. This difficulty will be mitigated by proper planning and resource assignments. The second risk involves ensuring all that three (3) underground projects go out as one cohesive package to ensure best possible and most competitive pricing. This will also be mitigated by proper planning and resource assignments. The third risk involves constructability issues. The townhouse/condos are 60 years old and working around existing underground infrastructure, hydro, gas, water, sewer will be extremely difficult. Depending on the difficulty this may affect timelines and increase costs. This will be mitigated by having the entire development area located to aid in design and having test holes possibly dug in areas with high congestion to confirm the feasibility of the designs.		

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Comparative Information	A comparable project in scope, size, and design to the Wickstead project is the Pinewood Backlot Elimination - Phase 6 – Civil and Electrical project which involved the installation of new HV and LV servicing in the city road allowance. The structure of the Wickstead project will be modeled after the Pinewood project where the engineering is done upfront, then a civil contractor is hired to install the civil infrastructure and then NBHDL completes the project by installing the electrical infrastructure. The timing of the Wickstead project will also follow the timing of the Pinewood project, where civil construction starts immediately after the winter thaw to ensure the project can be completed by year end. Pinewood – Phase 6 (Civil and Electrical) 2010: $273,827 + $144,278 = $418,105 The costs differ due to the number of services included in the Wickstead project, but the Pinewood project illustrates the magnitude of dollars for this type of work.
(5.4.5.2.A.fifth bullet)	
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment and therefore capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver is underground servicing that has reached it's end of life and is causing substantial O&M costs in the form of underground failures. Currently one of the two high voltage cables servcing the transclosures is failed and in an attempt to avoid significant O&M costs associated with the repar NBHDL has taken on the risk of leaving the servicing in said condition until the entire project can be tackled as a capital project. Should the remaining cable fail, a lenghty outage to approximately 60 customers would ensue. This is a major driver behind completing this project in 2015.
Related Objectives/Performance Targets	NBHDL objective 3 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Source of justification is the summary of the associated O&M costs caused by the failures and the ACA Report which indicates a significant need for underground infrastructure replacement.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver is the elimination of transclosures which involve polemounted transformers installed in custom built metal enclosures on the ground with live front primary connections (a safety risk) and the elimination of substandard secondary servicing (all servicing is tapped of one main conductor, causing a number of weak connection points in the main conductor and in the event of failure of the main conductor a number (up to 15 units) of customers experience a lengthy outage.)
Related Objectives/Performance Targets	NBHDL objectives 2 and 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The source of justification is the NBHDL longstanding practice or procedural goal of eliminating backlot plant and the knowledge of substandard servicing design that is causing increased O&M costs.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. This project ranked #3 of 13 projects as identified by the Prioritization Matrix prepared as part of this DSP. Given the condition of the asset, and the significant impact this project has on O&M costs, this is the thrid project required by the NBHDL Capital Expenditure Plan. This, along with the specific ranks of all System Renewal projects, is further explained in Section 4 of the DSP. To ensure the elimination of significant O&M costs related to this area, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The new design will restore the presence of loop fed primary underground supplies, ensuring quick restoration capability in the event of cable failures, as two options for supply will always be available. The elimination of transclosures allows much quicker access and maintenance on the transformer, and in outage situations allows for much easier restoration schemes or full on replacement
Net benefits to customers	Customers will benefit directly from increased reliability in the townhouses, as well as aesthetic benefits from the removal of the unsightly transclosures. The project will reduce O&M spending which is a benefit to all customers.
Impact on reliability performance	Although there are a number of secondary cable faults each year, they normally only affect 5 to 15 customers at a time. Given the low number of affected customers, the overall contribution to system reliability performance is quite low. This System Renewal project should eliminate underground secondary cable faults for the first 15-20 years after installation. On top of that all servicing will be individual feeds, so in the event of a secondary cable fault only one customer will be affected instead of 5 to 15.

Project Alternatives

The ACA Report (at page #77) clearly identifies the low voltage servicing involved with this project is in need of immediate replacement. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL has decided to address this starting in 2015. NBHDL decided to identify underground replacement projects that provided immediate payback to customers and this project was one of them. NBHDL considered several alternatives to achieve the replacement of the underground cabling involved with this project including: i) leaving the underground supply in its current state (the 'do nothing' opition); ii) replacing the underground high voltage and low voltage servicing but leaving the transclosures; and, iii) replacing the underground high voltage and low voltage servicing by using current day standards, including the replacment of the transclosures with padmounted transformers.

i) The current underground high voltage and low voltage servicing is 50 years old and is contributing significantly to annual O&M costs. Leaving the plant as is will continue, if not increase, the trend with respect to O&M costs, and will continue to impact the reliability to the customers fed from the servicing negatively. It will also mean leaving unsafe live front high voltage connections operating in poor condition.

ii) Renewal of both the underground high and low voltage but leaving the transclosures is an option, but not a practical one for NBHDL's current needs. The high voltage and low voltage servicing must be addressed but leaving the transclosures would be contrary to NBHDL's goal of eliminating all transclosures and associated live front high voltage connections. It is not practical to bring the cabling up to current standards and leave transformation based on 50 year old designs, that increase the risk for electrocution and are not easy to maintain or deal with in emergency situations, and therefore this alternative is not feasible for the purpose of the DSP.

iii) The final option, and the option decided on by NBHDL, is the replacement of the underground high and low voltage servicing and the replacement of all transclosures with deadfront padmounted transformers . As mentioned earlier, NBHDL has determined that the high and low voltage servicing has to be replaced. This is due to the fact that the assets are currently at end of life, built under a design methodology that hasn't been used in 30 plus years, and contribute significantly to annual O&M costs. A major advantage to this alternative is the replacement of two live front transclosures with deadfront padmount transformers. Option 3 is by far the best option and therefore has been selected by NBHDL.

Safety (5.4.5.2.B.2)

Safety is a driver to this project. The elimination of high voltage livefront connections removes a tremendous amount of risk with respect to electrocution in maintanence situations. NBHDL considers this a very important risk to mitigate as contact with high voltage has the high potential for fatality.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

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Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this project is in the middle of the service territory. Regional Planning is also not applicable to this project as capacity is not changing. The project will involve a lot of coordination with the individual condo/townhouse owners, both from a design and construction standpoint. It will also involve disruption to a number of customers in the form of excavation in and around their homes. Planning and communication will be critical to minimize the inconvenience of the required disruptions.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new infrastructure will be built to current day standards, which will allow for adaptability in the future, however at this time there are no plans to enable future technological functionality. The project is also not addressing future operational requirements.

Economic Development (5.4.5.2.B.5)

The work will be contracted out and may provide temporary economical benefit in the form of employment. Aside from the construction of the project it is simply the renewal of existing servicing and therefore does not represent an opportunity for Ontario economic growth.

Environmental Benefits (5.4.5.2.B.6)

Environmental benefits are not driving the project.

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The underground high and low voltage servicing is well past it's useful life, and has been repaired numerous times. This will continue to drive O&M costs if not addressed.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

Asset condition is very poor for both the high and low voltage underground servicing. This is expected as the assets are past their typical life cycles.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

92 Residential Customers are impacted by the project, however failures typically only involve 5-15 customers at a time.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative impacts are not available (reliability statistics by station or feeder are not available). However, from NBHDL's knowledge of the system, some of the customers in this area definitely see far worse reliability than the average customer.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

This project will have a high impact to the customers serviced by the existing plant planned for replacement. The impact will also be high for all customers, as the replacement of the plant will eliminate significant annual O&M costs. Risk is low, as public safety is not a major driver, and although reliability will be improved it will only be improved to the 92 customers impacted by the project.

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SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

This project provides great value to the 92 customers impacted, in the form of increased reliability. The reduction of annual O&M costs that will gained from the project is also of high value to all other customers.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on any other projects planned over the forecast period. The replacement of the assets in this project are in line with the recommendations of the ACA report and make up a "normal" capital plan for NBHDL (ability of current resourcing and comparable to CAPEX spending in previous years). The project ranked 3 of 13 planned projects for the 2015 capital program and therefore will be a high priority for NBHDL.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be a major impact to system O&M costs. The renewal of this area will eliminate approximately $5,000.00 annually from O&M costs. If this project is not implemented, the O&M costs will continue perpetually on the same or at an increasing trend. This is not acceptable and the project must be completed within the 2015 capital investment plan.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

From a system perspective, there will not be a material change to reliability statistics because of the project. That said, the 92 customers impacted directly by the project will see a large improvement to reliability. Safety is a driver for the project, as the danger of working around live front high voltage connections will be eliminated with the removal of the transclosures.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked 3 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations.
The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time.
The cost of the project is affected by the following: potential increases in contractor costs due to availability; limited access for backyard asset removals; and costs of the underground work associated.
Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in the loss of benefits associated with backyard plant elimination as well as allowing O&M costs for 2015 to increase due to the age of the assets.
The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would result in further reliability issues for the customers residing in the complex. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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Project Name	**Fourth Avenue Rebuild - Ferguson x Fisher**			
Investment Category	System Renewal			
Project Description	The Fourth Avenue Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Fourth Avenue between Ferguson Street and Fisher Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, elimination of #6 Cu busswork, elimination of underslung transformers and the elimination of the existing 4.16kV poleline that has identified as being in poor condition. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The determination of condition for both the equipment and poles has been verified by on-site determination by NBHDL staff. In addition, the completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$147,188		
	Customer Contribution	$0.00		
	Net Capital	$147,188		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	156		
	Customer Load (peak KVA)	256.2		
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering February 2015 - Construction		
	Expected In-Service Date	Apr-14		
	Expenditure Timing	Q1:	100%	$147,188
		Q2:	0%	$0
		Q3:	0%	$0
		Q4:	0%	$0
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is one of the first projects in 2015 one risk to the project will be ensuring the 2014 work plan is complete so the 2015 work plan can get underway. This is handled through weekly meetings where workload and status of projects is reviewed and action plans created. As this will be scheduled for winter construction, another risk is dealing with the consequences that winter brings including: narrower streets, cold weather, and frost in the ground. Although much of this cannot be mitigated, processes are in place to make sure the project flows as safely and efficiently as possible. A final risk, again related to time of year, is any required outages to accommodate the build must be kept to minimum as electric heat is prevalent in our region and therefore we try and minimize all outages in the winter months. Crews will mitigate by sectioning work into small pieces to minimize outages, and if that is not possible worst case will be to complete work requiring outages in the spring months.			

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Comparative Information (5.4.5.2.A.fifth bullet)	A comparable project in scope, size, and design to the Fourth Avenue project is the Cassells Street Rebuild project which involved the construction of same sized poles (45') with the same circuit configuration, 1-15kV circuit, and LV spun buss, the same number of blocks. In addition to that the Cassells project was also part of the Voltage Conversion Plan, like Fourth Avenue. Cassells Street Rebuild – 2012: $9,229 2013: $141,990 Note the expenditure in 2012 on the Cassells Street Rebuild reflects engineering costs incurred to have the project ready for construction in 2013.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Given the age of the asset and the objectives under NBHDL's AM plan, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver of this project is Safety, which NBHDL intends to ensure by the replacement of the substandard conditions of this poleline. Specifically, the elimination of 1 underslung transformer, 408m of #6 Cu busswork, and framing that no longer meets regulatory requirements. Safety will be further discussed below in 5.2.5.2.B.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions, established through its capital planning and O&M procedures, is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the Fourth Avenue Rebuild between Ferguson and Fisher is ranked #7. Given the poor condition of the asset and the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA Report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) As it stands, the ACA Report has identified that the poleline is end of life and operating at 4kV. Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height

Safety (5.4.5.2.B.2)

The project will involve the elimination of 1 under slung transformer which involve the transformer being installed below the secondary conductors and therefore causing the high voltage lead to enter the space below the low voltage space. Specifically, the underslung transformers involve HV leads that drop below the LV busswork, putting the HV below the neutral location on the poles. This is also a standard that is no longer accepted due to the hazard it creates for NBHDL workers and workers for communication providers that have assets attached to NBHDL poles. Upon completion of this project, the HV lead will not drop below the LV location on the pole, eliminating a major issue for communication space workers and improving clearances between LV and HV for NBHDL workers. The project will also involve the elimination of 408m of #6 Cu busswork which is prone to failure due to its brittleness, a hazard to both the public and all workers. The failure can result in hazards such as fire, energization of the ground and pieces of the poleline falling to the ground. Finally, the new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. All of the aforementioned risks are currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

The number of poles and transformers will be optimized, which will reduce the number of poles and transformers required to service the same load (2 less poles, 3 less transformers), although a small benefit it is a more efficient use of existing technologies.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The majority of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the poles, conductors and equipment generally are in very poor condition. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio, there are 5 poles that are between 70 and 80 years old scheduled for replacement as part of this project. While not all the assets are in a very poor condition, and that seemingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

153 Residential customers and 3 GS<50 customers would be potentially affected if the assets related to this project were to fail

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a small number of residential customers and even smaller number of commercial type customers, so when compared to the system as a whole this is very small piece of it. Typically in lines, assets fail one at a time and although costly, can be addressed quickly, and therefore the risk of prolonged outages is very low in the event of a typical failure.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Program and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #7 out of 13 for completion in 2015. Completion of this project will address the replacement of 13 of the 200 poles needed to keep up with the required system renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #7 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is driven by typical renewal costs of replacing polelines, the only aspect of this project that may lead to higher costs is the fact it is scheduled to take place over the winter months, aside from that, costs are quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Fifth Avenue Rebuild - Cassells x Wyld**			
Investment Category	System Renewal			
Project Description	The Fifth Avenue Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Fifth Avenue between Cassells Street and Wyld Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, elimination of #6 Cu busswork, elimination of underslung transformers and the elimination of the existing 4.16kV poleline that has identified as being in poor condition. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The determination of condition for both the equipment and poles has been verified by on-site determination by NBHDL staff. In addition, the completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$154,232		
	Customer Contribution	$0.00		
	Net Capital	$154,232		
	O&M Costs (if applicable)	$0.00 (not applicable)		
Customer Attachments/Load (kVA)	Customer Attachments (#):	128		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	334.1		
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering		
		February 2015 - Construction		
	Expected In-Service Date	Apr-14		
	Expenditure Timing	Q1:	100%	$154,232
		Q2:	0%	$0
		Q3:	0%	$0
		Q4:	0%	$0
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is one of the first projects in 2015 one risk to the project will be ensuring the 2014 work plan is complete so the 2015 work plan can get underway. This is handled through weekly meetings where workload and status of projects is reviewed and action plans created. As this will be scheduled for winter construction, another risk is dealing with the consequences that winter brings including: narrower streets, cold weather, and frost in the ground. Although a lot of this cannot be mitigated processes are in place to make sure the project flows as safely and efficiently as possible. A final risk, again related to time of year, is any required outages to accommodate the build must be kept to minimum as electric heat is prevalent in our region and therefore we try and minimize all outages in the winter months. Crews will mitigate by sectioning work into small pieces to minimize outages, and if that is not possible worst case will be to complete work requiring outages in the spring months.			

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Comparative Information (5.4.5.2.A.fifth bullet)(5.4.5.2.A.fifth bullet)	A comparable project in scope, size, and design to the Fifth Avenue project is the Cassells Street Rebuild project which involved the construction of same sized poles (45') with the same circuit configuration, 1-15kV circuit, and LV spun buss, the same number of blocks. In addition to that the Cassells project was also part of the Voltage Conversion Plan, like Fifth Avenue. Cassells Street Rebuild – 2012: $9,229 2013: $141,990 Note the expenditure in 2012 on the Cassells Street Rebuild reflects engineering costs incurred to have the project ready for construction in 2013.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Given the age of the asset and the objectives under NBHDL's AM plan, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver of this project is Safety, which NBHDL intends to ensure by the replacement of the substandard conditions of this poleline. Specifically, the elimination of 1 underslung transformer, 461m of high voltage #6 Cu and 513m of #6 Cu busswork, 12 cap type insulators and framing that no longer meets regulatory requirements. Safety will be further discussed below in 5.2.5.2.B.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL's existing knowledge of asset conditions, established through its capital planning and O&M procedures, is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the Fifth Avenue Rebuild between Cassells and Wyld is ranked #6. Given the poor condition of the asset and the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) As it stands, the ACA Report has identified that the poleline is end of life and operating at 4kV. Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer.

Safety (5.4.5.2.B.2)

The project will involve the elimination of 1 under slung transformer which involve the transformer being installed below the secondary conductors and therefore causing the high voltage lead to enter the space below the low voltage space. Specifically, the underslung transformers involve HV leads that drop below the LV busswork, putting the HV below the neutral location on the poles. This is also a standard that is no longer accepted due to the hazard it creates for NBHDL workers and workers for communication providers that have assets attached to NBHDL poles. Upon completion of this project, the HV lead will not drop below the LV location on the pole, eliminating a major issue for communication space workers and improving clearances between LV and HV for NBHDL workers. The project will also involve the elimination of 461m of high voltage #6 Cu and 513m of #6 Cu busswork which is prone to failure due to its brittleness, a hazard to both the public and all workers. The failure can result in hazards such as fire, energization of the ground and pieces of the poleline falling to the ground. The project will also involve the elimination of 12 cap type insulators that are notorious for failing while the pole is under stress or someone is working on it, representing the elimination of a major safety hazard. Finally, the new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. All of the aforementioned risks are currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

The number of poles and transformers will be optimized, which will reduce the number of poles and transformers required to service the same load (2 less poles, 1 less transformer), although a small benefit it is a more efficient use of existing technologies.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The majority of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the poles, conductors and equipment generally are in poor condition with some peaking at average. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio. While some of the assets are at an average condition, and that seemingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

122 Residential customers and 6 GS<50 customers would be potentially affected if the assets related to this project were to fail

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a small number of residential customers and even smaller number of commercial type customers, so when compared to the system as a whole this is very small piece of it. Typically in lines, assets fail one at a time and although costly, can be addressed quickly, and therefore the risk of prolonged outages is very low in the event of a typical failure.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks 6 out of 13 for completion in 2015. Completion of this project will address the replacement of 16 of the 200 poles needed to keep up with the required system renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #6 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is driven by typical renewal costs of replacing polelines, the only aspect of this project that may lead to higher costs is the fact it is scheduled to take place over the winter months, aside from that, costs are quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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Project Name	**Fraser Street Rebuild - Fifth x Chippewa**				
Investment Category	System Renewal				
Project Description	The Fraser Street Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Fraser Street between Fifth Avenue and Chippewa Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, elimination of #6 Cu busswork, and allow future operation of the poleline at 12.47kV. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.				
Capital Investment	Gross Capital	$116,034			
(5.4.5.2.A.first bullet)	Customer Contribution	$0.00			
	Net Capital	$116,034			
	O&M Costs (if applicable)	$0.00	(not applicable)		
Customer Attachments/Load (kVA)	Customer Attachments (#):	102			
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	112.1			
Project Timing	Start Date	January 2015 - Engineering			
(5.4.5.2.A.third bullet)		February 2015 - Construction			
	Expected In-Service Date	Mar-15			
	Expenditure Timing		Q1:	100%	$116,034
			Q2:	0%	$0
			Q3:	0%	$0
			Q4:	0%	$0

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B):

Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is one of the first projects in 2015, one risk to the project will be ensuring the 2014 work plan is complete so the 2015 work plan can get underway. This is handled through weekly meetings where workload and status of projects is reviewed and action plans created. As this will be scheduled for winter construction, another risk is dealing with the consequences that winter brings including: narrower streets, cold weather, and frost in the ground. Although a lot of this cannot be mitigated processes are in place to make sure the project flows as safely and efficiently as possible. A final risk, again related to time of year, is any required outages to accommodate the build must be kept to minimum as electric heat is prevalent in our region and therefore we try and minimize all outages in the winter months. Crews will mitigate by sectioning work into small pieces to minimize outages, and if that is not possible worst case will be to complete work requiring outages in the spring months.
Comparative Information (5.4.5.2.A.fifth bullet)	A project that parallels the design and construction of the Fraser Street Rebuild project is the Wyld Street Rebuild project which involved the construction of same sized poles (45') with the same circuit configuration, 1-15kV circuit, and LV spun buss. In addition to that the Wyld Street project was also part of the Voltage Conversion Plan, like Fraser Street. Wyld Street Line Rebuild – 2011: $11,719 2012: $25,394 Although the projects are similar, the Wyld Street project consisted of construction on two blocks only, whereas the Fraser project consists of 5 blocks of construction. Fraser Street is also much denser with residential customers than Wyld, and therefore will involve more costs.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as first identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. This overall condition of the assets under this project is average, some are poor, some are good, but because the majority of poles are less than 40' in height, the poleline has to be replaced in order to prepare for voltage conversion, which follows with the objectives under NBHDL's AM strategy and therefore, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and in-field assessment of the poleline are the sources of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver of this project is Safety, which NBHDL intends to ensure by the replacement of the substandard conditions of this poleline. Specifically, the elimination 235m of #6 Cu high voltage circuit, 76m of #6 Cu low voltage busswork and framing that no longer meets regulatory requirements. Safety will be further discussed below in 5.2.5.2.B.

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Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time, projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 planned projects schedule Fifth and Wyld is ranked #10. Given the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan. It should be noted that although this project ranks #10 of 13, it has been scheduled early in the year because of the following reasons: i) it is close to 12.47/4.16kV boundary (outward in concept); ii) it is ideal for winter construction because it is a smaller project and involves a small amount of load which is more practical to handle if outages are requires; iii) The street is not a major artery from a city traffic perspective and therefore the consequences of winter construction are more easily dealt with, specifically dealing with the limited working space due to snow banks.
Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)	
Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA Report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer.

Safety (5.4.5.2.B.2)

The project will involve the elimination of #6 Cu busswork which is prone to failure due to its brittleness, a hazard to both the public and all workers. The failure can result in hazards such as fire, energization of the ground and pieces of the poleline falling to the ground. Also, the new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. All of the aforementioned risks are currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Environmental Benefits (5.4.5.2.B.6)

The number of poles will be optimized, which will reduce the number of poles required to service the same load (1 less pole), although a small benefit it is a more efficient use of existing technologies.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

Approximately half of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The other half, although in fair to good condition, are too short to accommodate new framing standards and therefore must be replaced as part of the project. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

Approximately half of the poles, conductors and equipment are in poor condition with the other half falling between fair and good. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio. While some of the assets are at a fair to good condition, and that seemingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

96 Residential customers and 6 GS<50 customers would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a small number of residential customers and even smaller number of commercial type customers, so when compared to the system as a whole this is very small piece of it. Typically in lines, assets fail one at a time and although costly, can be addressed quickly. Therefore the risk of prolonged outages is very low in the event of a typical failure.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #10 out of 13 for completion in 2015. Completion of this project will address the replacement of 13 poles, 6 of which are part of the 200 poles needed to keep up with the required System Renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #10 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is driven by typical renewal costs of replacing polelines, the only aspect of this project that may lead to higher costs is the fact it is scheduled to take place over the winter months, aside from that costs are quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL distribution system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Project Name	**McIntyre Street Rebuild - Cassells x Wyld**			
Investment Category	System Renewal			
Project Description	The McIntrye Street Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on McIntyre Street between Cassells Street and Wyld Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, elimination of #6 Cu busswork, elimination of 240V delta servicing elimination of underslung transformers and the elimination of the existing 4.16kV poleline that has identified as being in poor condition. This project also includes a certain amount of underground work associated with the new servicing and reconfiguration of customer owned equipment. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The determination of condition for both the equipment and poles has been verified by on-site determination by NBHDL staff. In addition, the completion of this project is necessary to the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment	Gross Capital	$452,969		
(5.4.5.2.A.first bullet)	Customer Contribution	$0.00		
	Net Capital	$452,969		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA)	Customer Attachments (#):	83		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	1208.3		
Project Timing	Start Date	March 2015 - Engineering		
(5.4.5.2.A.third bullet)		June 2015 - Construction		
	Expected In-Service Date	September 31, 2014		
	Expenditure Timing	Q1:	2%	$9,059
		Q2:	28%	$126,831
		Q3:	70%	$317,078
		Q4:	0%	$0
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The largest risk to the project will be the work required on customer's premises to: a) eliminate delta servicing or b) amalgamate multiple services to one service. This can be extremely expensive and coordination with customers is always challenging. NBHDL will mitigate this risk by starting the engagement of affected customers early in the year. Specifically, the target for such engagement will be late Q1, early Q2 2015. A secondary risk is dealing with unknown subsurface conditions, rock and existing infrastructure for the completion of the underground services. To mitigate, test holes may be dug and locates will be called in at the design stage.			

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Comparative Information (5.4.5.2.A.fifth bullet)	The closest comparable project in the design and construction of the McIntyre Street Rebuild is the Worthington Street Rebuild which is one street north of McIntyre and runs parallel. Both are in the downtown core and involve the same customer make up. Although the Worthington project contained taller poles, 2 -15kV circuits, and 7 blocks of construction compared to 1-15kV circuit and 3 blocks of construction for the McIntyre project, the McIntyre project includes heavy servicing costs to resolve delta serving, and the elimination of multiple servicing to the same property, evening out the costs. In addition, the Worthington project was also part of the Voltage Conversion Plan, like McIntyre. If the McIntyre project was a similar length as the Worthington project the costs would be very comparable. Worthington Street Rebuild – 2010: $305,617 2011: $562,246 2012: $93,460 2013: $4606 (accounting adjustments) 2014: $1,817 (accounting adjustments) It should be noted that the Worthington project was a large project and was started in the late stages of 2010 (pole installation, framing), and was postponed until the summer due to traffic conjestion in the winter, at which time it started up again (finished framing, strung in conductor, and did the majority of the servicing work. The 2012 dollars reflect servicing that wasn't completed by the freeze up in 2011 and had to be carried over. NBHDL has learned from this and scheduled McIntyre to start immediately after the winter thaw, and will have the servicing work planned and coordinated with customers in the winter months to ensure all work is accomplished in 2015.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as first identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Given the age of the asset and the objectives under NBHDL's AM plan, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver of this project is Safety, which NBHDL intends to ensure by the replacement of the substandard conditions of this poleline. Specifically, the elimination of 5 delta services, 1 underslug transformer, and 510m #6 CU busswork and framing that no longer meets regulatory requirements. Safety will be further discussed below in 5.2.5.2.B.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL's existing knowledge of asset conditions established through its O&M procedures is the source of information that identified the secondary driver.

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Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the McIntyre Street Rebuild between Cassells and Wyld is ranked #4. Given the poor condition of the asset and the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. These remaining substations will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.
Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)	
Effect on system operation efficiency and cost effectiveness	This poleline will form a piece of a major tie between two 15kV substations, allowing for greater flexibility from a loading point of view and restoration in the event of substation outage situations. The elimination of multiple services to properties will simplify service delivery and customer billing in the future while also decreasing expected O&M from on-going maintenance as well as capital costs.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) As it stands, the ACA Report has identified that the poleline is end of life and operating at 4kV. Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesireable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer.

Safety (5.4.5.2.B.2)

The project will involve the elimination of 5 - 240V delta services, a service offering no longer available by NBHDL because of its known safety issues. Specifically, delta servicing can lead to unknown ground faults and as it is not a normal service offering, safety issues for workers can increase. The project will also involve the elimination of 1 under slung transformer which involve the transformer being installed below the secondary conductors and therefore causing the high voltage lead to enter the space below the low voltage space. Specifically, the underslung transformers involve HV leads that drop below the LV busswork, putting the HV below the neutral location on the poles. This is also a standard that is no longer accepted due to the hazard it creates for NBHDL workers and workers for communication providers that have assets attached to NBHDL poles. Upon completion of this project, the HV lead will not drop below the LV location on the pole, eliminating a major issue for communication space workers and improving clearances between LV and HV for NBHDL workers. The project will also involve the elimination of #6 Cu busswork which is prone to failure due to its brittleness, a hazard to both the public and all workers. The failure can result in hazards such as fire, energization of the ground and pieces of the poleline falling to the ground. Finally, the new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. All of the aforementioned risks are currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

The number of poles will be optimized, which will reduce the number of poles required to service the same load (1 less pole), although a small benefit it is a more efficient use of existing technologies.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet.first dash)

The majority of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet.second dash)

The majority of the poles, conductors and equipment generally are in poor condition with some peaking at average. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio. While some of the assets are at an average condition, and that seamingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet.third dash)

26 Residential customers, 48 GS<50 customers, and 10 GS>50 would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet.fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet.fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet.sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a fair number of commercial type customers, and a very small amount of residential customers. The type of customer and the existing servicing dictates the necessity of this project, as opposed to the cost of failure. The line exists in a built up, downtown core area with 240V delta servicing and multiple servicing connections. The impact on the customer comes with the requisite reconfigurations that will be required to eliminate the existing servicing.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. This particular poleline project has experienced some delay over the last few years due to changing strategies at NBHDL. In 2012, the Voltage Conversion Plan was refined and a 4 year strategy was employed to ensure the completion of the Voltage Conversion Plan. This strategy required some re-prioritization of projects for optimal efficiency and ultimately delayed the McIntyre rebuild project. Any further delay of this project however, is no longer a viable option. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #4 out of 13 for completion in 2015. Completion of this project will address the replacement of 14 of the 200 poles needed to keep up with the required System Renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #4 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is affected by the following: the fact that it is situated in a significantly built up area, in the downtown core, which causes increased construction costs; a large portion of the project requires eliminating servicing issues: 240V delta servicing and multiple services which involves not only costs to install our plant, but costs to change, or reconfigure customer owner equipment; and there is significant underground work associated with new servicing. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL distribution system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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Project Name	**Ferguson Street Rebuild - Princess x First**			
Investment Category	System Renewal			
Project Description	The Ferguson Street Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Ferguson Street between Princess Street and First Avenue to replace the existing poleline with a distribution circuit that was built to 5kV standards and operating at 4.16kV. The poleline also houses a 44kV circuit, which will be brought up to new framing standards as part of the project. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, the elimination of the existing 4.16kV poleline that has identified as being in poor condition and cap type insulators than are notorious for failing when the pole is under load or being worked on. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The determination of condition for both the equipment and poles has been verified by on-site determination by NBHDL staff. In addition, the completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$278,780		
	Customer Contribution	$0.00		
	Net Capital	$278,780		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA)	Customer Attachments (#):	60		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	347.8		
Project Timing	Start Date	June 2015 - Engineering		
(5.4.5.2.A.third bullet)		August 2015 - Construction		
	Expected In-Service Date	Nov-15		
	Expenditure Timing	Q1:	0%	$0
		Q2:	2%	$5,576
		Q3:	66%	$183,995
		Q4:	32%	$89,210
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is project is scheduled later in the year, a risk to getting this project completed is the execution of the work preceding it. This will be mitigated via weekly production meetings with both Operations staff and Engineering staff, and the tracking of capital spending in line with Section 2.3 of the DSP. The other risk, albeit very small, will be the coordination of isolating the 44kV circuit that is involved with project to allow for the installation of the new poles. As NBHDL's system is highly redundant, isolation of 44kV circuits is easily implemented and therefore this is an extremely small risk to be considered.			

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Comparative Information (5.4.5.2.A.fifth bullet)	A project that parallels the design and construction of the Ferguson Street Rebuild is the O'Brien Street – 44kV Line Extension project which involved installation of same sized poles (60') with the same circuit configuration, 1 - 44kV circuit, 1 – 15kV circuit and LV spun buss. O'Brien Street 44kV Line Extension – 2010: $210,978 Although the projects are similar there are four factors that explain why the costs are not identical and are as follows: i) The Ferguson Street project involves 7 blocks where the O'Brien project involved 6; ii) O'Brien was completed in 2010, and labour rates and material costs reflected market conditions in 2010 not 2014; iii) The O'Brien Street project involved new 44kV whereas the Ferguson project involves replacing existing 44kV, making construction more complicated and iv) the distribution circuit on the O'Brien Street project was already operating at 12.47kV, so there were no voltage conversion related costs on the O'Brien project. However, when considering the above 4 factors the magnitude of the projects are comparable.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Given the age of the asset and the objectives under NBHDL's AM plan, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objectives 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The project will involve the elimination of 12 cap type insulators which are a major safety hazard and 18 new poles which will employ much greater separations due to increased spacing of the new framing standards which will lead to safer maintenance of the line for workers while at the same time eliminating the risks with respect to possible hazards involved with the previous end of life assets.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the Ferguson Street Rebuild is ranked #8. Given the poor condition of the asset this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

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Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.

With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.

i) As it stands, the ACA Report has identified that the poleline is end of life and operating at 4kV. Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.

ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.

iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).

iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.

v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer. It is important that although this poleline also houses a 44kV circuit, it is not a factor in the decision making process, the main driver is the age of the poleline and the fact it is currently operating at 4.16kV.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Safety (5.4.5.2.B.2)

The project will involve the elimination of 12 cap type insulators that are notorious for failing while the pole is under stress or someone is working on it, representing the elimination of a major safety hazard. The new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. The aforementioned risk is currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

The number of poles will be optimized, which will reduce the number of poles and transformers required to service the same load (2 less poles), although a small benefit it is a more efficient use of existing technologies.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The majority of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the poles, conductors and equipment generally are in poor condition. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

51 residential customers, 7 GS<50 customers and 2 GS>50 customers would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk
(5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

Qualitative Customer Impact and Risk
(5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is moderate. Although this is a small section of line, there is a 44kV circuit present. In the case of asset catastrophic failure of a pole the outage would not be local but global as a typical 44kV circuit supplies substations that usually supply at least 2000 to 3000 customers. Although the risk of catastrophic failure is low due to the project only consisting of 18 poles and it not being a highly probable event, if something was to happen the consequence would be a significant sized outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #8 out of 13 for completion in 2015. Completion of this project will address the replacement of 16 of the 200 poles needed to keep up with the required System Renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked eighth of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. When compared to other similar jobs, the cost of this renewal project will be greater than normal due to the presence of a 44kV circuit, which requires much taller poles (60' poles vs. 45' poles) and consequently, more material to frame the 44kV circuit. Aside from these factors, the project is typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**First Avenue Rebuild - Fisher x Regina**			
Investment Category	System Renewal			
Project Description	The First Avenue Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on First Avenue between Fisher Street and Regina Street to replace the existing poleline with a distribution circuit that was built to 5kV standards and operating at 4.16kV. The poleline also houses a 44kV circuit, which will be brought up to new framing standards as part of the project. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, the elimination of the existing 4.16kV poleline that has identified as being in poor condition. The assets associated with the existing 4.16kV poleline have aged in line with the poleline itself and therefore are also in a similar state or 'poor condition'. The determination of condition for both the equipment and poles has been verified by on-site determination by NBHDL staff. In addition, the completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$136,126		
	Customer Contribution	$0.00		
	Net Capital	$136,126		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	44		
	Customer Load (peak KVA)	91		
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering February 2015 - Construction		
	Expected In-Service Date	Apr-14		
	Expenditure Timing	Q1:	0%	$0
		Q2:	0%	$0
		Q3:	58%	$78,953
		Q4:	42%	$57,173
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is project is scheduled later in the year, a risk to getting this project completed is the execution of the work preceding it. This will be mitigated via weekly production meetings with both Operations staff and Engineering staff, and the tracking of capital spending in line with Section 2.3 of the DSP. The other risk, albeit very small, will be the coordination of isolating the 44kV circuit that is involved with project to allow for the installation of the new poles. As NBHDL's system is highly redundant, isolation of 44kV circuits is easily implemented and therefore this is an extremely small risk to be considered.			
Comparative Information (5.4.5.2.A.fifth bullet)	There is no direct comparator in scope, size and/or design for this project			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Given the age of the asset and the objectives under NBHDL's AM plan, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a) **Related Objectives/Performance Targets**	This project only involves one block of First Avenue that was left out when the majority of the street was rebuilt in NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the First Avenue Rebuild between Fisher and Regina is ranked #12. Given the poor condition of the asset this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.
Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)	
Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.

With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.

i) As it stands, the ACA Report has identified that the poleline is end of life and operating at 4kV. Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.

ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.

iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).

iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.

v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer. It is important that although this poleline also houses a 44kV circuit, it is not a factor in the decision making process, the main driver is the age of the poleline and the fact it is currently operating at 4.16kV.

Safety (5.4.5.2.B.2)

The new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. The aforementioned risk is currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to this project.

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SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The majority of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the Voltage Conversion Plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the poles, conductors and equipment generally are in very poor condition. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

42 Residential customers and 2 GS<50 customers would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is moderate. Although this is a small section of line, there is a 44kV circuit present. In the case of asset catastrophic failure of a pole the outage would not be local but global as a typical 44kV circuit supplies substations that usually supply at least 2000 to 3000 customers. Although the risk of catastrophic failure is low due to the project only consisting of 6 poles and it not being a highly probable event, if something was to happen the consequence would be a significant sized outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #12 out of 13 for completion in 2015. Completion of this project will address the replacement of 6 of the 200 poles needed to keep up with the required System Renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

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Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #12 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. When compared to other similar jobs, the cost of this renewal project will be greater than normal due to the presence of a 44kV circuit, which requires much taller poles (60' poles vs. 45' poles) and consequently, more material to frame the 44kV circuit. Aside from these factors, the project is typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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Project Name	**Regina Street Rebuild - Second x Oak**			
Investment Category	System Renewal			
Project Description	The Regina Avenue Rebuild project consists of the design, construction and installation of 1 - 44kV, 12.47kV pole, a 3 phase bank replacement and 300m of new LV spun bus, on Regina Avenue between Second Street and Oak Street to replace 1 pole that doesn't have the required height, replace existing open wire secondary and allow for conversion of the approx. 300m of line to 12.47kV that is currently operating at 4.16kV. In addition, the completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan. Note that aside from the pole mentioned above, all existing poles in this section of line are being re-used as they are the required height, and are all still in fair to good condition.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$81,848		
	Customer Contribution	$0.00		
	Net Capital	$81,848		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA)	Customer Attachments (#):	20		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	133.5		
Project Timing	Start Date	September 2015 - Engineering		
(5.4.5.2.A.third bullet)		October 2015 - Construction		
	Expected In-Service Date	Dec-15		
	Expenditure Timing	Q1:	0%	$0
		Q2:	0%	$0
		Q3:	18%	$14,733
		Q4:	82%	$67,115
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is project is scheduled later in the year, a risk to getting this project completed is the execution of the work preceding it. This will be mitigated via weekly production meetings with both Operations staff and Engineering staff, and the tracking of capital spending in line with Section 2.3 of the DSP. Another risk, albeit very small, will be the coordination of isolating the 44kV circuit that is involved with project to allow for the installation of the new poles. As NBHDL's system is highly redundant, isolation of 44kV circuits is easily implemented and therefore this is an extremely small risk to be considered. And lastly, this project is dependent on having the work on First Avenue complete and therefore is dependent on that work. The jobs will be coordinated together to ensure the work is done as efficiently as possible and completed before year end.			

Comparative Information (5.4.5.2.A.fifth bullet)	There is no direct comparator in scope, size, and/or design for this project
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Aside from the replacement of one pole, all existing poles will be reused, however the opportunity to upgrade the secondary bus will be taken while NBHDL is working in the area. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and the ACA Report are the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver of this project is Safety, which NBHDL intends to ensure by the replacement of the substandard conditions of this poleline. Specifically, the elimination of 1 delta service and framing that no longer meets regulatory requirements. Safety will be further discussed below in 5.2.5.2.B.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 projects scheduled for 2015, and forming the substance of this DSP, the Regina Street Rebuild between Oak and Fisher is ranked #9. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. it is imperative that this project be completed as part of 2015's Capital Expenditure Plan to allow the continuance of the Voltage Conversion Plan.

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered three alternatives to achieve the work under this project including: i) leaving the line in its current state; ii) change the one pole required to meet new framing standards and allow for the 44kV midspan tap at Regina and First and do nothing else; iii) change the one pole, replace the secondary, and eliminate the delta transformer bank, along with converting the line to 12.47kV.
i) Leaving the line in this current state has the potential will prohibit a required 44kV tap from being made at the intersection of Regina and First, and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Changing the pole will address the new framing requirements and allow for the 44kV tap to be made but leaving the open wire secondary bus will require a return from the crews in less than 5 years to address, while encumbering more of each pole and limits the options for secondary connections. Leaving the delta bank also leaves a know hazard in place, which is not a risk NBHDL wants to take. NBHDL believes rolling the trucks once to the area and addressing all issues is a more efficient use of resources and therefore leaving the secondary and delta bank as is not the most efficient option and therefore has not been selected.
v) The final option, and the option decided on by NBHDL, is to address all issues and convert the line to 12.47kV. Given the requirements of pole height under regulatory framing requirements, the replacement of existing LV buss that will require replacement in 5 years or less with spun buss that is more functional and requires less pole space, and the elimination of a known safety hazard, and the fact work in this area has to be done, it is the most efficient option to address all issues while crews are on the street working.

Safety (5.4.5.2.B.2)

The project will involve the elimination of 1 - 240V delta service, a service offering no longer available by NBHDL because of its known safety issues. Specifically, delta servicing can lead to unknown ground faults and as it is not a normal service offering, safety issues for workers can increase. The new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors. All of the aforementioned risks are currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to this project.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

Aside from the one pole that requires replacement, the LV buss and the delta bank the majority of the assets that form this portion of the system are in fair to good condition and will be reused. However, without the proposed work the poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the voltage conversion plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the assets are in fair to good condition and do not require replacement and will be reused which is expected as the majority of the assets are between 10 and 20 years old.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

20 Residential customers would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is moderate. Although this is a small section of line, there is a 44kV circuit present. In the case of asset catastrophic failure of a pole the outage would not be local but global as a typical 44kV circuit supplies substations that usually supply at least 2000 to 3000 customers. Although the risk of catastrophic failure is low due to the project only consisting of 1 pole and about 300 m of poleline and it not being a highly probable event, if something was too happen the consequence would be a significant sized outage.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This part of this project is required due to the work being done on the First Avenue project in 2015 and therefore timing will be dictated by when the work on First Avenue starts. On top of that the Voltage Conversion Plan cannot be completed with this work being undertaken. There are no System Access, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #9 out of 13 for completion in 2015. Completion of this project will address the replacement of 1 of the 200 poles needed to keep up with the required system renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #9 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. When compared to other similar jobs, the cost of this renewal project will be greater than normal due to the presence of a 44kV circuit, which requires much taller poles (60' poles vs. 45' poles) and obviously more material to frame the 44kV circuit, aside from that, the project is quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Project Name	**Main Street West - Nipissing x Murray**			
Investment Category	System Renewal			
Project Description	The Main Street West Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Main Street West between Nipissing Street and Murray Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, and allow future operation of the poleline at 12.47kV. The completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$215,217		
	Customer Contribution	$0.00		
	Net Capital	$215,217		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA)	Customer Attachments (#):	165		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	740.4		
Project Timing	Start Date	January 2015 - Engineering		
(5.4.5.2.A.third bullet)		March 2015 - Construction		
	Expected In-Service Date	Jun-15		
	Expenditure Timing	Q1:	41%	$88,239
		Q2:	59%	$126,978
		Q3:	0%	$0
		Q4:	0%	$0
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is one of the first projects in 2015, one risk to the project will be ensuring the 2014 work plan is complete so the 2015 work plan can get underway. This is handled through weekly meetings where workload and status of projects is reviewed and action plans created. As this will be scheduled for winter construction, another risk is dealing with the consequences that winter brings, narrower streets, cold weather, frost in the ground. Although a lot of this cannot be mitigated, processes are in place to make sure the project flows as safely and efficiently as possible. A final risk, again related to time of year, is any required outages to accommodate the build must be kept to minimum as electric heat is prevalent in our region and therefore we try and minimize all outages in the winter months. Crews will mitigate by sectioning work into small pieces to minimize outages, and if that is not possible worst case will be to complete work requiring outages in the spring months. As the project will start in March, there is the possibility that the majority of the winter related issues will be done with making this a non-factor.			

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2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Comparative Information (5.4.5.2.A.fifth bullet)	A comparable project in scope, size, and design to the Main Street West Rebuild project is the Chippewa Street Rebuild project which involved the construction of same sized poles (50') with the same circuit configuration, 1-15kV circuit, and LV spun buss. In addition to that the Chippewa project was also part of the Voltage Conversion Plan, like Main Street West. Chippewa Street Rebuild – 2013: $189,177 Although the projects are similar the difference in cost can be attributed to the following x things: i) Main Street West involves construction over 5 blocks and Chippewa involved 4 blocks ii) Main Street West involves more residential services than the Chippewa project. When considering those two factors, the projects are very comparable.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. This overall condition of the assets under this project is poor to fair, approximately 16 are poor and 6 are fair to good, but because the majority of poles are too short for the framing required, the poleline has to be replaced in order to prepare for voltage conversion, which follows with the objectives under NBHDL's AM strategy and therefore, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and in-field assessment of the poleline are the sources of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	There is not a obvious secondary driver and therefore the driver to the project is the one mentioned above. Although there are not any major safety issues the 22 new poles will employ much greater separations due to increased spacing of the new framing standards which will lead to safer maintenance of the line for workers and will address end of life plant that can also lead to hazards for the public and workers.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 planned projects scheduled the Main Street West Rebuild is ranked #11. Given the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan. It should be noted that although this project ranks #11, it has been scheduled early in the year because of the following reasons: i) it is close to 12.47/4.16kV boundary (outward in concept); and ii) it provides a major tie between two substations, MS19 and MS18 which will help initiate voltage conversion earlier in 2015.
Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)	
Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA Report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer.

Safety (5.4.5.2.B.2)

The new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors and replacing end of life assets always reduces the risk relating to possible hazards. The aforementioned risk is currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

There are no environmental benefits related to this project

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The majority of the poles, conductor and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The remaining poles, although in fair to good condition are too short to accommodate new framing standards and therefore must be replaced as part of the project. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the voltage conversion plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The majority of the poles, conductor and equipment are in poor condition with the remaining assets falling between fair and good. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio. While some of the assets are at a fair to good condition, and that seemingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

154 Residential customers, 10 GS<50 customers, and 1 GS>50 customer would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a fairly number of residential customers and a small number of commercial type customers, so when compared to the system as a whole this is very small piece of it. Typically in lines, assets fail one at a time and although costly, can be addressed quickly, and therefore the risk of prolonged outages is very low in the event of a typical failure.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #11 out of 13 for completion in 2015. Completion of this project will address the replacement of 16 of the 200 poles needed to keep up with the required system renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #11 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is driven by typical renewal costs of replacing polelines, the only aspect of this project that may lead to higher costs is the fact it is scheduled to take place over the winter months, aside from that costs are quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Project Name	**Sherbrooke Street Rebuild - Second x Oak**			
Investment Category	System Renewal			
Project Description	The Sherbrooke Street Rebuild project consists of the design, construction and installation of a new poleline, built to 15kV standards, on Sherbrooke Street between Second Avenue and Oak Street to replace the existing poleline that was built to 5kV standards and operating at 4.16kV. The new construction will involve taller poles to accommodate new framing standards implemented as a result of Ontario Regulation 22-04, and allow future operation of the poleline at 12.47kV. The completion of this project is necessary to allow for the continuance of the NBHDL Voltage Conversion Plan.			
Capital Investment	Gross Capital	$112,822		
(5.4.5.2.A.first bullet)	Customer Contribution	$0.00		
	Net Capital	$112,822		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA)	Customer Attachments (#):	61		
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	300.2		
Project Timing	Start Date	October 2015 - Engineering		
(5.4.5.2.A.third bullet)		November 2015 - Construction		
	Expected In-Service Date	Dec-15		
	Expenditure Timing	Q1:	0%	$0
		Q2:	0%	$0
		Q3:	0%	$0
		Q4:	100%	$112,822
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	As this is project is scheduled later in the year, a risk to getting this project completed is the execution of the work preceding it. This will be mitigated via weekly production meetings with both Operations staff and Engineering staff, and the tracking of capital spending in line with Section 2.3 of the DSP. As this will be scheduled for November/December construction, winter conditions are a possibility and therefore another risk is dealing with the consequences that winter brings, narrower streets, cold weather, frost in the ground. Although a lot of this cannot be mitigated, processes are in place to make sure the project flows as safely and efficiently as possible. A final risk, again related to time of year, is any required outages to accommodate the build must be kept to minimum as electric heat is prevalent in our region and therefore we try and minimize all outages in the winter months. Crews will mitigate by sectioning work into small pieces to minimize outages, and if that is not possible worst case will be to complete work requiring outages in the spring months.			

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Comparative Information (5.4.5.2.A.fifth bullet)	As there are a number of different sized poles required on the Sherbrooke project, there is no direct comparator in scope, size and/or design for this project.
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and Information Requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver of this project is the completion of NBHDL's Voltage Conversion Plan (as identified in the DSP Section 1.0) which aligns with the replacement of end of life assets requiring renewal. Currently, the Voltage Conversion Plan is 74.2 percent complete. The majority of Capital Projects scheduled to be undertaken in 2015 relate to the completion of this plan. This overall condition of the assets under this project is fair, some are poor, some are good, but because the majority of poles are less than 40' in height, the poleline has to be replaced in order to prepare for voltage conversion, which follows with the objectives under NBHDL's AM strategy and therefore, this project, and similar poleline projects, is to be completed in 2015. Failing to do so will prevent the completion of the Voltage Conversion Plan and have a detrimental cascading effect on future AM planning at NBHDL.
Related Objectives/Performance Targets	NBHDL Objective's 3 & 4 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The NBHDL Voltage Conversion Plan and in-field assessment of the poleline are the sources of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	There is not a obvious secondary driver and therefore the driver to the project is the one mentioned above. Although there are not any major safety issues, the five new poles will employ much greater separations due to increased spacing of the new framing standards which will lead to safer maintenance of the line for workers and will address end of life plant that can also lead to hazards for the public and workers.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	NBHDL existing knowledge of asset conditions established through its capital planning and O&M procedures is the source of information that identified the secondary driver.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO and the Voltage Conversion Plan. Currently, a new prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required within the remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. Of the 13 planned projects scheduled, Sherbrooke is ranked #13. Given the safety risks to employees and public, this type of project is a priority for NBHDL in 2015. The specific ranking of this poleline project in the Voltage Conversion Plan is determined based on a radial (outward in) methodology wherein 4kV substations on the perimeter were (and continue to be) replaced with 15kV substations on the perimeter of the voltage conversion area which drove newly built 15kV polelines operating at 12.47kV into the 4kV areas. To offload substations in the core and convert them to 15kV feeders from the outside required replacing all substations until only a few remained by the currency of this DSP. One remaining substation will be decommissioned by early 2016 in accordance with the schedule of the Voltage Conversion Plan. This, along with the specific ranks of all similar poleline renewal projects, is further explained in Section 4.2.3.2 of the DSP. To ensure no further potential for service failure or any safety hazards due to the age, nature and condition of the assets relative to this project, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The renewal on this project will permit the operation of the line at 12.47kV, which increases flexibility of the system as whole in outage scenarios and day to day switching requirements. It will also contribute a small portion to the reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, increased flexibility of the system via harmonization of the distribution voltage to 15kV, and a decrease in line loss through this section of the circuit due to operation at a higher voltage.
Impact on reliability performance (including on the frequency and duration of outages)	This project has does not negatively impact reliability performance. In a catastrophic event (substation transformer failure, storm) the flexibility of having one distribution voltage will allow for faster restoration of the grid. This project is a piece of the overall plan to achieve the goal of one distribution voltage which ultimately provides more reliability by reducing the frequency and duration of outages. For clarity, it is not this specific poleline project that will address reliability issues but rather the overall replacement of the 4kV polelines remaining in the NBDHL service area.

Project Alternatives

The ACA Report (at page 63) states that around 319 poles should be replaced per year. Given this information and with thought to project affordability under the capital expenditure envelope, NBHDL made the decision to attempt to replace 200 poles/year. Historically, the prioritization of which poles to replace was done by replacing poles in the 4kV area because of the added benefits of replacing 4kV polelines vs. replacing 12.47kv lines (as identified in the Voltage Conversion Plan). Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards.
With the aforementioned considerations in mind, NBHDL considered several alternatives to achieve the poleline replacement goal and specifically this project including: i) leaving the line in its current state; ii) Renew or recondition the line; iii) replacement of the existing poleline to continue operating at 4kV; iv) replacement of the existing poleline to continue operating at 4kV with a higher standard of poleline asset and v) replacement with the poleline with a poleline operating at 15kV.
i) Leaving the line in this current state has the potential to cause safety and reliability issues, lead to increased O&M costs and hinder the completion of the Voltage Conversion Plan. Therefore this is not a feasible option.
ii) Renewal or reconditioning of the 4kV poleline is not a practical option as NBHDL is undertaking, and has almost completed, the elimination of all substations operating at 4kV as part of the Voltage Conversion Plan. Reconditioning the line as part of a renewal effort is also not an option as the current poles are not of sufficient height to meet regulatory requirements.
iii) As with renewal, replacement at 4kV is not a viable option. In addition to the elimination of 4kV substations that impacts reconditioning, replacement is also not a practical as the required pole height for a 4kV line is the same as a line for 15kV. As the costs are the same for the pole itself, this adds to the viability of installing a line that operates at 15kV. Further, insulators are no longer made at 5kV and all available insulators would be designed for 15kV. As the 4kV line is no longer up to NBHDL standards and specifically does not accord with the Voltage Conversion Plan, it would be impractical to install a pole line and insulators that are designed for 15kV for a 4kV replacement line. This would also cause considerable issues with inventory in stocking assets designed for two types of line voltage (a consideration in the formulation of the Voltage Conversion Plan).
iv) Building the 4kV polelines to a higher standard is an option, but this would lead to taller poles, new inventory and a line that would not be capable of operating at the voltage it was designed to without substantial investment into substation assets and the rest of the feeder. Given these undesirable consequences, this option is not practical for NBHDL.
v) The final option, and the option decided on by NBHDL, is the replacement of the 4kV line with a 15kV line. Given the requirements of pole height under regulatory framing requirements, the practicality of the 15kV line given the balance of the NBHDL asset portfolio and the feeders in the system, this option makes the best business sense and provides the best benefit to the customer.

Safety (5.4.5.2.B.2)

The new framing will employ standards that make general work on the poleline much safer due to increased separation of high voltage conductors, and increased separation between high voltage conductors to low voltage conductors and replacing end of life assets always reduces the risk relating to possible hazards. The aforementioned risk is currently managed by health & safety policies of NBHDL and required safety procedures for workers however; replacing this asset would result in a much safer system.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with other utilities is not applicable as this poleline is in the middle of NBHDL's service territory. Regional Planning is also not applicable to this project, as capacity is not changing. Communication companies attached to the pole will benefit by increased safety for their workers.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new construction will provide space for future equipment to be installed easily as 10'6" of space is left on all poles between phase conductors and the neutral conductor as part of the current framing design. At this time there is no future technological functionality being installed (i.e. automated switches). The poleline is part of a plan that will harmonize the distribution system to one voltage to increase the benefits of operating the system in the future.

Economic Development (5.4.5.2.B.5)

This is the renewal of an existing poleline in a fully developed part of NBHDL's service territory. There will be very limited economic development as a result of the project, however increased capacity will be available when the line is operating at 12.47kV should existing developments require it which could possibly lead to economic growth and job creation.

Environmental Benefits (5.4.5.2.B.6)

There are no environmental benefits related to this project.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

Over half of the poles, conductors and equipment in this section of line are past their useful life and will affect safety and reliability targets if not addressed. The remaining poles, although in fair to good condition are too short to accommodate new framing standards and therefore must be replaced as part of the project. The poleline is not capable of operating at 12.47kV and therefore is an obstacle to completing the voltage conversion plan if not rebuilt.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

Over half of the poles, conductors and equipment are in poor condition with the remaining assets falling between fair and good. This is to be expected as the 4kV system generally encompasses the oldest assets in the NBHDL portfolio. While some of the assets are at a fair to good condition, and that seemingly would not require urgent action, this poleline must be considered in its entirety and under that lens, the asset is, for the most part, considered in poor condition.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

49 Residential customers and 12 GS<50 customers would be potentially affected if the assets related to this project were to fail.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, eliminate safety issues and allow increased flexibility of the operation of the grid. All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact in terms of the affect of potential failure is low. This is a modest section of line that supplies a small number of residential customers and even smaller number of commercial type customers, so when compared to the system as a whole this is very small piece of it. Typically in lines, assets fail one at a time and although costly, can be addressed quickly, and therefore the risk of prolonged outages is very low in the event of a typical failure.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on other projects, but without it, the Voltage Conversion Plan cannot be completed. There are no System Access, System Renewal, System Service or General Plant projects that are required for completion in order to complete this project. This project also accords with NBHDL's typical rate of asset replacement that has been exhibited through the previous years of the Voltage Conversion Plan. Under the Voltage Conversion Plan and in accordance with NBDHL's Prioritization Matrix, this project is required to be completed and ranks #13 out of 13 for completion in 2015. Completion of this project will address the replacement of 5 of the 200 poles needed to keep up with the required system renewal plan.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no immediate material impact to O&M costs. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which will help reduce future O&M costs. The elimination of the 4kV system also as whole will result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 12.47kV stations, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, System O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) will be available for other O&M tasks at NBHDL.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however the 4kV renewal as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a detailed prioritization system for all projects to be implemented starting in 2016. This system will incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. For the year 2015, each project has been prioritized based on necessity as calculated by NBHDL and illustrated by the Prioritization Matrix. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked #13 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: forecasted reliability benefits, increased safety for public and employees, a reduction in overall system O&M cost, reduced project risks for the overall system from a timing perspective, minimizing service outages and outage time and ultimately the completion of the Voltage Conversion Plan. The cost of the project is driven by typical renewal costs of replacing polelines, the only aspect of this project that may lead to higher costs is the fact it is scheduled to take place over the winter months, aside from that costs are quite typical. Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in significant difficulties in completing the Voltage Conversion Plan as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives and the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The Voltage Conversion Plan, in its most recent iteration, has been in place for several years involving replacement of polelines from the perimeter of the service area inward, and it has now reached time for this project to be initiated.

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Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like was evaluated as a project alternative and found not to be a viable solution. Ultimately, given the efforts of the Voltage Conversion Plan and the elimination of the 4kV system, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. None of the alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Minor Betterments - System Renewal**			
Investment Category	System Renewal			
Project Description	Minor Betterment projects represent small unplanned projects over the year that fall under one of the following: 1) The rehabilitation or expansion of HV lines and LV lines required to service new customers or upgrade existing customers (5 poles or less). This type of project arises from service requests from new or existing customers. 2) Small renewal projects to replace assets found in very poor condition and require immediate replacement (5 poles or less). This type of project arises from trouble calls, maintenance programs, and information provided from 3rd parties (ESA, customers, communication companies). This capital project summary will detail projects relating to #2.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$106,591		
	Customer Contribution	$0.00		
	Net Capital	$106,591		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Information not available until work happens.		
	Customer Load (peak KVA)	Information not available until work happens.		
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	01/12/2015		
	Expenditure Timing	Q1:	25%	$26,648
		Q2:	25%	$26,648
		Q3:	25%	$26,648
		Q4:	25%	$26,648
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	Not Applicable.			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $69,504 2011: $87,896 2012: $120,395 2013: $251,724 2014: $86,676			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver behind the majority of these projects is the requirement to replace end of life assets that were not scheduled for replacement, but due to their present condition must be replaced and replaced immediately to ensure that safety, and reliability are not compromised.
Related Objectives/Performance Targets	NBHDL Objective's 2 & 3 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Asset conditions at the time of discovery and consequences of not doing anything provide the justification required.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	Investments are required in order to ensure continued service to existing customers and eliminate safety issues.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	All projects ensure the elimination of safety hazards and that reliability is maintained.
Impact on reliability performance (including on the frequency and duration of outages)	Reliability may be impacted by failed assets involved in projects, however replacement of failed assets will only help improve reliability in the future.

Project Alternatives

Alternatives are rarely considered for these projects as the majority involve like for like replacements. At times, pole heights will be adjusted to align to future needs, and transformer sizing may be increased or decreased based on loading information. Both adjustments are made to avoid future costs.

Safety (5.4.5.2.B.2)

The majority of these projects involve assets that have failed or are about to fail and therefore the work almost always involve eliminating a current or soon to be safety hazard.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Not applicable to this project.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to this project.

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SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Economic Development (5.4.5.2.B.5)

Not applicable to this project.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to this project.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

Assets involved with these projects are replaced because they have failed or are close to failure, and therefore are in line with lifecycle optimization policies and practices.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

As stated above, the assets involved with these projects have failed or about to fail and therefore have reached the end of their useful life. The asset condition relative to typical life varies project by project.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

The number of customers varies project by project.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

The quantitative customer impact varies project by project.

Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The renewal of this section of line will ensure future reliability statistics are maintained at or above the target, and eliminate safety issues All of which will maintain or improve customer satisfaction.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

The value of customer impact varies project by project.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

Due to the nature of the projects, they are done immediately or scheduled very quickly. Other projects are deferred if required.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

These projects do not materially impact system O&M costs.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

There will be no material impact on reliability, however spot replacement of end of life assets as a whole will help reduce interruptions related to failed equipment. The elimination of safety hazards were considered as factors to the importance of the project. See section 5.4.5.2.B.2 above.

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Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

Investments in this category are required immediately and are not subject to project prioritization as they are, for the most part, non-discretionary.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

The majority of the assets replaced in this category fall under the like-for-like renewal but are typically not configured at extra costs. As noted above, sometimes assets are adjusted to align with future needs or to improve operation and/or efficiency all in efforts to save future costs. Due to the nature of the projects, this varies from project to project and when changes are made, the decisions behind them are typically made quickly. Note that these changes do not have significant benefits or costs. [I.e. Replacing a 40' pole with a 45' pole versus a 40' pole, the only difference in cost is the actual material pole cost, which is $60, as installation is the same for a 40' and 45'. Doing this will save the future costs associated with harvesting a new 40' pole that is too short for new construction.]

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Project Name	**MS22 - Substation Construction**			
Investment Category	System Renewal			
Project Description	Design and construction of new 15/20MVA substation (44-12.47/7.2kV) on an undeveloped piece of property NBHDL has owned for years. The new station will replace MS9, an existing 15/20MVA substation (44-12.47/7.2kV), and involve the implementation of SCADA. The ACA Report has been deemed the current MS9 as being in poor to very poor condition and is the last station in NBH's service territory without SCADA.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$1,805,765		
	Customer Contribution	$0		
	Net Capital	$1,805,765		
	O&M Costs (if applicable)	$0	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	1,860		
	Customer Load (peak KVA)	9,000		
Project Timing (5.4.5.2.A.third bullet)	Start Date	January 2015 - Engineering June 2015 - Construction (by successful contractor)		
	Expected In-Service Date	Oct-15		
	Expenditure Timing	Q1:	15%	$270,865
		Q2:	15%	$270,865
		Q3:	55%	$993,171
		Q4:	15%	$270,865
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The largest risk to the project will be the successful award of the project to a construction contractor. Availability and the ability to complete the project within budget are two items outside of NBHDL's control. The risk will be reduced by a issuance of 2015 Q1 construction tender that will go out to at least 5 bidders. The other risk around the project will be material delivery and this has already been drastically reduced by procuring the power transformers in 2014. It will be further reduced by having all material on order by end of Q1 2015.			
Comparative Information (5.4.5.2.A.fifth bullet)	For MS22, NBHDL has used comparative information from MS21, which was built in 2013. This substation is similar in scope to what is proposed for MS22, particularly so in electrical design, equipment used, and protection schemes implemented (including the addition of SCADA). Importantly, there is some differentiation between the two projects in that MS22 is a 20MVA station whereas MS21 is a 10MVA station. In addition, MS22 will be built on undeveloped land whereas MS21 was built on an existing substation property. These two factors are attributed to the difference in cost between the otherwise similar projects.			
	MS21 - Substation Construction	$1,238,044		
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			

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Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver for the project is the need to replace an asset that has aged significantly and is now in poor to very poor condition thus posing reliability and safety risks. The poor condition of MS9 can be attributed to its deteriorating foundation which is now beyond repair. In the event of asset failure at MS9, a large number of customers served by the asset would experience extend outages. This is particularly so as MS9 is a radial load station that is not easily restored or fed by other stations. Other stations within NBHDL's portfolio are able to provide support by adjacent feeds, but due to the location of MS9 this is significantly more difficult. The assets also pose safety hazards for workers who have to maintain them and work around them given the state of the foundation. The risk of not addressing the above issues is no longer manageable and therefore needs to be mitigated in upcoming year.
Related Objectives/Performance Targets	NBHDL objectives 2 and 3 (as identified in Exhibit 1)
Source and Nature of the Information Used to Justify the Investment	The ACA Report is the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	A secondary driver is enabling the implementation of SCADA at this station. This is the last station requiring SCADA and it cannot be done with the current equipment and asset as is currently in place at MS9. The new assets will all be compatible with SCADA and will enable the implementation to take place which will increase staff efficiencies and reduce outage restoration times.
Related Objectives/Performance Targets	NBHDL objective 4 (as identified in Exhibit 1)
Source and Nature of the Information Used to Justify the Investment	The ACA Report is the source of information used to justify the investment.
Investment Priority (5.4.5.2.B.1.b)	NBHDL prioritized its projects for the 2015 year based on necessity, the ACA Report (including Health Index information) prepared by METSCO. Currently, a fulsome prioritization scheme is anticipated to be implemented for projects following the start of 2016 but, at this time projects have been prioritized individually as they are required remaining capital expenditure envelope available to NBHDL from the 2010 Distribution System Plan. The MS22 substation project ranked #1 of 13 projects as identified by the Prioritization Matrix prepared as part of this DSP. Given the condition of the asset, the lack of SCADA and the safety risks to employees, this is the first project required for the NBHDL Capital Expenditure Plan. As previously indicated, when this asset fails, there is no mechanism to provide quick replacement power and it requires workers to travel to the station to get power back online. This, along with the specific ranks of all System Renewal projects, is further explained in Section 4 of the DSP. To ensure no further potential for service failure or any safety hazards, it is imperative that this project be completed as part of 2015's Capital Expenditure Plan.

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	SCADA will be implemented and prevent truck rolls for hold-offs or required breaker operations. Currently customer calls are the only way NBH is informed of outages related to MS9, with the implementation of SCADA visibility will be given to the entire area, reducing outage times and improving system operations.
Net benefits accruing to customers	Reduced outage duration due to implementation of SCADA. Although reliability is not a current concern, the elimination of MS9 represents the mitigation of a potential major outage for the customers in the area due to the health index rating assigned to MS9 in the ACA.
Impact on reliability performance (including on the frequency and duration of outages)	Outage durations will be reduced due to automation (SCADA). At this time NBHDL does not have a worst performing station or feeder analysis and therefore this cannot be quantified. Such analysis is scheduled to be implemented by 2016 to provide a more fulsome indication of the impact of investments on reliability performance for future planning purposes.

Project Alternatives

The ACA Report (at page #57) indicated the overall health of substation MS9 is in poor condition, with some of the major components in very poor condition. Historically, substations have typically been replaced at end of life or when indicated as being in poor or very poor condition, subject to other objectives of NBHDL. Currently, NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards. This project is strictly a System Renewal project.

With the aforementioned considerations in mind, NBHDL considered several alternatives in making its decision to replace MS9 including: i) leaving the substation in its current state; ii) renewing the substation ; iii) rebuilding the substation at its current location; and, iv) replacing the substation with a new substation at a different location.

i) As it stands, the ACA Report indicated this substation is in poor condition which is typical for a station nearing its end of life. The current state of the substation foundations requires immediate replacement as it is now beyond repair. As it is, this substation is a significant risk to safety and reliability, therefore 'doing nothing' is not a viable alternative.

ii) Renewing the substation is not a practical alternative. The condition of the substation foundation is such that repair is unlikely to provide a permanent or effective fix. The property the substation is on is untenable as it similar to a swamp and located beside a concrete plant. In addition, the majority of the equipment is currently not in accordance with current date standards or regulations (i.e. obsolete) and would require full replacement. Absent such replacement, SCADA could not be implemented. Given the above factors and resulting amount of work, this is not a viable alternative.

iii) As was the case with the renewal alternative, rebuilding the substation at its current location is impractical as it does not provide the benefits of a new station with solid foundations, in a suitable location with the ability for SCADA to be implemented. Taking this substation offline for the rebuild on location is also not optimal.

iv) Given the state of the substation foundations, the age of the equipment and the goal of implementing SCADA, the only viable alternative is the replacement of the substation at a new location – the method elected by NBHDL for this project. This option also allows MS9 to continue in operation while MS22 is constructed.

Safety (5.4.5.2.B.2)

The construction of MS22 will allow for the elimination of MS9, which has the following safety concerns: 1) Entire substation yard is grass, and at times under water, which does not provide proper worker protection in ground fault conditions; 2) The foundations of the structures and the transformer pads have substantial cracking; and 3) The substation fence currently connects to the neighbouring property fence (a concrete mixing yard) and poses a possible potential rise issue to non utility staff under fault conditions.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

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Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Not applicable, coordination with other utilities or 3rd party providers is not an option and this project is not related to regional planning.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The inclusion of SCADA at the new station finalizes the deployment of the SCADA system into all of the substations and will provide endless functionality in the years to come. The relays being installed also will allow for endless programming and protection, keeping the doors open for future functionality and operational requirements.

Economic Development (5.4.5.2.B.5)

The construction will involve employment of a contractor and a number of subcontractors working in the North Bay area for at least 4 to 5 months. The new substation will replace an existing substation and the capacity will allow further development of vacant land at that end of the City.

Environmental Benefits (5.4.5.2.B.6)

The new substation will include oil containment; in the event of a catastrophic failure of the power transformer, all spilled oil will be contained. MS9 currently does not have this feature. The reclosers will be solid dielectric type and therefore in the event of catastrophic failure, there is no oil to be spilled.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

As indicated in the ACA Report, MS9 is the worst ranked substation in terms of asset health and age. The replacement of MS9 with MS22 will put the station at the top of the health index and ensure strong reliability and worker safety for the next 20 to 30 years.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

MS9 is in very poor condition, which is to be expected as it is at the end of it's life cycle. The replacement of MS9 with MS22 will put the asset health back into the very good category which is expected of new assets.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

Although the number of customers varies depending on system configuration, 1860 customers are currently served by station under normal system configuration and therefore 1860 customers would be affected if this asset was to fail. As noted above, a failure of this specific asset could lead to a lengthy outage due to the location and the limited redundancy with the neighbouring station. Unfortunately customers by class cannot be provided. The new station will be state of the art and minimize the risk of failure substantially, in turn providing better service to the current 1860 customers supplied by MS9.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

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Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The replacement of MS9 will address an aging asset serving a significant number of customers. The age and health index of MS9 represents an increased risk of service interruption to customers. In the event of catastrophic failure, some customers may be without power for 24-48 hours due to the inability to push power from neighbouring stations to the City limits. Customer satisfaction would be extremely low in such a case. MS22 will address the issues by minimizing risk and ensuring customer satisfaction is maintained at a high level.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact is high in terms of the affect of potential failure. In the event of a failure a number of customers would be impacted and backup service may not be available for all customers. Although customer impact will always be high because substation assets serve a large number of customers, the construction of MS22 will minimize the probability of failure to ensure customer impact is managed.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on any other projects planned over the forecast period. This is the highest ranked substation project for 2015 with respect to priority and must be done in 2015 in order to maintain reliability and eliminate safety hazards. NBHDL has replaced 3 substations over the past 6 years, one every two years, with the main driver being replacement of aging assets and the secondary driver being the inclusion of SCADA. The spending was staged this way to ensure project completion and to allow affordability. This is the last substation requiring replacement, and would have been replaced first if it was a station operating at 4kV due to the condition of the assets. However, due to the increased benefit of replacing the other stations (2 operating at 4kV, one located inside HONI T.S. that was no longer permitted to be there), this station was prioritized last. This substation project can no longer be pushed back. The deterioration of the foundation and potential for service problems has reached an unacceptable level. As indicated earlier, the replacement of MS9 with MS22 is NBHDL's top priority project, not only among substations but among all System Renewal projects.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no material impact to O&M costs however, truck rolls will be reduced to establish hold-offs and deal with breaker operations. This will not result in less cost, but will prevent inefficiencies with crews having to leave other projects or tasks. All outage situations should also be reduced due to more efficient operation of the station through SCADA.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

Reliability performance will be improved through the replacement of an end of life asset and reduced outage times due to automation. See section above for safety factors

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Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

NBHDL has committed to a fully functional prioritization system for all projects starting in 2016. This system will incorporate worst performing station and feeder analysis to ensure optimized capital expenditure planning. It will also incorporate a formalized prioritization matrix designed by METSCO to ensure optimized capital expenditure planning. Each project was given a weighted score based on the following factors: public and employee safety, reliability and supply system security, asset condition, O&M costs (minimizing asset life cycle costs, minimizing risk of premature failures), technology enablement, operating efficiency, minimizing environmental risks and regulatory compliance. This particular project has been ranked 1 of the 13 projects currently slated for 2015 in the Prioritization Matrix based on various factors and field based execution considerations. The timing of this project also takes into account the benefits and costs stated above which are described at a high level for the purpose of this 2015 DSP. The completion of this project will provide the following benefits: ensuring an efficiency O&M process by providing a newly optimized asset, ensuring the substation is in line with the remaining assets currently operating SCADA, providing safer conditions for workers and employees, minimizing service outages and outage time and removing the last of the 'very poor' assets in NBHDL's asset portfolio.
Given that there may be applicable variation or uncertainty in some of the factors discussed above in this summary, NBHDL is cognizant of certain trade-offs and consequences that must be considered as part of any capital expenditure plan. It is difficult to readily quantify the consequences of pushing the project beyond 2015 however, it would result in the continued potential for reliability and safety issues as well as causing impact to capital expenditure planning for 2016 and coordination with the implementation of the formalized prioritization methodology. The rate of expenditure for 2015 is required, according to the NBHDL objectives stated in the DSP, to ensure no further depreciation of the asset takes place that would render the system unsafe or result in any potential service issues. As mentioned previously, NBHDL considered several alternatives for this project which were rejected for reasons already discussed. The replacement of the MS9 substation with a new substation designated MS22 is the best alternative with the most benefit and minimum cost.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

As discussed under 5.4.5.2.B.1.c, like for like renewal was evaluated as a project alternative and found not to be a viable solution. Ultimately, given discussion above on the consequences of rebuilding the substation where it currently is situated, the project does not meet the requirement for like for like renewal. This analysis involved comparing a project configured solely to meet the requirement, the current proposed project and technically feasible alternatives. Although MS22 is replacing a similar MS9 substation, this is a substation designed to a higher standard with an increased voltage to meet the standards applied in the rest of the NBHDL system. None of the other alternatives were viable for the NBHDL system for the reasons discussed. In addition, no extra cost has been added to address other distributor planning objectives.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**MS13 - Transformer Replacement - 13T1**			
Investment Category	System Renewal			
Project Description	This project involves the replacement of an end of life 6MVA power transformer operating in poor condition at NBHDL's MS13 substation. The project will cover procurement, installation, and connection of a new 7.5/10MVA power transformer and removal and disposal of the existing transformer. There is no other work scheduled under this project.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$271,470		
	Customer Contribution	$0		
	Net Capital	$271,470		
	O&M Costs (if applicable)	$0	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	1,260		
	Customer Load (peak KVA)	6,320		
Project Timing (5.4.5.2.A.third bullet)	Start Date	February 2015 - Issue Tender. March 2015 - Award project. August 2015 - Installation and Connection.		
	Expected In-Service Date	Sep-15		
	Expenditure Timing	Q1:	10%	$27,147
		Q2:	30%	$81,441
		Q3:	60%	$162,882
		Q4:	0%	$0
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The largest risk to the project will be the successful award of the project to a transformer manufacturer. The risk will be reduced by the issuance of a 2015 Q1 tender that will go out to at least 3 bidders. The other risk around the project will be delivery of the transformer based on the successful manufacturer's production schedule. This will also be mitigated by awarding the project by March.			
Comparative Information (5.4.5.2.A.fifth bullet)	The MS13-T1 transformer project is comparable to the following 2014 project: MS1: $278,506 - procurement of 1-7.5/10MVA power transformer.			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver for the project is the need to replace an asset that has aged significantly and is now in poor condition thus posing reliability and safety risks. The poor condition of 13T1 can be attributed to its age and loading.
Related Objectives/Performance Targets	NBHDL objective 3 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	The ACA Report is the source of information used to justify the investment.
Secondary Driver (5.4.5.2.B.1.a)	Not applicable.
Related Objectives/Performance Targets	Not applicable.
Source and Nature of the Information Used to Justify the Investment	Not applicable.
Investment Priority (5.4.5.2.B.1.b)	Due to the serious risks involved with power transformer failures (lengthy outages involving large amounts of customers, the possibility of fire, and the possibility of damage to adjacent assets, etc.) individual power transformer replacements will follow the replacement strategy put forth in the ACA Report and are considered a high priority. This project was not included in the prioritization scheme (Prioritization Matrix) employed in 2015 and similar replacements in following years will also be outside of the new prioritization process.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not applicable.
Net benefits accruing to customers	Assurance of continued supply, by eliminating the increasing probability of having an in-service power transformer failure.
Impact on reliability performance (including on the frequency and duration of outages)	This project is aimed at ensuring long term reliability by replacing an asset prior to its failure as a failure interrupts service to a large number of customers and possibly for a long duration.

Project Alternatives

The ACA Report (at page #53) indicated the overall health of the 13T1 transformer in poor condition. NBHDL experiences no capacity issues, or reliability issues that can be addressed by capital projects, and there are no 12.47kV lines that are contributing major dollars to O&M or are causing major safety hazards. This project is strictly a System Renewal project.

With the aforementioned considerations in mind, NBHDL considered three alternatives in making its decision to replace the 13T1 power transformer including: i) leaving the existing power transformer in it's place; ii) replacing the power transformer at 6MVA ; iii) replacing the power transformer with a 7.5/10MVA transformer;

i) As it stands, the ACA Report indicated the power transformer is in poor condition which is typical for a power transformer past its useful life. As it is, this condition of the transformer contributes a high risk to maintaining reliability, and therefore 'doing nothing' is not a viable alternative. NBHDL is very sensitive to this as 4 power transformer failures have been experienced over the past 5 years, causing large power outages, loads of extra work both in the field and administratively, and a reduction in the redundancy of the system until the transformer is replaced (most cases 1 to 1.5 years).

ii) Replacing the transformer with the same size is a feasible option, however this is the only power transformer in the NBHDL system that is not a 7.5/10MVA transformer. The existing substation assets at MS13 are capable of accepting the increased power with no further investment, and aligning all substation transformer capacities makes interchangeability extremely easy if required. For the very little increase in costs to move to a 7.5MVA transformer it does not make sense to renew with a 6MVA transformer.

iii) For the reasons mentioned in ii) above, renewing the transformer with a capacity of 7.5/10MVA makes the most sense and for that reason is the option that NBHDL selected.

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Safety (5.4.5.2.B.2)

This project is not driven by safety related issues, although decreasing the risk of an in-service failure of the asset by renewing it could prevent a catastrophic failure from occurring, and in turn eliminating threats to worker and public safety

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Not applicable, coordination with other utilities or 3rd party providers is not an option and this project is not related to regional planning.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The new transformer will include a SEL 2414 relay that will provide telemetry data of the transformer back to the control room via SCADA, which aids in decision making with respect to grid operations and provides immediate annunciation of imminent problems.

Economic Development (5.4.5.2.B.5)

This project will involve the award of a power transformer to a transformer manufacturer, possibly in the province of Ontario, representing a significant contract for the successful manufacturer.

Environmental Benefits (5.4.5.2.B.6)

Although the existing transformer is well below the acceptable limit for PCB content as defined in the PCB regulations issued by Environment Canada, at 4.0ppm, the new transformer will be PCB free.

Category-specific requirements - System Renewal (5.4.5.2.C.b.)

Relationship between the Characteristics of Targeted Assets and the Consequences of Asset Failure (5.4.5.2.C.b.first bullet)

Asset Performance Targets and Asset Lifecycle Optimization Policies and Practices (5.4.5.2.C.b.first bullet. First dash)

The 13T1 transformer is well past it's useful life (48 years old) and in poor condition. This is the oldest power transformer in the NBHDL system and is in need of replacement. This is in line with NBHDL lifecycle optimization policies and practices.

Asset Condition Relative to Typical Life Cycle (5.4.5.2.C.b.first bullet. Second dash)

The 13T1 transformer is in poor condition, as per the ACA Report, which is to be expected as it is past the typical life cycle for power transformers. The replacement of 13T1 will put the asset health back into the very good category which is expected of new assets.

Number of Customers in Each Class Potentially Affected (5.4.5.2.C.b.first bullet. Third dash)

Although the number of customers varies depending on system configuration, 1260 customers are currently served by this station under normal system configuration and therefore 1260 customers would be affected if this asset was to fail. As noted above, a failure of a power transformer can lead to a lengthy outage and safety related issues. Unfortunately customers by class cannot be provided. The new transformer will be state of the art and minimize the risk of failure substantially, in turn providing better service to the current 1260 customers supplied by it.

Quantitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fourth dash)

Quantitative customer impacts and risk are not currently available (reliability statistics by station or feeder are not available).

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Qualitative Customer Impact and Risk (5.4.5.2.C.b.first bullet. Fifth dash)

The replacement of 13T1 will address an aging asset serving a significant number of customers. The age and health index of 13T1 represents an increased risk of service interruption to customers, and such interruptions would have a substantial impact on customers. The replacement of 13T1 will address the issues by minimizing risk and ensuring customer satisfaction is maintained at a high level.

Value of Customer Impact (5.4.5.2.C.b.first bullet. Sixth dash)

Customer impact is high in terms of the affect of potential failure. In the event of a failure a number of customers would be impacted. Although customer impact will always be high because substation assets serve a large number of customers, the replacement of 13T1 will minimize the probability of failure to ensure customer impact is managed.

Other Factors Affecting Project Timing (5.4.5.2.C.b.second bullet)

This project is not dependent on any other projects planned over the forecast period.

Consequences for System O&M costs (5.4.5.2.C.b.third bullet)

There will be no material impact to O&M costs however the probability of an in-service failure will be substantially reduced basically removing the chance of major O&M costs that would result in the event of a failure.

Reliability and Safety Factors (5.4.5.2.C.b.fourth bullet)

Reliability and safety factors are not drivers of the project, although the project will drastically reduce the chance of a lengthy outage and possible safety hazards related to an in service failure.

Analysis of Project Benefits and Timing (5.4.5.2.C.b.fifth bullet)

The timing of this project is strictly based on the increasing probability of failure due to the age and condition of the existing transformer and mitigating the associated risk. The scheduling of power transformer replacements over the forecast period has been prioritized based on the recommendations of the ACA Report.

Like for Like Renewal Analysis (5.4.5.2.C.b.sixth bullet)

This qualifies as a like for like replacement project, and although the size of the transformer is being increased slightly the additional costs are negligible and therefore no further analysis was conducted.

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GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

2015 Capital Project Summary

Project Name	**Capital Infrastructure Modernization - Conversion to Interval Meters**		
Investment Category	System Service		
Project Description	This project includes the execution of Year 2 targets in relation to a 6 year (2014~2019) capital strategy for the conversion of all traditional meters remaining in NBHDL's system to interval meters. 148 meters are to be replaced in 2015.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$199,213.00	
	Customer Contribution	$0.00	
	Net Capital	$199,213.00	
	O&M Expenditure	$0.00	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	148	
	Customer Load (peak KVA)	0	(not applicable)
Project Timing (5.4.5.2.A.third bullet)	Start Date	Jan-15	
	Expected In-Service Date	Dec-15	
	Expenditure Timing	Q1:	25%
		Q2:	25%
		Q3:	25%
		Q4:	25%
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The major risk of this project is related to the scheduling of work with customers in order to complete installations for 2015. Schedule risk is due to customer delays or restricted access to work sites. In many cases, this project will require after-hours work in order to accommodate commercial businesses and their need to minimize customer interruptions to service during operating hours. There may also be scenarios when customers do not have approved disconnect switches which may require upgrade in order to pass ESA inspection. To mitigate this risk, NBHDL will prepare a schedule of jobs and co-ordinate with customers well in advance of targeted dates. A letter from management will go out to all customers providing them with an overview and list of instructions that specify how they can be better prepared.		
Comparative Information (5.4.5.2.A.fifth bullet)	While NBHDL has significant experience from the Smart Meter implementation in 2009 and 2010, there have been no comparable projects of this scale for the conversion of the meter types involved in the transition to interval meters for larger businesses. These metering configurations are slightly more complex and additional site work is required to upgrade the services. An example of this may be the difference in changing out an existing S.Base meter versus a P.Base meter where the upgrade may or may not require the installation of a metering cabinet, routing of new wires, addition or removal of CT's and PTs, re-location of the dis-connect switch, and in some cases the re-location of the meter to enable AMI communication.		
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment and therefore capital and OM&A costs related to REG will not be incurred.		
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.		

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	NBHDL addressed the need for a long term plan for metering infrastructure and sought the expertise of Util-Assist in the preparation of that plan as part of the 2015 rate application. The Util-Assist Report that is a driver to this project is attached as Appendix P to the DSP. NBHDL understood that within its system there was a segment of customers that were not capable of hourly billing and recognized an opportunity to leverage existing infrastructure for a more automated process that also allows for improved technology as seen in the meters selected for the upgrade. The metering upgrade was also required to phase out legacy metering configurations and various meter types that were no longer supported by vendors and reaching end of seal life. Ultimately customers will transition to hourly billing which will allow electricity costs to more accurately reflect actual demand. Customers will better positioned to reduce demand, shift load and react to pricing signals in the market that will allow them the opportunity to reduce overall electricity costs.
Related Objectives/Performance Targets	NBHDL objectives 1and 4 (as identified in Exhibit 1).
Secondary Driver (5.4.5.2.B.1.a)	The secondary driver behind this project are the changes to Section 5.3.1b) of the Distribution System Code that are to take affect August 21, 2014 (*EB-2013-0311)* . The revisions to the code state that distributors have until 2020 to replace existing traditional meters in the GS>50 class with an interval or MIST meter. Due to the timing of NBHDL's COS application, NBHDL felt it appropriate to have the project included in rate base.
Related Objectives/Performance Targets	NBHDL objective 5 (as identified in Exhibit 1)
Investment Priority (5.4.5.2.B.1.b)	These investments cannot be deferred and must proceed as planned to meet regulatory compliance by 2020. The replacements coordinated based on meter seal expiry dates.
Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)	Metering asset management is governed by Measurement Canada regulation and customer requirements for new and upgraded services.
Effect on system operation efficiency and cost effectiveness	Standardized inventory will allow efficient management of NBHDL's metering assets. It will reduce employee training requirements to troubleshoot problems and further ease the formal sync process for the IESO MDM/R TOU billed customers and for other rate classes. Standardization will also allow NBHDL to leverage the existing capabilities of its AMI system to improve data collection costs, as well as administration of multiple business processes to facilitate billing. The AMI system will provide intelligence such as alarm/event information and instantaneous reads for useful engineering analysis.
Net benefits to customers	The investment into the metering infrastructure upgrade project will allow customers to have the benefit of being billed based on HOEP which reflects the actual market price of electricity. The system automation and streamlined billing processes will reduce the overall cost of billing customers; especially for the >50 rate classes. The data will be further utilized for conservation and demand management efforts as secured data can be used by third party applications for analytics and energy management. This provides further options to customers for reducing their baseline energy use and helps with evaluating the business case for investing in energy efficient technologies. Lastly, it serves as a benchmark against like-sized facilities and provides customers with historical information for tracking/reporting.
Impact on reliability performance	The new smart meters will improve billing reliability and accuracy due to the automated nature of the transaction. Data validation will take place and abnormalities will be identified by the AMI system. Storage of data will also be standardized which will allow NBHDL to investigate power quality issues or power interruption problems through analytics or engineering analysis.

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EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Project Alternatives	NBHDL has a total of 221 meters seals expiring in 2014/2015. The alternative to this project would result in the labor cost of removing these legacy meters from service followed by shipping them for re-certification and finally re-installing them back in service. Their interim replacement or end of life replacement would be a digital smart meter as the old thermal demand meters or other mechanical meters are no longer available. There is a high probability that the replacement smart meters would not have AMI communication capabilities which would not serve any real-benefits as the cost of maintaining the inventory for these meters, along with mechanical meters would not be effective. The manual billing processes will still exist and maintaining assets would become onerous and ineffective. For these reasons, a metering capital strategy was required to address the gap and to put a plan in place that simplifies the metering population and modernizes the infrastructure with the final goal of being cost effective.

Safety (5.4.5.2.B.2)

This project is not intended to address safety concerns with the distribution system. However, this project will require the inspection of disconnect switches to ensure they are in safe operating conditions. NBHDL will require customers to upgrade their disconnect switches when they pose a safety hazard during a shut-down scenario. Disconnect switches are often not maintained and can pose a fire or electric safety hazard.

Cyber-security, Privacy (5.4.5.2.B.3)

NBHDL's Smart Meter and related AMI network have been procured through Sensus. Sensus' system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols. It also includes a robust AES-256 based encryption, exceeding levels currently in use for banking. As part of its continuous improvement model, NBHDL along with the D9 group performs periodic security assessments to identify opportunities for enhanced system hardening. NBHDL, the D9 group, and several other utilities also partner with Power Stream to operate and maintain a Sensus test lab for functionality and security testing in a controlled environment further enhancing the proactive approach to operating a safe, reliable, and secure AMI.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links 3rd party providers (5.4.5.2.B.4.a)

Co-ordination with utilities and regional planning is not required. However, NBHDL has reviewed the approach adopted by Sensus group users which is similar to NBHDL's strategy of employing the Elster A3RL or A3RAL meter types. The advantage of utilizing the same technology by Ontario Sensus user groups provides an advantage to LDC's as they can ensure the AMI system maintained by Sensus is capable of meeting future operational and data transmission/collection requirements. With regards to upgrading the metering assets, NBHDL coordinates with customers, contractors, and ESA as required by the scope of work involved.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The Elster A3RL and A3RAL meters provide TOU and hourly data required for GS<50 and GS>50 customer bases respectively. The meters are enabled with a Sensus communication module which allows communication and data transmission through NBHDL's Advanced Metering Infrastructure. This functionality will allow future operational benefits as data can be transferred over the network to the head end systems where it can be directed as necessary for billing or customer value add services. The data will be streamlined, easy to manage, and will be useful for billing/conservation activities.

Economic Development (5.4.5.2.B.5)

NBHDL is executing this project internally with minimum use of local electrical contractors. NBHDL will be coordinating the scheduling of the work to minimize disruptions to businesses to the greatest extent possible so there are minimal economic impacts to the customer. From time to time, contractors may be used to re-run wires and to obtain ESA inspections when work is required on customer owned equipment.

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SYSTEM SERVICE SPECIFIC REQUIREMENTS (5.4.5.2.C.c)

Environmental Benefits (5.4.5.2.B.6)

The Smart Meter infrastructure supports the province's conservation culture. The granularity of the data will enable all business consumers to map their bills to their consumption and help drive savings. Smart meter data analytics is a growing and fast paced industry and many third party solutions are available to help customers introduce better control and intelligence into their operations. Smart meters will also reduce manual paper and manual on-site reading requirements which creates efficiency.

Assessment of the Benefits of the Project for Customers (5.4.5.2.C.c.first bullet)

This project is for system betterment as it will allow customers to be billed on HOEP as opposed to the net system load shape which would reflect their actual cost of electricity based on precisely the time of the day and hour they utilized the energy. The granularity of available data will also allow customers to participate in energy management activities, energy benchmarks, and help with the decision making process when investing in energy efficient technologies. The data available can also be leveraged by third party systems for monitoring, reporting, control, and other facility specific benefits. Customers will gain control of their energy profile and respond to market pricing signals to reduce their overall cost. Furthermore, customers can understand if or when they hit peaks and if there are opportunities to reduce waste. Based on these benefits, the result will be indirect reductions in cost through higher efficiencies. It is not practicable to provide an exact avoided cost as a result of this project.

Information on Regional Planning (5.4.5.2.C.c.second bullet)

This project is not related to or impacted by regional planning requirements.

Integration of Advanced Technology (5.4.5.2.C.c.third bullet)

The new smart meters will have the ability to integrate with NBHDL's AMI system and its head end software. This will allow a single point of storage for data and a secured transmission platform over the system which allows for the efficient use of existing systems. The data can be managed from the head end system and directed as necessary for billing or energy management or customer value add functions thereby making it adaptable and scalable for the future. The data will be encrypted with the AES 256 encryption, exceeding current levels used for banking.

System Benefits to Reliability, Efficiency and Safety (5.4.5.2.C.c.fourth bullet)

The new smart meters will allow NBHDL to accurately and efficiently bill customers based on the market price of electricity. The reliability of the meter population will also increase as the standardized population will be easy to manage and to perform QA/QC assessment when power quality and metering accuracy concerns are raised by customers. The data available can be used for behind-the-meter efficiency through means of energy management.

Factors Affecting Implementation Timing/Priority (5.4.5.2.C.c.fifth bullet)

The key factor affecting the implementation timing and priority is that NBHDL currently has 221 meters that are at the end of meter seal life. To address this, NBHDL needs to have an aggressive 2014/2015 upgrade schedule to avoid the costs of removing the existing population, sending them for re-certification, and finding interim alternatives.

Summary of Options Analysis (5.4.5.2.C.c.sixth bullet)

If NBHDL did not act on its metering capital strategy, NBHDL would become non-compliant with Measurement Canada requirements for recertifying meters when they reach end of seal life. The implications of this would be very significant; if audited, Measurement Canada can order the removal of all meters that are end of life. This would create a capacity issue for the organization on top of the cost of finding alternatives and the fees for being non-compliant. The technically feasible alternative to the proposed project could be to replace the existing meters with new smart meters that are not AMI compliant. This would mean that those meters would not communicate over the air and alternative communication paths such as modem/phone line would be required to integrate into the phone systems. This alternative would allow customers to be billed based on HOEP, however it will create inventory management challenges along with the continuation of multiple billing processes and increased communication costs. This approach, though technical feasible, is not as cost effective as the approach adopted by NBHDL which leverages the capabilities of the existing AMI system.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Transformer Purchases - System Access**			
Investment Category	System Access			
Project Description	This project represents the investment into distribution transformers, both overhead and underground, throughout the given year. All new transformers are brought into inventory and are included in the overall PP&E gross assets, they do not then begin to appreciate until put into service. Transformers are then assigned to different projects as required, some System Renewal, some System Access. This specific summary will deal with the System Access assignments. For clarity, the capital expenditures sought in this project are specific to transformers that will be put into service in 2015.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$95,113		
	Customer Contribution	$0		
	Net Capital	$95,113		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	0	(not applicable)	
	Customer Load (peak KVA)	0	(not applicable)	
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	31/12/2015		
	Expenditure Timing	Q1:	25%	$23,778
		Q2:	25%	$23,778
		Q3:	25%	$23,778
		Q4:	25%	$23,778
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The timing of transformer purchases is based on inventory levels and the demand projects that materialize over the given year. In the system access category purchases are made to cover transformer needs for the following demand sub-categories: road relocations, subdivisions, primary services, and secondary services			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: 93,439 2011: 156,988 2012: 187,612 2013: 115,377 2014: 166.872			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The requirement to fulfill the obligations of all types of demand work.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request for service from customers, developers, and road owners
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	Transformers investments are made as required.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Transformers are an integral part of servicing, and investments in them are required in order to facilitate connections and the continued operation of the system. NBHDL, as a member of the North Eastern District Buying Consortium ("NEDBC"), tenders the procurement of transformers on a 5 year contract, and therefore purchasing alternatives are basically nonexistent over the contract.

Safety (5.4.5.2.B.2)

The purchase of transformers for demand based work is not intended to address safety concerns

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to the purchase of transformers

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with the successful transformer manufacturer is a daily function. From the administration of the contract to the actual ordering and receiving of transformers, the relationship with the vendor is very important in ensuring inventory levels are always kept up to meet demand work. NBHDL is required to do a lot of coordination for the award of the contract in relation to the utilities that make up the NEDBC.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to road relocation projects.

Economic Development (5.4.5.2.B.5)

Not applicable.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

Environmental Benefits (5.4.5.2.B.6)

Not applicable.

Category-specific requirements - System Access (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

Distribution transformer purchases for demand work are made throughout the year and are based on necessity.

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

Transformers are purchased due to customer input, in the form of demand.

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet)

Transformer capital costs are determined based on a tendered 5 year contract. Prices are adjusted, both up and down, every quarter to reflect changes in the commodities that make up a transformer.

Controllable Cost Minimization (5.4.5.2.C.a.fourth bullet)

A tendered contract ensures competitive pricing and the control of costs associated with purchasing transformers.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

Not applicable.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

Not applicable.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

There are no options to consider, distribution transformer purchases are bound by the contract in place at the time of order.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

This is not applicable to the purchase of new transformers.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

Individual transformer purchase do not impact the system, nor do they require modifications to the system. Contributed capital is collected from the developer/customer for transformers that are used in subdivision projects and primary service projects.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Minor Betterments - System Access**			
Investment Category	System Access			
Project Description	Minor Betterment projects represent small unplanned projects over the year that fall under one of the following: 1) The rehabilitation or expansion of HV lines and LV lines required to service new customers or upgrade existing customers (5 poles or less). This type of project arises from service requests from new or existing customers. 2) Small renewal projects to replace assets found in very poor condition and require immediate replacement (5 poles or less). This type of project arises from trouble calls, maintenance programs, and information provided from 3rd parties (ESA, customers, communication companies). This capital project summary will detail projects relating to #1.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$230,102		
	Customer Contribution	$0.00		
	Net Capital	$230,102		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Information not available until work happens.		
	Customer Load (peak KVA)	Information not available until work happens.		
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	31/12/2015		
	Expenditure Timing	Q1:	25%	$57,526
		Q2:	25%	$57,526
		Q3:	25%	$57,526
		Q4:	25%	$57,526
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	Projects are completed as required, the only risks to completion of these type of projects would be if a high volume of them occurred at once. This would be managed with the use of queue process, first in, first out, and as a last resort by the hiring of contractors. This has not been required to date.			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $292,314 2011: $207,132 2012: $268,941 2013: $288,086 2014: $198,147			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver behind all of these projects is service requests, and the new or upgraded assets needed to accommodate the service requests.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request for service and the requirement to add or upgrade assets to faciliate the request
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	As these projects are to enable the connection of demand work (subdivisions, secondary services, and primary services), they to follow the requirements to connect customers set forth in the DSC and therefore are given top priority, and prioritized based on connection timeline requirements of the customers.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Minor Betterment projects relating to System Access are driven by customer requests and the specific requirements of the customer. Projects are considered individually and the most cost effective solutions to provide the assets up the point of connection of the customer are chosen, unless other options are requested by the customer, it is against policies and practices, or it contradicts municipal or provincial policy.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with customers and electricians are an important part of these projects, as it determines the options available or desired. As the projects involve new assets, coordination with the City is required when assessing feasible alternatives, as they have final approval on location of all assets within the road allowance.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to this project.

Economic Development (5.4.5.2.B.5)

Not applicable to this project.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to this project.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

SYSTEM RENEWAL SPECIFIC REQUIREMENTS (5.4.5.2.C.b)

Category-specific requirements - System Access (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

The timing of individual projects is based on what is required by the customer. As noted above, this work is top priority and therefore is handled as explained above in section 5.4.5.2.B.4

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

These projects are intiated by customers and are designed to meet the needs of customer requirements

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet)

The factors affecting final costs are normally a function of the following: municipal and provincial requirements (i.e. parts of town that must be underground), customer requests (i.e. the customer wants an extension to be underground), and from a construction point of view: the amout of the work required to connect the customer (i.e one new pole or five new poles, the location in town (urban or rural), and the subsurface conditions present. Rock can double or triple typical installation costs.

Controllabe Cost Minimization (5.4.5.2.C.a.fourth bullet)

The work required on the main lines to connect new customers or upgrade existing customers is done as cost effective as possible, unless influenced by factors out of NBHDL's control. In line extension situations, the customer is responsible for the full costs at which time the economic evaluation process is initiated.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

At times, other planning objectives are considered under these types of projects, however for the most part the projects pertain only to installing or upgrading assets to allow the connection of the new or upgraded customer making the request. The consideration for meeting other planning objetives can only be assesed once a reuqest is brought forth.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

NBHDL has options with respect to the assets required to provide the requested service, however feasible options must be reviewed on a project by project basis, which can not start until each individual project is initiated. In extension scenarios, the customer has the right to request underground servicing if desired.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

Alternatives are considered, however the analysis is completed on a project by project basis, and after the project is initiated. As the expenditure is based on forecasted amounts, this section is not relevant until a project is started or scheduled. When these projects are initiated however, they will be prioritized based on DSC requirements and, with all things equal, on a queue basis, first in, first out as described in Section 4.2.3.1 of the DSP.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

When applicable, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project. Results are not included as they cannot be determined until projects are brought forth. The majority of these projects do not require an economic evaluation to be required.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

System Access Minor Betterment projects for the most part have a low impact on the system, even when up to 5 poles are required. Individual project costs are typically below the materiality threshold and contributions from the customer are made in situations where applicable (line extensions with more than 2 poles) to cover costs, although the majority of the work does not require contribution.

North Bay Hydro Distribution Limited

2015 Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	Primary Services		
Investment Category	System Access		
Project Description	This category represents the capital work necessary to rehabilitate and/or expand infrastructure to service new customers or maintain existing customers, residential and general service, over the 400A threshold. These projects involve primary (high voltage) servicing and overhead or padmounted transformation.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$217,820	
	Customer Contribution	$122,421	
	Net Capital	$95,399	
	O&M Costs (if applicable)	$0.00	(not applicable)
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Various - driven by demand.	
	Customer Load (peak KVA)	Various - driven by demand.	
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015	
	Expected In-Service Date	31/12/2015	
	Expenditure Timing	Q1: 25%	$54,455
		Q2: 25%	$54,455
		Q3: 25%	$54,455
		Q4: 25%	$54,455
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	This type of servicing is common to NBHDL and is covered by well established processes both from design and construction perspectives which mitigates issues around timing related risk. As customer connections are very important NBH, timelines are strictly monitored and enforced to ensure obligations set forth in the DSC are met and that customer satisfaction is maintained.		
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $46,683 2011: $199,806 2012: $145,236 2013: $554,202 2014: $135,952		
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.		
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.		

North Bay Hydro Distribution Limited

2015 Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	Projects are mandatory and scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request for service and obligations set forth in the DSC.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	Upgrading existing or installing new primary services are top priority. Planning and design of these projects is handled through engineering work orders and are scheduled with crews as required.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Primary service projects are driven by customer requests and the specific requirements of the customer. Design and methodology for such projects is standardized through NBHDL policies and practices and in line with NBHDL's Conditions of Service. Alternatives are limited as servicing options are standardized, but if alternatives exist they are normally the choice of the customer. For example, the decision between an overhead or underground service is that of the customers.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to primary service projects.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with customers and electricians are an important part of primary service projects. For services of this size, the process starts with the customer filling out a NBHDL electrical planning requirements (EPR) form. An estimate, based on the information on the form is provided to the customer and the customer makes a decision is made to move forward with the servicing or not. NBHDL construction activates are based on a work order produced from Engineering and the scheduling of work is coordinated directly with the Operations department and the customer. Authorization from the Electrical Safety Authority is required prior to reconnection or new connection of all primary services, which is handled via an established process.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to primary service projects.

North Bay Hydro Distribution Limited

2015 Capital Project Summary

CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

Economic Development (5.4.5.2.B.5)

Individual connection of primary services do not generate economic development but can involve the connection of new commercial customers, which in turn may be advantageous for economic development.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to primary service projects.

Category-specific requirements - System Renewal (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

The timing of individual projects is based on what is required by the customer. As noted above, this work is top priority and therefore is handled as explained above in section 5.4.5.2.B.4.

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

These projects are initiated by customers and are designed to meet the needs of customer requirements.

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet)

As every primary service project is unique, final costs of individual projects can not be determined until the proposed work is shared with NBHDL. Factors that affect project costs are length of service, size of customer's main switchgear and main breaker and subsurface conditions. Charges to the customer are based on fixed and variable costs, that are updated annually.

Controllable Cost Minimization (5.4.5.2.C.a.fourth bullet)

The design and connection of primary services is standardized and therefore costs are controlled through well established processes, the use of standard material, and the efficiencies established through NBHDL's thorough experience in connecting such projects.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

Not applicable to primary service projects.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

Customers have options with respect to servicing, however feasible options must be reviewed on a project by project basis, which can not start until the project is initiated.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

Alternatives are considered, however the analysis is completed on a project by project basis, and after the project is initiated. As the expenditure is based on forecasted amounts, this section is not relevant until a project is started or scheduled. When these projects are initiated however, they will be prioritized based on DSC requirements and, with all things equal, on a queue basis, first in, first out as described in Section 4.2.3.1 of the DSP.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

This is not applicable for primary service projects.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

Primary service projects for the most part have a low impact on the system, although some can have a moderate impact depending on service size requirements. Individual project costs are typically below the materiality threshold and contributions from the customer, based on variable and fixed fees, cover the costs of servicing. When a customer requests a primary service that requires expansion of the system, the expansion is covered under a different type of project such as minor betterment or major betterment.

North Bay Hydro Distribution Limited

2015 Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Secondary Services**			
Investment Category	System Access			
Project Description	This category represents the capital work required to upgrade existing or install new secondary (low voltage) service wires, overhead and underground, from distribution plant located on the municipal street or in easements on private property to customer's premises. The majority of the work involves the services to the residential class.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$249,365		
	Customer Contribution	$0		
	Net Capital	$249,365		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Various - driven by demand.		
	Customer Load (peak KVA)	Various - driven by demand.		
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	31/12/2015		
	Expenditure Timing	Q1:	25%	$62,341
		Q2:	25%	$62,341
		Q3:	25%	$62,341
		Q4:	25%	$62,341
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	This work is very routine for NBHDL and is covered by well established processes both from design and construction perspectives which mitigates issues around timing related risk. As customer connections are very important NBH, timelines are strictly monitored and enforced to ensure obligations set forth in the DSC are met and that customer satisfaction is maintained.			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $299,563 2011: $404,425 2012: $288,463 2013: $204,301 2014: $361,792			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

North Bay Hydro Distribution Limited

2015 Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	Projects are mandatory and scope and timelines are based on requirements put forth by customers and/or obligations set forth in connecting customers in the DSC.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request for service and obligations set forth in the DSC.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	Upgrading existing or installing new services are top priority, but represent very small projects individually, and are easily handled by day to day operations. This work is processed by the engineering department and scheduled through the dedicated service truck daily to ensure timelines are met.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Secondary service projects are driven by customer requests and the specific requirements of the customer. Design and methodology for such projects is standardized through NBHDL policies and practices and in line with NBHDL's Conditions of Service. Alternatives are limited as servicing options are standardized, but if alternatives exist they are normally the choice of the customer. For example, the decision between an overhead or underground service is a decision made by customers.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to secondary service projects.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination with customers and electricians are an important part of secondary service work. This is handled through a well established service request procedure, known as a service spot. Actual coordination for installation is done through the Operations Dispatcher and the scheduling of the dedicated service truck. Authorization from the Electrical Safety Authority is required prior to reconnection or new connection of all secondary services, which is handled via an established process.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to secondary service projects.

CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

2015 Capital Project Summary

Economic Development (5.4.5.2.B.5)

Individual connection of secondary services do not generate economic development but can involve the connection of new commercial customers, which in turn may be advantageous for economic development.

Environmental Benefits (5.4.5.2.B.6)

Not applicable to secondary service projects.

Category-specific requirements - System Access (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

The timing of individual projects is based on what is required by the customer. As noted above, this work is top priority and therefore is handled by daily operations.

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

These projects are initiated by customers and are designed to meet the needs of customer requirements.

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet

As every secondary service project is unique, final costs of individual projects cannot be determined until the proposed work is shared with NBHDL. Factors that affect project costs are length of service, size of customer's service entrance and subsurface conditions. Charges to the customer are based on fixed and variable costs that are updated annually.

Controllable Cost Minimization (5.4.5.2.C.a.fourth bullet)

The design and connection of secondary services is standardized and therefore costs are controlled through well established processes, the use of standard material, and the efficiencies established through NBHDL's thorough experience in connecting such projects.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

Not applicable to secondary service projects.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

Customers have options with respect to servicing, however feasible options must be reviewed on a project by project basis, which can not start until the project is initiated.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

Alternatives are considered, however the analysis is completed on a project by project basis, and after the project is initiated. As the expenditure is based on forecasted amounts, this section is not relevant until a project is started or scheduled. When these projects are initiated however, they will be prioritized based on DSC requirements and, with all things equal, on a queue basis, first in, first out as described in Section 4.2.3.1 of the DSP.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

This is not applicable for secondary service projects.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

Secondary services projects have a very low impact on the system, costs are minimal but are fully recovered through a fee schedule. When a customer requests a secondary service that requires expansion of the system, the expansion is covered under a different type of project such as minor betterment or major betterment.

North Bay Hydro Distribution Limited

2015 Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Subdivisions**		
Investment Category	System Access		
Project Description	This project represents the capital work required to build and connect new subdivisions driven by developer demand. The expenditure represents cost to provide material to developers, and NBHDL labour to install transformers and make primary and secondary connections. Where possible, capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.		
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$100,973	
	Customer Contribution	$94,583	
	Net Capital	$6,390	
	O&M Costs (if applicable)	$0.00	(not applicable)
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Information not available until time of work.	
	Customer Load (peak KVA)	Information not available until time of work.	
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015	
	Expected In-Service Date	31/12/2015	
	Expenditure Timing	Q1: 25%	$25,243
		Q2: 25%	$25,243
		Q3: 25%	$25,243
		Q4: 25%	$25,243
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The timing of these projects are dictated by developer demand which can be hard to accommodate as requested. However, as with all demand work, these projects become top priority when brought to NBHDL's attention as per the obligations set forth in the DSC for connecting new customers. To help accommodate subdivision requests inventory levels are kept at a level that enables subdivision connections in a timely manner. A process for connecting new subdivisions is in place, which aids in planning and coordinating the demand work and helps mitigate some of the risk around timing.		
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $108,129 2011: $109,429 2012: $71,948 2013: $104,729 2014: $110,975		
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.		
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.		

North Bay Hydro Distribution Limited

2015 Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and Information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	Projects are mandatory and scope and timelines are based on requirements put forth by developers and/or obligations set forth in connecting customers in the DSC.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request for service and obligations set forth in the DSC.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable
Related Objectives/Performance Targets	Not Applicable
Source and Nature of the Information Used to Justify the Investment	Not Applicable
Investment Priority (5.4.5.2.B.1.b)	These projects are mandatory and therefore become top priority when NBHDL is made aware of them.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

Subdivision projects are driven by developer requests. Design and methodology for such projects is standardized through NBHDL policies and practices, although differs from project to project based on developer specific requirements. Alternatives cannot be considered until individual projects are brought forth.

Safety (5.4.5.2.B.2)

These projects are not intended to address safety concerns.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to subdivision projects.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

Coordination is required with a number of different parties during subdivision projects. An understanding of the project and the requirements of the developer need to be understood. This is typically handled through in person and on site meetings. Following such meetings, NBHDL coordinates with other utilities to ensure designs of all new infrastructure don't interfere with each other and efficiencies are leveraged (i.e. joint trenching); which is typically handled with a utility coordination meeting involving all parties. Then construction must be coordinated with all the involved parties, which is typically handled by a project manager designated by the developer. Success of these projects rests on effective coordination from start to finish.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to subdivision projects.

Economic Development (5.4.5.2.B.5)

Connection of new subdivisions, and in a timely manner, is important to the development of the City, and therefore is very important to NBHDL. New residences provide the base infrastructure to attract larger economic development opportunities for the community.

North Bay Hydro Distribution Limited

2015 Capital Project Summary

CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

Environmental Benefits (5.4.5.2.B.6)

Not applicable to subdivision projects.

Category-specific requirements - System Renewal (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

The timing of individual projects is based on what is required by the developer. As noted above, this work becomes top priority when it is brought forth.

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

These projects are initiated by developers and are designed to meet the needs of the proposed development.

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet

Final costs of individual projects can not be determined until the proposed development is communicated to NBHDL. The conditions of the land being developed, the number of lots and the type of residences being proposed are the largest factors that affect project costs.

Controllable Cost Minimization (5.4.5.2.C.a.fourth bullet)

The design of subdivision projects is fairly standardized and therefore costs are controlled through well established processes, the use of standard material, and the efficiencies established through NBHDL's thorough experience in connecting such projects. The developer also has the option to contest various parts of the required work in efforts to reduce costs further.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

This cannot be determined until projects are brought forth, and will differ from project to project. In all subdivision projects however, NBHDL considers future development in the design to ensure extensions, or future development can be easily handled while minimizing costs to do so.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

Alternatives are discussed, however the feasible options must be reviewed on a project by project basis, which can not start until the project is initiated.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

Alternatives are considered, however the analysis is completed on a project by project basis, and after the project is initiated. As the expenditure is based on forecasted amounts, this section is not relevant until a project is started or scheduled. When these projects are initiated however, they will be prioritized based on DSC requirements and, with all things equal, on a queue basis, first in, first out as described in Section 4.2.3.1 of the DSP.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

Capital contributions toward the cost of these projects are collected by NBHDL in accordance with the DSC and the provisions of its COS. NBHDL uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project. Results are not included as they cannot be determined until projects are brought forth.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

As NBHDL's system is not constrained, and growth in the area is very stagnant, new subdivision projects have very little impact on the system. Costs are typically around $100k annually for such projects and capital contributions are covered by the economic evaluation model.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

GENERAL INFORMATION ON THE PROJECT/ACTIVITY (5.4.5.2.A)

Project Name	**Road Relocations**			
Investment Category	System Access			
Project Description	This category represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground facilities installed within municipal or provincially owned road allowances. Based on a legislated cost sharing formula, the City or MTO, contribute 50% of all labour, labour saving devices, and equipment costs. In the case where the governing body directs NBHDL to replace overhead plant with underground plant the governing body funds the cost differential between overhead and underground.			
Capital Investment (5.4.5.2.A.first bullet)	Gross Capital	$212,218		
	Customer Contribution	$74,820		
	Net Capital	$137,398		
	O&M Costs (if applicable)	$0.00	(not applicable)	
Customer Attachments/Load (kVA) (5.4.5.2.A.second bullet)	Customer Attachments (#):	Information not available until time of work.		
	Customer Load (peak KVA)	Information not available until time of work.		
Project Timing (5.4.5.2.A.third bullet)	Start Date	01/01/2015		
	Expected In-Service Date	31/12/2015		
	Expenditure Timing	Q1:	25%	$53,055
		Q2:	25%	$53,055
		Q3:	25%	$53,055
		Q4:	25%	$53,055
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The timing of these projects are dictated by the City, or the MTO and therefore timing is out of NBHDL's control. Meetings with the City, as referenced in Section 2.2.1.2 of DSP, take place continuously through out the year which helps NBHDL to anticipate projects and allows NBHDL to plan these relocates amongst planned work.			
Comparative Information (5.4.5.2.A.fifth bullet)	Comparable investments in previous years are as follows: 2010: $407,924 2011: $48,372 2012: $274,664 2013: $6,484 2014: $103,218			
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.			
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.			

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	Projects are mandatory and scope and timelines are based on what the City or MTO requests.
Related Objectives/Performance Targets	NBHDL Objective 1 (as identified in Exhibit 1).
Source and Nature of the Information Used to Justify the Investment	Request from local or provincial authority.
Secondary Driver (5.4.5.2.B.1.a)	Not Applicable.
Related Objectives/Performance Targets	Not Applicable.
Source and Nature of the Information Used to Justify the Investment	Not Applicable.
Investment Priority (5.4.5.2.B.1.b)	These projects are mandatory and therefore become top priority when NBHDL is made aware of them.

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	Not Applicable.
Net benefits accruing to customers	Not Applicable.
Impact on reliability performance (including on the frequency and duration of outages)	Not Applicable.

Project Alternatives

The relocation of distribution assets is mandatory and is based on the proposed road design, however NBHDL's design is coordinated with the authority, or authorities agent, requesting the relocation of the road to determine the best alternative for relocation, while trying to keep costs controlled. NBHDL is not fully in control of the outcomes or the alternative selected on these type of projects.

Safety (5.4.5.2.B.2)

The intention of these type of projects are not to address safety concerns, although at times, end of life assets are replaced which may involve the elimination of safety hazards.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to road relocations project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

As referenced in section 2.2.1.2 of the DSP, coordination with the City and MTO is on-going throughout the year, which helps with respect to road relocation project coordination. Once a project is initiated NBHDL works closely with the authority requesting the work to consider alternatives, while trying to minimize costs.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

Not applicable to road relocation projects.

Economic Development (5.4.5.2.B.5)

Not applicable to road relocation projects.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

CATEGORY-SPECIFIC REQUIREMENTS - SYSTEM ACCESS (5.4.5.2.C.a.)

Environmental Benefits (5.4.5.2.B.6)

Not applicable to road relocation projects.

Category-specific requirements - System Access (5.4.5.2.C.a.)

Factors Affecting Implementing Project Timing/Priority (5.4.5.2.C.a.first bullet)

The timing of individual projects is based on scheduling provided by the owner of the road. NBHDL works closely with the local authorities to ensure projects are not entirely unplanned, but timing is for the most part not in NBHDL's control and road relocations remain reactionary in most circumstances.

Factors Relating to Customer Preference or 3rd Party Input (5.4.5.2.C.a.second bullet)

NBHDL works closely with the owner of the road to ensure the relocation of distribution assets is acceptable. All local utilities (communication companies, gas, water, sewer, etc.) work together to minimize costs and disruption; both in design and construction.

Factors Affecting Final Project Costs (5.4.5.2.C.a.third bullet

Final costs of individual projects can not be determined until a road relocation project is started. However, length of road section being relocated, subsurface conditions, and traffic involved are all things that can affect the final costs of any road relocation project

Controllable Cost Minimization (5.4.5.2.C.a.fourth bullet)

Through coordinated design, distribution assets are relocated in way to minimize costs as much as possible. Due to standing agreements, 50% of labour, labour saving devices, and equipment is covered by the road authority.

Other Planning Objectives Met (5.4.5.2.C.a.fifth bullet)

Other planning objectives are considered during road relocation projects, however specifics cannot be identified until projects are initiated. It is NBHDL's methodology to take advantage of the mandatory work to address any other issues, such as safety concerns, or requirements for the future in efforts to save cost, such as taller poles than what was existing to address new framing standards, or the installation of ductwork while the road is excavated to save future excavation costs. These types of options are considered on all projects.

Technically Feasible Project Options (5.4.5.2.C.a.sixth bullet)

Alternatives are discussed, however the feasible options must be reviewed on a project by project basis. As with other factors listed above, technically feasible project options cannot be reviewed until the project is initiated.

Summary of Options Analysis (5.4.5.2.C.a.seventh bullet)

Alternatives are considered, however the analysis is completed on a project by project basis, and after the project is initiated. As the expenditure is based on forecasted amounts, this section is not relevant until a project is started or scheduled. When these projects are initiated however, they will be prioritized based on DSC requirements and, with all things equal, on a queue basis, first in, first out as described in Section 4.2.3.1 of the DSP.

Results of the 'Final Economic Evaluation' (5.4.5.2.a.eighth bullet)

This is not applicable to road relocation projects.

Nature and Magnitude of System Impacts, Costs and Cost Coverage (5.4.5.2.a.ninth bullet)

Typically, road relocation projects have a very minimal impact on the system, costs can range from low to high ($10k-$500k), and 50% of labour, labour saving devices, and equipment costs are covered by the road authority requesting the work.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Project Name	**Replacement of Truck 30**		
Investment Category	General Plant		
Project Description	The project involves the replacement of Truck 30, a 1997 70' double bucket aerial device material handling truck with an 83' to 85' double bucket aerial device material handling truck. The existing vehicle will be over 16 years old and independent assessments confirm the entire truck (aerial device and body) are at end of life and will require substantial repair costs to keep on the road. The new truck will replace the only truck in the fleet capable of reaching 70' in the air, and/or reach poles that located well off the paved portion of road allowances. Note: The procurement of the truck started in 2014, with the award of the cab and chassis to Freightliner North Bay 930098 Ontario Ltd (Freightliner), and the boom and body to Posi-Plus Technologies Inc. (Posi-Plus) The finished unit will be delivered and put into service in April 2015.		
Capital Investment	Capital	$370,000 *	
	** will be updated to reflect awarded tender resulting from application process.*		
(5.4.5.2.A.first bullet)	Customer Contribution		
		$0.00	
	Net Capital	$370,000	
	O&M Costs (if applicable)		
		$0.00	(not applicable)
Customer Attachments/Load (kVA)	Customer Attachments (#):	Not applicable	
(5.4.5.2.A.second bullet)	Customer Load (peak KVA)	Not applicable	
Project Timing	Start Date	Apr-14	
(5.4.5.2.A.third bullet)	Expected In-Service Date	Apr-15	
	Expenditure Timing	Q1:	-
		Q2:	$370,000
		Q3:	-
		Q4:	-
Risk and Risk Mitigation (5.4.5.2.A.fourth bullet)	The main risk will be the adherence by the supplier to the delivery schedule. That risk has been already somewhat mitigated by starting the procurement process in 2014 and having the cab and chassis delivered to the Posi-Plus plant in July 2014. To further mitigate the risk, NBHDL will request delivery updates quarterly to ensure the truck still plans on being delivered in Q2 of 2015.		

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Comparative Information (5.4.5.2.A.fifth bullet)	NBHDL only has one truck with this reach and therefore it is a stand alone purchase with no recent purchases to compare to. Gross vehicle replacement costs for large trucks over the past 5 years are as follows: 2008 - $356,970 - replacement of Trk# 34 / cab & chassis - Trk# 38 replacement 2009 - $474,305 - replacement of Trk# 31 / body & bucket - Trk # 38 replacement 2011 - $289,660 - replacement of Trk# 37 / cab & chassis - Trk # 39 replacement 2012 - $159,620 - body & buck - Trk# 39 replacement / refurb - Trk# 33 2014 - $83,285 - cab & chassis - Trk#30 replacement
Total Capital & OM&A Costs Associated with REG Investments (5.4.5.2.A.sixth bullet)	This project is not associated with a REG investment; capital and OM&A costs related to REG will not be incurred.
Leave to Construct Approval (5.4.5.2.A.seventh bullet)	This project does not require Leave to Construct approval under Section 92 of the OEB Act and therefore this does not apply.

Evaluation Criteria and information requirements (5.4.5.2.B)

Efficiency, Customer Value, Reliability (5.4.5.2.B.1)

Main Driver (5.4.5.2.B.1.a)	The main driver to the project is the replacement of an end of life truck that is currently experiencing major reliability issues. The existing truck has been flagged in poor shape by Freightliner, NBHDL's cab and chassis mechanics, and they will deem it unfit for service if not replaced in the near future. A structural assessment was completed by Posi-Plus, and the aerial device requires approximately $65k worth of repairs to make it worthy for continued service.
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1)
Source and Nature of the Information Used to Justify the Investment	The Fleet Assessment and replacement strategy completed by John Saunders Utility Services and assessments completed by Freightliner and Posi-Plus on the condition of the existing truck.
Secondary Driver (5.4.5.2.B.1.a)	Safety is a secondary driver, as the removal of the existing truck from service eliminates possible safety hazards to both workers and the general public due to the assessed condition of both the cab and chassis and aerial device of the existing truck
Related Objectives/Performance Targets	NBHDL Objective 2 (as identified in Exhibit 1)
Source and Nature of the Information Used to Justify the Investment	The assessments completed by Freightliner and Posi-Plus on the condition of the existing truck.
Investment Priority (5.4.5.2.B.1.b)	The replacement of this truck is based on the replacement strategy provided in the Fleet Assessment completed by John Saunders Utility Services. It has also been prioritized by the fact the only truck in the fleet with a 70' reach has been deemed unfit for continued service and therefore replacement of said truck is necessary. The majority of investment planning for this Fleet asset occurred prior to the DSP, but it was prioritized in accordance with NBHDL's best practices and within the budget envelope available for 2014 projects. As $83,285 for the cab/chassis was allocated in 2014, the prioritization applies to the remaining 370,000 award for the boom/bucket in 2015.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS (5.4.5.2.B)

Analysis of the Project and Project Alternatives (5.4.5.2.B.1.c)

Effect on system operation efficiency and cost effectiveness	The truck forms part of the NBHDL fleet which allows NBHDL employees to efficiently maintain a safe and reliable distribution system for the City. As poles have continued to increase in height (to meet regulation) it is the utmost importance to have at least one bucket truck that can reach the top of the taller poles. This truck will also allow for work on polelines that are offset a fair distance from the road.
Net benefits accruing to customers	The replacement of Truck 30 will allow NBHDL to maintain its ability to provide a safe and reliable distribution system. The replacement removes an end of life truck that is no longer worthy for service from the road.
Impact on reliability performance (including on the frequency and duration of outages)	The replacement of Truck 30 allows for the continued efficient day to day operations of the NBHDL business. Reliability performance is impacted as the replacement permits safe and timely restoration of outages when presented.

Project Alternatives

This project is a replacement of an end of life truck and therefore there are only three alternatives: 1) Do not replace the truck; or 2) replace it with a truck of a different size than the truck NBHDL decided on; 3) sharing a truck with a neighbouring utility. Not replacing the truck will leave the already small NBHDL fleet short by 1 bucket truck, and will also result in the loss of the only truck in the fleet with over a 70' reach due to its end of life. Given that NBHDL requires a 70' reach for O&M and installs, this alternative is not feasible. For the second alternative, as poles have continued to increase in height, replacing with a normal size bucket truck (which we already have 4 of), will not allow NBHDL to safely and efficiently maintain all of its assets. At least one truck capable of reaching all pole heights is a necessity and therefore, replacing the truck with a smaller truck is also not a feasible option. The alternative of a larger truck than decided on was not considered as NBHDL does not require anything larger and such a purchase would be an inefficient use of the budget envelope. Lastly, NBHDL considered sharing a truck with a neighbouring utility. Sudbury Hydro was considered, but it would involve extreme coordination and use of labour resources to shuttle it back and forth between the two utilities (140km). As it is a unique truck; the only one in the NBHDL fleet capable of reaching tall poles, it would be detrimental if the truck was required for emergency work or planned work and was unavailable because it was in use by Sudbury Hydro. The sharing of a truck would be a more feasible option if it was the second truck of this size, however a second truck of this size is not required. Due to the current condition of the existing truck, if a truck is required prior to the arrival of the new truck, requesting the loan of truck with the required reach from Sudbury Hydro is an option.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

Safety (5.4.5.2.B.2)

The new truck will replace an end of life asset that, if not replaced, could lead to unsafe situations for employees and/or the public. The replacement also allows for safer O&M procedures for the distribution system. Accessing the poles by boom & bucket provides a significant increase in safety over manually climbing and working with the use of a harness.

Cyber-security, Privacy (5.4.5.2.B.3)

Not applicable to this project.

Co-ordination, Interoperability (5.4.5.2.B.4)

Co-ordination with utilities, regional planning and/or links with 3rd party providers and/or industry (5.4.5.2.B.4.a)

An alternative to co-own a truck with Sudbury Hydro was considered but ruled out due to the constraints involved. Sudbury Hydro is willing to consider loaning a vehicle in the interim should the existing truck become unavailable and a truck capable of reaching tall heights is required.

Enabling of future technological functionality or addressing of future operational requirements (5.4.5.2.B.4.b)

The truck will employ state of the art controls and has been designed to allow for easy future installation of remote based IT equipment (laptop, etc.)

Economic Development (5.4.5.2.B.5)

This will provide a cab and chassis order for Freightliner, a local company and the boom and body to Posi-Plus, a Quebec based company.

Environmental Benefits (5.4.5.2.B.6)

All new trucks must meet new environmental emission profiles and therefore, the new truck will be an improvement in this regard over the existing truck.

North Bay Hydro Distribution Limited

2015 Material Capital Project Summary

GENERAL PLANT SPECIFIC REQUIREMENTS (5.4.5.2.C.d)

Category-specific requirements - General Plant (5.4.5.2.C.d)

The Results of Quantitative and Qualitative Analyses, Including Assessments of Financially Feasible Options to the Proposed Project, and Identifying the Benefits of the Proposed Investment

NBHDL assesses vehicle replacements through the tracking of maintenance costs and on a replacement strategy put forth in the Fleet Assessment completed by John Saunders Utility Services which weighs typical vehicle life against on-going maintenance costs producing an optimum time to replace certain sized vehicles. Specific to this vehicle were two individual reports, mentioned above in section 5.4.5.2.B.1.a, that have deemed the vehicle unworthy for continued service. These reports identified that $65,000 worth of repairs were required to the aerial (boom/bucket) device alone to make it fit again for continued use. For requisitioning any large fleet vehicle, such as the one proposed, NBHDL creates a specification which is then put out for tender to ensure a competitive process. NBHDL undertook this tendering process in 2014, with separate tenders for the cab and chassis and boom and body. The successful vendors were Freightliner and Posi-Plus respectively. For all of the project alternatives considered by NBHDL, see above section 5.4.5.2.B.1.c. While each of these alternatives was considered, they were ultimately found to be unfeasible given the current state of Truck 30 and the requisite need for a high reach large vehicle. Finally, as to the net benefits of the proposed investment, this can be summarized as follows: the replacement of Truck 30 will allow NBHDL to keep its fleet whole, keep its workers productive and safe, and ensure NBHDL has equipment that can handle pole heights currently required for and employed in the NBHDL distribution system.

Business Case Documenting the Justifications for the Expenditure, Alternatives Considered, Benefits for Customers (short/long term), and Impact on Distributor Costs (short/long term)

This is not considered, in NBHDL's view, to be a project that substantially exceeds the materiality threshold of the Filing Requirements. Given this, NBHDL relies on the justifications provided above in lieu of providing a formal business case.

Appendix R – Pictures to support Capital Summaries in DSP

Appendix R - Pictures to support Capital Summaries in DSP

Project Reference: MS22 – Substation Construction

Number of Pictures: 4

MS22 – Substation Construction – Picture 1

Description: Picture from MS9, the station MS22 will replace. The picture illustrates the swampy vegetation within the substation yard, a hazard to worker safety.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

MS22 – Substation Construction – Picture 2

MS22 – Substation Construction – Picture 3

Description: Both pictures (2 and 3) are of existing foundations at MS9. The pictures illustrate the extremely poor condition the foundations are in.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

MS22 – Substation Construction – Picture 4

Description: Picture from MS9. The picture illustrates the use of the land immediately adjacent the MS9 property, and how the neighbour (a concrete plant) stores material, equipment and other items basically against the fence.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Project Reference: Turret Complex - Madelena

Number of Pictures: 2

Turret Complex – Madelena - Picture 1

Description: Picture of an existing inaccessible backlot pole (behind the house). All backlot poles will be eliminated as part of the project. If the transformer on the pole in the picture was to fail, it would be extremely costly to replace due to the impeded access and would result in a lengthy outage for the customers.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Turret Complex – Madelena – Picture 2

Description: Picture of an existing backlot poleline that is part of the project. The elimination of the backlot pole line will provide back green space and prevent future tree trimming costs.

Specific Reference within Capital Summary: Environmental Benefits (5.4.5.2.B.6)

Project Reference: Turret Complex – Wickstead

Number of Pictures: 2

Turret Complex – Wickstead – Picture 1

Description: Transclosure, housing for live front polemounted transformers. Transclosures are considered non-standard and are replaced with padmounted transformers in all NBHDL rebuild projects.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Turret Complex – Wickstead – Picture 2

Description: Live front polemounted transformer located in a transclosure (housing in previous picture). This picture illustrates the live front high voltage, and also other issues with transclosures, such as contamination, and the confined space they create.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Project Reference: Fourth Avenue Rebuild – Ferguson x Fisher

Number of Pictures: 3

Fourth Avenue Rebuild – Ferguson x Fisher – Picture 1

Description: An existing pole that will be replaced as part of the project. It illustrates the lack of separation between the high voltage conductor and the low voltage conductors. The current separation is much less than current day standards. The pole is also in very poor condition.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Fourth Avenue Rebuild – Ferguson x Fisher – Picture 2

Description: The presence of an underslung transformer on Fourth Avenue, where the high voltage conductor passes down below the low voltage conductors. Transformers are no longer installed this way because of the hazard created. All underslung transformers are eliminated/replaced as part of capital renewal projects

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Fourth Avenue Rebuild – Ferguson x Fisher – Picture 3

Description: #6 Cu busswork on Fourth Avenue. As evident, the insulation is falling off the conductor. #6 Cu is notorios for breaking due to it's brittleness and therefore is always replaced as part of a renewal project.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Project Reference: Fifth Avenue Rebuild – Cassells x Wyld

Number of Pictures: 3

Fifth Avenue Rebuild – Cassells x Wyld – Picture 1

Description: The presence of #6 Cu primary conductors. #6 Cu is deemed a safety hazard and is always replaced/eliminated on renewal projects. The poor condition of the pole and crossarm is also evident in this picture.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

Fifth Avenue Rebuild – Cassells x Wyld – Picture 2

Description: The butt of a pole on Fifth Avenue that will be replaced. The picture illustrates the poor conidtion the pole is in. The outer shell of the pole is gone, and the inner part of the pole is almost hollow due to rot.

Specific References within Capital Summary: Main Driver (5.4.5.2.B.1.a), and Safety (5.4.5.2.B.2)

Fifth Avenue Rebuild – Cassells x Wyld – Picture 3

Description: The presence of an underslung transformer on Fifth Avenue, where the high voltage conductor passes down below the low voltage conductors. Transformers are no longer installed this way because of the hazard created. All underslung transformers are eliminated/replaced as part of capital renewal projects. The picture also illustrates the twisting of the crossarms used to support the transformer.

Specific Reference within Capital Summary: Safety (5.4.5.2.B.2)

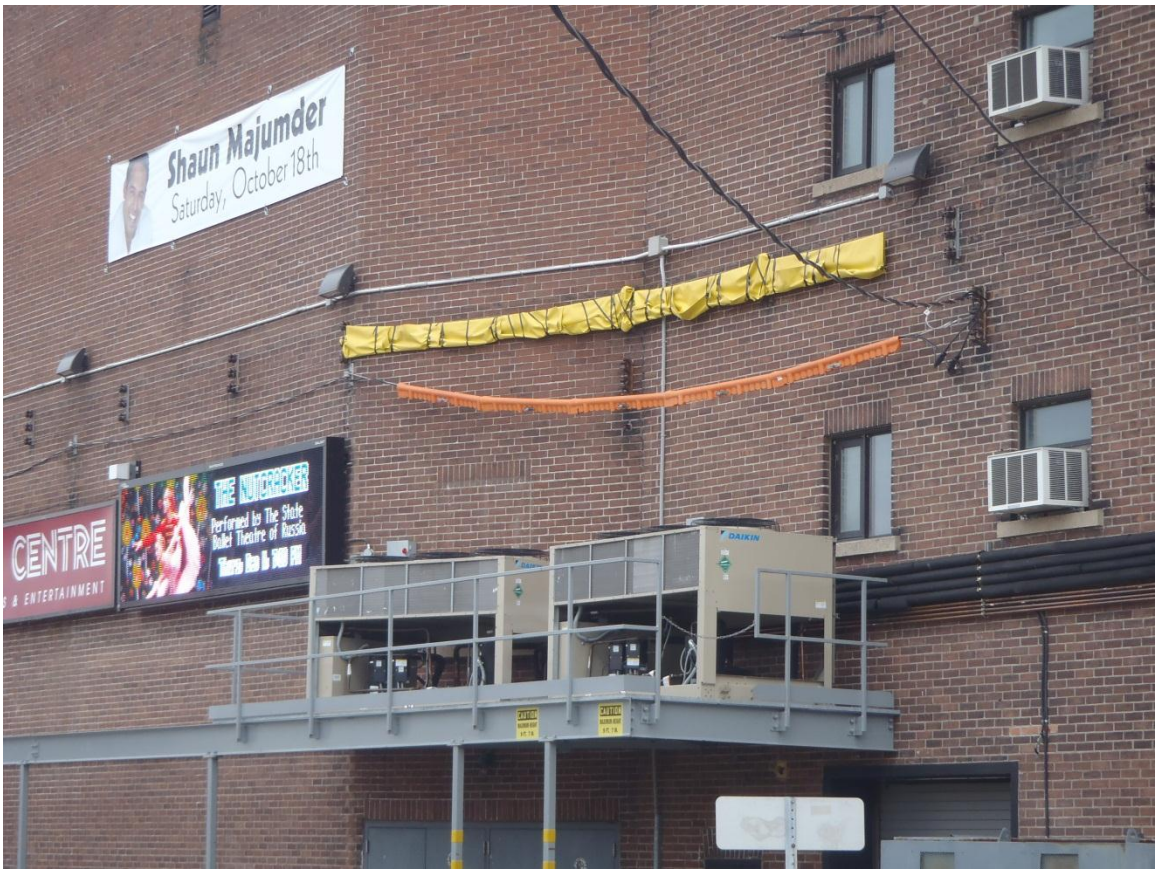
Project Reference: McIntyre Street Rebuild – Cassells x Wyld

Number of Pictures: 4

McIntyre Street Rebuild – Cassells x Wyld – Picture 1

Description: A leaning pole on McIntyre, due to the imbalance from the secondary services supplying only one side of the street. This will be corrected upon renewal by addressing all servicnig issues.

Specific Reference within Capital Summary: Value of Customer Impact (5.4.5.2.C.b.first bullet.sixth dash)



McIntyre Street Rebuild – Cassells x Wyld – Picture 2

Description: NBHDL service conductors attached to building A to feed building B. This is a major servicing issue, and as evident, the conductors have been covered with temporary insulation to allow maintenance on the A/C units to occur. The service conductors will be removed from building A to elminate the servicing and safety issues as part of the project.

Specific References within Capital Summary: Value of Customer Impact (5.4.5.2.C.b.first bullet.sixth dash), and Safety (5.4.5.2.B.2).

McIntyre Street Rebuild – Cassells x Wyld – Picture 3

Description: The presence of an underslung transformer on McIntyre Street, where the high voltage conductor passes down below the low voltage conductors. Transformers are no longer installed this way because of the hazard created. All underslung transformers are eliminated/replaced as part of capital renewal projects.

Specific References within Capital Summary: Safety (5.4.5.2.B.2).

McIntyre Street Rebuild – Cassells x Wyld – Picture 4

Description: This picture illustrates 2 issues: The first is the presence of a 240V delta bank and the associated #6 Cu delta busswork, both of which pose safety risks and will be eliminated as part of the renewal project. The poor conditon of the busswork is evident. The second is the presence of 5kV pin type insulators, which will be replaced to with 15V insulators to allow operation of line 12.47kV.

Specific References within Capital Summary: Safety (5.4.5.2.B.2).

Project Reference: Ferguson Street Rebuild – Princess x First

Number of Pictures: 1

Ferguson Street Rebuild – Princess x First – Picture 1

Description: This picture illustrates cap type insulators, that are notorious for failing when the pole is under load or is being worked on. These insulators will be replaced as part of the project.

Specific References within Capital Summary: Safety (5.4.5.2.B.2).