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Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 2): Rate Base

OVERVIEW

NOW Inc. has calculated rate base for the 2017 Test Year of $7,766,289 consistent with Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* issued on July 14, 2016. The rate base calculation is based on the average of the 2017 Test Year opening and closing balances of the net book value of assets, plus a working capital allowance. The working capital allowance is calculated as of 7.5% of the sum of controllable expenses and the cost of power. Controllable expenses include operations and maintenance, billing and collecting, and administrative expenses.

A rate base continuity schedule from the 2013 OEB Approved amount to the 2017 Test Year is provided below in **Table 1**. The 2016 Bridge Year and 2017 Test Year are budgeted costs as per the application.

Table 1: Rate Base Continuity Schedule

Description	2013 OEB Approved	2013 Actual CGAAP	2014 Actual CGAAP	2015 Actual CGAAP	2015 Actual IFRS	2016 Bridge IFRS	2017 Test IFRS
Opening Balance Gross Fixed Assets	$ 8,695,701	$ 8,808,386	$ 10,972,469	$11,492,910	$ 6,797,842	$ 7,087,085	$ 8,083,049
Closing Balance Gross Fixed Assets	$ 10,495,663	$10,972,469	$ 11,492,910	$11,830,261	$ 7,087,085	$ 8,083,049	$ 8,910,550
Average Gross Fixed Assets	$ 9,595,682	$ 9,890,428	$ 11,232,690	$11,661,586	$ 6,942,463	$ 7,585,067	$ 8,496,800
Opening Balance Accumulated Depreciation	-$ 3,759,330	-$ 3,985,275	-$ 4,808,389	-$ 5,301,274	-$ 606,206	-$ 1,212,115	-$ 1,823,137
Closing Balance Accumulated Depreciation	-$ 4,213,392	-$ 4,808,389	-$ 5,301,274	-$ 5,955,291	-$ 1,212,115	-$ 1,823,137	-$ 2,471,804
Average Accumulated Depreciation	-$ 3,986,361	-$ 4,396,832	-$ 5,054,832	-$ 5,628,283	-$ 909,160	-$ 1,517,626	-$ 2,147,471
Opening Net Book Value	$ 4,936,371	$ 4,823,111	$ 6,164,080	$ 6,191,636	$ 6,191,636	$ 5,874,970	$ 6,259,912
Closing Net Book Value	$ 6,282,271	$ 6,164,080	$ 6,191,636	$ 5,874,970	$ 5,874,970	$ 6,259,912	$ 6,438,745
Average Net Book Value	$ 5,609,321	$ 5,493,596	$ 6,177,858	$ 6,033,303	$ 6,033,303	$ 6,067,441	$ 6,349,329
Working Capital	$ 14,594,610	$17,014,684	$ 15,911,523	$16,814,529	$16,814,529	$18,774,020	$ 18,892,797
Working Capital %	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	7.5%
Working Capital Allowance	$ 1,663,786	$ 1,939,674	$ 1,813,914	$ 1,916,857	$ 1,916,857	$ 2,140,238	$ 1,416,960
Rate Base	**$ 7,273,107**	**$ 7,433,270**	**$ 7,991,772**	**$ 7,950,160**	**$ 7,950,160**	**$ 8,207,679**	**$ 7,766,289**

NOW Inc. does not have any non-distribution assets, and opening and closing gross fixed asset and depreciation balances have been submitted into evidence in the fixed asset continuity schedules (OEB Chapter 2 Appendix 2-BA) which are provided in E2/T1/S1/Att1.

A summary of the cost components used to calculate the Working Capital Allowance is provided below in **Table 2**. As shown in the table, Cost of Power is a significant factor in the total working capital. This is not controllable by NOW Inc. and NOW Inc. must pay the IESO invoices regardless if customers default on their payments.

Table 2: Working Capital Summary

Description	2013 OEB Approved	2013 Actual CGAAP	2014 Actual CGAAP	2015 Actual CGAAP	2015 Actual IFRS	2016 Bridge IFRS	2017 Test IFRS
Cost of Power	$12,290,062	$13,463,456	$13,450,479	$14,422,963	$14,422,963	$16,098,334	$15,984,891
Operations	$ 455,369	$ 600,841	$ 749,465	$ 618,070	$ 618,070	$ 617,237	$ 815,665
Maintenance	$ 439,411	$ 631,448	$ 487,822	$ 509,810	$ 509,810	$ 592,253	$ 697,590
Billing and Collecting	$ 693,896	$ 1,072,708	$ 584,730	$ 752,020	$ 752,020	$ 714,670	$ 746,564
Administrative and General Expenses	$ 715,872	$ 1,252,523	$ 646,500	$ 515,318	$ 515,318	$ 751,526	$ 648,087
Working Capital	**$14,594,610**	**$17,020,976**	**$15,918,996**	**$16,818,181**	**$16,818,181**	**$18,774,020**	**$18,892,797**

Major Drivers of Change in Rate Base

From the 2013 OEB approved to the 2017 Test Year, the average net book value (NBV) of property, plant and equipment has increased by $740,008 Over the same period working capital allowance has decreased $246,826.

The main drivers of the changes in rate base are as follows:

- The ongoing capital expenditures and additions for distribution system investments as outlined in E2/T2/S1
- Partially offset by ongoing depreciation of capital assets, and
- An increase in the working capital allowance as a result of higher Cost of Power (2013-2016) and then a reduction in 2017 due to the reduction in the working capital allowance rate from 11.4% to 7.5%

The primary driver of the increase in rate base is the increase in the net book value of assets. The net book values for 2013 to 2017 are summarized in Table 3 and the associated year over year variances follow in Table 4. Year over year changes greater than the NOW Inc. materiality level of $50,000 are highlighted and explained below:

Table 3: 2013 – 2017 Net Book Value

		2013 Approved	2013	2014	2015	2016	2017
OEB Account	Description	Net Book Value	Net Book Value	Net Book Value	Net Book Value	Net Book Value	Net Book Value
1611	Computer Software (Formally known as Account 1925)	59,155	52,657	30,954	10,224	351,496	380,203
1805	Land	87,700	87,700	87,700	87,700	87,700	87,700
1808	Buildings	426,974	450,991	442,160	422,257	402,884	383,511
1815	Transformer Station Equipment >50 kV	2,189	0	0	0	0	0
1820	Distribution Station Equipment <50 kV	229,181	209,505	189,924	181,781	230,699	258,722
1830	Poles, Towers & Fixtures	1,724,662	1,683,344	1,714,422	1,783,947	1,925,687	2,201,152
1835	Overhead Conductors & Devices	894,557	935,062	1,015,688	1,068,240	1,100,171	1,162,190
1840	Underground Conduit	5,645	9,548	8,184	6,820	5,456	4,092
1845	Underground Conductors & Devices	2,339	2,111	1,809	1,508	1,207	906
1850	Line Transformers	495,450	465,604	481,318	525,780	572,215	648,773
1855	Services (Overhead & Underground)	257,062	153,451	184,134	216,694	204,069	191,444
1860	Meters	894,539	20,905	19,627	16,526	14,235	12,299
1860	Meters (Smart Meters)	0	654,254	603,109	542,994	497,527	451,060
1910	Leasehold Improvements	470	470	0	0	0	0
1915	Office Furniture & Equipment (10 years)	144	682	491	299	239	179
1920	Computer Equipment - Hardware	0	2,225	2,164	5,900	16,800	20,500
1920	Computer Equip.-Hardware(Post Mar. 19/07)	20,483	348,363	314,248	280,133	246,633	213,748
1930	Transportation Equipment	1,115,374	1,014,276	1,046,204	817,037	700,784	512,090
1935	Stores Equipment	474	877	595	313	138	70
1940	Tools, Shop & Garage Equipment	55,430	70,869	48,509	28,820	21,125	26,409
1955	Communications Equipment	1,185	1,186	395	0	0	0
1960	Miscellaneous Equipment	9,258	0	0	0	0	0
2440	Deferred Revenue				-122,003	-119,153	-116,303
	Sub-Total	**6,282,271**	**6,164,080**	**6,191,635**	**5,874,970**	**6,259,912**	**6,438,745**

Table 4: 2013 – 2017 Net Book Value Variances

		2013 Actual vs 2013 OEB Approved	2014 Actual vs 2013 Actual	2015 Actual vs 2014 Actual	2016 Bridge vs 2015 Actual	2017 Test vs 2016 Bridge
OEB Account	Description	NBV Variance	NBV Variance	NBV Variance	NBV Variance	NBV Variance
1611	Computer Software (Formally known as Account 1925)	-6,498	-21,703	-20,730	341,272	28,707
1805	Land	0	0	0	0	0
1808	Buildings	24,017	-8,831	-19,903	-19,373	-19,373
1815	Transformer Station Equipment >50 kV	-2,189	0	0	0	0
1820	Distribution Station Equipment <50 kV	-19,676	-19,581	-8,143	48,918	28,023
1830	Poles, Towers & Fixtures	-41,318	31,078	69,525	141,740	275,465
1835	Overhead Conductors & Devices	40,505	80,626	52,552	31,931	62,019
1840	Underground Conduit	3,903	-1,364	-1,364	-1,364	-1,364
1845	Underground Conductors & Devices	-228	-302	-301	-301	-301
1850	Line Transformers	-29,846	15,714	44,462	46,435	76,558
1855	Services (Overhead & Underground)	-103,611	30,683	32,560	-12,625	-12,625
1860	Meters	-873,634	-1,278	-3,101	-2,291	-1,936
1860	Meters (Smart Meters)	654,254	-51,145	-60,115	-45,467	-46,467
1910	Leasehold Improvements	0	-470	0	0	0
1915	Office Furniture & Equipment (10 years)	538	-191	-192	-60	-60
1920	Computer Equipment - Hardware	2,225	-61	3,736	10,900	3,700
1920	Computer Equip.-Hardware(Post Mar. 19/07)	327,880	-34,115	-34,115	-33,500	-32,885
1930	Transportation Equipment	-101,098	31,928	-229,167	-116,253	-188,694
1935	Stores Equipment	403	-282	-282	-175	-68
1940	Tools, Shop & Garage Equipment	15,439	-22,360	-19,689	-7,695	5,284
1955	Communications Equipment	1	-791	-395	0	0
1960	Miscellaneous Equipment	-9,258	0	0	0	0
2440	Deferred Revenue	0	0	-122,003	2,850	2,850
	Sub-Total	**-118,191**	**27,555**	**-316,665**	**384,942**	**178,833**

EXPLANATION OF MATERIAL YEAR OVER YEAR VARIANCES

2013 Actual to 2013 OEB Approved

- Services (Overhead & Underground), $103,611 less than approved as a result of decrease in expected capital work on services.
- Meters, are net $219,380 (-$873,634 + 654,254) lower than approved due to fewer three-phase meters and the allocation of deferred smart meter capital costs.
- Computer Equipment/Hardware increase in Net Book Value by $327,880 as a result of the Smart Meter disposition which moved deferred capital costs in account 1555 to the proper account.
- Transportation Equipment, $101,098 below approved primarily due to delay in acquisition of a chassis on a bucket truck, which was received in 2014.

2014 Actual to 2013 Actual

- Overhead Conductors and Devices, $80,626 higher than 2013 primarily due to additional work as a result of storms and trouble calls and findings resulting from line patrols.
- Meters (Smart Meters), the 2014 Net Book Value is $51,145 lower than 2013 NBV due to the amortization of smart meters.

2015 Actual to 2014 Actual

- Poles, Towers and Fixtures, Net Book Value in 2015 is $69,525 higher than 2014 primarily due to more capital pole replacements.
- Overhead Conductors and Devices, NBV in 2015 is $52,552 higher than 2014 primarily due to more capital work required that was identified from line patrols.
- Meters (Smart Meters), 2015 NBV is $60,115 lower than 2014 primarily due to smart meter depreciation exceeding any additions.

- Transportation Equipment, Net Book Value in 2015 is $229,167 lower than 2014 because no new fleet vehicles were purchased in 2015 resulting in NBV decreasing from depreciation with no offsetting increase in cost.
- Deferred Revenue, $122,003 lower than 2014 primarily due to the fact that this is the first time NOW Inc. has had contributed capital.

2016 Bridge Year to 2015 Actual

- Computer Software, $341,272 higher than 2015 primarily due to the GIS project.
- Poles, Towers and Fixtures, $141,740 higher than 2015 primarily due to identified areas of concern as a result of line patrols that will result in more anticipated pole replacements.
- Transportation Equipment, NBV in 2016 is anticipated to be $116,253 lower than 2015 as a result of depreciation and no significant increase in cost.

2017 Test Year to 2016 Bridge Year

- Poles, Towers and Fixtures, NBV in 2017 is anticipated to be $275,465 higher than 2016 primarily due to increase in scope of work for upgrade projects, in addition to a large pad-mount transformer replacement.
- Overhead Conductors and Devices, NBV in 2017 is anticipated to be $62,019 higher than 2016 primarily due to additional work as a resulting from the increased scope of project upgrades.
- Line Transformers, NBV is anticipated to be $76,558 higher than 2016 primarily due to the replacement of additional transformers as a part of the conversion projects.
- Transportation Equipment, NBV in 2017 is anticipated to be $188,694 lower than 2016 as a result of depreciation and no increase in cost.

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2013**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 159,158	$ 30,616	-$ 320	$ 189,454	-$ 113,356	-$ 23,441		-$ 136,797	$ 52,657
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700				$ -	$ 87,700
47	1808	Buildings	$ 385,577	$ 133,783		$ 519,360	-$ 54,754	-$ 15,459	$ 1,844	-$ 68,369	$ 450,991
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 3,644		-$ 3,644	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 556,393		$ 2,554	$ 558,947	-$ 329,861	-$ 19,581		-$ 349,442	$ 209,505
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,787,996	$ 210,026		$ 2,998,022	-$ 1,193,778	-$ 120,900		-$ 1,314,678	$ 1,683,344
47	1835	Overhead Conductors & Devices	$ 1,657,849	$ 190,428		$ 1,848,277	-$ 883,437	-$ 29,778		-$ 913,215	$ 935,062
47	1840	Underground Conduit	$ 112,571			$ 112,571	-$ 101,659	-$ 1,364		-$ 103,023	$ 9,548
47	1845	Underground Conductors & Devices	$ 3,690			$ 3,690	-$ 1,278	-$ 301		-$ 1,579	$ 2,111
47	1850	Line Transformers	$ 749,129	$ 87,841		$ 836,970	-$ 352,643	-$ 18,723		-$ 371,366	$ 465,604
47	1855	Services (Overhead & Underground)	$ 294,061	$ 42,542		$ 336,603	-$ 173,049	-$ 10,103		-$ 183,152	$ 153,451
47	1860	Meters	$ 31,277			$ 31,277	-$ 9,094	-$ 1,278		-$ 10,372	$ 20,905
47	1860	Meters (Smart Meters)		$ 886,212		$ 886,212	-$ 173,893	-$ 58,065		-$ 231,958	$ 654,254
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements	$ 4,692			$ 4,692	-$ 3,284	-$ 938		-$ 4,222	$ 470
8	1915	Office Furniture & Equipment (10 years)	$ 17,607			$ 17,607	-$ 20,678	-$ 404	$ 4,157	-$ 16,925	$ 682
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 91,509			$ 91,509	-$ 76,520	-$ 12,764		-$ 89,284	$ 2,225
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 501,882		$ 501,882	-$ 119,404	-$ 34,115		-$ 153,519	$ 348,363
10	1930	Transportation Equipment	$ 1,505,079	$ 224,313		$ 1,729,392	-$ 525,517	-$ 204,312	$ 14,713	-$ 715,116	$ 1,014,276
8	1935	Stores Equipment	$ 680	$ 1,501		$ 2,181	-$ 1,456	-$ 282	$ 434	-$ 1,304	$ 877
8	1940	Tools, Shop & Garage Equipment	$ 192,397	$ 12,485		$ 204,882	-$ 114,560	-$ 25,514	$ 6,061	-$ 134,013	$ 70,869
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 4,638			$ 4,638	-$ 2,662	-$ 790		-$ 3,452	$ 1,186
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 6,603			$ 6,603	-$ 3,962	-$ 2,641		-$ 6,603	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue [5]									
						$ -				$ -	$ -
		Sub-Total	**$ 8,652,250**	**$ 2,321,629**	**-$ 1,410**	**$ 10,972,469**	**-$ 4,254,845**	**-$ 580,753**	**$ 27,209**	**-$ 4,808,389**	**$ 6,164,080**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 8,652,250**	**$ 2,321,629**	**-$ 1,410**	**$ 10,972,469**	**-$ 4,254,845**	**-$ 580,753**	**$ 27,209**	**-$ 4,808,389**	**$ 6,164,080**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 580,753**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 202,629
Stores Equipment	-$ 15,459
Net Depreciation	-$ 362,665

Notes:

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2014

			Cost						Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**IFRS Adjustment**	**Adjusted Jan 1, 2014 Cost**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**IFRS Adjustment**	**Adjusted Jan 1, 2014 Acc. Dep**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 189,454	-$ 136,797	$ 52,657			$ 52,657	-$ 136,797	$ 136,797	$ -	-$ 21,703		-$ 21,703	$ 30,954
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700	$ -	$ 87,700			$ 87,700	$ -	$ -	$ -			$ -	$ 87,700
47	1808	Buildings	$ 519,360	-$ 68,369	$ 450,991	$ 10,228		$ 461,219	-$ 68,369	$ 68,369	$ -	-$ 19,059		-$ 19,059	$ 442,160
13	1810	Leasehold Improvements	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 558,947	-$ 349,442	$ 209,505			$ 209,505	-$ 349,442	$ 349,442	$ -	-$ 19,581		-$ 19,581	$ 189,924
47	1825	Storage Battery Equipment	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,998,022	-$ 1,314,678	$ 1,683,344	$ 156,027		$ 1,839,371	-$ 1,314,678	$ 1,314,678	$ -	-$ 124,949		-$ 124,949	$ 1,714,422
47	1835	Overhead Conductors & Devices	$ 1,848,277	-$ 913,215	$ 935,062	$ 113,882		$ 1,048,944	-$ 913,215	$ 913,215	$ -	-$ 33,256		-$ 33,256	$ 1,015,688
47	1840	Underground Conduit	$ 112,571	-$ 103,023	$ 9,548			$ 9,548	-$ 103,023	$ 103,023	$ -	-$ 1,364		-$ 1,364	$ 8,184
47	1845	Underground Conductors & Devices	$ 3,690	-$ 1,579	$ 2,111			$ 2,111	-$ 1,579	$ 1,579	$ -	-$ 302		-$ 302	$ 1,809
47	1850	Line Transformers	$ 836,970	-$ 371,366	$ 465,604	$ 35,857		$ 501,461	-$ 371,366	$ 371,366	$ -	-$ 20,143		-$ 20,143	$ 481,318
47	1855	Services (Overhead & Underground)	$ 336,603	-$ 183,152	$ 153,451	$ 41,377		$ 194,828	-$ 183,152	$ 183,152	$ -	-$ 10,694		-$ 10,694	$ 184,134
47	1860	Meters	$ 31,277	-$ 10,372	$ 20,905			$ 20,905	-$ 10,372	$ 10,372	$ -	-$ 1,278		-$ 1,278	$ 19,627
47	1860	Meters (Smart Meters)	$ 886,212	-$ 231,958	$ 654,254	$ 8,210		$ 662,464	-$ 231,958	$ 231,958	$ -	-$ 59,355		-$ 59,355	$ 603,109
N/A	1905	Land	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 4,692	-$ 4,222	$ 470			$ 470	-$ 4,222	$ 4,222	$ -	-$ 470		-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 17,607	-$ 16,925	$ 682			$ 682	-$ 16,925	$ 16,925	$ -	-$ 191		-$ 191	$ 491
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 91,509	-$ 89,284	$ 2,225	$ 1,800		$ 4,025	-$ 89,284	$ 89,284	$ -	-$ 1,861		-$ 1,861	$ 2,164
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 501,882	-$ 153,519	$ 348,363			$ 348,363	-$ 153,519	$ 153,519	$ -	-$ 34,115		-$ 34,115	$ 314,248
10	1930	Transportation Equipment	$ 1,729,392	-$ 715,116	$ 1,014,276	$ 261,375	-$ 113,322	$ 1,162,329	-$ 715,116	$ 715,116	$ -	-$ 229,446	$ 113,321	-$ 116,125	$ 1,046,204
8	1935	Stores Equipment	$ 2,181	-$ 1,304	$ 877			$ 877	-$ 1,304	$ 1,304	$ -	-$ 282		-$ 282	$ 595
8	1940	Tools, Shop & Garage Equipment	$ 204,882	-$ 134,013	$ 70,869	$ 5,007		$ 75,876	-$ 134,013	$ 134,013	$ -	-$ 27,367		-$ 27,367	$ 48,509
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 4,638	-$ 3,452	$ 1,186			$ 1,186	-$ 3,452	$ 3,452	$ -	-$ 791		-$ 791	$ 395
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 6,603	-$ 6,603	$ -			$ -	-$ 6,603	$ 6,603	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	
			$ -	$ -	$ -			$ -	$ -	$ -	$ -			$ -	$ -
		Sub-Total	**$ 10,972,469**	**-$ 4,808,389**	**$ 6,164,080**	**$ 633,763**	**-$ 113,322**	**$ 6,684,521**	**-$ 4,808,389**	**$ 4,808,389**	$ -	**-$ 606,207**	**$ 113,321**	**-$ 492,886**	**$ 6,191,635**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 10,972,469**	**-$ 4,808,389**	**$ 6,164,080**	**$ 633,763**	**-$ 113,322**	**$ 6,684,521**	**-$ 4,808,389**	**$ 4,808,389**	**$ -**	**-$ 606,207**	**$ 113,321**	**-$ 492,886**	**$ 6,191,635**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total										**-$ 606,207**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 229,446
Stores Equipment	-$ 19,059
Net Depreciation	-$ 357,702

Notes:

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2015**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**		**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**		**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 52,657	$ -	$ -		$ 52,657	-$ 21,703	-$ 20,730	$ -	$ -	-$ 42,433	$ 10,224
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 87,700	$ -	$ -		$ 87,700	$ -	$ -	$ -	$ -	$ -	$ 87,700
47	1808	Buildings	$ 461,219	$ 1,165	$ -		$ 462,384	-$ 19,059	-$ 21,068	$ -	$ -	-$ 40,127	$ 422,257
13	1810	Leasehold Improvements	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 209,505	$ 11,743	$ -		$ 221,248	-$ 19,581	-$ 19,886	$ -	$ -	-$ 39,467	$ 181,781
47	1825	Storage Battery Equipment	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,839,371	$ 198,591	-$ 4,123		$ 2,033,839	-$ 124,949	-$ 128,139	$ 3,196	$ -	-$ 249,892	$ 1,783,947
47	1835	Overhead Conductors & Devices	$ 1,048,944	$ 89,749	-$ 2,167		$ 1,136,526	-$ 33,256	-$ 35,515	$ 485	$ -	-$ 68,286	$ 1,068,240
47	1840	Underground Conduit	$ 9,548	$ -	$ -		$ 9,548	-$ 1,364	-$ 1,364	$ -	$ -	-$ 2,728	$ 6,820
47	1845	Underground Conductors & Devices	$ 2,111	$ -	$ -		$ 2,111	-$ 302	-$ 301	$ -	$ -	-$ 603	$ 1,508
47	1850	Line Transformers	$ 501,461	$ 65,578	-$ 4,084		$ 562,955	-$ 20,143	-$ 21,016	$ 3,984	$ -	-$ 37,175	$ 525,780
47	1855	Services (Overhead & Underground)	$ 194,828	$ 44,341	-$ 1,727		$ 237,442	-$ 10,694	-$ 11,781	$ 1,727	$ -	-$ 20,748	$ 216,694
47	1860	Meters	$ 20,905	$ -	$ -		$ 20,905	-$ 1,278	-$ 3,101	$ -	$ -	-$ 4,379	$ 16,526
47	1860	Meters (Smart Meters)	$ 662,464	$ 5,088	$ -		$ 667,552	-$ 59,355	-$ 65,203	$ -	$ -	-$ 124,558	$ 542,994
N/A	1905	Land	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ 470	$ -	$ -		$ 470	-$ 470	$ -	$ -	$ -	-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 682	$ -	$ -		$ 682	-$ 191	-$ 192	$ -	$ -	-$ 383	$ 299
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,025	$ 6,000	$ -		$ 10,025	-$ 1,861	-$ 2,264	$ -	$ -	-$ 4,125	$ 5,900
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,363	$ -	$ -		$ 348,363	-$ 34,115	-$ 34,115	$ -	$ -	-$ 68,230	$ 280,133
10	1930	Transportation Equipment	$ 1,162,329	$ -	$ -		$ 1,162,329	-$ 116,125	-$ 229,167	$ -	$ -	-$ 345,292	$ 817,037
8	1935	Stores Equipment	$ 877	$ -	$ -		$ 877	-$ 282	-$ 282	$ -	$ -	-$ 564	$ 313
8	1940	Tools, Shop & Garage Equipment	$ 75,876	$ 2,500	$ -		$ 78,376	-$ 27,367	-$ 22,189	$ -	$ -	-$ 49,556	$ 28,820
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,186	$ -	$ -		$ 1,186	-$ 791	-$ 395	$ -	$ -	-$ 1,186	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	-$ 123,412	$ -		-$ 123,412	$ -	$ 1,409	$ -	$ -	$ 1,409	-$ 122,003
			$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 6,684,521**	**$ 301,343**	**-$ 12,101**	**$ -**	**$ 6,973,763**	**-$ 492,886**	**-$ 615,299**	**$ 9,392**	**$ -**	**-$ 1,098,793**	**$ 5,874,970**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 6,684,521**	**$ 301,343**	**-$ 12,101**		**$ 6,973,763**	**-$ 492,886**	**-$ 615,299**	**$ 9,392**		**-$ 1,098,793**	**$ 5,874,970**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**-$ 615,299**				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 229,167
Stores Equipment	-$ 21,067
Net Depreciation	-$ 365,065

Notes:

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 52,657	$ 388,964		$ 441,621	-$ 42,433	-$ 47,692		-$ 90,125	$ 351,496
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,384			$ 462,384	-$ 40,127	-$ 19,373		-$ 59,500	$ 402,884
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 221,248	$ 70,000		$ 291,248	-$ 39,467	-$ 21,082		-$ 60,549	$ 230,699
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,033,839	$ 276,000		$ 2,309,839	-$ 249,892	-$ 134,260		-$ 384,152	$ 1,925,687
47	1835	Overhead Conductors & Devices	$ 1,136,526	$ 69,250		$ 1,205,776	-$ 68,286	-$ 37,319		-$ 105,605	$ 1,100,171
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 2,728	-$ 1,364		-$ 4,092	$ 5,456
47	1845	Underground Conductors & Devices	$ 2,111			$ 2,111	-$ 603	-$ 301		-$ 904	$ 1,207
47	1850	Line Transformers	$ 562,955	$ 69,250		$ 632,205	-$ 37,175	-$ 22,815		-$ 59,990	$ 572,215
47	1855	Services (Overhead & Underground)	$ 237,442			$ 237,442	-$ 20,748	-$ 12,625		-$ 33,373	$ 204,069
47	1860	Meters	$ 20,905			$ 20,905	-$ 4,379	-$ 2,291		-$ 6,670	$ 14,235
47	1860	Meters (Smart Meters)	$ 667,552	$ 15,000		$ 682,552	-$ 124,558	-$ 60,467		-$ 185,025	$ 497,527
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 470			$ 470	-$ 470			-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 682			$ 682	-$ 383	-$ 60		-$ 443	$ 239
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 10,025	$ 15,000		$ 25,025	-$ 4,125	-$ 4,100		-$ 8,225	$ 16,800
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,363			$ 348,363	-$ 68,230	-$ 33,500		-$ 101,730	$ 246,633
10	1930	Transportation Equipment	$ 1,162,329	$ 85,000		$ 1,247,329	-$ 345,292	-$ 201,253		-$ 546,545	$ 700,784
8	1935	Stores Equipment	$ 877			$ 877	-$ 564	-$ 175		-$ 739	$ 138
8	1940	Tools, Shop & Garage Equipment	$ 78,376	$ 7,500		$ 85,876	-$ 49,556	-$ 15,195		-$ 64,751	$ 21,125
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,186			$ 1,186	-$ 1,186			-$ 1,186	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 123,412			-$ 123,412	$ 1,409	$ 2,850		$ 4,259	-$ 119,153
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 6,973,763**	**$ 995,964**	**$ -**	**$ 7,969,727**	**-$ 1,098,793**	**-$ 611,022**	**$ -**	**-$ 1,709,815**	**$ 6,259,912**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 6,973,763**	**$ 995,964**	**$ -**	**$ 7,969,727**	**-$ 1,098,793**	**-$ 611,022**	**$ -**	**-$ 1,709,815**	**$ 6,259,912**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 611,022**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 201,253
Stores Equipment	-$ 19,373
Net Depreciation	-$ 390,396

Notes:

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2016-0096
Exhibit:	2
Tab:	1
Schedule:	1
Attachment:	1
Page	5 of 5
Date:	26-Aug-16

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 441,621	$ 115,000		$ 556,621	-$ 90,125	-$ 86,293		-$ 176,418	$ 380,203
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,384			$ 462,384	-$ 59,500	-$ 19,373		-$ 78,873	$ 383,511
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 291,248	$ 50,000		$ 341,248	-$ 60,549	-$ 21,977		-$ 82,526	$ 258,722
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,309,839	$ 417,500		$ 2,727,339	-$ 384,152	-$ 142,035		-$ 526,187	$ 2,201,152
47	1835	Overhead Conductors & Devices	$ 1,205,776	$ 101,250		$ 1,307,026	-$ 105,605	-$ 39,231		-$ 144,836	$ 1,162,190
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 4,092	-$ 1,364		-$ 5,456	$ 4,092
47	1845	Underground Conductors & Devices	$ 2,111			$ 2,111	-$ 904	-$ 301		-$ 1,205	$ 906
47	1850	Line Transformers	$ 632,205	$ 101,250		$ 733,455	-$ 59,990	-$ 24,692		-$ 84,682	$ 648,773
47	1855	Services (Overhead & Underground)	$ 237,442			$ 237,442	-$ 33,373	-$ 12,625		-$ 45,998	$ 191,444
47	1860	Meters	$ 20,905			$ 20,905	-$ 6,670	-$ 1,936		-$ 8,606	$ 12,299
47	1860	Meters (Smart Meters)	$ 682,552	$ 15,000		$ 697,552	-$ 185,025	-$ 61,467		-$ 246,492	$ 451,060
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 470			$ 470	-$ 470			-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 682			$ 682	-$ 443	-$ 60		-$ 503	$ 179
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,025	$ 10,000		$ 35,025	-$ 8,225	-$ 6,300		-$ 14,525	$ 20,500
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,363			$ 348,363	-$ 101,730	-$ 32,885		-$ 134,615	$ 213,748
10	1930	Transportation Equipment	$ 1,247,329			$ 1,247,329	-$ 546,545	-$ 188,694		-$ 735,239	$ 512,090
8	1935	Stores Equipment	$ 877			$ 877	-$ 739	-$ 68		-$ 807	$ 70
8	1940	Tools, Shop & Garage Equipment	$ 85,876	$ 17,500		$ 103,376	-$ 64,751	-$ 12,216		-$ 76,967	$ 26,409
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,186			$ 1,186	-$ 1,186			-$ 1,186	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 123,412			-$ 123,412	$ 4,259	$ 2,850		$ 7,109	-$ 116,303
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 7,969,727**	**$ 827,500**	**$ -**	**$ 8,797,227**	**-$ 1,709,815**	**-$ 648,667**	**$ -**	**-$ 2,358,482**	**$ 6,438,745**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 7,969,727**	**$ 827,500**	**$ -**	**$ 8,797,227**	**-$ 1,709,815**	**-$ 648,667**	**$ -**	**-$ 2,358,482**	**$ 6,438,745**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 648,667**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 188,695
Stores Equipment	-$ 20,292
Net Depreciation	-$ 439,680

Notes:

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

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

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

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

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

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

GROSS ASSETS (PP&E)

NOW Inc.'s Fixed Asset Continuity Statements containing both costs and depreciation for historic years 2013 to 2015 and for Bridge Year 2016 and Test Year 2017 are provided in E2/T1/S1/Att1. The figures in the Bridge and Test Year are representative of the capital expenditure programs in both cases.

NOW Inc. utilizes the straight-line method in calculating depreciation for all capital assets. The estimated useful life is the driver for the calculation, and impairments are evaluated each year. In calculation depreciation of current year additions, NOW Inc. employs the half-year rule.

DEPRECIATION EXPENSE

Since 2013, NOW Inc.'s depreciation has been consistent with MIFRS. Under MIFRS, costs are depreciated over the assets useful life, subject to the half-year rule on additions. Due to the transition to MIFRS, NOW Inc. is depreciating the opening net book value of assets upon transition over their average remaining life.

These values are consistent with the Fixed Asset Continuity Schedules in E2/T1/S1/Att1 which is OEB Appendix 2-BA.

Depreciation expense from 2013 Board Approved to 2017 TY is presented in **Table 1**.

Table 1: Annual Depreciation Expense for Rate-Setting Purposes

		Historical				Bridge	Test
	2013 Approved	2013	2014	2015	2015	2016	2017
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**IFRS**	**IFRS**	**IFRS**
Total Depreciation	$454,062	$580,753	$606,207	$615,299	$615,299	$611,022	$648,667
Fully Allocated Depreciation	-$135,932	-$218,088	-$248,505	-$250,234	-$250,234	-$220,626	-$208,987
Net Depreciation	**$318,130**	**$362,665**	**$357,702**	**$365,065**	**$365,065**	**$390,396**	**$439,680**

ALLOWANCE FOR WORKING CAPITAL

In a letter dated June 3, 2015, the Board provided an update to electricity distributors on the options for calculating of the allowance for working capital. The applicant is permitted to take one of two approaches for the calculation of its allowance for working capital:

(1) the 7.5% allowance approach;
(2) or the filing of a lead/lag study.

NOW Inc. has elected to use the 7.5% allowance approach. The 7.5% Allowance Approach is calculated to be 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). The commodity price estimate used to calculate the Cost of Power has been determined in a way that bases the split between RPP and non-RPP customers on actual data and uses the most current RPP price. The calculation reflects the most recent Uniform Transmission Rates approved by the Board (EB- 2015-0311), issued on January 15, 2016. Should new information become available for Uniform Transmission Rates and RPP during the course of a proceeding, the Cost of Power will be updated to reflect the new rates. NOW Inc. confirms that it has not been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based.

NOW Inc. proposes a Working Capital Allowance of $1,416,960 for the 2017 Test Year, which relies on the working capital allowance percentage of 7.5% as shown in **Table 1**.

Table 1: 2017 Working Capital Allowance Calculation

Description	2017 Test IFRS
OM&A	$ 2,907,906
Cost of Power	$ 15,984,891
Working Capital	**$ 18,892,797**
Working Capital Allowance Rate	7.5%
Working Capital Allowance	**$ 1,416,960**

Table 2 below shows the working capital allowance calculation from the 2013 OEB Approved to the 2017 Test Year.

Table 2: Working Capital Allowance Calculation

Description	2013 OEB Approved	2013 Actual CGAAP	2014 Actual CGAAP	2015 Actual CGAAP	2015 Actual IFRS	2016 Bridge IFRS	2017 Test IFRS
Controllable Expenses							
Operations	$ 455,369	$ 600,841	$ 749,465	$ 618,070	$ 618,070	$ 617,237	$ 815,665
Maintenance	$ 439,411	$ 631,448	$ 487,822	$ 509,810	$ 509,810	$ 592,253	$ 697,590
Billing and Collecting	$ 693,896	$ 1,072,708	$ 584,730	$ 752,020	$ 752,020	$ 714,670	$ 746,564
Community Relations		$ -					
Administrative and General Expenses	$ 714,370	$ 1,250,630	$ 644,677	$ 513,370	$ 513,370	$ 751,118	$ 647,667
Taxes other than Income Taxes	$ 1,502	$ 1,893	$ 1,823	$ 1,948	$ 1,948	$ 408	$ 420
Total Controllable Expenses*	$ 2,304,548	$ 3,557,520	$ 2,468,517	$ 2,395,218	$ 2,395,218	$ 2,675,686	$ 2,907,906
Cost of Power	$ 12,290,062	$13,463,456	$ 13,450,479	$14,422,963	$14,422,963	$16,098,334	$ 15,984,891
Working Capital	**$ 14,594,610**	**$17,020,976**	**$ 15,918,996**	**$16,818,181**	**$16,818,181**	**$18,774,020**	**$ 18,892,797**
Working Capital Allowance Rate	11.4%	11.4%	11.4%	11.4%	11.4%	11.4%	7.5%
Working Capital Allowance	**$ 1,663,786**	**$ 1,940,391**	**$ 1,814,766**	**$ 1,917,274**	**$ 1,917,274**	**$ 2,140,238**	**$ 1,416,960**

* 2013 Approved OM&A not adjusted for allocated depreciation in this table

Table 3 shows that the 2017 Working Capital Allowance has decreased by $246,826 (-15%) as compared to the 2013 OEB approved amount. This is primarily due to the reduction in the Working Capital Allowance rate from 11.4% to 7.5%, partially offset by an increase in Cost of Power expenditures

Table 3: Change in Working Capital Allowance

Description	2013 OEB Approved	2017 Test IFRS	Change ($)	Change (%)
Cost of Power	$ 12,290,062	$ 15,984,891	$ 3,694,829	30%
Controllable Expenses *	$ 2,304,548	$ 2,907,906	$ 603,358	26%
Working Capital	**$ 14,594,610**	**$ 18,892,797**	**$ 4,298,187**	**29%**
Working Capital Allowance Rate	11.4%	7.5%		
Working Capital Allowance	**$ 1,663,786**	**$ 1,416,960**	**-$ 246,826**	**-15%**

* 2013 Approved OM&A not adjusted for allocated depreciation in this table

Exhibit 2: Rate Base

Tab 2 (of 2): Capital Expenditures

PLANNING

This exhibit provides information on Northern Ontario Wires capital plans. The key component of the capital planning process is the Distribution System Plan (DSP) and this is provided in Attachment 1. The DSP has been prepared following the guidance provided in the Chapter 5 – Consolidated Distribution System Plan Filing Requirements dated March 28, 2013. Capital expenditures are categorized based on the specified System Access, System Renewal, System Service and General Plant groupings in the DSP. This is the first Distribution System Plan that Northern Ontario Wires has prepared and it will guide future capital projects and spending. Funding for the 2017 portion of the DSP is included in the calculation of 2017TY revenue requirement, with projects assumed to be in service using the half-year rule.

Capital contributions are typically not significant in the operations of NOW Inc. However, in 2015, NOW Inc. had capital contributions, for a total of $123,412. The amount of the contribution is the cost of materials and labour. NOW Inc. has not forecast for any future capital contributions because they are not typical of historic patterns and future amounts are not determinable.

It is difficult to quantify the capital and operating efficiencies of the smart meter deployment. However, efficiencies since the deployment of smart meters include reduced labour in meter reading, more accurate billing, less chance for human error, and access to smart meter information for customer enquiries. NOW Inc. is continuing with plans to generate more benefits from the current smart meter technology by maximizing capabilities with the implementation of the Outage Management System. This will improve decision making and allow for greater customer service.

As part of the planning process, NOW Inc. considered the possibility of the potential impacts of incremental CDM initiatives, however, none were identified.

The following **Table 1** provides capital expenditure information for the years 2012 - 2021, and is summarized from OEB Appendix 2-AB which is provided in E2/T2/S1/Att2.

Table 1: Summary of Capital Expenditures

CATEGORY	Historical Period				Forecast Period (planned)					
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	$ -	$ 40	$ 8	$ 58	$ 15	$ 15	$ 15	$ 20	$ 20	$ 20
System Renewal	$ 283	$ 245	$ 112	$ 179	$ 213	$ 355	$ 395	$ 370	$ 350	$ 380
System Service	$ 185	$ 269	$ 235	$ 178	$ 227	$ 315	$ 355	$ 370	$ 385	$ 400
General Plant	$ 363	$ 254	$ 366	$ 171	$ 248	$ 143	$ 33	$ 33	$ 33	$ 33
TOTAL EXPENDITURE	**$ 831**	**$ 808**	**$ 721**	**$ 586**	**$ 703**	**$ 828**	**$ 798**	**$ 793**	**$ 788**	**$ 833**

Capital expenditure projects for the years 2013 – 2017 are provided in **Table 2** below. This information is based on OEB Appendix 2-AA (E2/T2/S1/Att3) and also includes 2013 OEB Approved capital expenditures.

Table 2 – Capital Projects Table

Table 2: 2013 – 2017 Capital Expenditures

Projects	2013 Approved	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
System Access						
Metering		40,344	8,210	5,089	15,000	15,000
Sub-Total	0	40,344	8,210	5,089	15,000	15,000
System Renewal						
Pole Changes- Cochrane	53,560	105,504	49,270	58,096	55,000	105,000
Pole Changes- Kapuskasing	53,560	2,013	14,050	8,103	55,000	55,000
Pole Changes-Iroquois Falls	53,560	8,323	3,229	419	27,500	55,000
Cochrane - 5 kV Upgrade - Lanew	172,578	129,232				
Cochrane - Primary 11th and Maple			38,660	7,334		
Cochrane Lakefront Rebuild					50,000	
Cochrane 5 - kV Upgrade						90,000
Cochrane Substation Feeder			686		25,000	50,000
IF - Pole Changes - CC				52,253		
Cochrane Pole Changes - CC				29,665		
Kapuskasing Pole Changes -CC				9,232		
Sub-Total	333,258	245,072	105,895	165,102	212,500	355,000
System Service						
Kapuskasing 5kV to 25kV Convers	101,351	205,501	203,393	94,251	140,000	175,000
Iroqois Falls 2.4 to 12kV Upgrade	77,920	63,936	31,322	83,829	87,000	140,000
Sub-Total	179,271	269,437	234,715	178,080	227,000	315,000
General Plant						
Transportation Equipment	176,500	224,313	261,375		85,000	
Computer Hardware	10,300		1,800	6,000	30,000	10,000
Computer Software	5,150		87,493	160,557	120,914	115,000
Buildings		17,535	10,228	1,165		
Sub-Total	191,950	241,848	360,896	167,722	235,914	125,000
Miscellaneous	20,600	12,485	11,550	69,777	12,500	17,500
Total	**725,079**	**809,186**	**721,266**	**585,770**	**702,914**	**827,500**

Table 3 is derived from the information in Table 2 and provides the year over year changes in capital expenditures by project. Variances greater than $50,000 are highlighted and explanations are provided below.

Table 3 – Year Over Year Change in Capital Expenditures

Table 3: 2013 – 2017 Capital Expenditures Variances

Projects		2013 Actual vs 2013 OEB Approved	2014 Actual vs 2013 Actual	2015 Actual vs 2014 Actual	2016 Bridge vs 2015 Actual	2017 Test vs 2016 Bridge
		Variances	Variances	Variances	Variances	Variances
Reporting Basis		CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
System Access						
Metering		40,344	-32,134	-3,121	9,911	0
Sub-Total		40,344	-32,134	-3,121	9,911	0
System Renewal						
Pole Changes- Cochrane		51,944	-56,234	8,826	-3,096	50,000
Pole Changes- Kapuskasing		-51,547	12,037	-5,947	46,897	0
Pole Changes-Iroquois Falls		-45,237	-5,094	-2,810	27,081	27,500
Cochrane - 5 kV Upgrade - Laneway		-43,346	-129,232	0	0	0
Cochrane - Primary 11th and Maple		0	38,660	-31,326	-7,334	0
Cochrane Lakefront Rebuild		0	0	0	50,000	-50,000
Cochrane 5 - kV Upgrade		0	0	0	0	90,000
Cochrane Substation Feeder		0	686	-686	25,000	25,000
IF - Pole Changes - CC		0	0	52,253	-52,253	0
Cochrane Pole Changes - CC		0	0	29,665	-29,665	0
Kapuskasing Pole Changes -CC		0	0	9,232	-9,232	0
Sub-Total		-88,186	-139,177	59,207	47,398	142,500
System Service						
Kapuskasing 5kV to 25kV Conversion		104,150	-2,108	-109,142	45,749	35,000
Iroqois Falls 2.4 to 12kV Upgrade		-13,984	-32,614	52,507	3,171	53,000
Sub-Total		90,166	-34,722	-56,635	48,920	88,000
General Plant						
Transportation Equipment		47,813	37,062	-261,375	85,000	-85,000
Computer Hardware		-10,300	1,800	4,200	24,000	-20,000
Computer Software		-5,150	87,493	73,064	-39,643	-5,914
Buildings		17,535	-7,307	-9,063	-1,165	0
Sub-Total		49,898	119,048	-193,174	68,192	-110,914
Miscellaneous		-8,115	-935	58,227	-57,277	5,000
Total		**84,107**	**-87,920**	**-135,496**	**117,144**	**124,586**

2013 Actual over 2013 OEB Approved

- Pole Changes – Cochrane, $51,944 higher primarily due to more frequent line patrols that identified poles which required immediate attention.

- Pole Changes – Kapuskasing $51,547 lower primarily due to pole changes being included in the 25kV upgrade.
- Kapuskasing 5kV to 25kV Conversion, $104,150 higher primarily due the increase in priority of sections of the 25kV upgrade.

2014 Actual over 2013 Actual

- Pole Changes – Cochrane, $56,234 lower primarily due to pole replacements returning to the approved and anticipated level.
- Cochrane – 5kV Upgrade Laneway, $129,232 lower as the project was completed in 2013 and new projects were undertaken in 2014.
- Computer Software, $87,493 higher primarily due to the GIS work program.

2015 Actual over 2014 Actual

- IF Pole Changes, $52,253 higher due to contributed capital work
- Transportation Equipment $261,375 lower due to no new equipment being required in 2015. In 2014 a Digger Derrick was purchased, the critical replacements were complete and no vehicle additions were required in 2015.
- Computer Software, $73,064 higher primarily due to the GIS project.
- Kapuskasing 5kV to 25 kV Conversion, $109,142 lower primarily due to more intensive equipment installation (poles, transformers, conductors) in 2014. Remaining work in 2015 was to complete the line section and energize.
- Iroquois Falls 2.4 to 12 kV Upgrade, $52,507 higher primarily due to further work on the extension of the distribution system.
- Miscellaneous (tools and equipment, transformers etc}, $58,227 higher primarily due to multiple smaller expenditures driven primarily by customer requests and equipment purchases.

2016 Bridge Year over 2015 Actual

- IF Pole Changes, $52,253 lower due to there being no contributed capital work in 2016
- Transportation Equipment, $85,000 higher primarily due to the purchase of a new pickup truck and anticipated capital component replacements on a fleet vehicle.
- Miscellaneous [tools, equipment, transformers, etc.}, $57,277 lower primarily due to non-recurring items (e.g. contributed capital projects identified in 2015).

2017 Test Year over 2016 Bridge Year

- Cochrane 5kV Upgrade, $90,000 higher primarily due a rebuild in the downtown core.
- Pole changes in Cochrane have increased $50,000 due to poles identified during line patrols.
- Iroquois Falls 2.4kV to 12kV upgrade has increase by $53,000 in 2017 primarily due to the increased scope of the project and includes a padmount transformer.

Partially offset by:

- Lower Cochrane lakefront rebuild of $50,000 completion of project.
- Transportation Equipment, $85,000 lower due to the fact that no equipment requires replacement.

Capital Planning

NOW Inc. participates in the municipal planning process in the towns of Kapuskasing, Iroquois Falls and Cochrane, it is also active with regional planning (such as Hydro One Networks Inc.) and other major stakeholders. Further information on Regional Planning can be found on in the DSP at E2/T2/S1/Att1, Appendix B.

In addition to the DSP, NOW Inc.'s capital plans have also been informed by the annual O.Reg 22/04 Audit Report, the site inspection oil samples report, and the fleet matrix. The most recent versions of these reports are provided in E2/T2/S1/Att 4-6 respectively.

Table 4 provides a summary of Capital Expenditures for 2016 -2021.

Table 4: Summary of Capital Expenditures 2016 - 2021

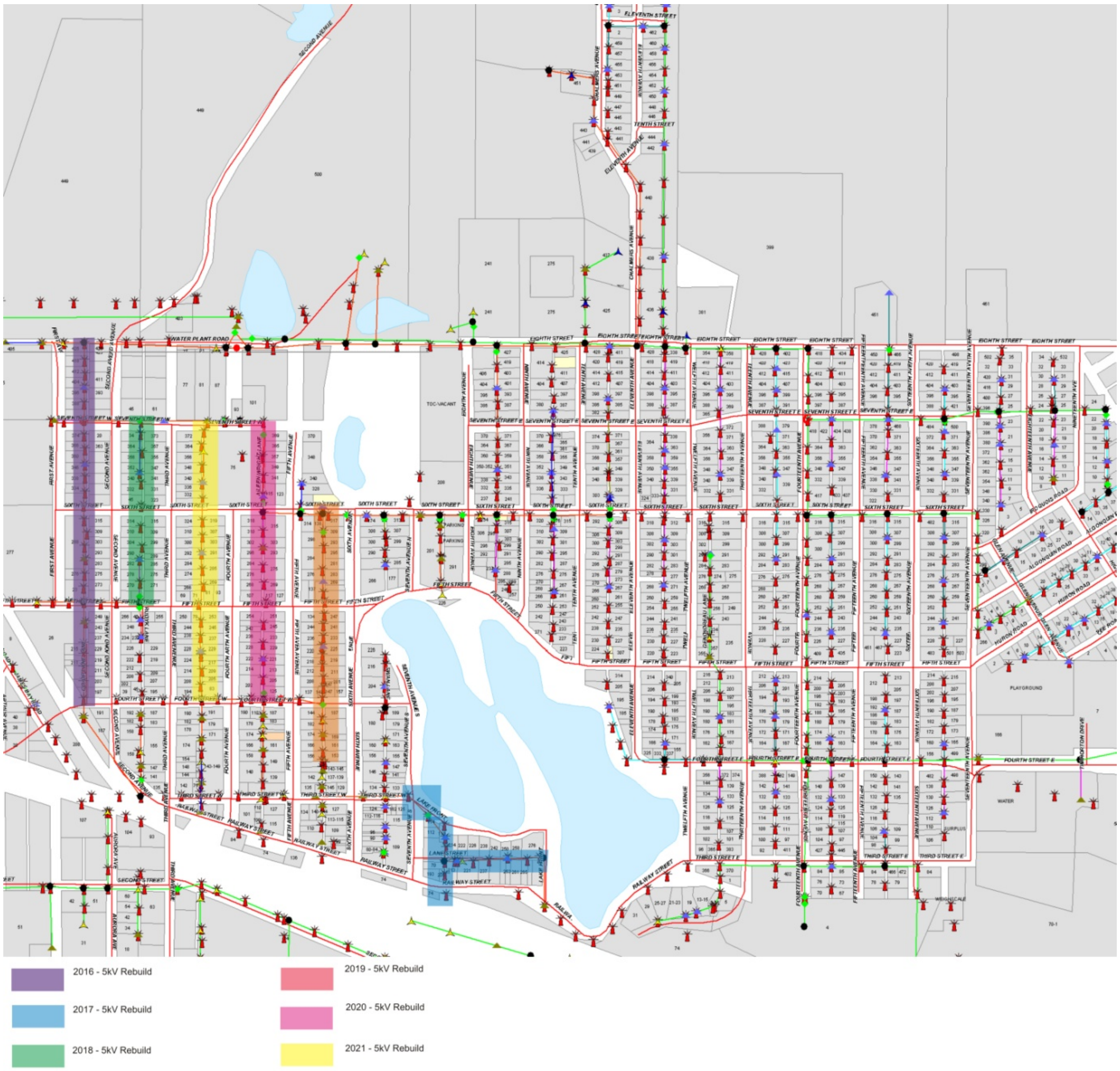
CATEGORY	**Forecast Period** (planned)					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
	$ '000	**$ '000**	**$ '000**	**$ '000**	**$ '000**	**$ '000**
System Access	$ 15	$ 15	$ 15	$ 20	$ 20	$ 20
System Renewal	$ 213	$ 355	$ 395	$ 370	$ 350	$ 380
System Service	$ 227	$ 315	$ 355	$ 370	$ 385	$ 400
General Plant	$ 248	$ 143	$ 33	$ 33	$ 33	$ 33
TOTAL EXPENDITURE	**$ 703**	**$ 828**	**$ 798**	**$ 793**	**$ 788**	**$ 833**

The key to effective capital planning is to prioritize the work as identified in NOW Inc.'s DSP. Capital work to the system benefits the consumer by ensuring that electricity is delivered in a reliable and safe manner.

Overall Capital Expenditure Strategy by Town

Cochrane – Northern Ontario Wires Inc. is continuing the rebuild of the 5kV circuit (*Figure 1).* Replacements of existing infrastructure equipment is approaching and/or exceeding projected lifespan, as identified within the Distribution System Plan (DSP). Northern Ontario Wires Inc. also plans to perform upgrades to its station transformer. NOW Inc. continuously monitors equipment and assets on a monthly basis to assess condition and schedule replacement, if required.

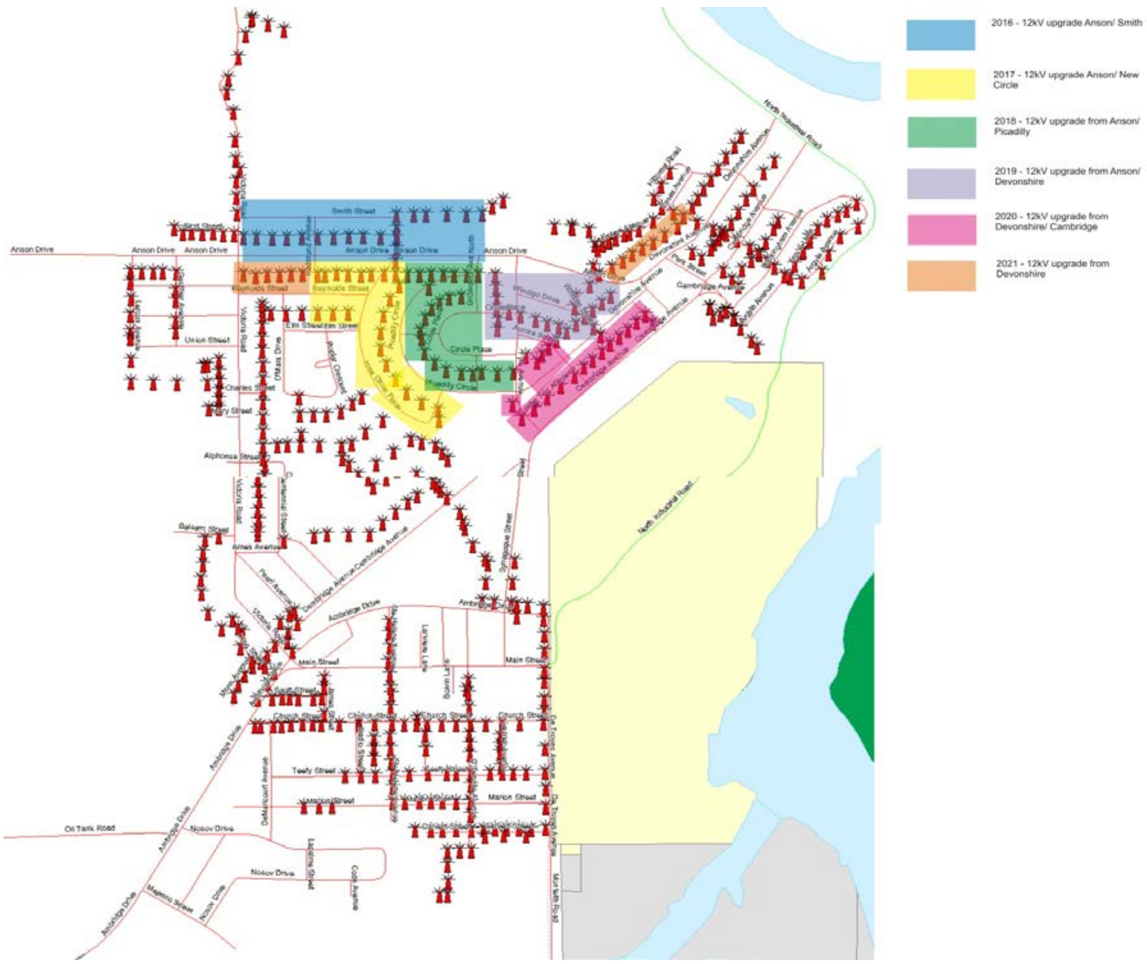
Figure 1 - Cochrane



Iroquois Falls – Projects in this community are being performed in order to remove an old 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability (*Figure 2)*. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022. Furthermore, through

NOW Inc.'s inspection process, certain poles have been identified (DSP) that require changing.

Figure 2 – Iroquois Falls



Kapuskasing – In order to mitigate line losses and improve reliability, an ongoing decommissioning project is underway in Kapuskasing (*Figure 3)*. The decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV is expected to end in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. Additionally, poles which require upgrades as identified in the Distribution System Plan (DSP) have been identified.

These improvements are expected to reduce future maintenance costs and increase service reliability.

Figure 3 - Kapuskasing

Description by Project

2016 CAPITAL PROJECTS

System Renewal	$	212,500
General Plant	$	248,414
System Access	$	15,000
System Service	$	227,000
2016 Actual Capital Projects	**$**	**702,914**

System Renewal:

Project 2016: Cochrane Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to vehicle collisions or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2016: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to vehicle collisions or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2016: Iroquois Falls Pole Changes – Total Cost $ 27,500

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

<u>Project 2016: Cochrane Lakefront Rebuild – Total Cost $ 50,000</u>

- An ongoing project since 2011, this rebuild project comprises of replacing deteriorating poles and increasing conductor size. These upgrades are expected to reduce maintenance and improve system reliability as well as aesthetics in the area. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference. The Cochrane Lakefront is a high traffic area with many town activities around the lake. The upgrade also reduces safety risk as the higher poles allow for greater vehicle clearance. This part of town is also older and is in need of pole replacements which are done as a part of this project.

<u>Project 2016: Cochrane Substation Feeder – Total Cost $ 25,000</u>

- Given the severe climate in northern Ontario, factors such as weather will affect distribution assets. Temperatures can dip to -40 degrees Celsius and frost begins as early as September. As a result of ongoing frost, structures and poles at the Cochrane Substation Feeder have shifted. These assets will require replacing for reliability and safety purposes. In consultation with an engineer, the options for reducing environment impacts due to geographic challenges will be examined. NOW Inc. staff has noticed that climate change and the different weather patterns are impacting equipment that was historically not affected.

General Plant:

<u>2016 Transportation Equipment – Total Cost $85,000</u>

Due to geography, NOW Inc. has multiple vehicles that perform similar functions. The communities' services are so far apart with only one main road between towns, it is necessary to have redundancies as road closures are common in the winter months. The extra capital and OM&A costs help reduce outages and response time in all communities which has significant benefits to our customers.

- Pickup – Unit 537 -$45,000; This unit was purchased to replace two other vehicles within NOW Inc.'s fleet. Northern Ontario Wires Inc. has a comprehensive Fleet Matrix (*See Attachment*) which comprises of the annual inspection, identification and determination of a vehicle based on year, mileage, mechanical and physical condition, as well as maintenance and repair costs. Having a reliable fleet is essential to distribution companies in order to perform maintenance and upgrades to the system.
- Unit 526 – Transmission repair- $40,000 – Unit 526 is a fairly new bucket truck which experienced transmission problems. It is more feasible to have this unit repaired as opposed to replaced.

<u>2016 Tools and Equipment – Total Cost $ 12,500</u>

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc. By ensuring that tools are being replaced, NOW Inc. reduces the risk of injury to employees by having a tool malfunction.

<u>2016 Computer Hardware – Total Cost $ 30,000</u>

- In 2016, Northern Ontario Wires Inc. will be replacing its servers. The current Windows 2003 operating system is no longer supported. This server replacement is necessary in order to run NOW Inc.'s information technology network, which includes databases, billing software, etc. The servers had power supply issues recently, and have been repaired in order to allow for continued use until replacements can be installed. The new servers will allow for maintained data security as a server failure can result in the loss of valuable data and operational effectiveness.

<u>2016 Computer Software – Total Cost $ 120,914</u>

- Northern Ontario Wires Inc. will be implementing an outage management system in 2017 as a result of the increasing demand for accurate and timely information. As a result, updates to our current CGIS (mapping) system are required. This entails a physical inspection and precise location of each pole, transformer, overhead conductor and other identified assets. This will permit NOW Inc. to map its distribution area and easily identify any problematic areas, thus resulting in fewer outages and quicker response times. This will allow for future efficiencies and increased customer accessibility. The GIS project will impact the Outage Management System that NOW Inc. will be implementing. Without the GIS project, the OMS system would not provide the benefits that are needed in the changing distribution system. The age of the distribution system and the advancement of internal processes have identified the need to invest into this project. This will benefit operations and customers in the future as the new processes will allow for maintained data integrity and continuous improvement without significant operating costs.

System Access:

<u>2016 Metering – Total Cost $ 15,000</u>

- On an annual basis, a certain number of smart meters require replacement, either due to age, seal dates, or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing. As technologies evolve in metering equipment, NOW Inc. will evaluate in order to create efficiencies in metering and the connectedness of the smart grid.

System Service:

Project 2016: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $ 140,000

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. As part of the conversion, poles, and transformers are also being replaced which reduces the age of the infrastructure and extends the life of the distribution system. Decommissioning the Mateev Substation B will reduce future operation and maintenance costs along with liability. By eliminating the substation, NOW Inc. will feed off of Hydro One directly. Additionally, conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2016: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $ 87,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022. When the 2.4kV Delta station is removed, an aged asset will be eliminated which decreases risk associated with failure being both cost and environmental impacts. After eliminating the station, the service territory will be fed by a Hydro One station. This will reduce costs associated with maintenance and repairs for NOW Inc.

2017 CAPITAL PROJECTS

System Renewal	$	355,000
General Plant	$	142,500
System Access	$	15,000
System Service	$	315,000
2017 Actual Capital Projects	**$**	**827,500**

System Renewal:

Project 2017: Cochrane Pole Changes – Total Cost $ 105,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference. In 2017, NOW Inc. identified additional poles that will require installation as a result of third party requirements. As a result of customer engagement, NOW Inc. has ensured that areas of concern are treated with more priority in order to service customer needs. This has allowed for efficiencies for our metered customers as assets can be replaced with the assistance of third parties which reduces the assets in rate base.

Project 2017: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2017: Iroquois Falls Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2017: Cochrane 5kV Upgrade – Total Cost $ 90,000

- This upgrade project consists of replacing and upgrading the 5kV station. The upgrade will consist of replacing one bank of transformers at the 5kV station. The existing banks range as far back as the 1940's. These improvements will enhance service reliability, while reducing line loss and increase the useful life of the station. This project is expected to be completed in 2022.

Project 2017: Cochrane Substation Feeder – Total Cost $ 50,000

- Given the severe climate in northern Ontario, factors such as weather will affect distribution assets. As a result of ongoing frost, structures and poles at the Cochrane Substation Feeder have shifted. These assets will require replacing for reliability and safety purposes. This project is expected to be completed in 2017.

General Plant:

2017 Tools and Equipment – Total Cost $ 17,500

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc.

2017 Computer Hardware – Total Cost $ 10,000

- In order to remain abreast of technological advances, NOW Inc. plans for cyclical replacement of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers. Additionally, with the introduction of the new outage management software, workers will be able to manage outages in a more efficient manner.

2017 Computer Software – Total Cost $ 115,000

- Northern Ontario Wires Inc. will be incorporating an outage management system. This software will permit staff to manage, react and communicate outages within NOW Inc.'s distribution system. Additionally, the software will pinpoint overloaded transformers or areas that require attention (hotspots). The software will work in conjunction with our CGIS mapped system and will assist NOW Inc. staff in long-term planning, in addition to many short term advantages. As NOW Inc. does not have a control room, the outage managements system will assist in this area and allow for quicker notification and troubleshooting solutions. The outage management system will also assist office staff stay abreast of the situation and will allow for improved customer service as timely and accurate information will be more readily available.
- Customers have informed NOW Inc. that they would like greater communication and updates regarding outages. As such, NOW Inc. is listening to customers and is why this solution is being undertaken.
- NOW Inc. is planning to upgrade the billing and CIS system in 2017. The version currently being used is outdated and will no longer be supported. With the regulatory changes impacting billing, (eg. OESP), the replacement is required. This upgrade will also position NOW Inc. to potentially offer an electronic billing option.

System Access:

2017 Metering – Total Cost $ 15,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Service:

Project 2017: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $175,000

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. This conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2017: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $140,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022.

2018 CAPITAL PROJECTS

System Renewal	$	395,000
General Plant	$	32,500
System Access	$	15,000
System Service	$	355,000
2018 Actual Capital Projects	**$**	**797,500**

System Renewal:

Project 2018: Cochrane Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2018: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2018: Iroquois Falls Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2018: Cochrane 5kV Upgrade – Total Cost $ 180,000

- This upgrade project consists of replacing and upgrading the 5kV station. These improvements will enhance service reliability, while reducing line loss. This project is expect to be completed in 2022.

Project 2018: Cochrane Substation Transformer – Total Cost $ 50,000

- As identified in the Distribution System Plan (DSP), the transformer banks at the Cochrane substation will require replacement. This replacement is necessary in order to upgrade an end-of-life asset and maintain system reliability. This project will be performed in two stages in 2018 and 2019.

General Plant:

2018 Tools and Equipment – Total Cost $ 17,500

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc.

2018 Computer Hardware – Total Cost $ 10,000

- In order to remain abreast of technological advances, NOW Inc. plans for cyclical replacement of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers. Additionally, with the introduction of the new outage management software, workers will be able to manage outages in a more efficient manner.

2018 Computer Software – Total Cost $ 5,000

- These costs consist of maintenance and licencing agreements associated with NOW Inc.'s software. This is necessary in order to maintain our information technology and data system.

System Access:

2018 Metering – Total Cost $ 15,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Service:

Project 2018: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $200,000

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. This conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2018: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $155,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022.

2019 CAPITAL PROJECTS

System Renewal	$	370,000
General Plant	$	32,500
System Access	$	20,000
System Service	$	370,000
2019 Actual Capital Projects	**$**	**792,500**

System Renewal:

Project 2019: Cochrane Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2019: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2019: Iroquois Falls Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2019: Cochrane 5kV Upgrade – Total Cost $ 130,000

- This upgrade project consists of replacing and upgrading the 5kV station. These improvements will enhance service reliability, while reducing line loss. This project is expect to be completed in 2022.

Project 2019: Cochrane Substation Transformer – Total Cost $ 75,000

- As identified in the Distribution System Plan (DSP), the transformer banks at the Cochrane substation will require replacement. This replacement is necessary in order to upgrade an end-of-life asset and maintain system reliability. This project will be performed in two stages, this being the second and final stage.

General Plant:

2019 Tools and Equipment – Total Cost $ 17,500

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc.

2019 Computer Hardware – Total Cost $ 10,000

- In order to remain abreast of technological advances, NOW Inc. plans for cyclical replacement of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers. Additionally, with the introduction of the new outage management software, workers will be able to manage outages in a more efficient manner.

2019 Computer Software – Total Cost $ 5,000

- These costs consist of maintenance and licencing agreements associated with NOW Inc.'s software. This is necessary in order to maintain our information technology and data system.

System Access:

2019 Metering – Total Cost $ 20,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Service:

<u>Project 2019: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $205,000</u>

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. This conversion will reduce line loss and improve reliability and safety of the distribution system.

<u>Project 2019: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $165,000</u>

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022.

<u>2020 CAPITAL PROJECTS</u>

System Renewal	$	350,000
General Plant	$	32,500
System Access	$	20,000
System Service	$	385,000
2020 Actual Capital Projects	**$**	**787,500**

System Renewal:

Project 2020: Cochrane Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2020: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2020: Iroquois Falls Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2020: Cochrane 5kV Upgrade – Total Cost $ 135,000

- This upgrade project consists of replacing and upgrading the 5kV station. These improvements will enhance service reliability, while reducing line loss. This project is expect to be completed in 2022.

Project 2020: Iroquois Falls Substation (Detroyes) Switch Gear and Primary Cable – Total Cost $ 50,000

- As identified in the Distribution System Plan (DSP), the switch gear needs to be added in order to replace the underground feed at the Iroquois Falls substation. The current termination point of the feed is no longer up to code and the cable will be replaced. This replacement is necessary in order to upgrade an end-of-life asset and maintain system reliability. This project will be performed in two stages.

General Plant:

2020 Tools and Equipment – Total Cost $ 17,500

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc.

2020 Computer Hardware – Total Cost $ 10,000

- In order to remain abreast of technological advances, NOW Inc. plans for cyclical replacement of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers. Additionally, with the introduction of the new outage management software, workers will be able to manage outages in a more efficient manner.

2020 Computer Software – Total Cost $ 5,000

- These costs consist of maintenance and licencing agreements associated with NOW Inc.'s software. This is necessary in order to maintain our information technology and data system.

System Access:

2020 Metering – Total Cost $ 20,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Service:

Project 2020: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $215,000

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. This conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2020: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $170,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022

2021 CAPITAL PROJECTS

System Renewal	$	380,000
General Plant	$	32,500
System Access	$	20,000
System Service	$	400,000
2021 Actual Capital Projects	**$**	**832,500**

System Renewal:

Project 2021: Cochrane Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2021: Kapuskasing Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2021: Iroquois Falls Pole Changes – Total Cost $ 55,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2021: Cochrane 5kV Upgrade – Total Cost $ 140,000

- This upgrade project consists of replacing and upgrading the 5kV station. These improvements will enhance service reliability, while reducing line loss. This project is expect to be completed in 2022.

Project 2021: Cochrane Substation Transformer – Total Cost $ 75,000

- As identified in the Distribution System Plan (DSP), the transformer banks at the Cochrane substation will require replacement. This replacement is necessary in order to upgrade an end-of-life asset and maintain system reliability. This project will be performed in two stages, this being the second and final stage.

General Plant:

2021 Tools and Equipment – Total Cost $ 17,500

- Through general wear and tear, miscellaneous tools sometimes become defective and/or broken. Tools used by distribution companies are essential to the maintenance and upkeep of the system. Such tools may include, but are not limited to, vegetation control tools, hand tools, safety equipment, climbing tools, etc.

2021 Computer Hardware – Total Cost $ 10,000

- In order to remain abreast of technological advances, NOW Inc. plans for cyclical replacement of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers. Additionally, with the introduction of the new outage management software, workers will be able to manage outages in a more efficient manner.

2021 Computer Software – Total Cost $ 5,000

- These costs consist of maintenance and licencing agreements associated with NOW Inc.'s software. This is necessary in order to maintain our information technology and data system.

System Access:

2021 Metering – Total Cost $ 20,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Service:

Project 2021: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $220,000

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2025. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. This conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2021: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $180,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2022

Northern Ontario Wires Inc.
Distribution System Plan

Filed with

NOW Inc.'s 2017 Cost of Service Application

Historical Period: 2012 to 2016

Forecast Period: 2017 to 2021

15 August 2016

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1 Introduction

Northern Ontario Wires Inc. ("**Now Inc.**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 28 March 2013 (the "**Filing Requirements**") as part of its 2017 Cost of Service Application (the "**Application**").

1.1 Background & Drivers

NOW Inc.'s DSP has been prepared to support the four key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

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

NOW Inc.'s capital investments over the planning period have been aligned to the four categories of system access, system renewal, system service, and general plant. Investments within these categories have been paced and prioritized to meet the objectives of the RRFE.

1.1.1 System Access

System access investments are modifications to NOW Inc.'s distribution system (including asset relocations) that NOW Inc. is obligated to perform to provide customers with access to electricity services via the distribution system. Drivers for this investment category are customer service requests, other third party infrastructure development requests, and mandated service obligations (e.g. as per the Distribution System Code).

1.1.2 System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of NOW Inc.'s distribution system to provide customers with electricity services. Assets and asset systems may be at the end of their service life due to failure, failure risk, substandard performance, high performance risk, or functional obsolescence.

1.1.3 System Service

System service investments are modifications to NOW Inc.'s distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. Drivers for this investment category include expected changes in load that will constrain the ability of the system to provide consistent service delivery and meeting system operational objectives in safety, reliability, power quality, and system efficiency.

1.1.4 General Plant

General plant investments are modifications, replacements or additions to NOW Inc.'s assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. Drivers for this investment category include system capital investment support, system maintenance support, business operations efficiency, and non-system physical plant.

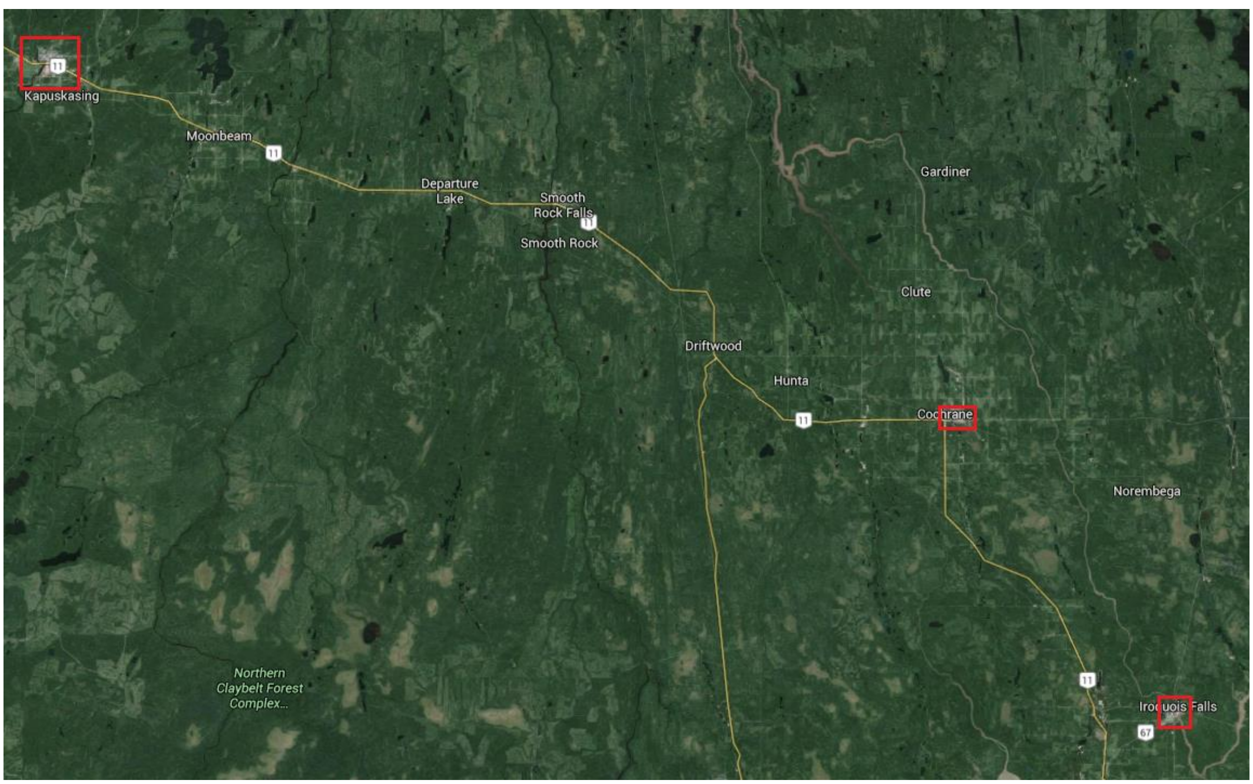
1.2 Description of the Utility Company

NOW Inc. is a local distribution company ("**LDC**") holding Distribution License ED-2003-0018. As mandated by the *Electricity Act, 1998*, NOW Inc. was incorporated in 1999 during the amalgamation of the Cochrane Public Utilities Commission and the Iroquois Falls Hydro Electric Commission. In the year 2000, NOW Inc. purchased the assets of Kapuskasing Wires Inc.

1.2.1 Service Area

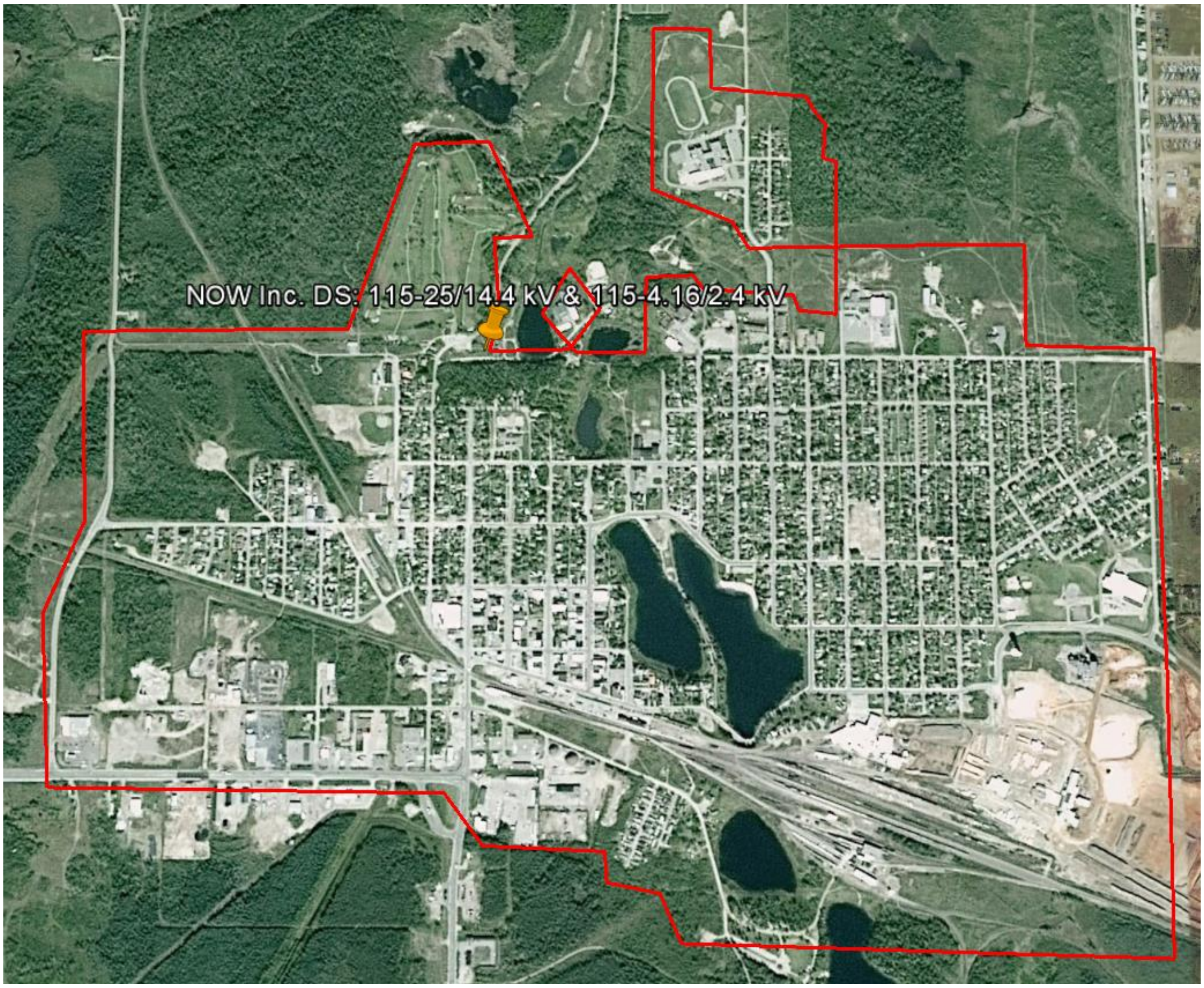
NOW Inc. owns and operates electrical infrastructure, serving customers in the Town of Cochrane, the Town of Iroquois Falls, and the Town of Kapuskasing. These non-contiguous service areas are depicted in Figure 1-1 and total 28 square kilometres, all of which is classified as urban.

Figure 1-1: NOW Inc.'s service area – Kapuskasing, Cochrane, and Iroquois Falls



NOW Inc. owns a total of six distribution substation ("**DS**"). In Cochrane, NOW Inc. receives power at 115 kV from Hydro One Networks Inc. ("**HONI**") and steps it down to 25/14.4 kV and 4.16/2.4 kV. Figure 1-2 depicts NOW Inc.'s service area in the Town of Cochrane outlined in red, and the location of the two DS (at the same location).

Figure 1-2: NOW Inc.'s service area – Town of Cochrane

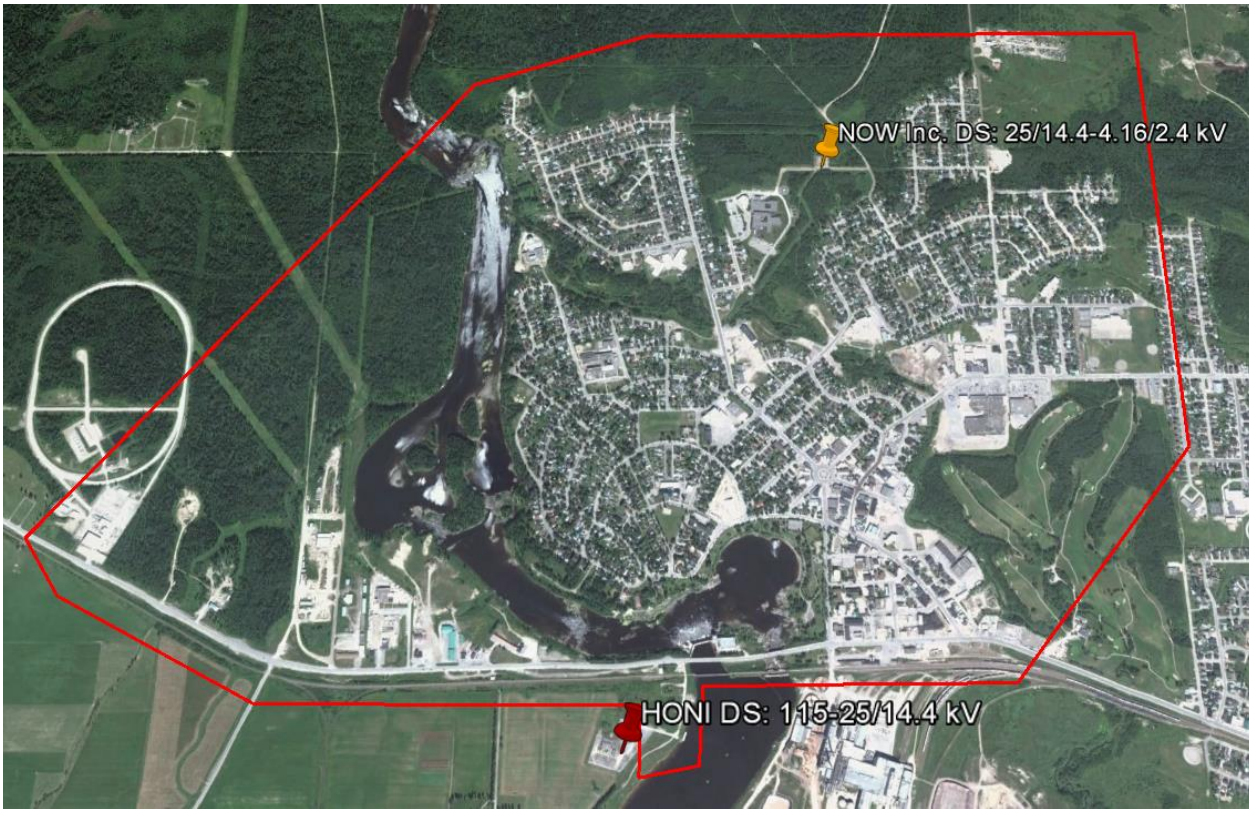


In Iroquois Falls, NOW Inc. receives power from the HONI-owned Iroquois Falls DS feeders F1 and F2 at 12.5/7.2 kV. Now Inc. owns two DS in Iroquois falls which step power down to 4.16/2.4 kV and one DS which steps power down to 2.4 kV delta. NOW Inc. is in the process of converting its 2.4 kV delta system to 12.5/7.2 kV, at which point it will retire the 12.5/7.5-2.4 kV delta DS. Figure 1-3 depicts NOW Inc.'s service area in the Town of Iroquois Falls outlined in red, the location of the three DS owned by NOW Inc., and the location of the HONI-owned DS.

Figure 1-3: NOW Inc.'s service area – Town of Iroquois Falls

In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. NOW Inc. owns one DS in Kapuskasing which steps power down to 4.16/2.4 kV. NOW Inc. is in the process of upgrading the 4.16/2.4 kV system in Kapuskasing to 25/14.4 kV, which will eliminate the need for a DS in Kapuskasing. Figure 1-4 depicts NOW Inc.'s service area in the Town of Kapuskasing outlined in red, the location of the DS owned by NOW Inc., and the location of the HONI-owned DS.

Figure 1-4: NOW Inc.'s service area – Town of Kapuskasing



1.2.2 Corporate Ownership and Organization

NOW Inc. has a single shareholder – the Corporation of the Town of Cochrane – and is governed by a Board of Directors. The Board of Directors has nine members, who are appointed by the shareholder, the Town of Iroquois Falls, and the Town of Kapuskasing. The Board of Directors meets, at a minimum, quarterly and receives reports outlining financial, operational, and safety performance in addition to the progress in maintenance, operational, and capital programs.

NOW Inc.'s General Manager is accountable to the Board of Directors and its management level is accountable to the General Manager through business goals, the development and execution of annual budgets, and various standards and processes that apply to the distribution system assets. Accountability for financial and regulatory activities lies with the Chief Financial Officer, who oversees all financial reporting, assets funding provisions, and the budgeting process. Accountability for managing the lifecycle of existing assets, the installation of new developments, and the installation of new assets lies with the Operations Supervisor (in this instance, the General Manager and Operations Supervisor are the same individual). This role addresses long term planning issues, such as capacity and security and is accountable for system reliability.

1.2.3 Customers and Load

The three towns have a combined population of approximately 18,100. Similar to most communities in northeastern Ontario, there has been a decline in population, predominantly due to job losses at paper mills and sawmills. However, growth is expected in Cochrane in the near future as a result of the opening of the Detour Lake Gold Mine, which is located 185 kilometres northeast of the town.

NOW Inc. serves 6,101 customers as of the 2015 year-end customer count. NOW Inc. has five customer classes: residential, General Service less than 50 kW (“**GS<50**”), General Service greater than 50 kW (“**GS>50**”), unmetered scattered loads (“**USL**”), and streetlights. Figure 1-5 breaks down the year-end customer counts by customer class for the years 2012 to 2015.

Figure 1-5: Historical year-end customer counts by customer class

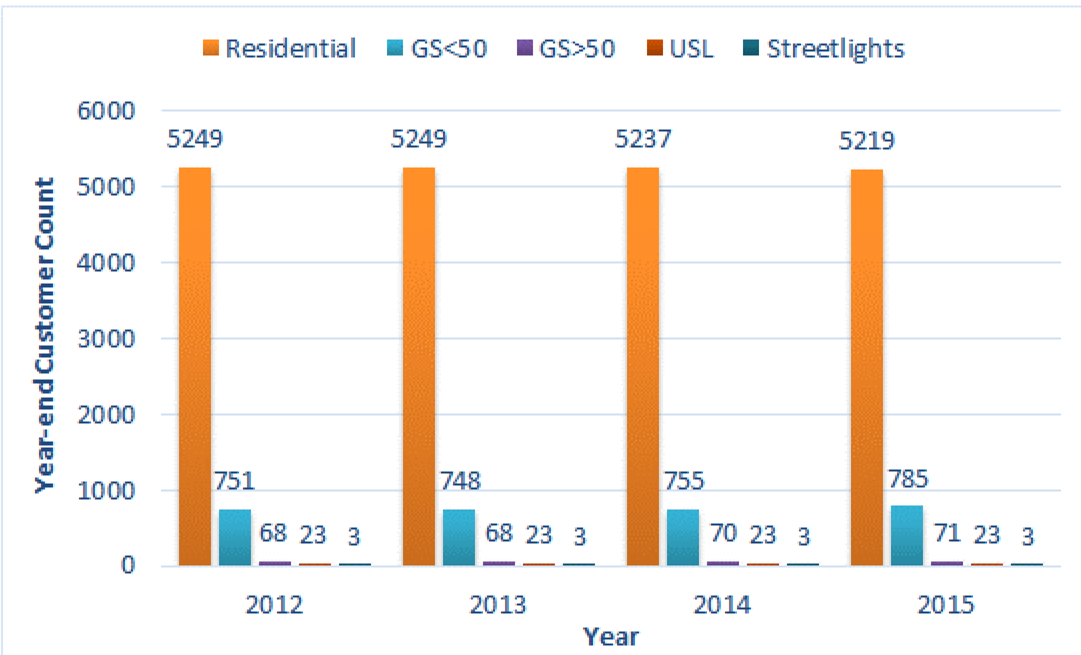
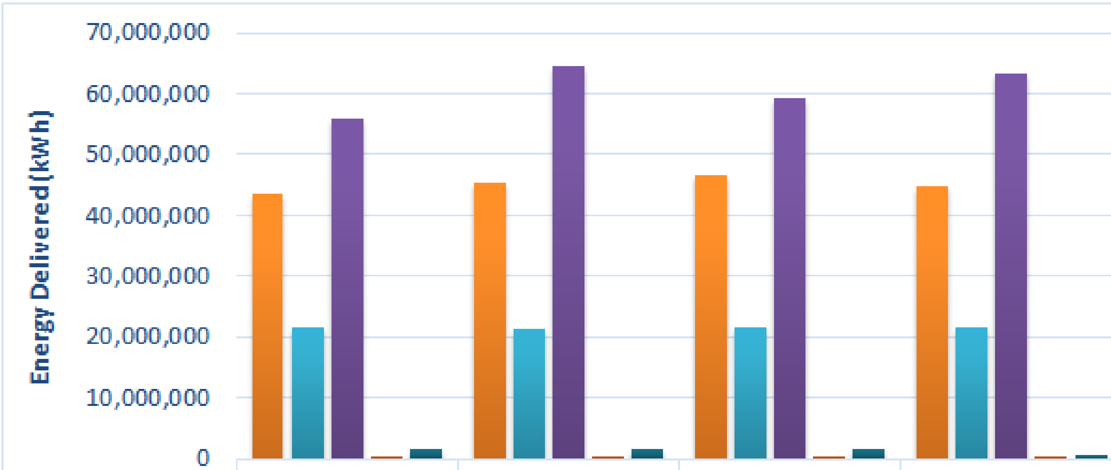


Figure 1-6 summarizes the energy delivered by NOW Inc. to its customers from 2012 to 2015. Energy consumption per customer is expected to trend downward with energy conservation efforts and improved technology.

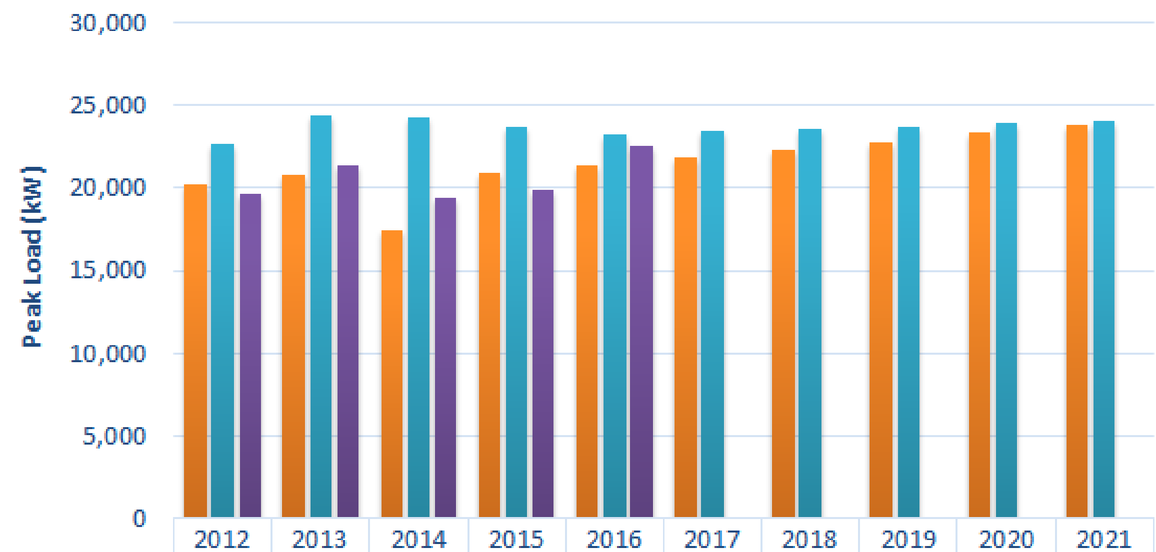
Figure 1-6: Historical energy consumption by customer class



	2012	2013	2014	2015
Residential	43,415,906	45,284,430	46,577,067	44,656,813
GS<50	21,551,729	21,218,224	21,685,166	21,574,212
GS>50	55,890,426	64,551,391	59,394,118	63,383,516
USL	149,927	173,430	168,328	137,172
Streetlights	1,612,889	1,624,441	1,539,728	703,646

Figure 1-7 presents peak loading data, typified as summer peak, winter peak, and average peak. The 2012 to 2015 data is historical, the 2016 data is year-to-date as of the first quarter of 2016, and the 2017 to 2021 data is forecast.

Figure 1-7: Summer, winter and average peak for historical and forecast period



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Summer Peak	20,200	20,765	17,433	20,888	21,370	21,844	22,328	22,823	23,330	23,847
Winter Peak	22,683	24,398	24,246	23,679	23,251	23,414	23,577	23,742	23,908	24,075
Average Peak	19,677	21,329	19,421	19,931	22,524					

1.2.4 Embedded Generation

The existing REG connections within NOW Inc.'s service territory under the Feed-in Tariff ("**FIT**") Program, all fall under the category of microFIT (10 kW or less). All of the installed REG are solar photovoltaics ("**PV**"). There are currently thirteen microFIT connections with a cumulative capacity of 127.97 kW, as listed in Table 1-1.

Table 1-1: List of installed REG connections

Address	City	Type	Installation Date	Feeder	Capacity (kW)
14 Ash St.	Kapuskasing	Solar PV	Apr. 6, 2010	M2	9.8
459 Eleventh Ave.	Cochrane	Solar PV	July 17, 2010	EAST	10
438 Eleventh Ave.	Cochrane	Solar PV	Sep. 3, 2012	EAST	10
444 Eleventh Ave.	Cochrane	Solar PV	May 19, 2011	EAST	10
80 Cedar St.	Kapuskasing	Solar PV	Aug. 26, 2011	M2	10
Millview Rd.	Kapuskasing	Solar PV	Apr. 2, 2012	M2	10
499 Fourth St.	Cochrane	Solar PV	Apr. 10, 2012	EAST	10
364 Eleventh Ave.	Cochrane	Solar PV	June 19, 2012	EAST	10
58 Algonquin Rd.	Cochrane	Solar PV	Apr. 25, 2013	EAST	10
31 Mateev Ave.	Kapuskasing	Solar PV	June 5, 2013	M2	8.17
531 Cedar St.	Kapuskasing	Solar PV	Jan. 11, 2012	M2	10
201 Murdock Ave.	Kapuskasing	Solar PV	Jan. 17, 2012	M2	10
533 Niagara St.	Kapuskasing	Solar PV	July 19, 2012	M2	10

1.2.5 Conservation and Demand Management

NOW Inc. participates in province-wide conservation and demand management ("**CDM**") programs contracted by the Independent Electricity System Operator ("**IESO**"). Under the previous 2011 to 2014 Framework, NOW Inc. was assigned a net annual peak demand savings target or 1.06 MW and a net annual cumulative energy savings target of 5.88 GWh. Since NOW Inc.'s service area is characterized by very few industrial customers, it has relied on its Consumer Program, Business Program, Home Assistance Program, and Time-of-Use savings, as well as the pre-2011 High Performance Construction Program. NOW Inc. achieved 54.4% of its net annual peak demand savings target and 100.5% of its net annual cumulative energy savings target during the 2011 to 2014 Framework, as shown in Table 1-2.

Table 1-2: 2011-2014 CDM program achievements

	Net Annual Peak Demand Savings (kW)	Net Annual Cumulative Energy Savings (kWh)
Achieved	576	5,911,396
Target	1,060	5,880,000
Percentage Achieved	**54.4%**	**100.5%**

The current 2015 to 2020 Conservation First Framework focuses only on energy conservation and has a reduced incentive and administration budget relative to the 2011 to 2014 Framework. NOW Inc.'s target for the 2015 to 2020 Conservation First Framework is 4.31 GWh. As of the Q4 2015 report released by IESO in March 2016, NOW Inc. has achieved 107% of its annual target for 2015 and 7% of its overall target. NOW Inc. will continue to promote a culture of energy conservation in the communities it serves in order to achieve its target.

1.3 Objectives & Scope of Work

This DSP has been developed to achieve the four performance outcomes established in the RRFE: customer focus, operational effectiveness, public policy responsiveness, and financial performance. To realize these four outcomes, NOW Inc. has outlined the following objectives:

- provide customers with a safe and reliable supply of electricity;
- operate effectively and efficiently, reducing costs where feasible;
- facilitate the connection of Renewable Energy Generation ("**REG**"); and
- promote a culture of energy conservation.

1.4 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading.

The DSP contains four sections, including this introductory section as Section 1. Section 2 provides a high level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of NOW Inc.'s asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of NOW Inc.'s capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for REG, and justification of material projects.

2 Distribution System Plan (5.2)

The intent of this DSP is to support NOW Inc.'s plan to:

- add customer facing software as requested by the customer base;
- increase spending on system renewal as driven by asset management results;
- continue the voltage conversion programs to improve operational efficiencies; and
- manage electricity rates as requested by customers.

2.1 Distribution System Plan Overview (5.2.1)

This section provides the OEB and stakeholders with a high level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to NOW Inc.'s asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 Key Elements of the DSP (5.2.1a)

Table 2-1 presents the capital expenditures by investment category and the system operations and maintenance ("**O&M**") costs for both the historical and forecast period.

Table 2-1: Historical and forecast capital expenditures and system O&M

	Historical ($ '000)					Forecast ($ '000)				
Category	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
System Access	0	40	8	58	15	15	15	20	20	20
System Renewal	283	245	112	179	213	355	395	370	350	380
System Service	185	269	235	178	227	315	355	370	385	400
General Plant	363	254	366	171	248	143	33	33	33	33
Net Capital Expenses	830	809	721	586	703	828	798	793	788	833
System O&M	1,102	1,232	1,237	1,128	1,209	1,513	1,586	1,626	1,668	1,711

A brief description of the mix of capital investments by investment category over the forecast period are provided below.

2.1.1.1 *System Access*

Capital investments in the system access category over the forecast period are driven by mandated service obligations to meter customers. NOW Inc. has budgeted for the replacement of smart meters, which have a useful life ranging from five to fifteen years, and are beginning to fail. NOW Inc. has not budgeted for any expenditures due to customer service requests or other third party infrastructure development requests.

2.1.1.2 *System Renewal*

Capital investments in the system renewal category over the forecast period are driven by assets at the end of their service life. NOW Inc. has three pole replacement programs – one for each Town – to replace poles that have reached the end of their service life, which is budgeted each year. In addition, there is an overhead rebuild project to replace sections of the 4.16/2.4 kV line in the Town of Cochrane, which will take place each year from 2017 to 2021.

Investments into substations have been planned for each year of the historical period. In 2017 there is a capital upgrade project at Cochrane DS to replace a frosted support structure and the existing glass insulators with silicone insulators. Substation transformer refurbishments will be made at Cochrane DS in 2018 and 2019: the transformer bank T2 will be replaced and its base and the bus work will be reconstructed. In 2020 the primary switchgear and underground cables at the Detroyes substation in Iroquois Falls require replacement. In 2021 the Mill Gate substation (2.4 kV delta) will be retired from service and the ground remediated.

2.1.1.3 *System Service*

Capital investments in the system service category over the forecast period are driven by system operational objectives in safety, efficiency, and reliability. There are two voltage conversion projects – one in Iroquois Falls and one in Kapuskasing – planned for each year of the forecast period, which are continuations of the ongoing conversion in these areas. Distribution losses are reduced at higher voltages, thus system efficiency is improved. Both these projects are replacing older poles and sections of line, thus are expected to mitigate customer outages and trouble call costs.

The 2.4 kV delta system in Iroquois Falls is being upgraded to 12.5/7.2 kV. The delta system has no reference to ground and will not trip in case of a ground fault, making safety the primary driver of this project. Legacy #6 copper conductors are being replaced with larger 3/0 aluminum conductor steel reinforced (“**ACSR**”) to reduce the probability of breaking during high winds. The conclusion of the voltage conversion will allow NOW Inc. to retire the 2.4 kV delta DS in Iroquois Falls, which will reduce system O&M costs. The 4.16/2.4 kV system in Kapuskasing is being upgraded to 25/14.4 kV. The completion of the voltage conversion will allow NOW Inc. to retire the DS in Kapuskasing and serve the entire Town at 25/14.4 kV supplied by HONI’s DS, which will reduce system O&M costs.

2.1.1.4 *General Plant*

Capital investments in the general plant category over the forecast period are driven by improvements to operational efficiency, required software and hardware purchases to support day-to-day business activities, and non-distribution system equipment reaching its end-of-life. Capital expenditures to purchase tools and equipment have been budgeted each year of the forecast period to replace equipment that is no longer useful. Computer hardware expenditures are also budgeted each year of the forecast period to purchase new hardware, as necessary. Finally, computer software expenditures are budgeted each year of the forecast period, and are higher in 2017 when NOW Inc. is planning to purchase new software that will improve its operational efficiency. Improvements will be made to NOW Inc.’s Geo-spatial Information System (“**GIS**”), Outage Management System (“**OMS**”), and Customer Information System (“**CIS**”).

2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

Through good planning and DSP execution, NOW Inc. anticipates cost savings over the forecast period from the sources described below.

Proactive Asset Replacements

Planned overhead rebuild and voltage conversion projects allow sections of lines to be replaced more efficiently. Individual pole replacements are also planned in each of the three Towns. NOW Inc. utilizes its pole inspection program to identify poles that have reached end-of-life, therefore avoiding the cost of replacing an asset too early or too late. Replacing these assets before a failure occurs prevents outages and avoids the cost of emergency restoration and repair work.

Distribution Plant Life Extension

Life extension of NOW Inc.'s distribution plant extends the useful life of the assets by deferring the capital investment until maintenance is no longer economical. Maintenance in substations is key to ensuring continuity of electrical service and extending the lives of substation equipment. Gang-operated switches and pad-mounted switchgear also receive regular maintenance that extend their useful lives. Finally, pad-mounted transformers are maintained as required to extend their useful lives.

Improved Capital and Maintenance Planning (GIS)

NOW Inc. is improving its capital and maintenance planning using its GIS. Information such as inspection and maintenance records, which were previously stored on paper forms, are now stored in the GIS making them easily accessible. This decreases the resource requirement of project and work order planning and allows projects to be planned using a more complete set of information. NOW Inc. is planning to complete the upgrades to its GIS in 2017.

Improved Fault Locating Capability (OMS)

NOW Inc. is planning to upgrade its OMS in 2017. The upgraded OMS will have fault location capabilities, allowing crews to be effectively dispatched to restore the outage, rather than locating the outage from crew vehicles. This will provide a number of benefits to NOW Inc.'s customers, including more outage information, faster restoration times, and less cost to restore power.

Voltage Conversions

Voltage conversions reduce line losses since less current is required to supply the same power at a higher voltage. Cost savings due to the planned decommissioning of two substations will not be realized over the forecast period, because these fall outside of the five-year window.

Buying Consortium

NOW Inc. is a member of the Northeast District Buying Consortium ("**NEDBC**"). The NEDBC consists of seven LDCs. It negotiates prices based on volume, therefore reducing costs of materials.

Standardized Designs

As a member of Utilities Standards Forum ("**USF**"), NOW Inc. has access to standardized designs that meet the requirements of the *Distribution System Code*. The use of standardized designs reduces the resource requirements of project design.

Compliance Audits

Annual Electrical Safety Authority ("**ESA**") *Ontario Regulation 22/04* compliance audits are done in conjunction with other utilities in northeastern Ontario to save costs.

Resource Sharing

NOW Inc.'s shares human resources and facilities with its affiliate, Cochrane Telecom Services ("**CTS**"), in order to improve operational efficiency.

2.1.3 Period Covered by DSP (5.2.1c)

This DSP covers a historical period of 2012 to 2016, where 2016 is the Bridge Year. The forecast period is 2017 to 2021, where 2017 is the Test Year.

2.1.4 Vintage of the Information (5.2.1d)

The information contained in this DSP is current as of 15 August 2016.

2.1.5 Important Changes to Asset Management Process (5.2.1e)

This is NOW Inc.'s first DSP filing and, as such, there are no changes to NOW Inc.'s asset management process since its last DSP filing.

2.1.6 DSP Contingencies (5.2.1f)

The system access budget as planned is contingent upon the planning activities of the three Towns of Cochrane, Iroquois Falls, and Kapuskasing. A large portion of NOW Inc.'s distribution plant occupies the public right-of-way ("**ROW**") and NOW Inc. is obligated to move its distribution plant to accommodate road widenings and other construction projects by the Towns through partial cost sharing agreements with the respective Towns. Since the Towns have not proposed any road works requiring relocation of NOW Inc.'s plant, NOW Inc. has not budgeted any capital expenditures to accommodate third party infrastructure development projects over the forecast period; however, since the Town planning cycles are shorter than the five-year planning period of the DSP, new projects may be required subject to Town initiation. The system access budget is also contingent upon customer service requests for new connections within NOW Inc.'s service area. Due to the stagnant growth in the region, NOW Inc. has not budgeted for any capital expenditures due to customer service requests over the forecast period outside of its metering budget.

As per the Needs Assessment Report for the North and East of Sudbury Region (Appendix B), a localized wires solution for possible voltage regulation issues at Timmins TS is required and will be led by HONI. HONI has yet to initiate local planning to address this issue, and NOW Inc. is not forecasting any expenditures to arise from this process.

General plant investments are planned to upgrade NOW Inc.'s GIS, OMS, and CIS as part of the computer software budget. The costs and benefits of each of these systems depend on the software vendors and their ability to provide the requisite services within NOW Inc.'s budget envelope. NOW Inc.'s ability to upgrade all three of these systems depends on its approved distribution rates. The GIS enhancements are complete, with costs carried over into 2017; while the OMS roll-out takes priority over the CIS upgrades.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Stakeholder Consultations (5.2.2a)

NOW Inc. is governed by a Board of Directors and has one shareholder: the Corporation of the Town of Cochrane. Other stakeholders to NOW Inc.'s operations include:

- electricity retailers, customers and end consumers;
- the power transmitter (HONI);
- tree owners;
- the OEB and IESO; and
- land owners where NOW Inc. distribution lines run.

Stakeholder interests can be viewed from a number of perspectives including financial stability, electricity rates, quality of supply, safety, and compliance. Financial stability is required to ensure sufficient confidence of ownership and investment in NOW Inc. Electricity rates provide the means for NOW Inc. to create revenue and signal underlying costs; not charging appropriate rates has economic implications for both NOW Inc. and its customers. Quality of supply includes emphasis on reliability with respect to the number of interruptions, the duration of interruptions, the amount of flicker, and the quality of voltage. Safety involves staff, contractors, customers, and the general public; NOW Inc. must ensure the operation of the distribution system is safe for all.

NOW Inc. coordinates its planning activities with key stakeholders as detailed below.

2.2.1.1 *Residential Customer Consultations*

NOW Inc. often meets with residential customers to coordinate infrastructure development, such as NOW Inc. pole lines and property owner fences. These meetings may be initiated by either party and are necessary to ensure all proposed development is completed safely and to the satisfaction of all parties. NOW Inc. also coordinates development with its affiliate, CTS, which often uses NOW Inc.'s poles for its telecom service.

2.2.1.2 *Large Customer Meetings*

NOW Inc. has annual one-on-one meetings with its large customers, the largest of whom are the saw mill and paper plant. These meetings are informal and initiated by NOW Inc. for the purpose of discussing what NOW Inc. can do to meet its large customers' needs and requirements. Large customers provide feedback on NOW Inc.'s ability to deliver electricity reliably, the overall quality of NOW Inc.'s customer service, and electricity prices, among other topics. Generally, large customers are satisfied with NOW Inc.'s service and remark that electricity is more affordable compared to neighbouring electrical utilities.

2.2.1.3 *Cochrane Mayor's Address*

NOW Inc. is invited to speak at the annual mayor's address in the Town of Cochrane, which started in 2014 and takes place in January of each year. This event is open to the public and is attended by residents, workers, and business owners in the Town of Cochrane. NOW Inc. presents its corporate goals, ongoing energy conservation efforts, and upcoming initiatives at the address.

2.2.1.4 *Virtual Town Hall*

NOW Inc. made a virtual town hall presentation available online during July 2016. The purpose of the virtual town hall was to collect customer feedback on NOW Inc.'s investment and spending plan from 2017 to 2021. In summary, the presentation covered the role that consumer feedback plays in electricity system planning in Ontario, electricity sector regulation in Ontario, a description of NOW Inc.'s distribution system, reliability statistics, cost pressures, types of capital investments, operating cost drivers and efficiencies, customer bill breakdown, and forecast rate impacts.

The survey responses were limited in sample size (10 responses, compared to over 450 for the customer satisfaction survey – see Section 4.2.4 for more details); therefore, the results were not weighted highly in NOW Inc. planning process. Of note is that 90% of respondents supported proactive replacement to avoid power outages, whereas 10% supported reactive replacements "to get full value" (see the third page of the survey responses).

2.2.1.5 *Public Works Meetings*

NOW Inc. meets annually with each of the public works directors of the three Towns. These meetings take place in the first couple months of the year and serve as a two-way communication between NOW Inc. and the Towns to share their upcoming capital plans. This allows NOW Inc. to coordinate its construction projects with the three Towns to minimize the impact on the communities.

The capital plans of the Towns feeds into NOW Inc.'s budgeting process, with pole line relocation projects planned to accommodate road works. The three Towns do not have any development plans requiring relocation over the forecast period, therefore NOW Inc. has not budgeted any third party infrastructure development projects in this DSP. However, since the Town planning cycles are shorter than the five-year planning period of the DSP, new projects may be required subject to Town initiation.

2.2.1.6 *Hydro One Coordination and Consultation*

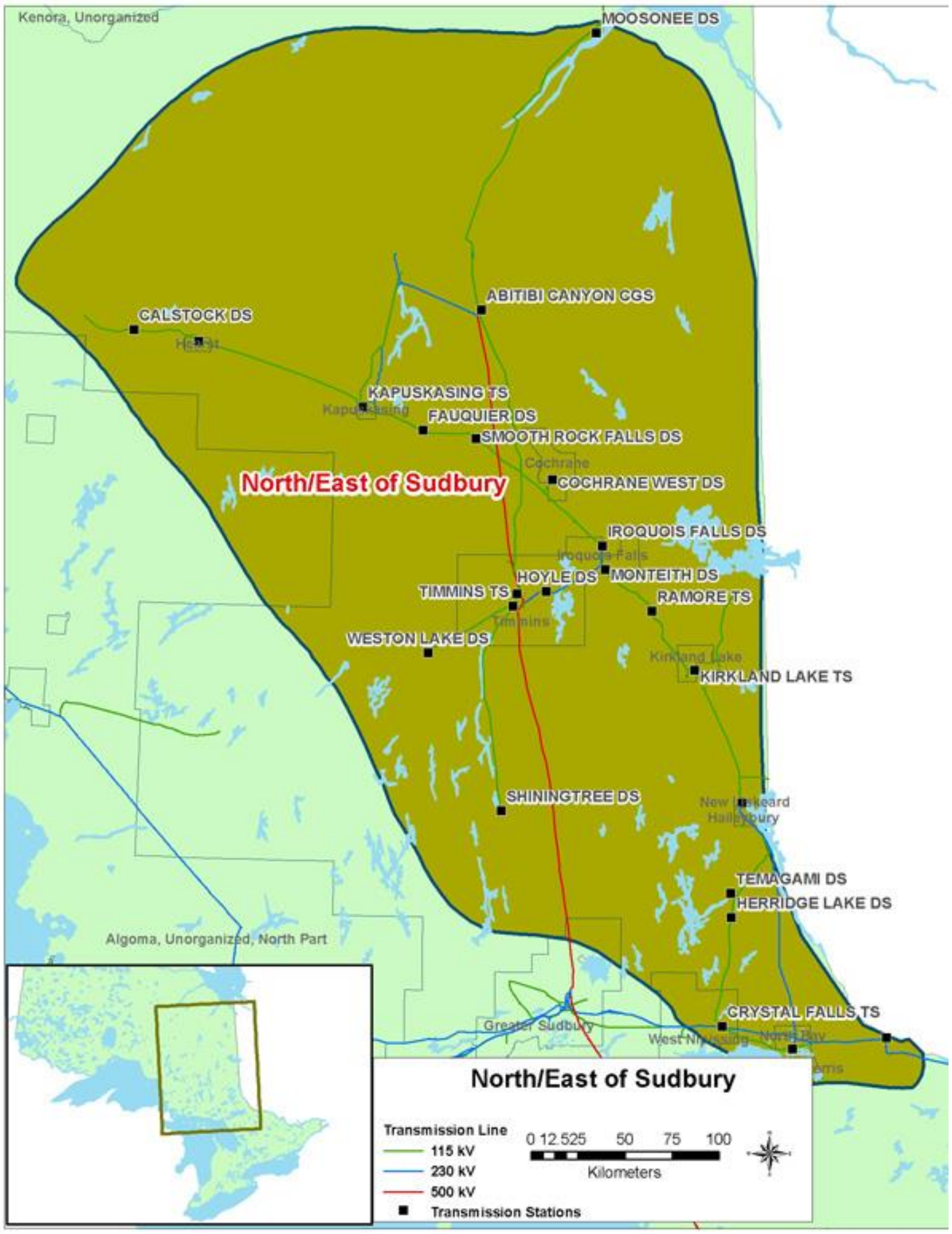
NOW Inc. meets annually with the electricity transmitter, HONI, to coordinate scheduled outages up to one year in advance. HONI initiates these meetings and invites representatives from its other regional customers, including Hearst Power Distribution Company Limited ("**HPDCL**"), generators such as Ontario Power Generation, Kirkland Lake Power, and Algonquin Power, and mining companies. NOW Inc. schedules outages to coincide with HONI's planned outages in order to minimize customer impact whenever feasible. The most recent meeting was in 2015, so HONI's outage schedule for 2017 is not available at this time.

These meetings also provide a forum to discuss upstream system issues such as the capacity issues at Timmins TS. HONI has not indicated when capacity will become available to connect new REG, therefore NOW Inc. has not projected any new REG connections over the planning period.

2.2.2 Regional Planning Process (5.2.2b)

The IESO is facilitating regional system planning to ensure a reliable supply of electricity, considering conservation, generation, transmission and distribution, and innovative resources. NOW Inc. is in the North/East of Sudbury planning region, which is roughly bordered by Moosonee to the north, Hearst to the northwest, Ferris to the south, and Kirkland Lake to the east, as depicted in Figure 2-1. This region also includes Greater Sudbury Hydro Inc., HPDCL, North Bay Distribution Ltd., and HONI.

Figure 2-1: Map of the North/East of Sudbury planning region



The Needs Assessment Report for this region was completed by HONI on 15 April 2016 and is attached as Appendix B. The scope of the Needs Assessment Report was ten years up to 2026. The report found that the 115 kV H9K circuit, which runs between Kapuskasing TS and Hunta SS may experience thermal overloading during high generation, but this is a bulk system issue that will be addressed jointly with the IESO outside of the Regional Planning Process. The report also identified possible voltage drop issues at Timmins TS and Kirkland Lake TS under contingency scenarios, which will be addressed with a local wires solution led by HONI. The voltage drop at Timmins TS can affect NOW Inc., therefore NOW Inc. will be involved in the local planning process. HONI has yet to indicate at what date this planning will commence.

The Needs Assessment Report concluded that no further regional coordination is required.

2.2.3 IESO Letter of Comment (5.2.2c)

On 12 May 2016, NOW Inc. submitted its REG Investments Plan to the IESO, informing them that “there are no constraints on NOW Inc.’s distribution system that would prevent the connection of new REG installations”, but that “there is currently no capability to connect new REG projects in NOW Inc.’s service territory due to upstream capacity constraints at the HONI-owned Timmins TS”. The REG Investments Plan goes on to state that “no investments have been proposed to facilitate new REG connections over the years 2017 to 2021” and that “NOW Inc. will continue to consult with HONI in order to enable new REG connections”. See Appendix C: Renewable Energy Generation Investments Plan for more information.

On 27 May 2016, the IESO responded with a Letter of Comment, stating that the information contained in NOW Inc.’s REG Investments Plan is “consistent with that of the IESO”. The IESO also confirmed that, as per its Transmission Availability Table, there is no capacity for REG at Timmins TS. Finally, the IESO confirmed that, as per the Needs Assessment Report for the North and East of Sudbury Region, there is no need for further regional coordination and the possible voltage regulation issues at Timmins TS will be addressed through a localized wire solution led by HONI.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

NOW Inc. has identified a number of metrics to monitor its distribution planning progress performance. These metrics stem from the three performance measures of customer oriented performance, cost efficiency and effectiveness, and asset and systems operations performance. Table 2-2 lists the performance indicators for each measure, its motivation (consumer, regulatory, or corporate), and the metrics that will be monitored by NOW Inc.

Table 2-2: Performance metrics and their motivation

Measure	Indicator	Motivation	Metrics
Customer oriented performance	Reliability	Consumer Regulatory	SAIFI SAIDI CAIDI Customer outages by cause code
	Service quality	Consumer Regulatory	Telephone accessibility Telephone abandon rate Low voltage connections High voltage connections Appointments scheduling Appointments met Missed appointment rescheduling Written response to enquiries Emergency response – rural Emergency response – urban Reconnection performance standards Billing accuracy
Cost efficiency & effectiveness	DSP implementation	Regulatory Corporate	Physical progress vs. plan Financial progress vs. plan Actual vs. planned cost of work completed
	Total cost	Consumer Corporate	Total cost per customer Total cost per km of line
	Efficiency assessment	Regulatory Consumer Corporate	PEG efficiency assessment
Asset & systems operations performance	Distribution losses	Corporate	Percentage line loss
	Progress of voltage conversions	Corporate	2.4 kV delta conversion progress (Iroquois Falls) 4.16/2.4 kV conversion progress (Kapuskasing)

2.3.1 Customer Oriented Performance

The two performance indicators which NOW Inc. uses to track customer oriented performance are reliability and service quality measures.

2.3.1.1 *Reliability*

2.3.1.1.1 Definition (5.2.3a)

In order to measure the reliability of electricity delivered to its customers, NOW Inc. tracks System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year. NOW Inc.'s SAIFI target is 2.19 or less and its SAIDI target is 4.63 or less. Since CAIDI is the ratio of SAIDI to SAIFI, NOW Inc.'s CAIDI target is therefore 2.11 or less.

NOW Inc. also tracks customer outages by cause code to determine the root cause of its power interruptions.

2.3.1.1.2 Historical Performance (5.2.3b)

Figure 2-2 depicts NOW Inc.'s SAIFI performance over the historical period from 2012 to 2015, including and excluding loss of supply. The SAIFI excluding loss of supply was at or below target for all four years.

Figure 2-2: Historical SAIFI performance from 2012 to 2015

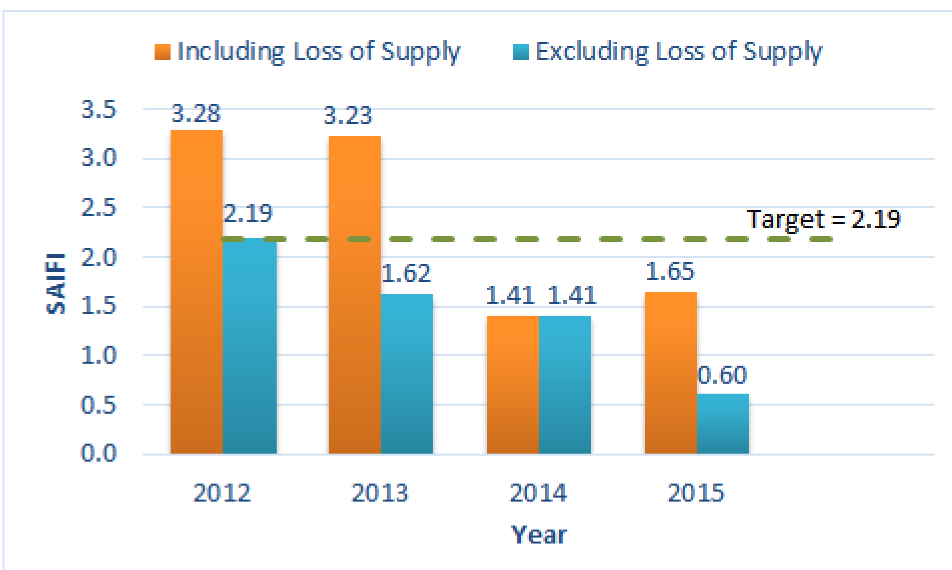


Figure 2-3 depicts NOW Inc.'s SAIDI performance over the historical period from 2012 to 2015, including and excluding loss of supply. The SAIDI excluding loss of supply was at or below target for all four years.

Figure 2-3: Historical SAIDI performance from 2012 to 2015

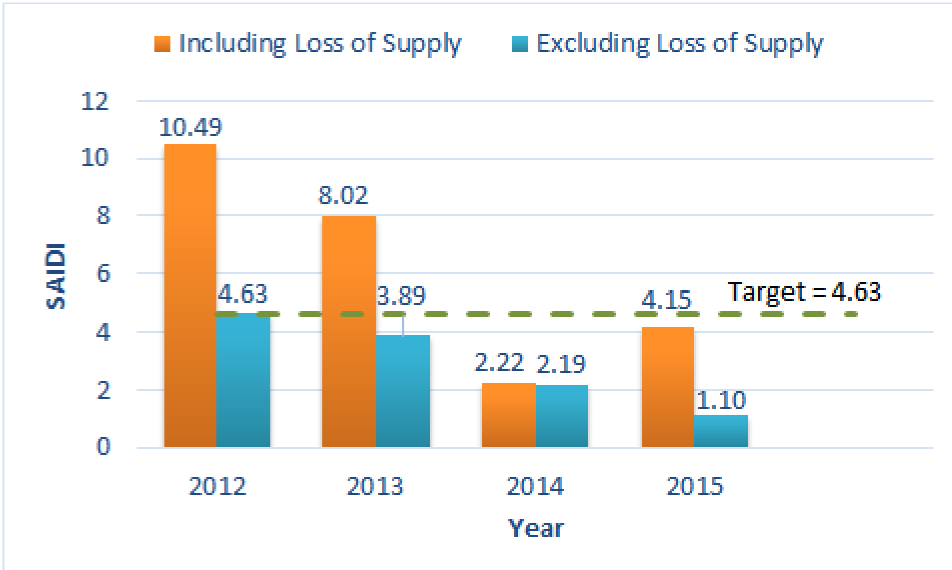


Figure 2-4 depicts NOW Inc.'s CAIDI performance over the historical period from 2012 to 2015, including and excluding loss of supply. The CAIDI excluding loss of supply was higher than the target in 2013. This was mostly due to two scheduled outages that disconnected the Town of Kapuskasing for 8 hours each and a defective equipment outage in Iroquois Falls that affected 1000 customers for over 12 hours.

Figure 2-4: Historical CAIDI performance from 2012 to 2015

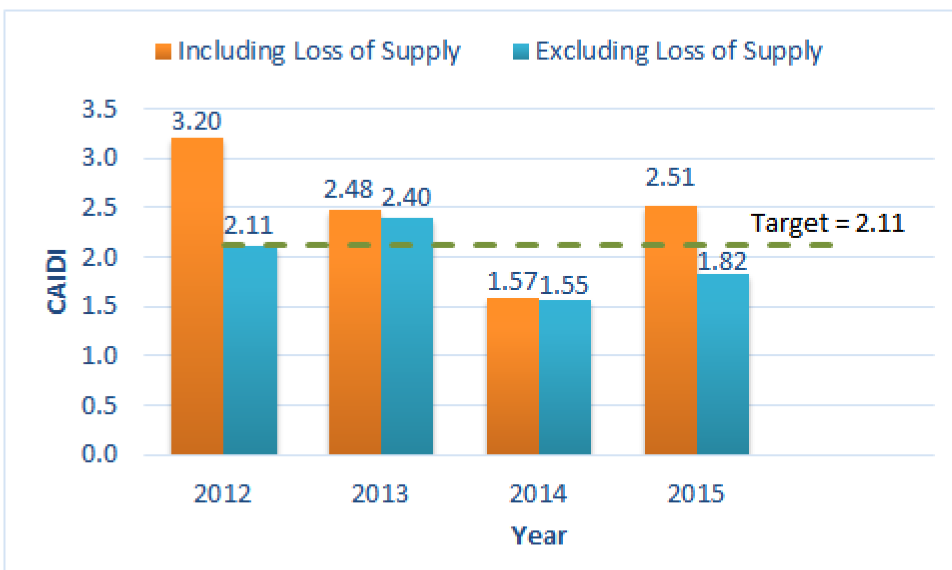
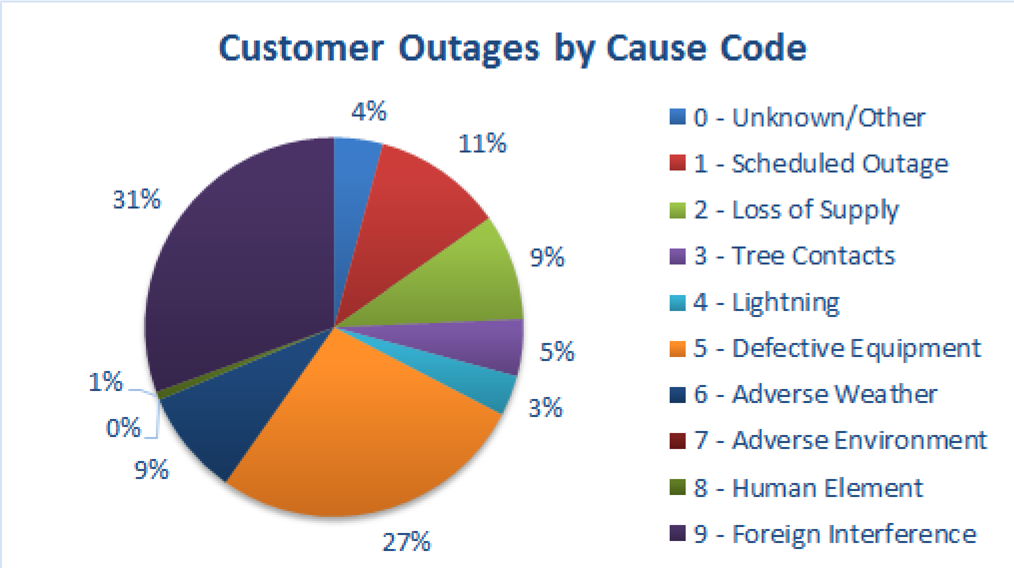


Figure 2-5 depicts customer outages by cause code for the years 2012 to 2015. Over these years, the most common outage causes were foreign interference and defective equipment, followed by scheduled outages, loss of supply, and adverse weather.

Figure 2-5: Outage frequency by cause code (2012 to 2015)



2.3.1.1.3 Effect on DSP (5.2.3c)

NOW Inc. has generally met its reliability targets and has met or exceeded both its SAIFI and SAIDI target for each year from 2012 to 2015. Therefore, NOW Inc. has not proposed any system service projects that are primarily driven by reliability, such as improved redundancy, feeder/substation automation, or improved switching (but reliability is a secondary driver for NOW Inc.'s projects/programs that replace assets at the end of their service life). NOW Inc. believes that its current system will continue to meet its reliability targets based on the proposed asset replacement projects and programs.

Analysis of the frequency of outages by cause code indicates that the most frequency causes of outages are foreign interference and defective equipment. NOW Inc.'s system renewal projects/programs and voltage conversion projects replace assets at the end of their service life, which is expected to reduce the number of outage due to defective equipment. Additionally, animal guards will be installed in identified, problematic areas in order mitigate foreign interference outages.

2.3.1.2 *Service Quality Measures*

2.3.1.2.1 Definition (5.2.3a)

The *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Energy Competition Act, 1998*. As required by the OEB, NOW Inc. records and submits all performance measures, which are compared with the OEB's established levels to evaluate NOW Inc.'s customer service quality. The performance measures are described below, as defined in the *Distribution System Code*.

Telephone Accessibility

The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the 30 second time period as established below:

- For qualified incoming calls that are transferred to the distributor's interactive voice response system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the 30 seconds shall be counted from the first ring.

The target for this metric is 65%.

Telephone Call Abandon Rate

As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be 10% or less on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the 30 second time period has elapsed.

Connection of New Services

The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage ("**LV**") (less than 750 V) service must be completed within five business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed by the customer and distributor.
- A connection for a new service request for a high voltage ("**HV**") (greater than 750 V) service must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

The target for this metric is 90%.

Appointment Scheduling

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. This includes Underground Locate Requests. The target for this metric is 90%.

Appointments Met
When an appointment is either:

- requested by a customer or a representative of a customer; or
- required by a distributor with a customer or a representative of a customer,

the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four hours. The distributor must then arrive for the appointment within the scheduled timeframe. This includes Underground Locate Requests. The target for this metric is 90%.

Rescheduling a Missed Appointment
When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
- attempt to contact the customer within one business day to reschedule the appointment.

The target for this metric is 100%.

Written Responses to Enquiries
A written response to a qualified enquiry shall be sent by a distributor within ten business days. The target for this metric is 80%.

Emergency Response
Emergency calls (i.e. assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two hours in rural areas and within one hour in urban areas. NOW Inc.'s entire service area is classified as urban. The target for this metric is 80%.

Reconnection Performance Standards
Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within two business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrears payment agreement with the distributor.

The target for this metric is 85%.

Billing Accuracy
The billing accuracy metric was established by the OEB in 2014. The percentage of bills accurately issued is calculated by subtracting the number of inaccurate bills issued for the year from the total number of bills issued for the year and dividing that number by the total number of bills issued for the year (the total number of bills issued for the year includes original and reissued bills). Accurate bills that

need to be cancelled in order to correct another bill shall not be included in the calculation of billing accuracy measure. A distributor should not include customer accounts that are unmetered accounts (e.g. street lighting and unmetered scattered loads) or power generation accounts when calculating the percentage of accurate bills.

A bill is considered inaccurate if:

- the bill contains incorrect customer information, meter readings, or rates; or
- the bill has been issued to the customer and subsequently cancelled due to a billing error; or
- there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

The target for this metric is 98%.

2.3.1.2.2 Historical Performance (5.2.3b)

Table 2-3 presents NOW Inc.'s service quality measure performance for each of the years 2012 to 2015. NOW Inc. changed its call overflow procedures in 2013 to meet the OEB requirements. Otherwise, NOW Inc. has met or exceeded each of the targets.

Table 2-3: Historical service quality measures performance

Measure	Target	Performance			
		2012	2013	2014	2015
Telephone accessibility	65%	0%	100%	100%	100%
Telephone abandon rate	10%	0%	0%	0%	0%
Low voltage connections	90%	97.2%	91.9%	100.0%	100.0%
High voltage connections	90%	100%	N/A	N/A	100%
Appointments scheduling	90%	100%	100%	100%	100%
Appointments met	90%	100%	100%	100%	100%
Missed appointment rescheduling	100%	100%	100%	100%	N/A
Written response to enquiries	80%	100%	100%	100%	100%
Emergency response – rural	80%	N/A	N/A	N/A	N/A
Emergency response – urban	80%	100%	100%	100%	100%
Reconnection performance standards	85%	96%	88%	96%	97%
Billing accuracy	98%	N/A	N/A	100%	100%

High voltage connections are shown as "N/A" in 2013 and 2014 since there were no high voltage connections these years. Missed appointments rescheduling is shown as "N/A" in 2015 since there were no missed appointments to reschedule. Emergency response – rural is shown as "N/A" each year because NOW Inc.'s entire service area is classified as urban. Finally, billing accuracy is a new metric tracked from 2014 onwards, so is shown as "N/A" in 2012 and 2013.

2.3.1.2.3 Effect on DSP (5.2.3c)

NOW Inc.'s positive performance on each of its service quality measures indicates that there is no need to drive investment or change processes to better serve customers in these regards. NOW Inc. will continue to meet its service quality measures to the best of its abilities.

2.3.2 Cost Efficiency and Effectiveness

To assess its cost efficiency and effectiveness with respect to planning quality and DSP implementation, NOW Inc. considers three performance indicators, which are DSP implementation, total cost, and its efficiency assessment.

2.3.2.1 *DSP Implementation*

2.3.2.1.1 Definition (5.2.3a)

NOW Inc. has selected three metrics for measuring the implementation of its DSP:

- the physical DSP progress, which measures the percentage of projects/programs completed in the year they were budgeted;
- the financial DSP progress, which measures the total variance of the annual capital expenditures against the plan; and
- the actual vs. planned cost of work completed, which measures the variance of an individual projects/programs against the planned cost.

NOW Inc.'s targets for these three metrics are presented in Table 2-4.

Table 2-4: DSP implementation metrics and targets

DSP Implementation Metric	Target
Physical DSP progress, plan vs. actual	100% of budgeted projects/programs completed in the year budgeted
Financial DSP progress, plan vs. actual	Less than 10% variance between actual and budgeted DSP expenditure level
Actual vs. planned cost of work completed	Less than 10% variance between actual and budgeted project/program costs

2.3.2.1.2 Historical Performance (5.2.3b)

Since this is NOW Inc.'s first DSP, there is no historical performance on DSP implementation to report.

2.3.2.1.3 Effect on DSP (5.2.3c)

The projects and programs listed in this DSP have been carefully planned in order to meet these DSP implementation targets.

2.3.2.2 *Total Cost*

2.3.2.2.1 Definition (5.2.3a)

Total cost includes all capital, operations, maintenance, and administration expenses and is normalized per customer and per km of line. NOW Inc. does not have a specific target for neither its total cost per customer nor its total cost per km of line, but monitors these metrics for trends.

2.3.2.2.2 Historical Performance (5.2.3b)

Figure 2-6 presents NOW Inc.'s total cost per customer and Figure 2-7 presents NOW Inc.'s total cost per km of line for the years 2012 to 2014. In 2013, NOW Inc. experienced an atypical bad debt expense in conjunction with accounting treatment required by regulators.

Figure 2-6: Historical total cost per customer (2012 to 2014)

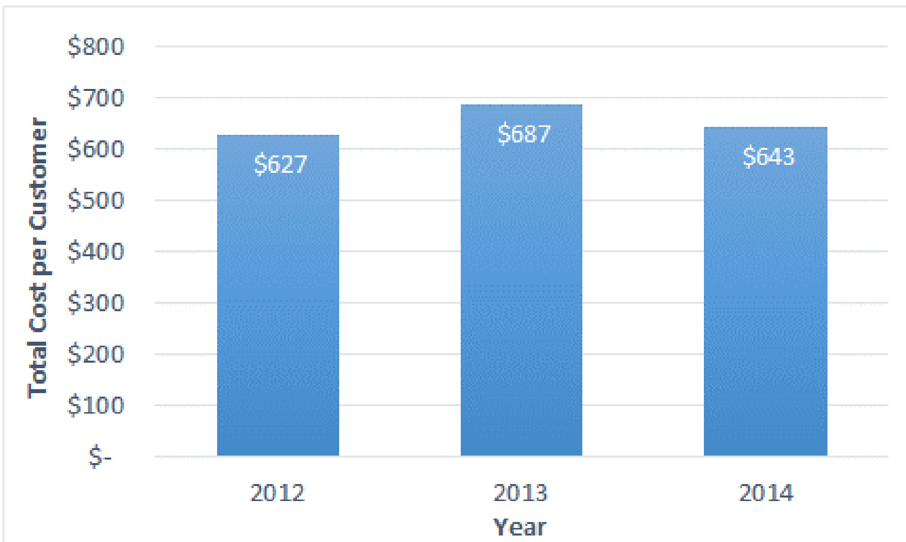
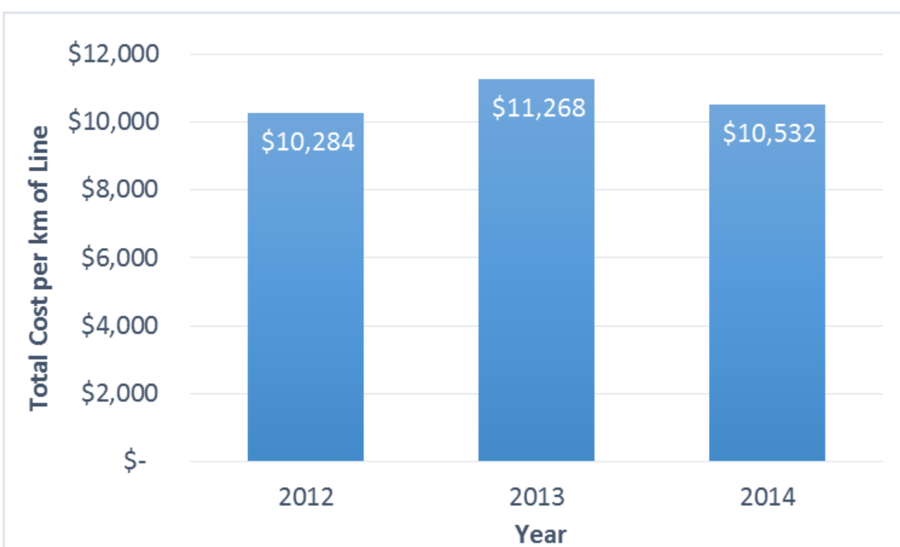


Figure 2-7: Historical total cost per km of line (2012 to 2014)



2.3.2.2.3 Effect on DSP (5.2.3c)

With customers in mind, projects and programs in this DSP have been paced and prioritized in order to keep the cost of electricity at a reasonable level. Several projects in this DSP are aimed to reduce costs, such as the voltage conversions in Kapuskasing and Iroquois Falls, which will allow two DS to be decommissioned. Section 2.1.2 lists the anticipated sources of cost savings over the forecast period of the DSP.

2.3.2.3 *Efficiency Assessment*

2.3.2.3.1 Definition (5.2.3a)

A total benchmarking analysis conducted by Pacific Economics Group ("**PEG**") is used by the OEB to compare the actual costs of an LDC against the predicted costs from the PEG model. Based on its performance, an LDC is placed in "groups" numbered 1 through 5, as defined in Table 2-5. NOW Inc. is targeting to be in Group 1 (actual costs are 25% or more below predicted costs).

Table 2-5: PEG efficiency assessment definition

Efficiency Assessment Result	Relative Cost Performance
Group 1	Actual costs are 25% or more below predicted costs
Group 2	Actual costs are 10% to 25% below predicted costs
Group 3	Actual costs are within +/-10% of predicted costs
Group 4	Actual costs are 10% to 25% above predicted costs
Group 5	Actual costs are 25% or more above predicted costs

2.3.2.3.2 Historical Performance (5.2.3b)

NOW Inc. has been in group 1 for each year of the PEG efficiency assessment (2012 to 2014), indicating that its actual costs are 25% or more below the costs predicted by the PEG model. NOW Inc. is continually working to ensure this exceptional performance continues.

2.3.2.3.3 Effect on DSP (5.2.3c)

As previously listed in Section 2.1.2, NOW Inc. anticipates sustaining its operational efficiency through a number of cost saving measures over the forecast period of the DSP. Through its buying consortium membership, use of USF standards, resource sharing with CTS, and ESA compliance audits in conjunction with other utilities, NOW Inc. reduces its costs. Other cost saving measures include proactive asset replacements, distribution plant life extensions, and voltage conversions.

Several projects in this DSP are aimed to improve operational efficiency, such as the computer software investments planned in 2017 that will enable improved project planning (GIS) and faster outage location (OMS). With the completion of the 2.4 kV delta voltage conversion to 12.5/7.2 kV in Iroquois Falls in 2021, the 2.4 kV delta substation (Mill Gate DS) will be decommissioned, which will eliminate the inspection and maintenance costs of that substation. The voltage conversion in Kapuskasing from 4.16/2.4 kV to 25/14.4 kV will eventually lead to the decommissioning of the substation in Kapuskasing, but not over the forecast period.

2.3.3 Asset and Systems Operations Performance

To document its asset and systems operations performance, NOW Inc. tracks its distribution losses and the progress of its voltage conversion program.

2.3.3.1 *Distribution Losses*

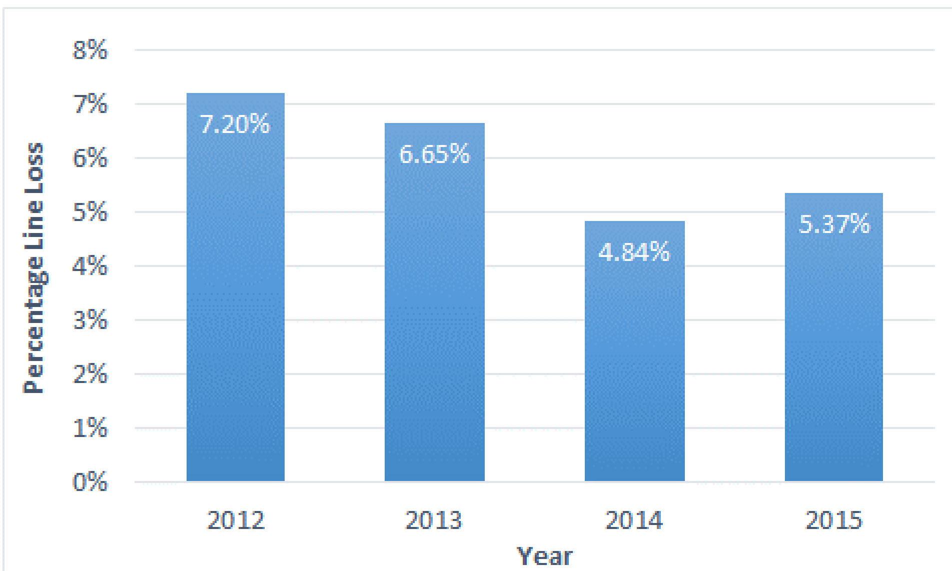
2.3.3.1.1 Definition (5.2.3a)

Distribution losses are measured as the percentage line loss, which is the energy lost during distribution divided by the total energy received at the primary metering (i.e. the sum of the energy lost and the energy delivered to customers). Since distribution losses are dependent on a number of external factors such as temperature and loading, NOW Inc. does not have a specific target for percentage line loss, but monitors it to track the performance of its distribution system.

2.3.3.1.2 Historical Performance (5.2.3b)

Figure 2-8 depicts NOW Inc.'s percentage line loss from 2012 to 2015, which is a downward trend, but increased from 2014 to 2015 due to the higher summer peak and average peak load in 2015.

Figure 2-8: Historical percentage line loss (2012 to 2015)



2.3.3.1.3 Effect on DSP (5.2.3c)

NOW Inc.'s voltage conversion projects aim to reduce distribution losses by delivering power at higher voltage. These projects also replace older transformers and, in some area, replace #6 copper conductors with 1/0 ACSR, both of which reduce distribution losses. The 4.16/2.4 kV overhead rebuild projects also replaces older transformers.

2.3.3.2 *Voltage Conversion Progress*

2.3.3.2.1 Definition (5.2.3a)

NOW Inc. is in the process of converting two of its system voltages: the 2.4 kV delta system in Iroquois Falls to 12.5/7.2 kV and the 4.16/2.4 kV system in Kapuskasing to 25/14.4 kV. Each of these conversions will facilitate the decommissioning of a DS, which will reduce system O&M costs.

The Iroquois Falls 2.4 kV delta system conversion is targeted for completion by 2022 and the Kapuskasing 4.16/2.4 kV conversion is targeted for completion by 2025. Table 2-6 shows the targeted length of circuits to be converted for each year of the forecast period.

Table 2-6: Annual targets for voltage conversion programs (2017 to 2021)

Project	Annual Length of Circuits to be Converted (km)				
	2017	2018	2019	2020	2021
Iroquois Falls 2.4 kV Delta Conversion	0.75	0.75	0.75	0.75	0.75
Kapuskasing 4.16/2.4 kV Conversion	1	1	1	1	1

2.3.3.2.2 Historical Performance (5.2.3b)

The circuit length converted for each year of the historical period (including the planned replacements in 2016) is shown in Table 2-7. In 2015 the pace of the Iroquois Falls 2.4 kV delta conversion was increased from 0.5 km per year to 0.75 km per year.

Table 2-7: Historical annual circuit lengths of voltage conversions (2012 to 2016)

Project	Annual Length of Circuits Converted (km)				
	2012	2013	2014	2015	2016*
Iroquois Falls 2.4 kV Delta Conversion	0.5	0.5	0.5	0.75	0.75
Kapuskasing 4.16/2.4 kV Conversion	1	1	1	1	1

**2016 data is planned replacements not actual*

2.3.3.2.3 Effect on DSP (5.2.3c)

Voltage conversion projects have been phased through each year of the forecast period of the DSP: one project per year in Iroquois Falls and one project per year in Kapuskasing. In 2015, the rate of voltage conversion in Iroquois Falls was increased from 0.5 km per year to 0.75 km per year in order to meet to 2022 completion target.

3 Asset Management Process (5.3)

This section provides an overview of NOW Inc.'s asset management process, an overview of the assets managed by NOW Inc., and a presentation of its asset lifecycle optimization policies and practices.

3.1 Asset Management Process Overview (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

NOW Inc. is committed to providing its customers with a safe and reliable electricity supply while operating effectively and efficiently at an equitable cost. NOW Inc. strives for excellence and continuous improvement in order to maximize shareholder value. Based on these corporate goals, NOW Inc.'s asset management objectives are prioritized as follows:

1. Operating a safe electrical system for employees and the public.
2. Meeting regulatory requirements.
3. Engaging in environmental protection.
4. Accommodating load growth and new customer connections.
5. Delivering a reliable supply of electricity.
6. Managing costs and rate stability.

Safety is NOW Inc.'s top priority in every aspect of its business. NOW Inc. always strives to maintain and operate its electrical system in such a way that poses minimal hazard to its employees and the public. Meeting regulatory requirements set out by the OEB is the next priority, since the OEB's mandate comes directly from the provincial government. Thirdly, NOW Inc. prioritizes environmental protection, but this is not usually a driver for investment due to the nature of NOW Inc.'s system. NOW Inc.'s fourth priority is to provide power to its customers by accommodating load growth and new customer connections, which relates to its fifth priority of delivering power reliably. Finally, NOW Inc. aims to improve its operational efficiency and manage costs in order to keep electricity prices low for its customers.

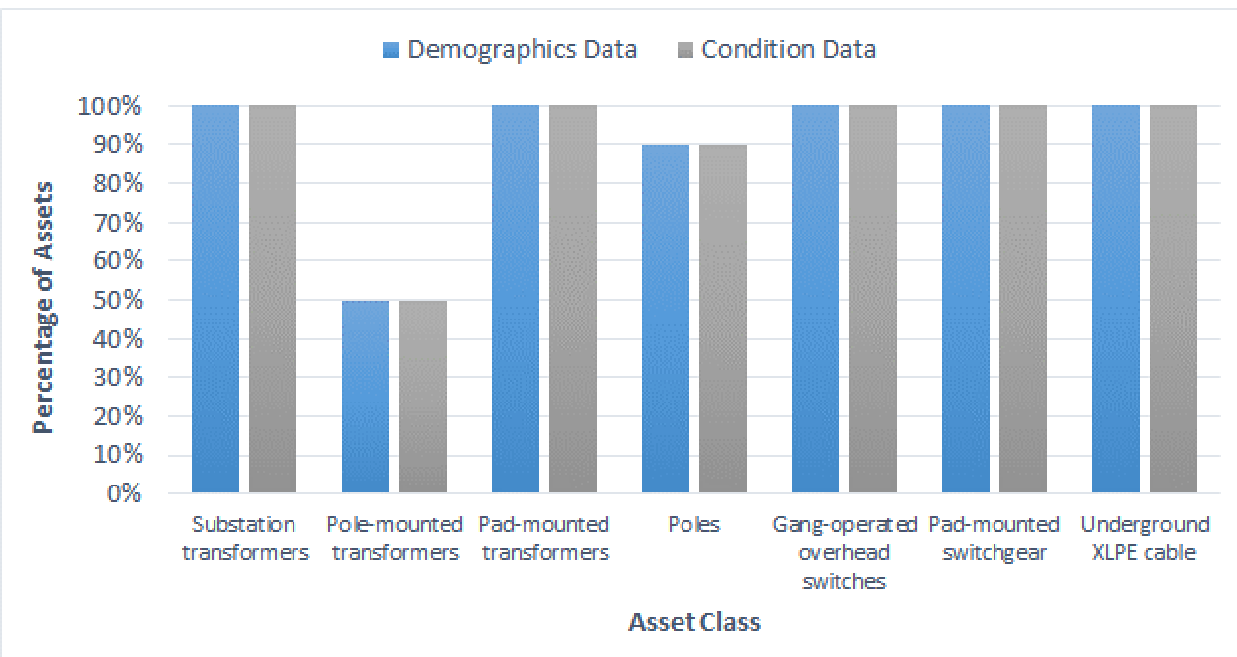
3.1.2 Components of the Asset Management Process (5.3.1b)

Asset management systems used by NOW Inc. include inspection and maintenance databases, paper records of inspection and maintenance activities, an asset register, and a GIS. When an asset is serviced or refurbished, a paper record is generated; when an asset is replaced, the information is uploaded onto a spreadsheet. NOW Inc. also uses its accounting/inventory system to track changes and has established a system of inspection and performance reporting procedures, which satisfy the OEB reporting requirements. In 2013, NOW Inc. switched its accounting practices to the International Financial Reporting Standards ("**IFRS**").

NOW Inc.is in the process of updating its GIS, which will be the cornerstone of its asset management activities going forward. Asset information is essential for proper investment planning; NOW Inc. prioritized the collection of asset demographics and condition data into its GIS in 2010 and 2011. The major asset classes tracked in NOW Inc.'s GIS are substation transformers, pole-mounted transformers, pad-mounted transformers, poles, gang-operated overhead switches, pad-mounted switchgear, and underground cross-linked polyethylene ("**XLPE**") cables.

Figure 3-1 summarizes the percentage of demographics data and condition data known for each asset class. Only 50% of pole-mounted transformer data has been captured, while 90% of pad-mounted transformer data is known; other asset classes are all 100%. NOW Inc. will continue to improve the data quality in its GIS to include all inspection and maintenance records, which will be complete over the next five years.

Figure 3-1: Percentage of demographics and condition data known



Demographics and condition data are used to plan capital expenditures in the system renewal category, as summarized in Figure 3-2. Assets are grouped by age and efficiency to manage them better and are replaced geographically in overhead and underground rebuild projects based on inspections and demographics. Underground cables only account for 1% of NOW Inc.'s distribution system, and no underground rebuilds have been planned over the forecast period. Age demographics are used to plan the number of poles for replacement, while line patrols identify the worst poles for replacement as part of the pole replacement programs. Substation maintenance records as well as the Transformer Oil Analysis Report are used to plan substation refurbishments.

Figure 3-2: Planning process for system renewal projects

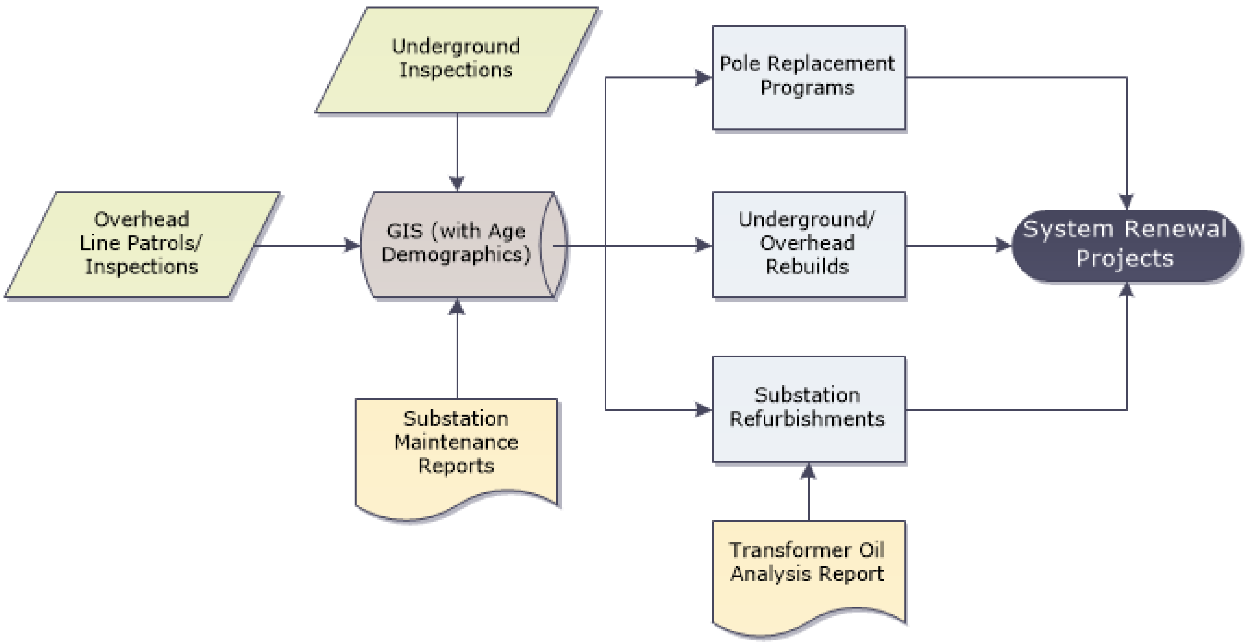
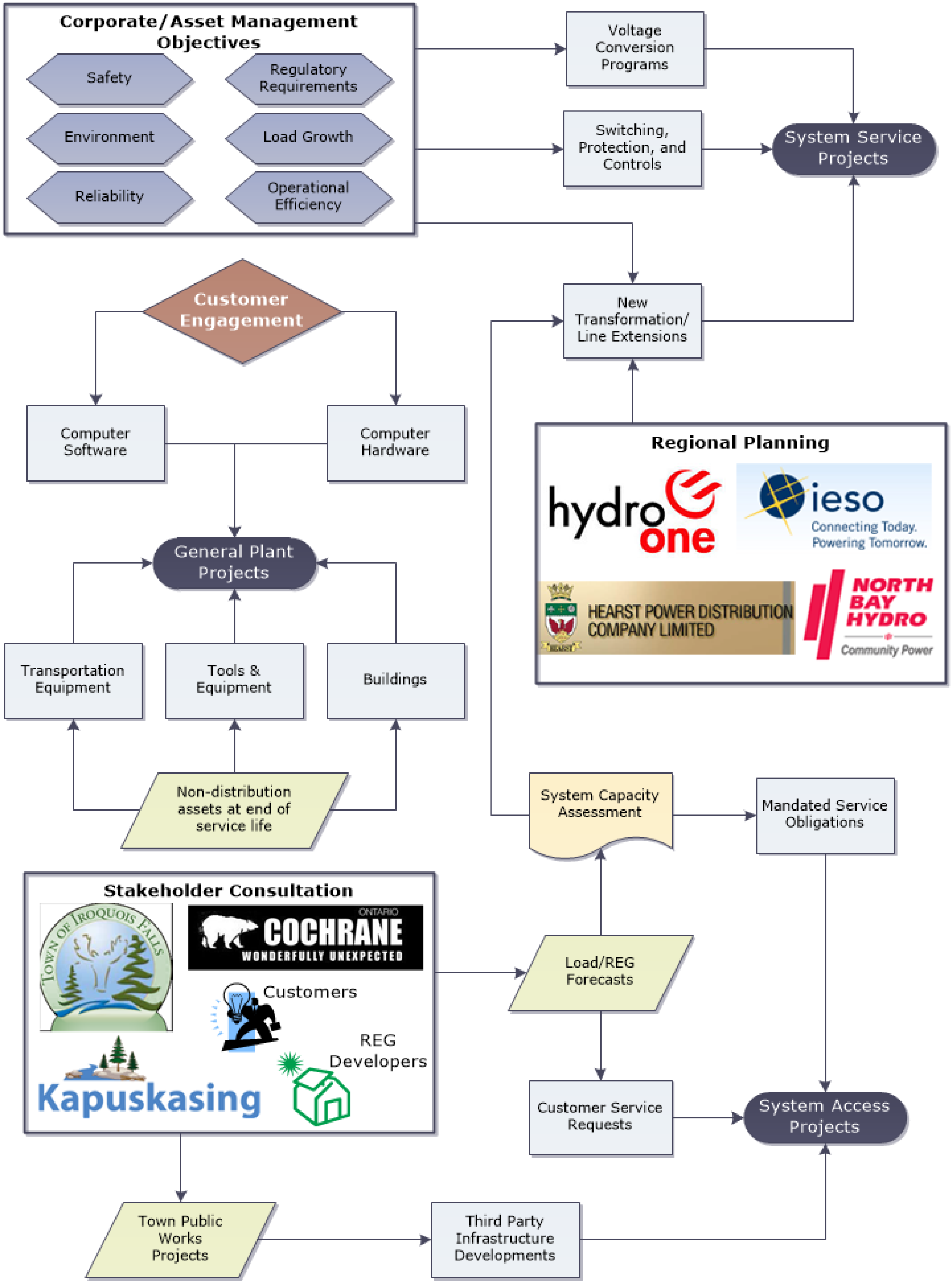


Figure 3-3 summarizes the planning process for the remaining three investment categories: system access, system service, and general plant. Stakeholder consultations with the three Towns, customers, and REG developers are important to identify Town public works projects and load and REG connection forecasts. These drive system access projects due to third party infrastructure developments, customer service requests, and mandatory service obligations such as metering.

The system capacity assessment identifies system service projects in new transformation and line extensions, in conjunction with regional planning where long term load transfers or other solutions may exist. Load growth and system capacity are not drivers for NOW Inc. over the forecast period and there is no capacity for new REG connections due to upstream constraints at the HONI-owned Timmins TS. NOW Inc.'s asset management objectives identify other system service projects, including voltage conversions driven by safety, operational efficiency, and reliability. NOW Inc. has not planned any projects in switching, protection, and controls over the forecast period.

NOW Inc.'s asset management objectives also identify general plant expenditures in computer hardware and software for improved operational efficiency, along with its customer engagement. Customers have asked for paperless billing and improved communication of outages. To accommodate these requests and improve its operational efficiency, NOW Inc. is planning to improve its GIS, OMS, and CIS. Other routine expenditures in computer hardware and software support NOW Inc.'s day-to-day business activities. Investments into transportation equipment, tools, and buildings are driven by fully depreciated non-distribution assets requiring repairs or replacement.

Figure 3-3: Planning process for system access, system service, and general plant projects



3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

NOW Inc.'s service area consists of three non-contiguous urban centres in northeastern Ontario, serving the Towns of Cochrane, Iroquois Falls, and Kapuskasing. Similar to most communities in northeastern Ontario, these regions are in a period of slow economic growth; however, growth is expected in Cochrane in the near future as a result of the opening of the Detour Lake Gold Mine, which is located 185 kilometres northeast of the town.

NOW Inc.'s distribution system is predominantly overhead. The climate is typical of most towns in northern Ontario, with about 5500 to 8000 heating degree days per year and reaching 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 strong wind storms, which are a common occurrence.

3.2.2 Summary of System Configuration (5.3.2b)

NOW Inc. uses four primary voltage levels to distribute power. There is one 2.4 kV delta overhead circuit, which serves a portion of the Town of Iroquois Falls. A 4.16/2.4 kV system is present all three Towns and is mostly overhead, with 1.18 km of underground cable. There are two 12.5/7.2 kV overhead circuits, which also serve the Town of Iroquois Falls. Finally, a 25/14.4 kV system operates in both the Town of Cochrane and the Town of Kapuskasing and is mostly overhead, with 2 km of underground cable. Table 3-1 summarizes the number of circuits and lengths of overhead conductors and underground cables for each voltage level. These data were compiled in May 2016.

Table 3-1: Circuit length by voltage

Voltage Level	Number of Circuits	Underground Cable Length (km)	Overhead Conductor Length (km)	Total Circuit Length (km)
2.4 kV Delta	1	0	10	10
4.16/2.4 kV	6	1.18	124.2	125.38
12.5/7.2 kV	2	0	72	72
25/14.4 kV	3	2	160.5	162.5
Total	12	3.18	366.7	**369.88**

NOW Inc. owns six DS: two in Cochrane (115-25/14.4 kV and 115-4.16/2.4 kV), three in Iroquois Falls (two 12.5/7.2-4.16/2.4 kV and one 12.5/7.2-2.4 kV delta), and one in Kapuskasing (25/14.4-4.16/2.4 kV). The Cochrane 115-25/14.4 kV DS is two transformers paralleled, while the Cochrane 115-4.16/2.4 kV DS is two transformer banks paralleled. Table 3-2 lists the vintage, voltage, nominal capacity, and number of feeders for each substation transformer, as compiled in May 2016.

Table 3-2: List of substation transformers

Name	Vintage	High Side Voltage (kV)	Low Side Voltage (kV)	Capacity (MVA)	Number of Feeders
Cochrane 25 kV – T1	1975	115	25/14.4	7.5	2
Cochrane 25 kV – T2	1975	115	25/14.4	7.5	
Cochrane 4.16 kV – T1A	1960	115	4.16/2.4	1	2
Cochrane 4.16 kV – T1B	1960	115	4.16/2.4	1	
Cochrane 4.16 kV – T1C	1960	115	4.16/2.4	1	
Cochrane 4.16 kV – T2A	1953	115	4.16/2.4	1	
Cochrane 4.16 kV – T2B	1953	115	4.16/2.4	1	
Cochrane 4.16 kV – T2C	1953	115	4.16/2.4	1	
Iroquois Falls – Abitibi	1953	12.5/7.2	4.16/2.4	2	1
Iroquois Falls – Mill Gate	1975	12.5/7.2	2.4 Delta	2	1
Iroquois Falls – Detroyes	1966	12.5/7.2	4.16/2.4	4	2
Kapuskasing	1963	25/14.4	4.16/2.4	5	1

3.2.3 Asset Demographics and Condition (5.3.2c)

The present counts of NOW Inc.'s major asset classes are presented in Table 3-3, as compiled in May 2016. NOW Inc. does not have an Asset Condition Assessment report and instead relies on asset age and demographics data, as presented below for each asset class. The typical useful life ("**TUL**") of each asset is assumed based on Kinectrics' *Asset Depreciation Study for the Ontario Energy Board*.

Table 3-3: Counts of major asset classes

Asset Class	Count
Substation transformers	12
Pole-mounted transformers	570
Pad-mounted transformers	6
Wood poles	2,721
Gang-operated overhead switches	5
Pad-mounted switchgear	5
Overhead conductors (km)	366.7
Underground cables (km)	3.18

3.2.3.1 *Substation Transformers*

The TUL of substation transformers is 45 years. NOW Inc.'s oldest substation transformers include the Cochrane 4.16 kV T2 bank. These transformers have been in service for over 60 years and require replacement over the forecast period. Some photographs of the rusted transformers and cracked foundations are shown in Figure 3-4, which clearly show that the transformers are at end of life.

Figure 3-4: Photos of Cochrane DS 4.16/2.4 kV transformer bank T2

The primary supply at the Detroyes substation in Iroquois Falls has a leaking lead pothead, which requires the primary switchgear and underground cables to be replaced with some related work done on the primary side of the transformer.

Substation transformer condition also largely depends upon operating conditions such as loading cycles and moisture ingress. The most recent (2015) Substation Oil Analysis Report identified eleven substation transformers, load tap changers ("**LTC**"s), and reactors with concerning results from the dissolved gas analysis ("**DGA**") and oil quality tests. Table 3-4 summarizes the condition of the substation transformers, LTCs, and regulators based on the report. These devices will be tested and investigated further, as recommended in the report. The complete report is attached as Appendix E.

Table 3-4: Transformer condition data based on DGA and oil quality tests

Equipment	DGA	Oil Quality	Insulation Power Factor	Condition
Transformer - Main - Kapuskasing	B	E	A	Fair
LTC - Detroyes - Iroquois Falls	A	E	A	Fair
Transformer - Abitibi - Iroquois Falls	B	E	A	Fair
LTC - Abitibi - Iroquois Falls	A	E	A	Fair
Transformer - Mill Gate - Iroquois Falls	C	A	B	Fair
Transformer - Regulator - Cochrane	A	E	A	Fair
LTC - T1 - Cochrane	A	E	A	Fair
Transformer - T REG MAIN	A	E	A	Fair
Transformer - T1C - Cochrane	A	C	A	Good
Transformer - T1B - Cochrane	A	E	A	Fair
Transformer - T1A - Cochrane	A	C	A	Fair

3.2.3.2 *Pole-mounted Transformers*

Table 3-5 lists the number of pole-mounted transformers for each size owned by NOW Inc.

Table 3-5: Number of pole-mounted transformers by size

Transformer Size	Region			Total
	Cochrane	Iroquois Falls	Kapuskasing	
10 kVA	0	0	1	1
15 kVA	0	1	3	4
25 kVA	67	42	26	135
37.5 kVA	9	18	5	32
50 kVA	143	73	87	303
75 kVA	0	6	25	31
100 kVA	7	8	49	64
Total	226	148	196	**570**

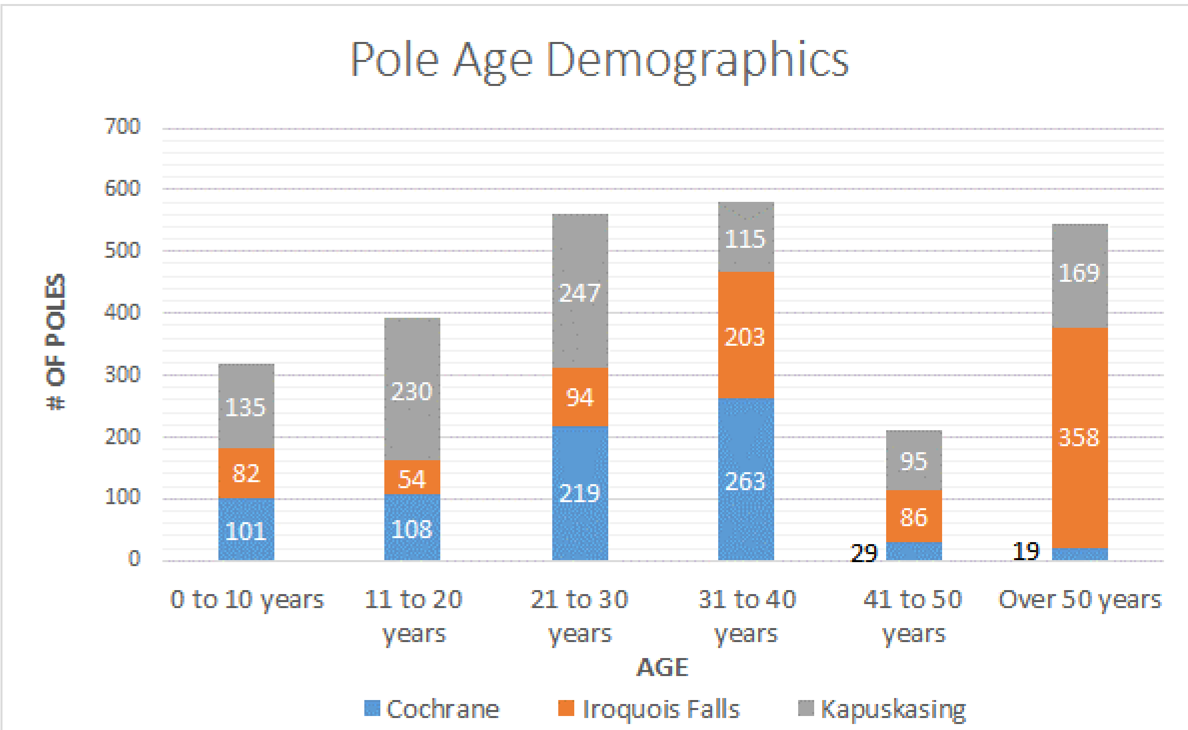
As part of the continued information gathering for the GIS, condition and demographic data for pole-mounted transformers will be gathered. Some of the pole-mounted transformers in NOW Inc.'s service territory are in noticeably poor condition, such as the one shown Figure 3-5. NOW Inc. does not have a dedicated transformer replacement program and, therefore, pole-mounted transformers are run-to-failure, except where replaced as part of a spot pole replacement or overhead rebuild.

Figure 3-5: Example of a typical poor condition pole-mounted transformer

3.2.3.3 *Poles*

Wood poles have a TUL of 45 years; therefore, poles greater than 40 years of age have a significant probability of failure. Furthermore, poles greater than 50 years of age are prioritized for replacement. As depicted in Figure 3-6, 29% of NOW Inc.'s poles have exceeded 40 years of age and 21% have exceeded 50 years of age. A significant portion of the poles greater than 50 years of age are in Iroquois Falls. This indicates a prudent need to invest in pole replacements through NOW Inc.'s pole replacement program, overhead rebuilds, and voltage conversion programs, before ballooning pole failure rates put undue strain on NOW Inc.'s operating budget.

Figure 3-6: Wood pole age demographics



A number of poles within NOW Inc.'s service territory are in visibly poor condition, such as those shown in Figure 3-7 below, which are over 50 years old. Short poles require pole-top extensions to meet clearances and are less resilient to ice and wind. Leaning poles are also likely to succumb to wind stress. Other common issues requiring remediation are insect infestation, woodpecker damage, pole rot, and broken crossarms.

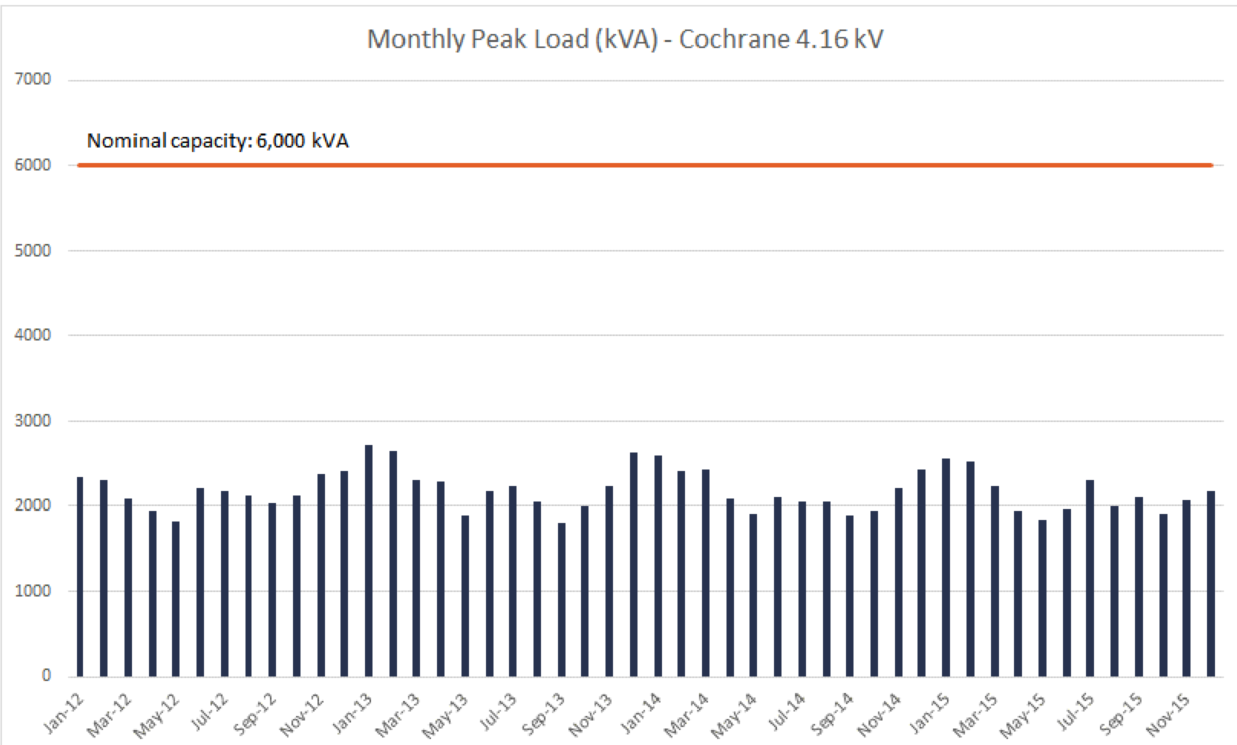
Figure 3-7: Examples of typical short/leaning/poor condition poles

3.2.4 System Utilization (5.3.2d)

The capacity of the HONI feeders (12.5/7.2 kV in Iroquois Falls and 25/14.4 kV in Kapuskasing) assigned to NOW Inc. have sufficient capacity to serve NOW Inc.'s existing DS. Therefore, converting the 2.4 kV delta and 4.16/2.4 kV distribution plants to 12.5/7.2 kV and 25/14.4 kV will not add load to the distribution or transmission system.

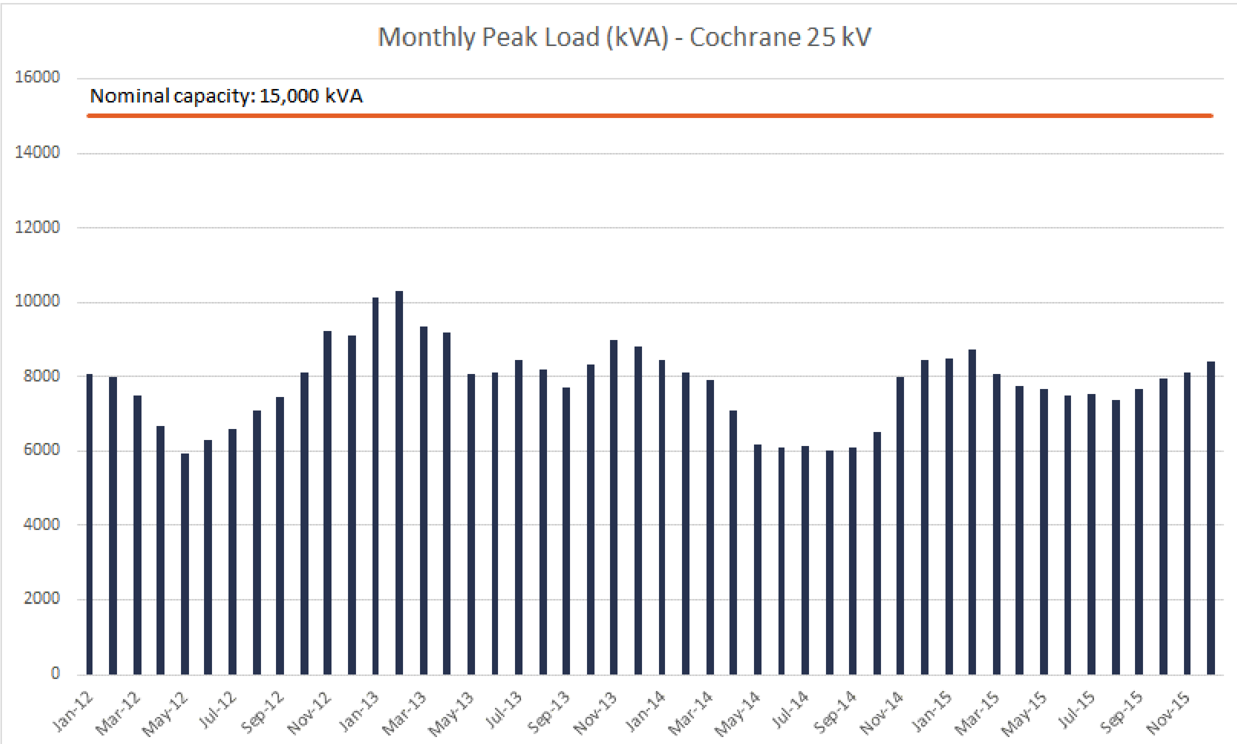
The peak monthly loads at the 4.16/2.4 kV Cochrane DS (read from the primary metering equipment) are presented in Figure 3-8 for the years 2012 to 2015. The utilization peaks in winter with a smaller peak in summer, but is much below the 6 MVA nominal capacity. Since there are two parallel transformer banks rated 3 MVA each, the Cochrane 4.16/2.4 kV substation can withstand a contingency due to maintenance or the unplanned outage of one transformer bank even during peak load. System utilization is not a driver for material investment at the 4.16/2.4 kV Cochrane DS.

Figure 3-8: Monthly peak load for the 4.16/2.4 kV Cochrane DS (2012 to 2015)



The peak monthly loads at the 25/14.4 kV Cochrane DS (read from the primary metering equipment) are presented in Figure 3-9 for the years 2012 to 2015. The annual peak occurs in January or February, but November 2013 was unusually higher than January/February 2014. A smaller summer peak is not always prevalent. Since there are two parallel transformer banks rated 7.5 MVA each, the Cochrane 25/14.4 kV substation can only withstand a contingency due to maintenance or the unplanned outage of one transformer bank if the load is not peak. System utilization is not a driver for material investment at the 25/14.4 kV Cochrane DS.

Figure 3-9: Monthly peak load for the 25/14.4 kV Cochrane DS (2012 to 2015)



Monthly peak loading data is not available at the DS in Iroquois Falls and Kapuskasing since the primary metering equipment at the demarcation points with the HONI-owned feeders are not located at the DS. System utilization is not a driver for material investment at the DS in Iroquois Falls and Kapuskasing.

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

NOW Inc. manages assets with the intent of providing a safe, efficient, reliable and cost effective distribution system.

Electricity assets like any other type of physical asset have a lifecycle. For example, distribution transformers are manufactured with the intent that there is no need to provide regular maintenance for the duration of their lifecycle. However, a small percentage of distribution assets, such as substation transformers, benefit from life extension maintenance. Components wear out in a number of ways including oxidation, pitting or erosion. Equipment failures may be caused by a number of factors, such as quality of manufacture, installation, age, operating hours, loading cycles, temperature, contaminants and stress, to name a few. NOW Inc. has a maintenance program in place for early detection of problems.

3.3.1.1 *Asset Replacement and Refurbishment Policies*

The intent of NOW Inc.'s maintenance programs is to provide base knowledge to make informed decisions and identify any future upgrades. The data collected also provides valuable information upon which to base repair work, refurbishment activities, and asset replacement schedules. NOW Inc.'s asset replacement and refurbishment policies for each class of assets is summarized below.

<u>Substations</u>

Testing of substation transformer oil is a very good predictor of when a transformer is reaching the end of its life. NOW Inc. retains a third-party consultant to perform Dissolved Gas Analysis ("**DGA**") on its substation transformers, tap changers, and regulators. NOW Inc. accounts for the recommendations of the third-party consultant – whether to continue re-testing, schedule shut-downs for investigation, or plan for replacement – when making replacement or refurbishment decisions for substation transformers and tap changers. When weighing the consultant's recommendations, NOW Inc. considers the impact on its distribution weights.

Annual oil testing allows time to make decisions about replacement and capital investment is therefore based on a proactive approach. Maintaining substations over the long term adds system O&M costs, which would not be present if the stations were eliminated.

<u>Distribution Transformers</u>

The majority of NOW Inc.'s distribution transformers are pole-mounted, with only a few pad-mounted transformers. All distribution transformers are inspected and monitored regularly and replaced on a reactive basis. Failed transformers are replaced in order to restore power. Small deficiencies are repaired during inspections or scheduled for a follow-up repair, but more severe deterioration necessitates replacement. Pole-mounted transformers with cracked bushing or evidence of oil leaks, for example, are considered for replacement. Pad-mount transformers may be replaced due to severe rusting on the tank or frame, cracked bushings, or evidence of oil leaks.

Life extension techniques for distribution transformers are limited. NOW Inc. does not implement life extension programs for distribution transformers outside of its regular three-year inspection cycle. This helps keep system O&M costs low. System renewal budgets account for reactive replacements of transformers, as needed.

Poles

NOW Inc.'s overhead lines are all supported by wood poles. Poles are regularly inspected and corrective action is taken as needed on flagged issues. Pole replacements are budgeted each year and the inspection process identifies individual poles for replacement. NOW Inc. does not see value in the testing or maintenance of poles.

Distribution Switches

The major switching assets on NOW Inc.'s distribution system are overhead gang-operated switches and pad-mounted switchgear. This is a small group of assets, with only five gang-operated switches and five pad-mounted switchgear in NOW Inc.'s service territory. Distribution switches are inspected, maintained, and monitored regularly. Regular maintenance adds to system O&M costs, but extends the life of the switches to reduce system renewal spending. Switches which have deteriorated beyond maintenance capabilities are replaced.

Cables/Conductors

Underground cables make up less than 1% of NOW Inc.'s distribution system, yet underground cables require particular attention during inspection and maintenance as they are prone to insulation failure. NOW Inc. has a mixture of direct-buried and duct-embedded cables. NOW Inc.'s inspection program covers terminations of cable only, which are exposed in pad-mounted equipment and riser poles. Underground cables are monitored for failure and replaced when a failure occurs. Direct-buried cables are replaced with duct structures, which will decrease the cost of future replacements. NOW Inc. has not seen the need for proactive maintenance of cables or cable injection.

The remaining 99% of NOW Inc.'s distribution system is comprised of overhead conductors. Overhead conductors typically outlive the poles that carry them and are replaced when the pole line is rebuilt; however, NOW Inc. has some older #6 copper conductors in its system, which is more prone to breaking. Overhead conductors are inspected on a three-year cycle to manage this risk. During line patrols, conductors are assessed for signs of corrosion, broken strands, abrasions, annealing, and elongation. There are no maintenance programs for overhead conductors.

3.3.1.2 *Maintenance Planning Criteria and Assumptions*

NOW Inc.'s maintenance and inspection programs have been carefully selected and are carried out such that present service levels will continue to be maintained to balance customer needs, price/reliability trade-offs, and industry best practices. It is assumed that service levels will not be changed significantly due to the introduction of new regulatory requirements. Assumptions regarding TUL are based on Kinectrics' *Asset Depreciation Study for the Ontario Energy Board*. NOW Inc. adopts the following maintenance planning criteria and assumptions:

- The TUL of substation transformer is 45 years.
- The 4.16/2.4 kV distribution plant in Kapuskasing and the 2.4 kV delta system in Iroquois Falls are of a similar age or older than the substation transformers also have a TUL of 45 years.
- A pole failure can be a significant risk as the result could injure the public and/or cause a lengthy interruption.
- As distribution plant is replaced, it is built to 12.5/7.2 kV in Iroquois Falls and 25/14.4 kV in Kapuskasing, which replaces older poles.
- Eliminating stations does not generally require line extensions as the existing path or pole line is already in place.
- The TUL of pole-mounted and pad-mounted transformers is 40 years, and their outage impact is limited to a small number of customers for a short duration.
- The TUL of gang-operated overhead switches is 60 years and their risk of failure is low.
- The TUL of pad-mounted switchgear is 35 years and the impact of a switchgear failure is a significant risk; wherein a customer outage would likely occur and the safety of the public and staff would be impacted.
- The TUL of XLPE cable is 25 to 35 years and the impact of cable failure is low risk and public safety is not likely to be impacted as cables are buried and not exposed.

3.3.1.3 *Inspection and Maintenance Programs*

The inspection and maintenance of distribution assets involves substation inspections, line patrol records, and underground inspections. Maintenance standards are built upon manufacturer's recommendations, industry and regulatory requirements, and industry best practices. NOW Inc.'s inspection and maintenance programs are continually being improved.

NOW Inc.'s inspection and maintenance programs for each asset are summarized in Table 3-6. Inspection cycles are based on the *Distribution System Code, Appendix C – Minimum Inspection Requirements*.

Table 3-6: Summary of inspection and maintenance programs for each asset

Asset	Inspection Programs	Maintenance Programs
Substations	> Monthly substation inspection > Annual oil analysis for substation transformers, tap changers, and regulators	> Regular maintenance (vegetation control, switch-gear maintenance, battery bank maintenance, snow removal)
Pole-mounted transformers	> Inspected every three years	> None
Pad-mounted transformers	> Inspected every three years	> Some maintenance as required (vegetation control, connection cleaning and tightening)
Poles	> Inspected every three years	> None
Gang-operated switches	> Inspected every three years	> Regular maintenance (adjustments as required)
Pad-mounted switchgear	> Inspected every three years	> Regular maintenance (cleaning and adjusting)
Underground cables	> Terminations inspected every three years (at pad-mounted equipment and riser poles)	> None
Overhead conductors	> Inspected every three years	> None

Substations are inspected once per month to check the visual condition of the substation equipment, as well as the building, fence, locks, and signs. Transformer and regulator oil temperature, liquid temperature, and pressure gauges are read. The insulators on transformers and regulators are inspected for contamination or cracks; oil tanks are inspected for leaks. The arrestors and tap totalizers on the transformers are also checked. Phase currents are read and fuses are checked on both sides of the transformers; secondary voltages are read from the metering equipment. Lights, housekeeping, batteries, personal protective equipment, and fire extinguishers are all checked in switch rooms. In addition to the monthly inspections, annual oil testing for substation transformers, tap changers, and regulators is employed for condition assessment purposes.

Line patrols are performed on a three-year cycle. Pole-mounted transformers are inspected for signs of corrosion or oil leaks; transformer bushings are checked for cracks or contamination. Wood poles are checked for insect infestation or woodpecker damage; crossarms, pole tops, and pole shells are assessed for deterioration; leaning poles are noted. Insulators on the poles are checked for chips, cracks, and contamination. Gang-operated switches are inspected for corrosion or mechanical deterioration and are maintained regularly. Finally, overhead lines are checked for signs of corrosion, broken strands, abrasions, annealing, and elongation. Line patrol inspection results are not formally documented. Instead, line staff note any deficiencies during line patrols or trouble calls for immediate or scheduled replacement depending on the severity of the damage or deterioration.

NOW Inc.'s underground inspection program covers pad-mounted equipment and underground cable terminations. Pad-mounted transformers require very little maintenance and are inspected for signs of corrosion or oil leaks; transformer bushings are checked for cracks or contamination. Pad-mounted switchgear are inspected for corrosion or mechanical deterioration and are maintained regularly. Underground cable terminations, which are exposed in pad-mounted equipment and riser poles, are inspected for signs of moisture ingress.

In addition to the asset maintenance programs listed above, NOW Inc. has an infrared camera inspection program and tree trimming program. The infrared camera program commenced in 2012, to identify deficiencies (hot spots) within the distribution system. Tree trimming is conducted in order to decrease the number of distribution system outages and momentary interruptions. NOW Inc. cycles throughout its territory every year to trim trees that interfere with, or have potential to interfere with the distribution system on a regular basis. Other indications that a tree may need to be trimmed are:

a) reports of electrical outages caused by trees;
b) areas where trees have been damaged by storms;
c) periodic inspections by NOW Inc. personnel; and
d) reports from customers indicating potential tree problems.

NOW Inc. has an established reporting mechanism for tree trimming for the general public.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

NOW Inc.'s distribution system maintenance and inspection programs are aimed in part to protect the public from physical, electrical and environmental hazards by maintaining a schedule of regular asset inspections and maintenance activities. *Ontario Regulation 22/04 – Electrical Distribution Safety* is a key regulation which requires NOW Inc. and all other LDCs to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. The ESA is responsible for enforcing the regulation and this is done through a system of annual audits and regular field inspections. NOW Inc. follows all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

From a risk perspective, the failure of a substation transformer would have the greatest impact on reliability – since every customer served from the DS would be affected – and on the environment – since there is a potential for oil spilling – but is generally not a safety concern. A failure of the protective equipment on the primary side of the transformer or upstream power delivery equipment poses a serious reliability risk and slight safety concern, but is not an environmental risk. A failure of the feeder protection at the secondary side of the transformer is less of a reliability risk than the transformer or primary side, but would likely cause an outage along the entire feeder.

On the overhead distribution side, a pole failure can be a significant safety risk as the result could injure the public and/or cause a lengthy interruption. Poles which are closer to the DS have a greater reliability impact in case of a failure, since they serve a greater number of downstream customers. Pole-mounted transformers have a low risk of failure; their outage impact is limited to a small number of customers for a short duration. The risk of failure of gang-operated switches and overhead conductors are low; although these assets may have a high failure impact, their failure probability is low. Small conductors (e.g. #6 copper) on NOW Inc.'s system have a higher probability of failure than larger ACSR conductors.

On the underground system, pad-mounted switchgear also pose a significant failure risk, as a customer outage would likely occur and the safety of the public and staff would be impacted. As with pole-mounted transformers, pad-mounted transformers have a low risk of failure, their outage impact is limited to a small number of customers for a short duration. The impact of an underground cable failure is low and public safety is not likely to be impacted as cables are buried and not exposed.

Improvements in operational efficiency are achieved my proactively replacing assets, which can be done quicker than a reactive replacement and avoids maintenance costs. Due to the high repair and replacement cost for buried cables, operational efficiency improvements are greater for proactive replacements on the underground distribution assets, compared with overhead distribution assets. Similarly, substation equipment takes long to repair or procure new equipment in case of an unplanned outage.

Each of these asset classes can be assigned a "risk score" between 0 and 10 – where 10 is the maximum – for each of the four risk factors of reliability, safety, environment, and efficiency. Figure 3-10 summarizes the risk factors for each asset class. These risk scores provide a risk comparison across asset classes used in the project prioritization process (Section 4.2.3) where capital expenditures are selected and prioritized based on the risk analysis of the individual assets. The risks scores for the asset classes in the project scope are totalled and multiplied by the numeric weight of each risk factor (see Table 4-3). The asset risk scores are considered in conjunction with other project benefits that fall with these four risk factors, as well as regulatory and load growth (see Section 4.2.3 for more details).

Figure 3-10: Summary of risk scores by asset class

Asset Class / Risk Factor	Reliability	Safety	Environment	Efficiency
Substation Transformers	10	1	4	5
Substation Primary	10	2	0	4
Substation Secondary	5	2	0	3
Poles	4	4	0	2
Pole-mounted Transformers	1	1	2	2
Gang-operated Switches	2	1	0	2
Overhead Conductors	2	1	0	2
Pad-mounted Switchgear	3	4	0	4
Pad-mounted Transformers	1	1	2	4
Underground Cables	2	1	0	4

4 Capital Expenditure Plan (5.4)

This section describes NOW Inc.'s five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of NOW Inc.'s capital expenditure planning process, an assessment of NOW Inc.'s system capability to connect new REG, a summary of capital expenditures, and justification of Material Investments.

4.1 Summary (5.4.1)

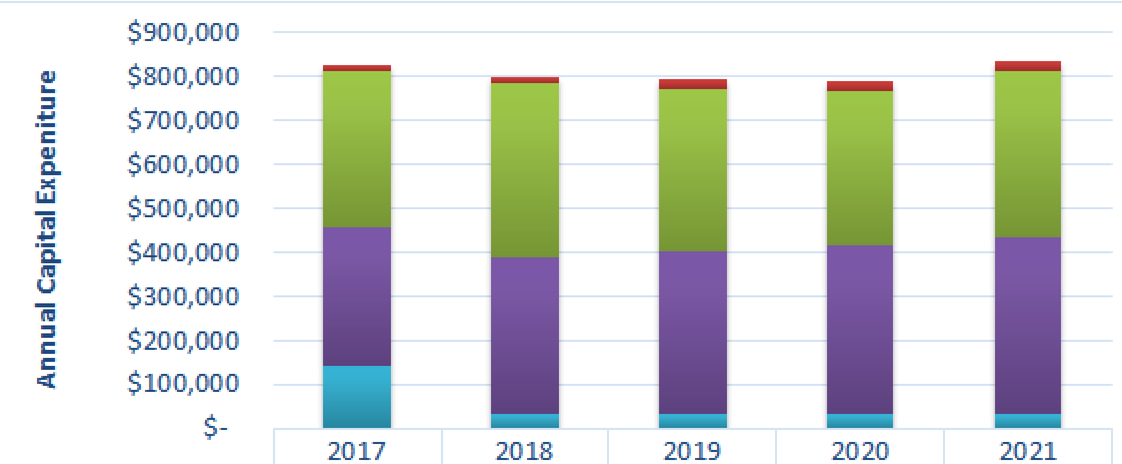
4.1.1 Ability to Connect New Load/Generation (5.4.1a)

Due to the stagnant growth in the region, the ability to connect new load is not an investment driver over the forecast period; and due to upstream capacity constraints at the HONI-owned Timmins TS, NOW Inc. cannot accommodate new REG connections.

4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

Figure 4-1 presents the total annual capital expenditures over the forecast period divided into the four investment categories of system access, system renewal, system service, and general plant. NOW Inc. has purposefully developed its capital expenditure plan to keep spending relatively constant over the forecast period.

Figure 4-1: Annual capital expenditures over the forecast period by investment category



	2017	2018	2019	2020	2021
System Access	$15,000	$15,000	$20,000	$20,000	$20,000
System Renewal	$355,000	$395,000	$370,000	$350,000	$380,000
System Service	$315,000	$355,000	$370,000	$385,000	$400,000
General Plant	$142,500	$32,500	$32,500	$32,500	$32,500

4.1.3 Description of Investments (5.4.1c)

A brief description is provided below of how, for each category of investment, the outputs of NOW Inc.'s asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories.

4.1.3.1 *System Access*

Customer service requests and third party infrastructure development projects are both driven by parties external to NOW Inc. Since there is no growth in the region and since the respective Towns have not planned any road widening projects over the forecast period, NOW Inc. has not budgeted any capital expenditures due to customer service requests and third party infrastructure development. NOW Inc.'s system access budget only includes metering, based on the expected rate of failure of the existing smart meters and the resource constraint of dispersing the meter replacement over the five years of the forecast period.

4.1.3.2 *System Renewal*

System renewal projects are driven by assets at the end of their service life. NOW Inc.'s risk analysis (Figure 3-10) indicates that failure at a substation poses the greatest reliability risk and system renewal projects have been identified to replace substation assets at the end of their service life. A significant number of wood poles have surpassed their TUL and would be expected to fail without intervention. Individual pole replacements are planned to partly address this. An annual overhead rebuild project on the 4.16/2.4 kV system in Cochrane will also replace poles at the end of their service life. Additional pole replacements in Iroquois Falls and Kapuskasing are addressed through voltage conversions in the system service category.

4.1.3.3 *System Service*

The ability to accommodate new load is not currently strained on NOW Inc.'s system and is therefore not an investment driver over the forecast period. Voltage conversion projects have been planned to achieve system operational objectives of safety, reliability, system efficiency, and reduced costs. Voltage conversion projects are planned such that they replace assets at the end of their service life. More expenditures over the forecast period have been allocated to pole replacements (including the voltage conversion projects) in Iroquois Falls and Kapuskasing than in Cochrane because the majority of poles exceeding TUL are in these two Towns.

4.1.3.4 *General Plant*

General plant expenditures in tools and equipment, computer hardware, and computer software are planned each year to replace equipment at the end of its useful life and support software licensing fees. Additional expenditures in computer software have been planned to improve operational efficiency and to accommodate customer requests for paperless billing and improved outage communication.

4.1.4 List of Capital Expenditures (5.4.1d)

Table 4-1 presents the list of material capital expenditures over the forecast period. For NOW Inc., the materiality threshold is $50,000. The system access (metering) project is not included since it is immaterial and other immaterial general plant projects are excluded.

Table 4-1: Material capital expenditures over the forecast period

Category	Project/Program	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2021 Budget
System renewal	Pole Replacements – Cochrane	$105,000	$55,000	$55,000	$55,000	$55,000
System renewal	Pole Replacements – Kapuskasing	$55,000	$55,000	$55,000	$55,000	$55,000
System renewal	Pole Replacements – Iroquois Falls	$55,000	$55,000	$55,000	$55,000	$55,000
System renewal	Cochrane 4.16/2.4 kV Rebuild	$90,000	$180,000	$130,000	$135,000	$140,000
System renewal	Cochrane Substation Feeder	$50,000				
System renewal	Cochrane Substation Transformer Bank T2		$50,000	$75,000		
System renewal	Detroyes DS Primary Side Replacement				$50,000	
System renewal	Mill Gate DS Decommissioning					$75,000
System service	Kapuskasing 4.16/2.4 kV Conversion	$175,000	$200,000	$205,000	$215,000	$220,000
System service	Iroquois Falls 2.4 kV Delta Conversion	$140,000	$155,000	$165,000	$170,000	$180,000
General plant	Computer Software	$115,000	$5,000	$5,000	$5,000	$5,000

System renewal expenditures include three pole replacement programs – one for each Town – to replace poles that have reached the end of their service life. The planned system renewal projects include the annual overhead rebuild of the 4.16/2.4 kV system in Cochrane, substation feeder upgrades at Cochrane DS in 2017, substation transformer upgrades at Cochrane DS in 2018 and 2019, the replacement of primary switchgear and underground cables at Detroyes DS in 2020. These programs and projects all replace assets at the end of their service life. In addition, the 12.5/7.2-2.4 kV delta Mill Gate DS will be decommissioned in 2021.

The two planned system service projects are annual voltage conversions. The primary driver of the voltage conversion in Iroquois Falls is safety, as the 2.4 kV delta system will be replaced with a 12.5/7.2 kV wye system. This project will eventually enable the 2.4 kV delta DS to be decommissioned. The primary driver of the voltage conversion in Kapuskasing is reduced costs, as it will facilitate the decommissioning of the DS in Kapuskasing. Voltage conversions also reduce line losses and are planned to replace assets at the end of their service life.

Finally, computer software investments (outage management system, potential billing software upgrades – depending on project prioritization) in the general plant category have been planned in 2017 to improve operational efficiency.

4.1.5 Expenditures related to a Regional Planning Process (5.4.1e)

The Needs Assessment Report for the North and East of Sudbury Region (Appendix B) recommended that there is no need for further regional coordination and the possible voltage regulation issues at Timmins TS will be addressed through a localized wire solution led by HONI. HONI has yet to initiate the localized planning, therefore NOW Inc. has not forecast any expenditure related to a Regional Planning Process.

4.1.6 Customer Engagement Activities (5.4.1f)

Customer engagement is an ongoing process at NOW Inc. and is rooted in NOW Inc.'s culture. NOW Inc. often coordinates its infrastructure development activities with customers and has regular face-to-face meetings with its large customers to understand their needs and expectations. To facilitate the development of this DSP, NOW Inc. also distributed a survey to its customers in order to obtain information of their preferences.

4.1.6.1 *Customer Consultations*

As introduced in Section 2.2.1, NOW Inc. often meets with residential customers to coordinate infrastructure development and initiates annual one-on-one meetings with its large customers. Generally, customers are satisfied with NOW Inc.'s service and remark that their rates are less than those served by neighbouring utilities. Based on this feedback, NOW Inc. has planned to keep its rate increase low and to continue steady investment into its distribution system in order to maintain system reliability.

Particular emphasis has been placed on selecting projects that will improve operational efficiency and ultimately lead to cost savings. The voltage conversions in Kapuskasing and Iroquois Falls will each allow NOW Inc. to decommission a substation and eliminate the associated O&M costs for those substations. The computer software project involves upgrades to NOW Inc.'s GIS for improved project planning and upgrades to the OMS to reduce crew time for locating outages.

4.1.6.2 *Customer Satisfaction Survey*

The customer survey was completed by 423 residential customers and 41 commercial customers. Overall, customers are satisfied with the service they receive from NOW Inc. Commercial customers are very satisfied with the reliability and power quality of their electricity service, while residential customers are generally satisfied with the level of reliability of their electricity supply; although customers in Kapuskasing tend to be less satisfied than the other two Towns. Customers expressed a desire for improved communication from NOW Inc., such as power saving tips, outage information, and paperless billing. In response to this, NOW Inc. has planned to upgrade its OMS and CIS to allow improved outage reporting to its customers and to switch to paperless billing. This is included as part of the computer software budget in 2017.

4.1.6.3 *Virtual Town Hall*

A virtual town hall presentation was made available to consumers online, with the link to a follow-up survey provided at the end of the presentation. The purpose of the virtual town hall was to collect customer feedback on NOW Inc.'s investment and spending plan from 2017 to 2021. Participation in the virtual town hall presentation and follow-up survey was less successful than the customer satisfaction survey and, therefore, less emphasis was placed on its results in NOW Inc.'s planning process.

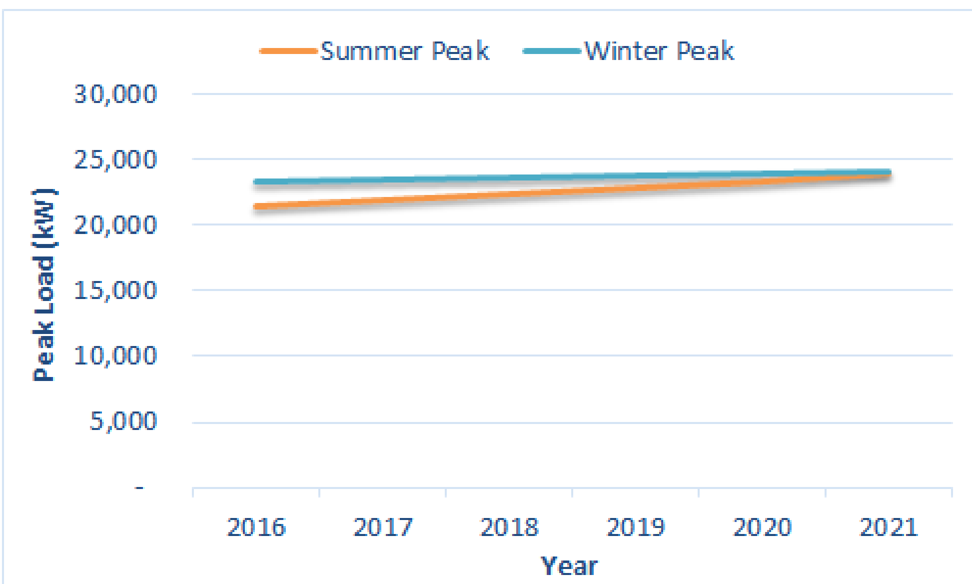
4.1.7 System Development over the Forecast Period (5.4.1g)

Below is a brief description of how NOW Inc. expects its system to develop over the next five years in relation to load and customer growth, smart grid development, and the accommodation of forecasted REG projects.

4.1.7.1 *Load and Customer Growth*

NOW Inc. expects that electricity growth rates will continue to be slow over the next five years due to economic recovery and the impact of CDM programs in lowering demand and electricity usage. The Town of Cochrane is expected to experience some growth, which can be sustained by NOW Inc.'s existing distribution system. Figure 4-2 depicts the relatively flat, but positive load growth forecast from 2016 to 2021.

Figure 4-2: Forecast peak load from 2016 to 2021



4.1.7.2 *Smart Grid Development*

Over the forecast period, existing smart meters will begin reaching their end-of-life and will require replacement as they fail. NOW Inc.'s metering budget includes these expected replacements, which must account for available crew hours to perform the work. NOW Inc. does not have any other smart grid initiatives planned over the forecast period.

4.1.7.3 *REG Accommodation*

Due to upstream capacity constraints at the HONI-owned Timmins TS, NOW Inc. is not forecasting any new REG connections over the next five years. NOW Inc. will continue to work with HONI to obtain REG connection capacity for its customers.

4.1.8 Customer Preferences/Technology Based Opportunities/Innovation (5.4.1h)

Table 4-2 lists the capital projects planned in response to customer preferences, technology based opportunities, and to demonstrate innovative processes, service, business models, or technologies, including the total capital cost over the forecast period.

The computer software budget in 2017 includes $5,000 for operating system software licenses and the remaining $110,000 has been budgeted for OMS, CIS, and GIS upgrades in response to customer preferences and technology based opportunities to improve operational efficiency.

Table 4-2: Projects in response to customers, technology, and innovation

Item	Budget	Project	Customer Preferences	Technology Based Opportunities	Innovation
Computer Software	$110,000 (2017)	OMS Upgrades	✓	✓	
		CIS Upgrades	✓		
		GIS Upgrades		✓	

4.1.8.1 *Customer Preferences*

Surveyed customers indicated that they would like improved communication from NOW Inc. during power outages. NOW Inc. is planning to upgrade its OMS, partly to allow for interactive outage maps that customers can access online. Customers also indicated that they would like more information on their electricity usage and more options to receive their electricity bills. NOW Inc. is planning to upgrade its CIS in order to introduce paperless billing and to provide customers with on-demand electricity consumption information.

4.1.8.2 *Technology Based Opportunities*

The planned upgrades to NOW Inc.'s OMS will also establish fault location capability, which will improve operational efficiency during outage information by providing crews with an estimation of the fault location. Planned upgrades to the GIS will allow NOW Inc. to plan projects and work orders faster and using a more complete data set.

4.1.8.3 *Innovative Processes, Services, Business Models, or Technologies*

NOW Inc. has not planned any projects to study or demonstrate innovative processes, services, business models, or technologies. The previously mentioned computer software projects (OMS, CIS, and GIS upgrades) are proven technologies in the domain of electrical utilities.

4.2 Capital Expenditure Planning Process Overview (5.4.2)

4.2.1 Planning Process (5.4.2a)

NOW Inc.'s planning objectives, assumptions, and criteria, as well as the outlook for accommodating new REG investments are described below.

4.2.1.1 *Planning Objectives*

NOW Inc. uses the same objectives for its capital expenditure planning process as its asset management process. These are:

1. Operating a safe electrical system for employees and the public.
2. Meeting regulatory requirements.
3. Engaging in environmental protection.
4. Accommodating load growth and new customer connections.
5. Delivering a reliable supply of electricity.
6. Managing costs and rate stability.

Capital projects and programs are planned to improve NOW Inc.'s performance with respect to one or more of these objectives. Due to the stagnant load growth in the region, accommodating load growth and new customer connections are not investment drivers over the forecast period.

4.2.1.2 *Planning Assumptions and Criteria*

In its planning process, NOW Inc. assumes that small conductors such as #6 copper are more likely to break than standard conductors such as 1/0 or 3/0 ACSR. In its voltage conversion in Iroquois Falls and overhead rebuild in Cochrane, NOW Inc. is replacing #6 copper conductors.

As per the asset demographics in Figure 3-6, the poles in Iroquois Falls are assumed to be in the worst condition, followed by the poles in Kapuskasing. NOW Inc.'s pole replacement program budgets the number of poles for replacement each year in each of the three Towns, while its inspection program identifies the worst poles for replacement. Therefore, in its planning process, NOW Inc. assumes that poles replaced as part of a pole replacement program are more likely to fail (if not replaced) than poles replaced as part of a voltage conversion or overhead rebuild.

Benefits from computer software investments have been assumed, but depend on vendor price and capability, as well as NOW Inc.'s approved funding level.

4.2.1.3 *Outlook for Accommodating REG*

There are no constraints on NOW Inc.'s distribution system that would prevent the connection of new REG installations; however, there is currently no capability to connect new REG projects in NOW Inc.'s service territory due to upstream capacity constraints at the HONI-owned Timmins TS. NOW Inc.'s objective is to provide sufficient REG capacity to allow new REG connections and will continue to work with HONI to free up capacity at Timmins TS.

4.2.2 Non-Distribution System Alternatives to Relieving System Capacity (5.4.2b)

NOW Inc. does not have any policies on non-distribution system alternatives to relieving system capacity or operational constraints. NOW Inc.'s customers can choose to participate in IESO-administered Demand Response programs and NOW Inc. actively promotes the uptake of these and other CDM programs.

The Regional Planning Process in the North and East of Sudbury region did not identify any non-distribution system alternative to relieving system capacity.

4.2.3 Project Prioritization (5.4.2c)

As introduced in Section 4.2.1, projects and programs are planned to improve NOW Inc.'s performance with respect to one or more of its objectives of safety, regulatory, environment, load growth, reliability, and efficiency. For the purpose of ranking and prioritizing projects/programs, these objectives are numerically weighted as shown in Table 4-3 below.

Table 4-3: Objective weights applied to project prioritization

Objective	Numeric Weight
Operating a safe electrical system for employees and the public	10
Meeting regulatory requirements	8
Engaging in environmental protection	7
Accommodating load growth and new customer connections	6
Delivering a reliable supply of electricity	5
Managing costs and improving efficiency	4

The asset related impacts for each project/program are evaluated as per Figure 3-10 with the following scaling factors used for differentiation:

- Poles in Iroquois Falls are in the worst condition and are most likely to fail; multiply Iroquois Falls pole replacement impacts by 1.4.
- Poles in Kapuskasing are in the worse condition than those in Cochrane; multiply Kapuskasing pole replacement impacts by 1.2.
- Small conductors are more likely to fail than standard sizes; multiply impacts of small conductors by 2.
- Poles identified for replacement in the pole replacement programs are the very worst poles and are the most likely to fail; multiply impacts of pole replacement programs by 2.

In addition to the asset related impacts, additional impacts are scored for each project/program as summarized in Table 4-4.

Table 4-4: Impact scores for other project activities

Objective	Activity	Impact Score
Safety	Delta to wye conversion	10
Safety	Improved clearances	6
Environment	Oil containment close to a waterway	10
Efficiency	Substation decommissioning	10
Efficiency	Voltage upgrade	6

The end result is a single numerical score for each project/program that is used for ranking and prioritization. Table 4-5 presents the prioritized list of projects/programs over the forecast period.

Table 4-5: Prioritized list of projects/programs over the forecast period

Rank	Project/Program	Numeric Score
1	Iroquois Falls 2.4 kV Delta Conversion	370.2
2	Kapuskasing 4.16/2.4 kV Conversion	228.6
3	Mill Gate DS (2.4 kV Delta) Decommissioning	218
4	Cochrane 4.16/2.4 kV Rebuild	211
5	Cochrane Substation Feeder	200
6	Pole Replacements – Iroquois Falls	190.4
7	Pole Replacements – Kapuskasing	163.2
8	Pole Replacements – Cochrane	136
9	Detroyes DS Primary Side Replacement	129
10	Cochrane 4.16/2.4 kV Substation Transformer Bank Replacement	108
11	Computer Software (GIS, CIS, OMS)	81

Annual budget figures are drafted based on the analysis of the impact of planned capital expenditures on customer bills. Projects/programs are then selected in order of priority and scoped to fit within budget envelopes. In particular, annual scopes of multi-year projects are selected to align with budget envelopes and scaled back where necessary to ease rate impacts.

4.2.4 Customer Engagement Details (5.4.2d)

As introduced in Section 4.1.6, NOW Inc. engages its customers through consultations, a virtual town hall, and a customer satisfaction survey for the purpose of identifying their needs, priorities, and preferences.

Consultations with residential customers are incorporated into the detailed project planning process. Scheduling is coordinated with affected customers to better serve the community.

Large customer consultations are incorporated early into the planning process in order that NOW Inc. can meet its customers' needs and expectations. Large customers are satisfied with their electricity service from NOW Inc. and remark that their electricity costs are lower than those served by neighbouring utilities. Therefore, NOW Inc. has not planned any specific investments as a result of large customer consultations, and instead has opted to limit its rate impact by proposing only moderate and necessary increases to capital spending.

The follow-up survey to the virtual town hall presentation only received ten responses, so it wasn't weighted highly in the project planning process compared to the customer satisfaction survey.

The customer satisfaction survey was administered online and was completed by 423 residential customers and 41 commercial customers. One of the survey's main findings is that customers are generally unwilling to pay more to maintain reliability and reduce costs over the long term; therefore, one of NOW Inc.'s asset management and project planning objectives is rate stability. As a result, NOW Inc. has only proposed conservative increases to its capital spending. Customers also expressed a desire for improved communication from NOW Inc., such as power saving tips, outage information, and paperless billing (see pages 40 to 44 of the English version and page 25 of the French version). In response to this, NOW Inc. has planned to upgrade its OMS and CIS to allow improved outage reporting to its customers and to switch to paperless billing.

Overall, customers are satisfied with the service they receive from NOW Inc. Commercial customers are very satisfied with the reliability and power quality of their electricity service. Residential customers are generally satisfied with the level of reliability of their electricity supply, although customers in Kapuskasing tend to be less satisfied than the other two Towns. There were a couple of scheduled and unplanned outages that recently affected the entire Town of Kapuskasing in 2013.

Some of the most relevant questions from the survey are presented below. The survey results for residential customers are divided by Town and presented as relative frequency distributions to allow for comparison between the three Towns. The survey results for commercial customers lumped together and presented as frequency distributions due to the smaller sample size.

4.2.4.1 *Overall Satisfaction*

Customers were asked to comment on their overall satisfaction level with the electricity service they receive from NOW Inc. As shown in Figure 4-3 and Figure 4-4, most residential and commercial customers responded that they are either “very satisfied” or “somewhat satisfied” with the service they receive from NOW Inc. Although the combined relative frequency of “very satisfied” and “somewhat satisfied” is similar across the three Towns, residents of Kapuskasing lean more towards only “somewhat satisfied” than the other two Towns. This is probably because a number of scheduled and unplanned outages recently affected the entire Town of Kapuskasing in 2013.

Figure 4-3: Overall residential customer satisfaction

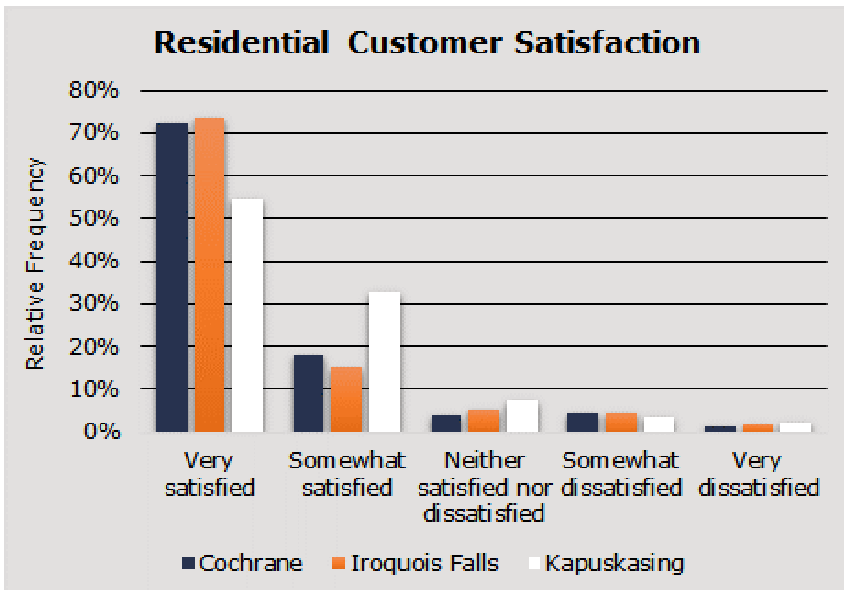
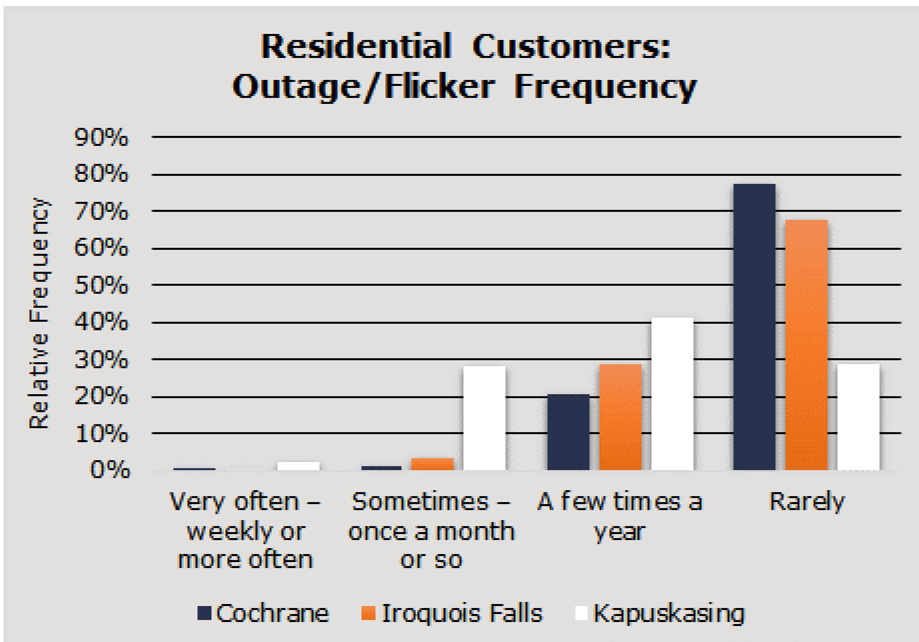


Figure 4-4: Overall commercial customer satisfaction

4.2.4.2 *Reliability/Power Quality*

A series of questions in the survey focused on customers' opinions on the reliability of the electricity supplied by NOW Inc. Residential customers were asked how often they experienced problems with their electricity service, such as power outages or flickering lights. As depicted in Figure 4-5, most customers responded that they "rarely" experience problems with their electricity, or "a few times a year". A higher percentage of customers in Kapuskasing indicated that they experience problems with their electricity "sometimes – once a month or so", probably because a number of scheduled and unplanned outages recently affected the entire Town of Kapuskasing in 2013.

Figure 4-5: Outage/flicker frequency – residential customers

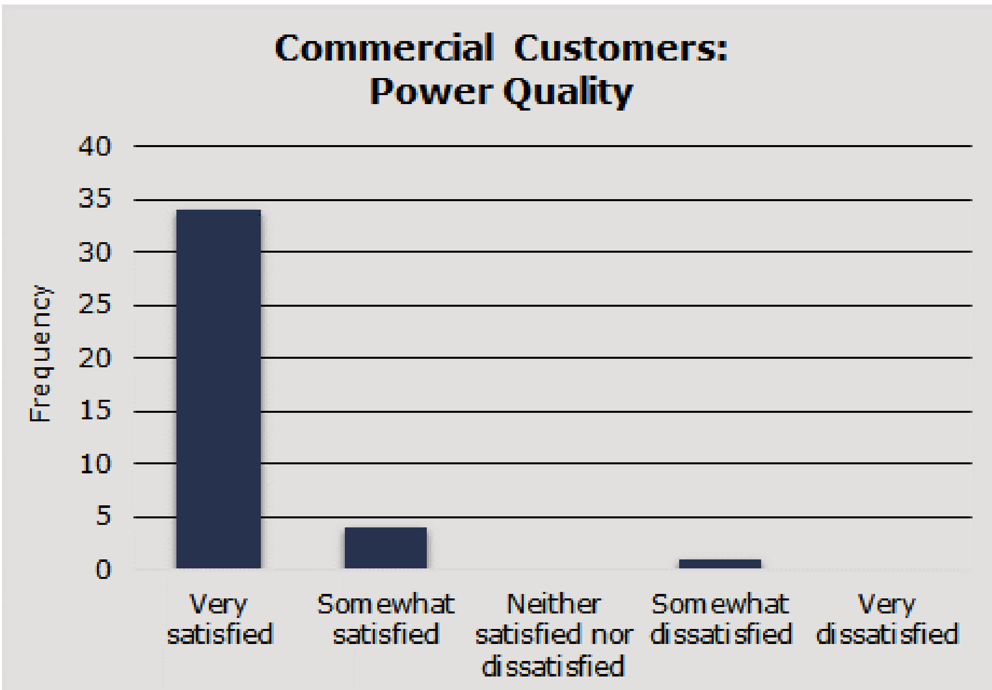


Commercial customers were asked how satisfied they were with the power quality supplied by NOW Inc., where power quality was defined as:

> The electrical network's or the grid's ability to supply a clean and stable power supply. In other words, power quality ideally creates a perfect power supply that is always available, and is always within voltage and frequency tolerances.

As depicted in Figure 4-6, an overwhelming number of commercial customers responded that they are "very satisfied" with the quality of the power they receive from NOW Inc.

Figure 4-6: Power quality – commercial customers



A number of questions were posed to both residential and commercial customers on NOW Inc.'s effectiveness with respect to power outages. First, customers were asked to rate NOW Inc.'s effectiveness at restoring service when a power outage occurs. As shown in Figure 4-7 and Figure 4-8, most customers rated NOW Inc. as "extremely effective" or "very effective" at power restoration. A greater proportion of residential customers in Kapuskasing rated NOW Inc. as only "somewhat effective" at restoring powers after an outage compared to the other two Towns.

Figure 4-7: Outage restoration effectiveness – residential customers

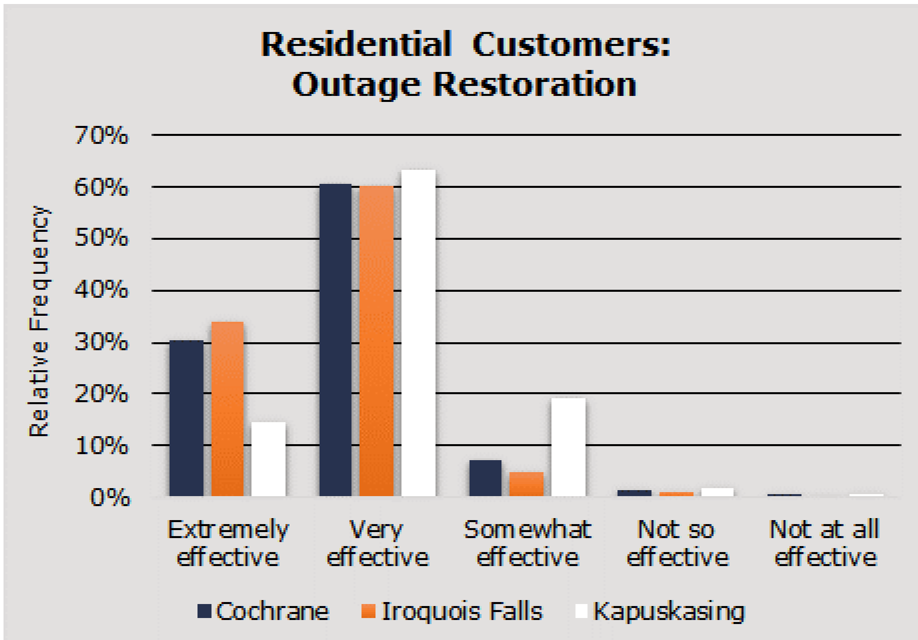
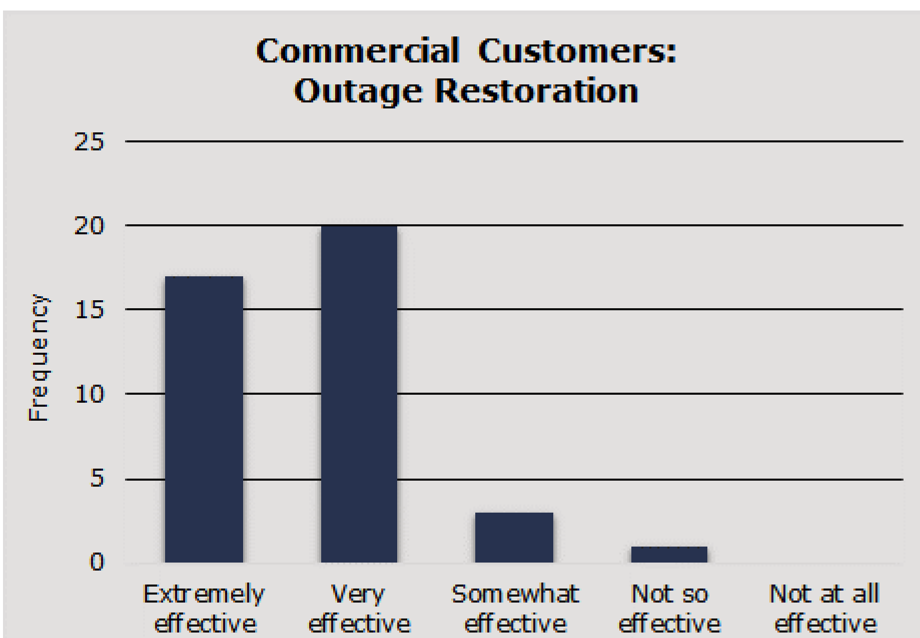


Figure 4-8: Outage restoration effectiveness – commercial customers



Customers were also asked to rate NOW Inc.'s effectiveness at minimizing the number of power outages. Similar to the previous question, most customers rated NOW Inc. as "extremely effective" or "very effective" at minimizing the number of outages, but a greater percentage of Kapuskasing residents rated NOW Inc. as only "somewhat effective" compared to the other two Towns, as shown in Figure 4-9 and Figure 4-10.

Figure 4-9: Effectiveness at minimizing outages – residential customers

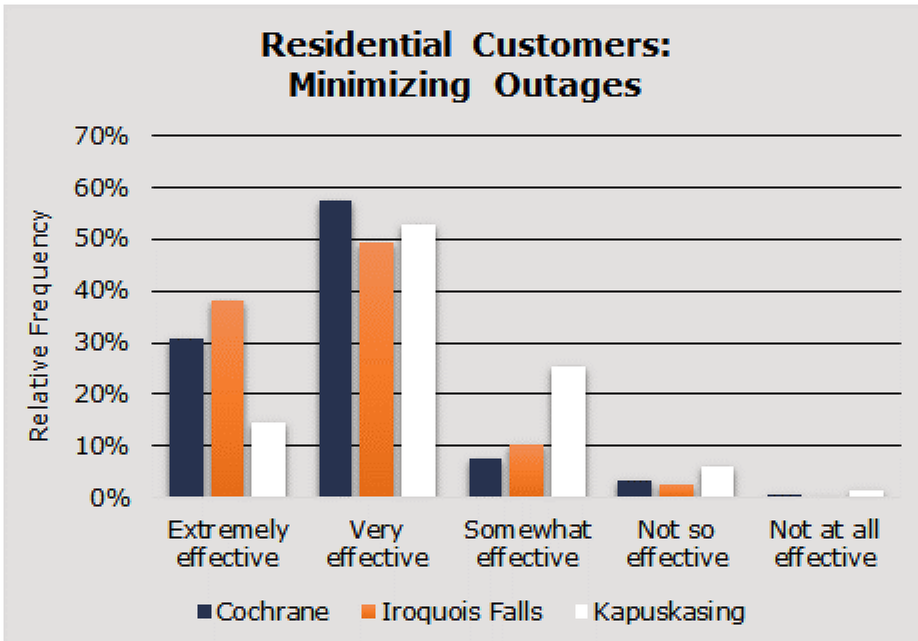
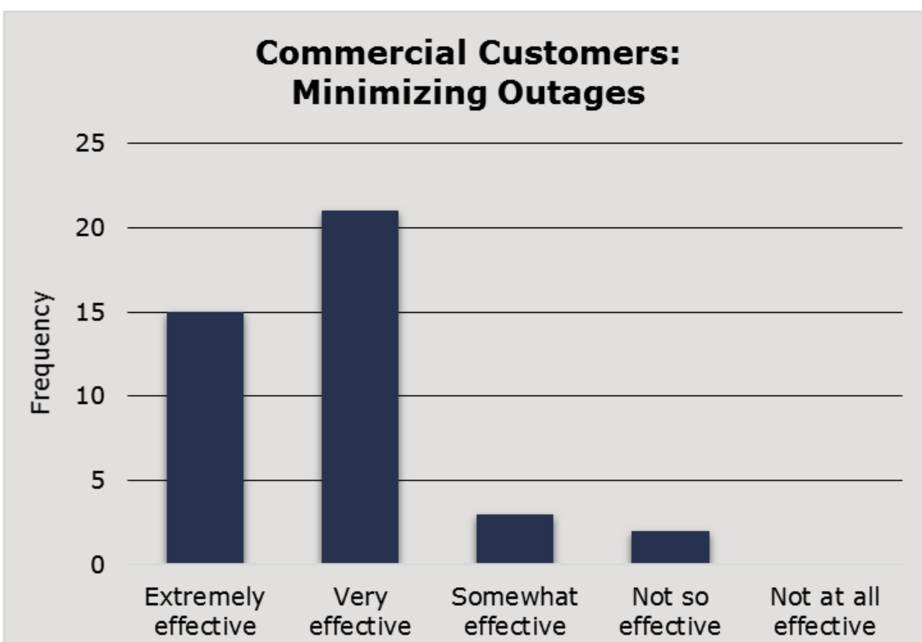


Figure 4-10: Effectiveness at minimizing outages – commercial customers



Customers were then asked to rate NOW Inc.'s effectiveness at providing information about extended outages. The percentage of residential customers describing NOW Inc. as "extremely effective" or "very effective" was less than the previous two questions, as depicted in Figure 4-11; while this proportion for commercial customers was relatively unchanged, although a few customers shifted from "extremely effective" to "very effective", as shown in Figure 4-12. Customer opinions on NOW Inc. being reachable by telephone during an outage were almost identical, as shown in Figure 4-13 and Figure 4-14.

Figure 4-11: Effectiveness at providing information on extended outages – residential customers

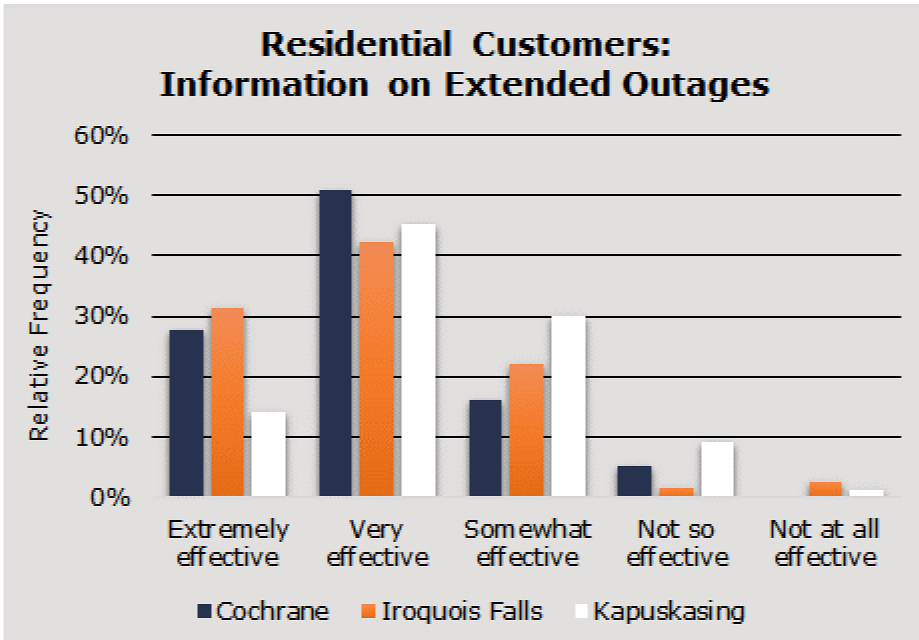


Figure 4-12: Effectiveness at providing information on extended outages – commercial customers

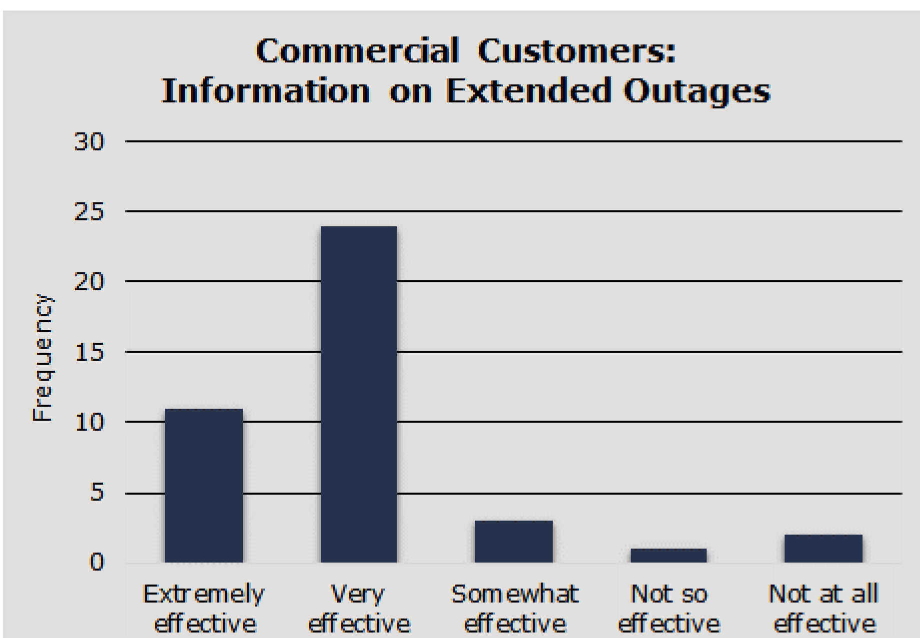


Figure 4-13: Telephone reachability during outages – residential customers

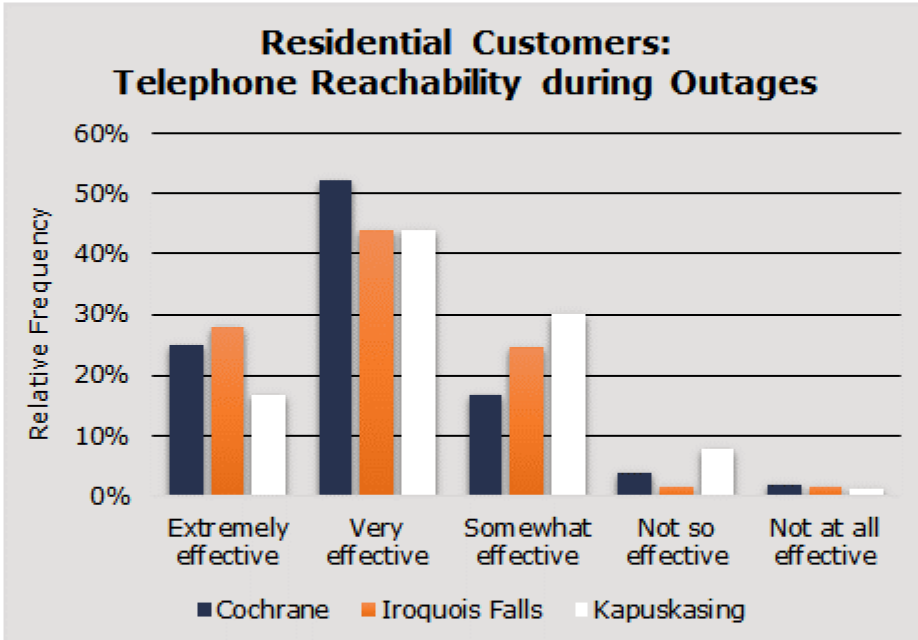
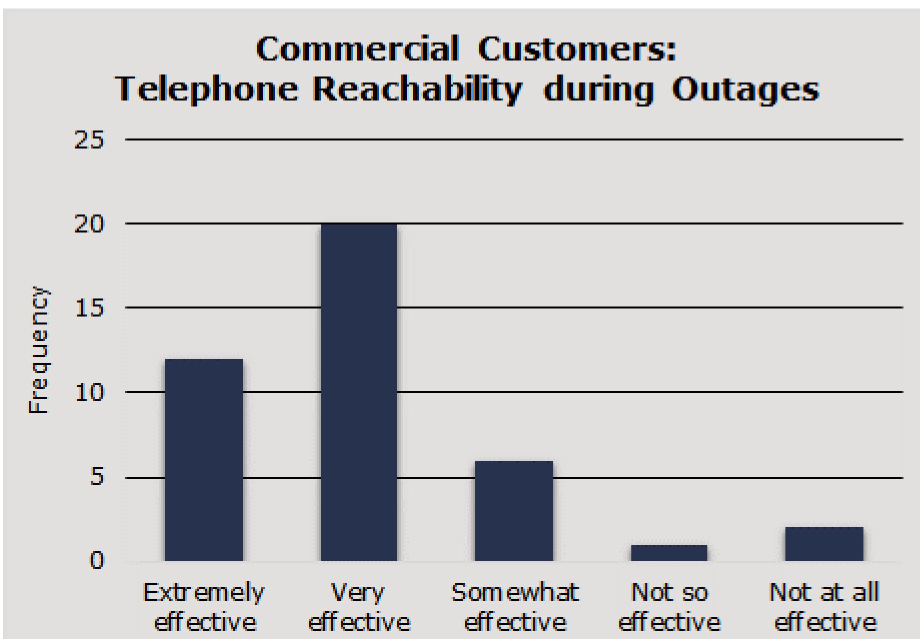


Figure 4-14: Telephone reachability during outages – commercial customers



Residential and commercial customers were asked to rate the overall reliability of electricity supplied by NOW Inc. As depicted in Figure 4-15 and Figure 4-16, most customers rate NOW Inc. as "extremely reliable" or "very reliable". A greater proportion of customers in Kapuskasing rated their electricity supply as only "somewhat reliable" compared to the other two Towns.

Figure 4-15: Overall reliability – residential customers

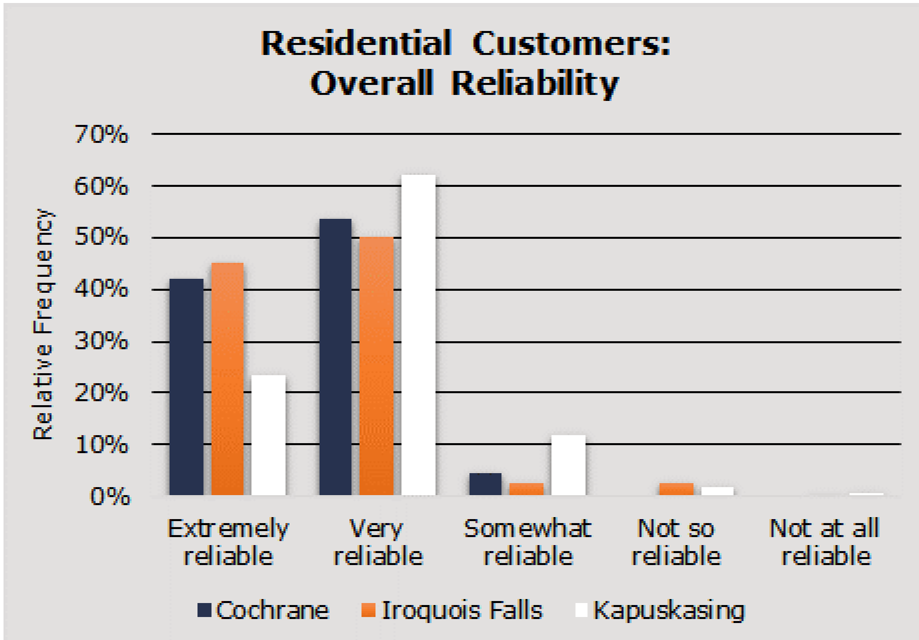
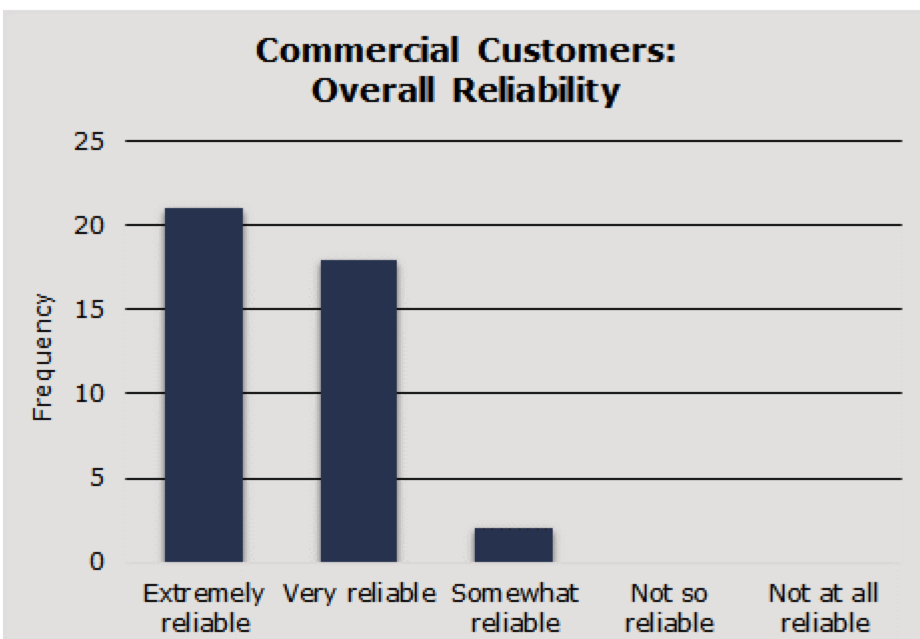
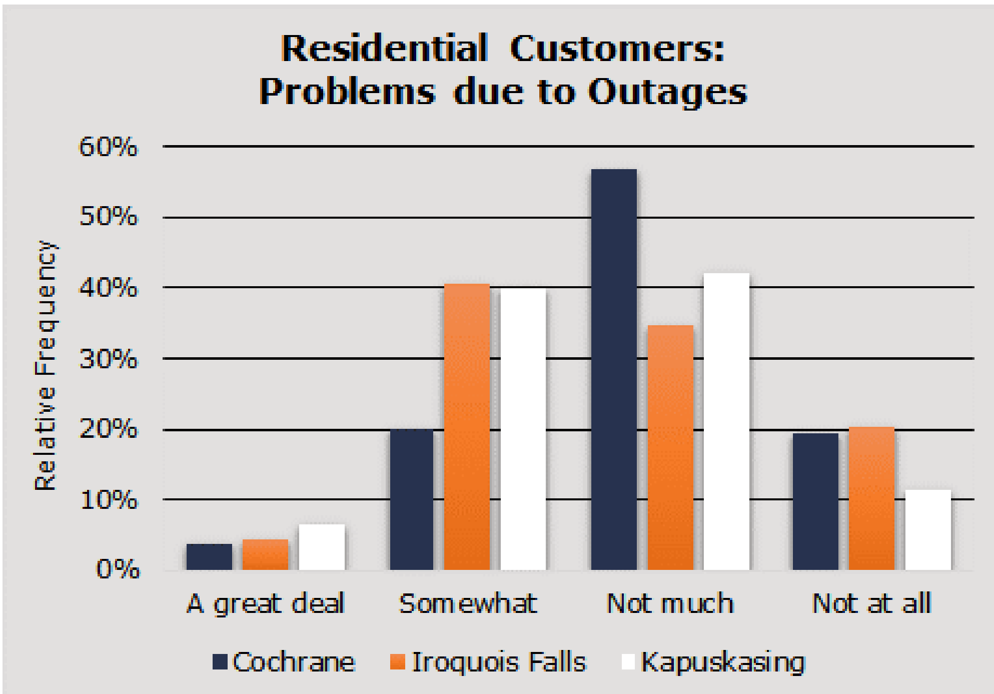


Figure 4-16: Overall reliability – commercial customers



Residential customers were asked to think back to the last time they experienced a power outage and comment on how much of a problem it created for their household. About three quarters of the residents of Cochrane rated their last power outage as “not much” of a problem or “not at all” problem, while for Iroquois Falls and Kapuskasing the proportion was closer to half. This is likely indicative of lengthier or more frequent outages in these areas.

Figure 4-17: Problems due to outages – residential customers



4.2.4.3 *Cost of Electricity*

Residential and commercial customers were asked if they would be willing to pay 3% more on their total bill next year if it would mean maintained reliability and lower long term delivery costs. As depicted in Figure 4-18 and Figure 4-19, the majority of commercial customers are unwilling to pay more for reliability and long term cost savings and residential customers are leaning more towards "no" than "yes", with a fair amount "unsure" or "indifferent".

Figure 4-18: Willingness to pay for reliability/long term cost savings – residential customers

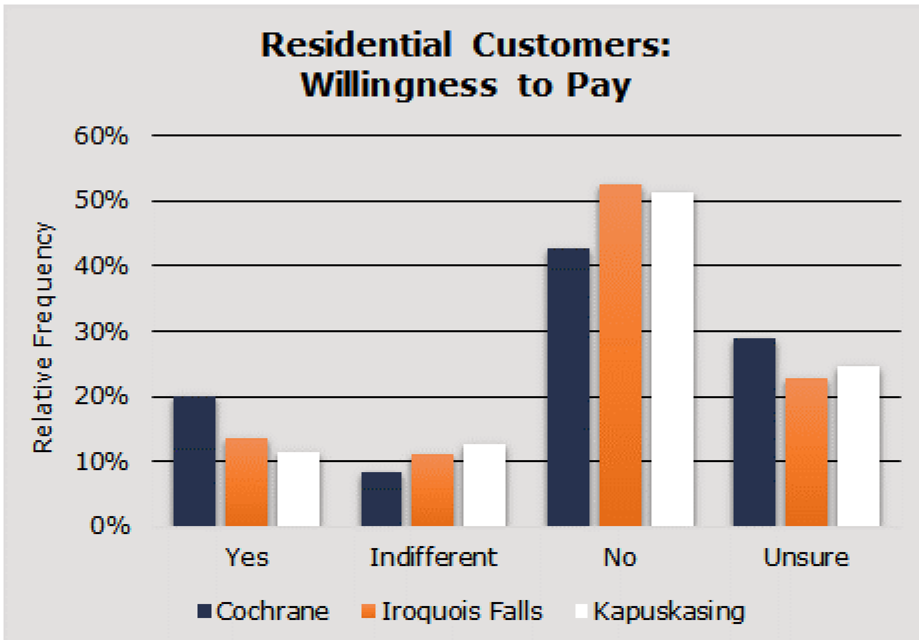
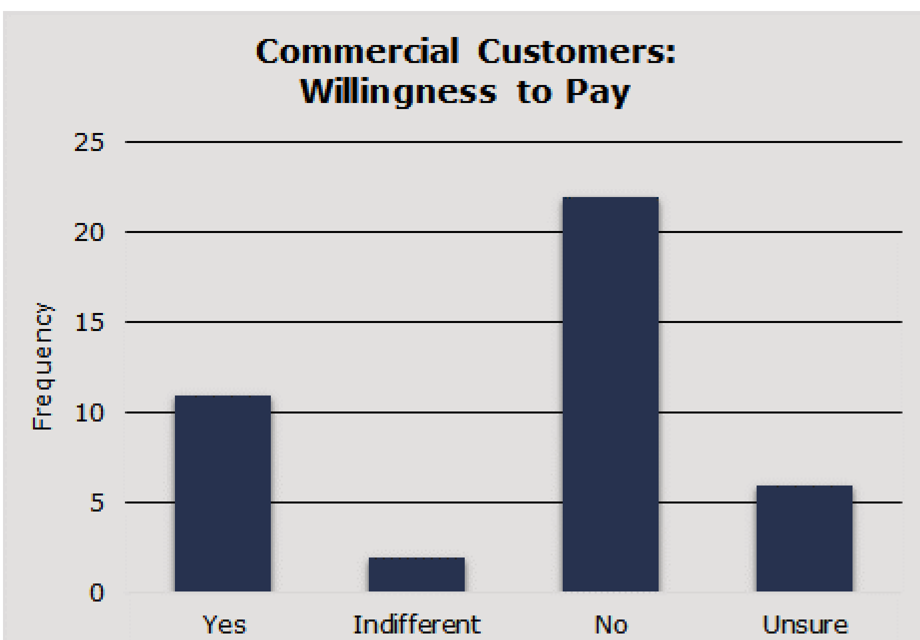


Figure 4-19: Willingness to pay for reliability/long term cost savings – commercial customers



Residential customers were asked to what extent, if any, is the cost of electricity a strain on their household budget. As shown in Figure 4-20, between 20% and 30% of respondents commented that the cost of electricity put "a great deal" of strain on their household budget, while the greatest proportion commented that it "somewhat" strained their household budget. Similarly, commercial customers were asked how significant is the cost of electricity in the budget of their business or organization. Almost all of the respondents indicated the cost of electricity is "very significant" or "somewhat significant".

Figure 4-20: Electricity cost strain on household budget – residential customers

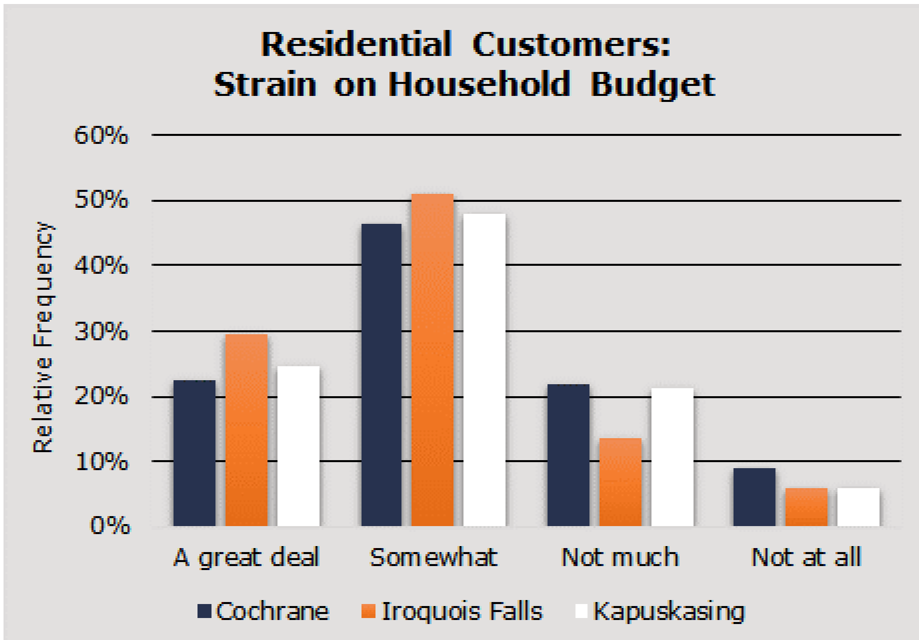
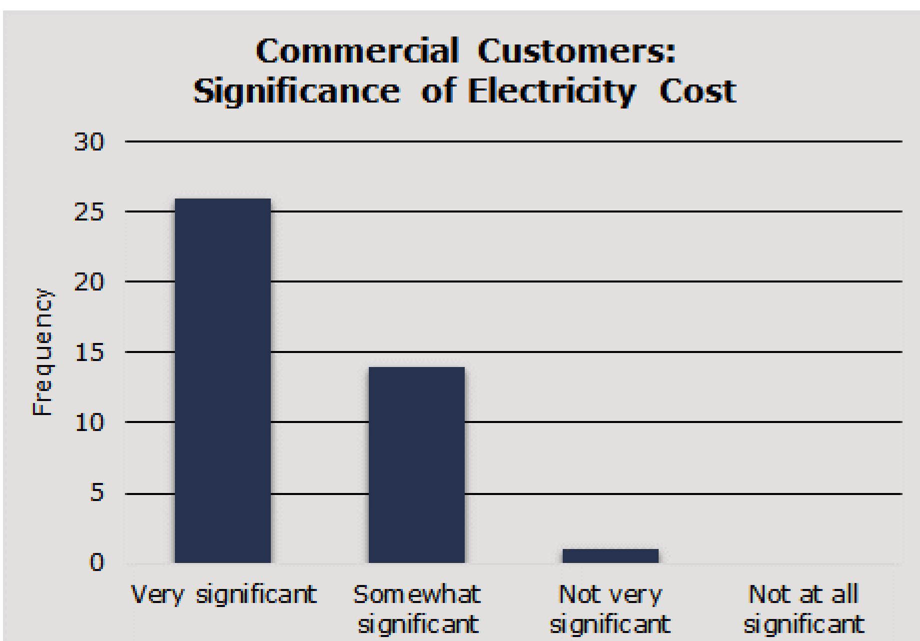


Figure 4-21: Significance of electricity cost – commercial customers



4.2.4.4 *Information Provided by NOW Inc.*

Residential customers were asked how satisfied they are with NOW Inc. in getting the, the information they need. As shown in Figure 4-22, about 80% of NOW Inc.'s customers responded that they are either "very satisfied" or "somewhat satisfied". Most of the remainder constitutes "neither satisfied nor dissatisfied". Residential customers were asked whether NOW Inc. provides them with useful information, tools, tips, and assistance to help them manage their electricity consumption and bills. As shown in Figure 4-23, about three-quarter of NOW Inc.'s customer responded positively.

Figure 4-22: Satisfaction with information provided by NOW Inc. – residential customers

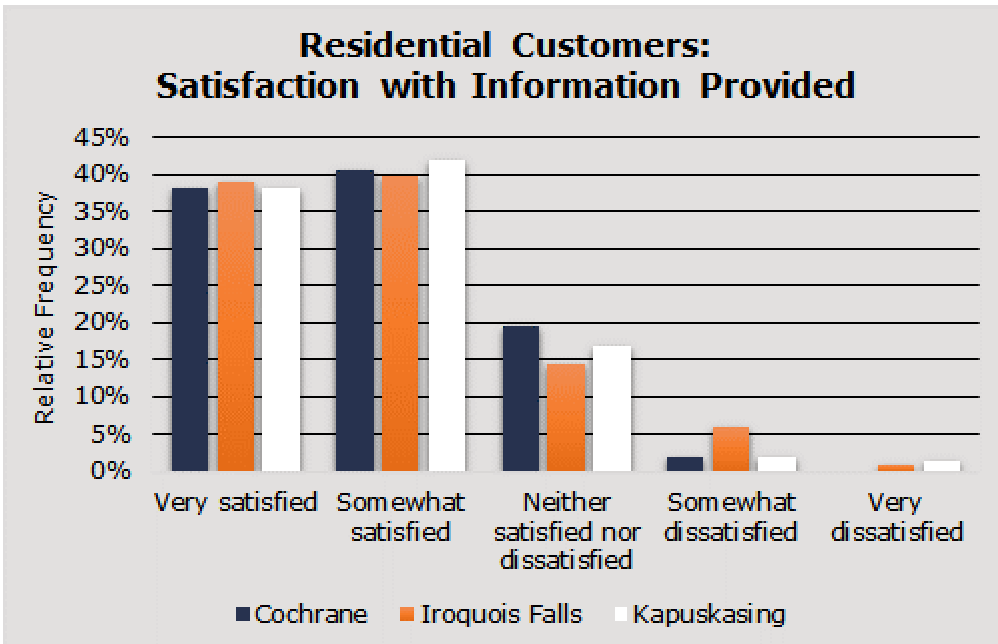
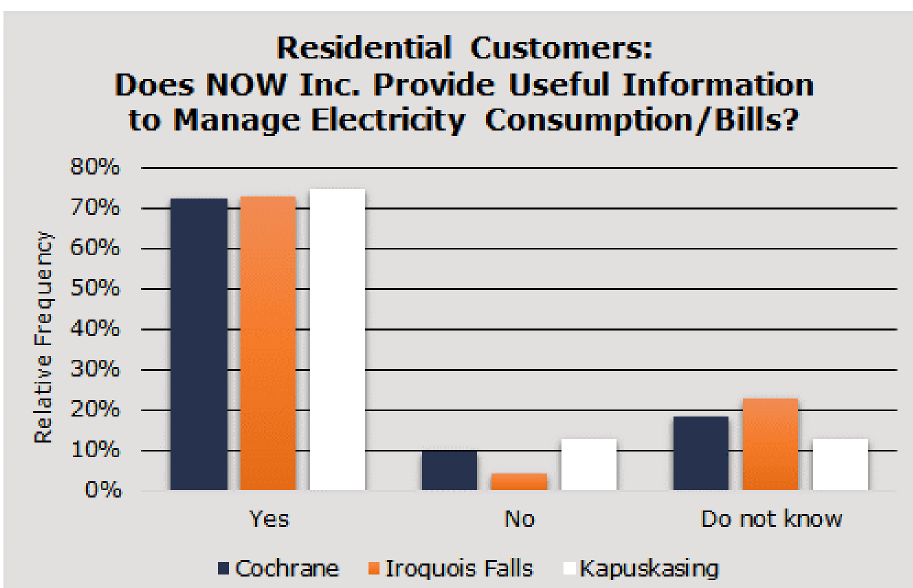


Figure 4-23: Useful tools/tips/information provided by NOW Inc. – residential customers



Customers were also asked an open-ended question on how NOW Inc. could improve the methods by which it provides information to them. Customers responded by asking for more data on their electricity consumption, more information and better communication on power outages, paperless billing, and other services such as time of use reminders. For data on electricity consumption, NOW Inc.'s customers are particularly interested in tips to save electricity. For power outage communication, customers would like immediate notification and specifically mentioned telephone, e-mail, and social media, as well as radio and newspaper ads for scheduled outages. For paperless billing, customers also mentioned the difficulty of understanding their bill, which is a common issue across the province.

4.2.4.5 *Support for Renewable Energy*

Finally, customers where asked whether they support renewable energy. As shown in Figure 4-24 and Figure 4-25, almost all of NOW Inc.'s customers support renewable energy. However, over half of NOW Inc.'s residential customers are only supportive of renewable energy if it doesn't increase their electricity bill. While an overwhelming proportion of commercial customers "absolutely" support renewable energy or support it even if it caused a 5% or 10% increase to their electricity bills.

Figure 4-24: Support for renewable energy – residential customers

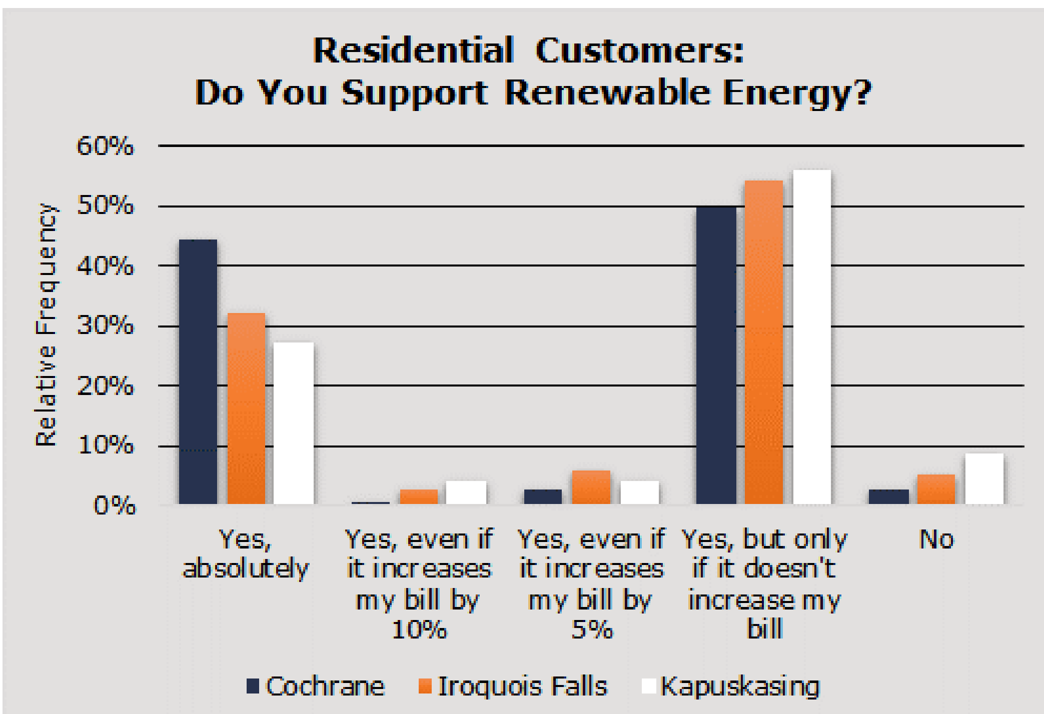
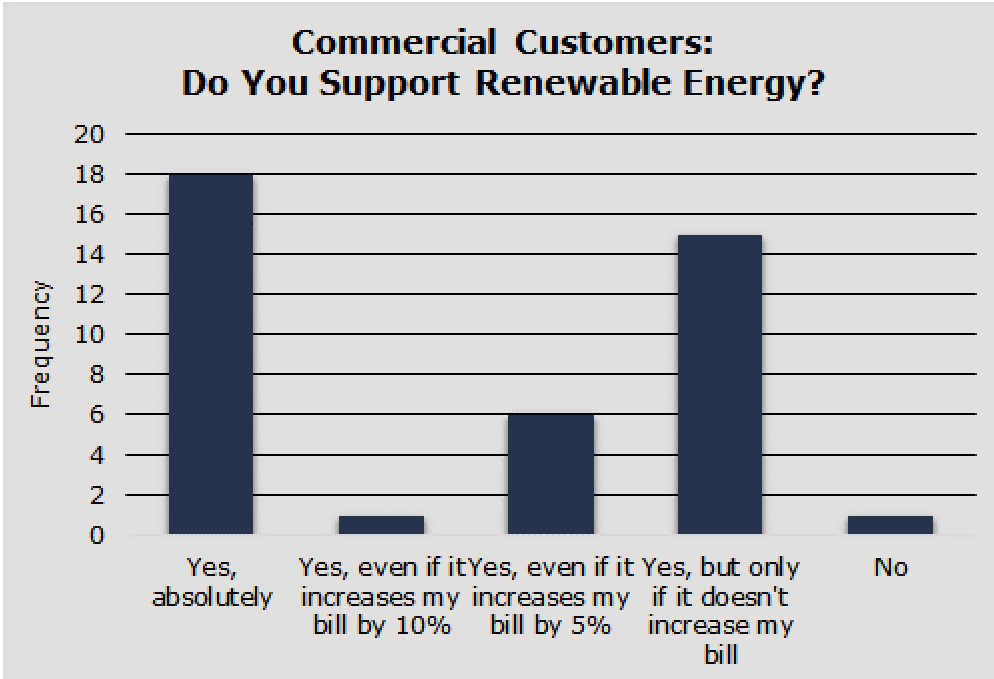


Figure 4-25: Support for renewable energy – commercial customers



4.2.5 REG Investment Prioritization (5.4.2e)

Due to upstream capacity constraints at the HONI-owned Timmins TS, NOW Inc. is not forecasting any new REG connections over the next five years. Therefore, NOW Inc. is not proposing any investments to accommodate new REG.

4.3 System Capability Assessment for Renewable Energy Generation (5.4.3)

4.3.1 Applications for Renewable Generators over 10 kW (5.4.3a)

There are no applications from renewable generators over 10 kW in NOW Inc.'s service area. NOW Inc. had previously received four applications for CHP projects from the Town of Kapuskasing: North Centennial Manor, The Sports Palace, and the hospital in conjunction with a new senior residence. Due to constraint on HONI's upstream system, only one project was permitted.

4.3.2 Forecast REG Connections (5.4.3b)

Due to upstream capacity constraints at the HONI-owned Timmins TS, NOW Inc. is not forecasting any new REG connections over the next five years.

4.3.3 Capacity to Connect REG (5.4.3c)

There is currently no capability to connect new REG projects in NOW Inc.'s service territory due to upstream capacity constraints at the HONI-owned Timmins TS.

4.3.4 REG Connection Constraints (5.4.3d)

There are no constraints on NOW Inc.'s distribution system that would prevent the connection of new REG installations; however, there is currently no capability to connect new REG projects in NOW Inc.'s service territory due to upstream capacity constraints at the HONI-owned Timmins TS.

4.3.5 Embedded Distributor Constraints (5.4.3e)

NOW Inc. does not have an embedded distributor.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-6 presents the historical and forecast capital expenditures and system O&M. The historical period includes the audited actual expenditures for 2012 to 2015 and the forecast expenditures for 2016 (includes 0 months of actual data). Since this is NOW Inc.'s first DSP, there is neither a historical plan nor variances to report.

Table 4-6: Historical and forecast capital expenditures and system O&M

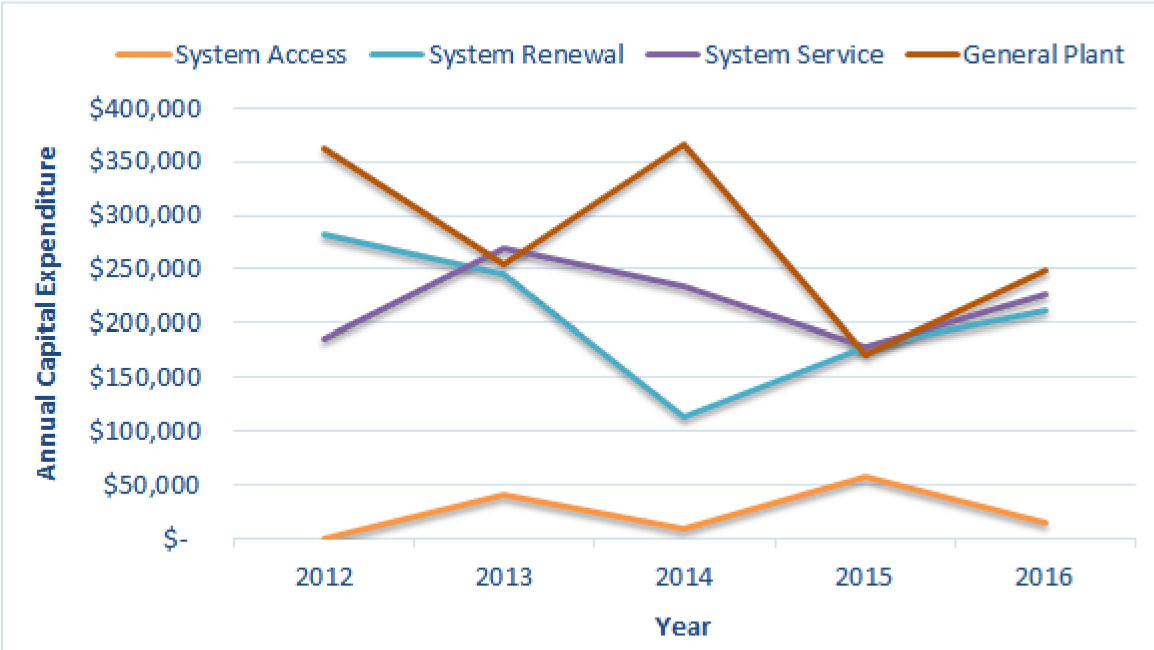
Category	Historical															Forecast				
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual*	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	-	0	-	-	40	-	-	8	-	-	58	-	-	15	-	15	15	20	20	20
System Renewal	-	283	-	-	245	-	-	112	-	-	179	-	-	213	-	355	395	370	350	380
System Service	-	185	-	-	269	-	-	235	-	-	178	-	-	227	-	315	355	370	385	400
General Plant	-	363	-	-	254	-	-	366	-	-	171	-	-	248	-	143	33	33	33	33
Total	**-**	**830**	**-**	**-**	**809**	**-**	**-**	**721**	**-**	**-**	**586**	**-**	**-**	**703**	**-**	**828**	**798**	**793**	**788**	**833**
System O&M	-	1,102	-	-	1,232	-	-	1,237	-	-	1,128	-	-	1,209	-	1,513	1,586	1,626	1,668	1,711

**0 months of actual data included in 2016.*

4.4.1 Trends in Capital Expenditures over the Historical Period

Figure 4-26 depicts the overall trends in capital expenditures over the historical period.

Figure 4-26: Trend in capital expenditures over the historical period



From 2012 to 2013, system access investments increased by $40,344 since there were no capital expenditures in this category in 2012 and metering investments were made in 2013 instead. There were less pole replacements in Kapuskasing between 2012 and 2013, which decreased system renewal spending by $37,517, since more poles were changed as part of the voltage conversion project in Kapuskasing, which increased system service spending by $84,335. Finally, general plant spending decreased by $108,271 due to less spending on building upgrades.

From 2013 to 2014, system access investments decreased by $32,134 due to less spending on metering. System renewal spending decreased by $132,634 due to less spending on pole replacement programs and system renewal projects, including laneway construction for the Cochrane 4.16/2.4 kV overhead rebuild that was completed in 2013. System service spending decreased by $34,722 due to less spending on the voltage conversion projects. Finally, general plant spending increased by $111,570 due to spending on computer software to upgrade the GIS and increased spending on transportation equipment.

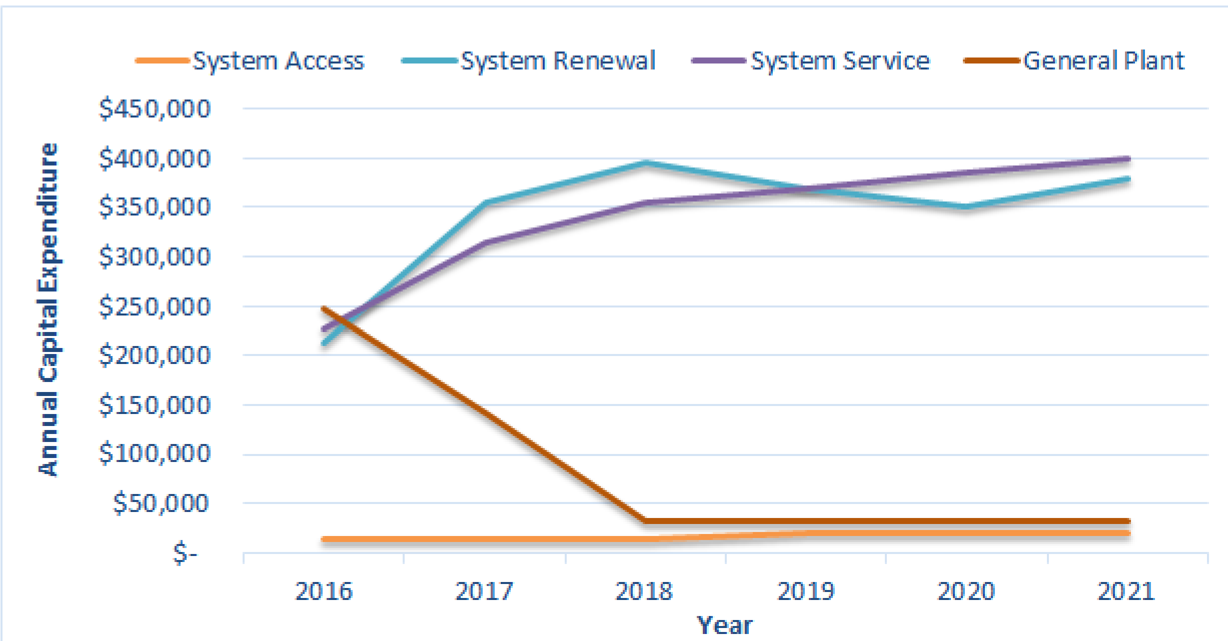
From 2014 to 2015, system access investments increased by $49,647 to accommodate customer service requests. System renewal investments increased by $66,717 due to increased spending on pole projects, distribution transformers, and substation equipment in all three Towns. With more investment into system renewal, system service spending was $56,635 less in 2015, with less spending on voltage conversions. Finally, general plant spending was $195,225 less, since no investments into transportation equipment were required in 2015.

From 2015 to 2016, system access spending is forecast to be $42,857 less, since no customer service requests are expected in 2016. System renewal spending is forecast to increase by $33,345 due to additional pole replacements planned in Kapuskasing and Iroquois Falls. System service expenditures are also forecast to increase by $48,920 due to increased investment into voltage conversions in Kapuskasing and Iroquois Falls. Finally, general plant expenditures are forecast to be $77,736 greater in 2016 due to additional spending on computer hardware and tools and equipment, as well as investments required to purchase new transportation equipment.

4.4.2 Trends in Capital Expenditures over the Forecast Period

Figure 4-27 depicts the overall trends in capital expenditures over the forecast period, including 2016 for reference. From 2016 to 2021, capital investment in the system access category is forecast to be relatively constant and only includes metering.

Figure 4-27: Trends in capital expenditures over the forecast period (including 2016)



From 2016 to 2017, system renewal spending is forecast to increase by $142,500 due to additional spending on pole replacements in Iroquois Falls, investment into the substation feeder at Cochrane DS, and the 4.16/2.4 kV overhead rebuild project in Cochrane. System service spending is forecast to increase by $77,000 due to increased investment in voltage conversions in Kapuskasing and Iroquois Falls. General plant expenditures are forecast to decrease by $105,914, with less spending on computer hardware and software, and no planned investments in transportation equipment.

From 2017 to 2018, system renewal spending is forecast to increase by $40,000 due to additional spending on the Cochrane 4.16/2.4 kV rebuild (but less spending on the pole replacement program in Cochrane), as well as capital upgrades to the DS in Cochrane. System service expenditures are also forecast to increase by $40,000 due to increased spending on voltage conversions in Kapuskasing and

Iroquois Falls. General plant spending is forecast to decrease by $110,000, since the major software additions will be completed by 2017.

From 2018 to 2019, system renewal expenditures are forecast to decrease by $25,000 due to less spending on the Cochrane 4.16/2.4 kV rebuild. System service spending is, therefore, forecast to be $25,000 higher with increased investment into the conversions of Iroquois Falls and Kapuskasing.

From 2018 to 2021, general plant capital investments are forecast to be constant, with steady investments into tools and equipment, computer hardware, and computer software.

From 2019 to 2020, system renewal spending is forecast to decrease by $20,000 due to less investment in substations, while system service spending is forecast to increase by $15,000 due to more investment into the conversions of Iroquois Falls and Kapuskasing.

Finally, from 2020 to 2021, system renewal spending is forecast to increase by $30,000 due to additional investments into substations, while system service spending is forecast to increase by $15,000 due to more investment into the conversions of Iroquois Falls and Kapuskasing.

4.5 Justifying Capital Expenditures (5.4.5)

4.5.1 Overall Plan (5.4.5.1)

Comparative expenditures over the historical period for each of the four investment categories, as well as the forecasted impact on system O&M costs are presented in Table 4-6 (Section 4.4 above). System access investments are driven by mandated service obligations to provide metering to customers and have historically also been driven by customer service requests. System renewal investments are driven by assets at the end of their service life due to failure or failure risk, especially poles, transformers, and substation equipment. System service projects include two voltage conversion: the 2.4 kV delta conversion in Iroquois Falls is primarily driven by safety and the 4.16/2.4 kV conversion in Kapuskasing is primarily driven by cost reduction. General plant investments are driven by improving operational efficiency and supporting NOW Inc.'s day-to-day operations, and have historically also been driven by non-system physical plant (i.e. buildings and vehicles) at the end of its service life.

NOW Inc.'s system capability assessment to accommodate REG can be found in Section 4.3. There is currently no capability to connect new REG projects in NOW Inc.'s service territory due to upstream capacity constraints at the HONI-owned Timmins TS.

4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For NOW Inc., the materiality threshold is $50,000. Table 4-7 lists the material projects/programs planned over the forecast period, including the investment category and primary driver of each project/program. Additional information for each of these projects/programs is provided below, with a complete project narrative included as Appendix A: Project Narratives for Material Investments.

Table 4-7: List of material projects/programs over the forecast period

Category	Designation*	Name	Primary Driver	Type	Rank
System renewal	SR1	Pole Replacements – Cochrane	Assets at end of service life due to failure or failure risk	Program	8
System renewal	SR2	Pole Replacements – Kapuskasing	Assets at end of service life due to failure or failure risk	Program	7
System renewal	SR3	Pole Replacements – Iroquois Falls	Assets at end of service life due to failure or failure risk	Program	6
System renewal	SR4	Cochrane 4.16/2.4 kV Rebuild (2017-2021)	Assets at end of service life due to failure risk	Project	4
System renewal	SR5	Cochrane Substation Feeder (2017)	Assets at end of service life due to failure risk	Project	5
System renewal	SR6	Cochrane Substation Transformer (2018-2019)	Assets at end of service life due to failure risk	Project	10
System renewal	SR7	Detroyes DS Primary Side Replacement (2020)	Assets at end of service life due to failure risk	Project	9
System renewal	SR8	Mill Gate Substation Decommissioning (2021)	Assets at the end of service life due to obsolescence	Project	3
System service	SS1	Kapuskasing 4.16/2.4 kV Conversion (2017-2021)	Cost reduction	Project	2
System service	SS2	Iroquois Falls 2.4 kV Delta Conversion (2017-2021)	Safety	Project	1
General plant	GP1	Computer Software (2017)	Operational efficiency	Project	11

**See Appendix A, Project Narratives for Material Investments*

Pole Replacement Programs

Pole inspections identify the worst poles for replacement in each of the three Towns (Cochrane, Iroquois Falls, and Kapuskasing), which are addressed through the pole replacement program. If a flagged pole is supporting an overhead transformer, then the transformer is also replaced; therefore, the number of pole replacements each year can vary for the same budgeted cost. The pole replacement programs over the forecast period for the three Towns are summarized in Table 4-8. The cost per pole replacement is expected to be higher in 2017, since a number of high risk corner poles have been identified for replacement, which require an outage to replace.

Table 4-8: Pole replacement program scopes

	Cochrane		Iroquois Falls		Kapuskasing	
Year	Forecast Cost	Number of Pole Replacements	Forecast Cost	Number of Pole Replacements	Forecast Cost	Number of Pole Replacements
2017	$105,000	10-14	$55,000	8-10	$55,000	8-10
2018	$55,000	8-10	$55,000	8-10	$55,000	8-10
2019	$55,000	8-10	$55,000	8-10	$55,000	8-10
2020	$55,000	8-10	$55,000	8-10	$55,000	8-10
2021	$55,000	8-10	$55,000	8-10	$55,000	8-10

Cochrane 4.16/2.4 kV Rebuild

An overhead rebuild project planned each year in the Town of Cochrane replaces poles, pole-mounted transformers, and overhead conductors. The replacement cost per pole is higher for an overhead rebuild than for a pole replacement program, since the conductors are replaced as part of the overhead rebuild. Table 4-9 summarizes the budgeted overhead rebuild cost in the Town of Cochrane and the corresponding asset replacements for each year of the forecast period.

Table 4-9: Cochrane overhead rebuild annual scopes

Year	Three-Phase Line	Poles	Transformers	Forecast Cost
2017	700 m	10	5 single-phase pole-mounted 1 three-phase pole-mounted bank	$90,000
2018	900 m	18	6 single-phase pole-mounted	$180,000
2019	900 m	18	6 single-phase pole-mounted	$130,000
2020	900 m	18	6 single-phase pole-mounted	$135,000
2021	900 m	18	6 single-phase pole-mounted	$140,000

Substation Renewal Projects

A number of system renewal projects are planned in NOW Inc.'s substations over the forecast period, as summarized in Table 4-10. In 2017 a project is planned at Cochrane DS to replace the glass insulators and a frosted structure. In 2018 and 2019 a project is planned to refurbish T2 bank transformers at Cochrane DS. In 2020 and 2021 a project is planned to refurbish Mill Gate and Detroyes substation at Iroquois Falls Abitibi DS.

Table 4-10: Substation system renewal projects over the forecast period

Year	Substation	Project Scope	Forecast Cost
2017	Cochrane DS	• Replace glass insulators with silicone insulators • Replace a frosted steel structure	$50,000
2018	Cochrane DS	• Replace substation transformer bank	$50,000
2019	Cochrane DS	• Replace substation transformer bank	$75,000
2020	Detroyes DS	• Replace primary switchgear and cables	$50,000
2021	Mill Gate DS	• Decommission substation	$75,000

Voltage Conversions

A voltage conversion of the 4.16/2.4 kV system in Kapuskasing to 25/14.4 kV is planned each year, as summarized in Table 4-11. A voltage conversion of the 2.4 kV delta system in Iroquois Falls to 12.5/7.2 kV wye is planned each year, as summarized in Table 4-12. Voltage conversions replace poles, pole-mounted transformers, and overhead conductors with higher voltage equipment. Similar to an overhead rebuild, the replacement cost per pole is higher for a voltage conversion than for a pole replacement program, since the conductors are replaced as part of the voltage conversion. The voltage conversion of the delta system is planned from the outside in; the innermost areas have the oldest poles and higher span lengths due to the wider lots.

Table 4-11: Kapuskasing 4.16/2.4 kV conversion to 25/14.4 kV annual scopes

Year	Three-Phase Line	Poles	Transformers	Forecast Cost
2017	1000 m	20	7 single-phase pole-mounted	$175,000
2018	1100 m	16	6 single-phase pole-mounted	$200,000
2019	1100 m	16	6 single-phase pole-mounted	$205,000
2020	1100 m	16	6 single-phase pole-mounted	$215,000
2021	1100 m	16	6 single-phase pole-mounted	$220,000

Table 4-12: Iroquois Falls 2.4 kV delta conversion to 12.5/7.2 kV wye annual scopes

Year	Three-Phase Line	Poles	Transformers	Forecast Cost
2017	1000 m	12	6 single-phase pole-mounted 1 three-phase pad-mounted	$140,000
2018	1000 m	20	5 single-phase pole-mounted 1 three-phase pole-mounted bank 1 three-phase pad-mounted	$155,000
2019	900 m	15	5 single-phase pole-mounted 1 three-phase pad-mounted	$165,000
2020	900 m	15	5 single-phase pole-mounted 1 three-phase pad-mounted	$170,000
2021	1000 m	16	5 single-phase pole-mounted 1 three-phase pad-mounted	$180,000

Computer Software

Regular software investments are made into operating system (“**OS**”) software over the forecast period, as well as upgrades to NOW Inc.’s OMS and CIS.

Table 4-13: Computer software investments over the forecast period

Year	2017	2018	2019	2020	2021
OS Software		$5,000	$5,000	$5,000	$5,000
OMS Upgrades	$40,000				
CIS Upgrades	$75,000				
Total	**$115,000**	**$5,000**	**$5,000**	**$5,000**	**$5,000**

Appendix A: Project Narratives for Material Investments

Material Investments – Index of Projects/Programs

SR1 Project/Program Description

This is an ongoing capital program to replace individual poles that are identified as having failed or being a high risk of failure during NOW Inc.'s inspection process. This particular program covers poles in the Town of Cochrane. In the case where a pole requiring replacement is supporting an overhead transformer, then the transformer is also replaced. Insulators and hardware attachments are replaced, but conductors are not replaced as part of this program.

Poles that were installed in the 1950s are failing at a higher rate. This replacement program focuses on these high risk poles. In 2017 a number of corner poles (which are under the most strain) are planned for replacement. Corner poles are more expensive to replace since an outage is required.

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; NOW Inc. targets these for replacement.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital costs for this program are shown in the table below. Spending over the historical period fluctuates with the number of pole failures each year. 2013 had an usually high number of failures due to carpenter ant infestation that did not persist into 2014. The pole replacement budget is higher in 2017, since NOW Inc. is targeting a number of high risk corner poles, which are more expensive to replace since an outage is required, for replacement in 2017.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
80,318	105,504	49,270	58,096	55,000	105,000	55,000	55,000	55,000	55,000

Start Date
N/A

In-service Date
N/A

Customer Attachments
Poles are identified for replacement during inspections, therefore the customer attachments cannot be known at this time.

Load
If the pole is supporting an overhead transformer, then the transformer is also replaced.

Risks/Mitigation
Pole replacements are budgeted based on the need to replace poles at the end of their service life in each Town. Crew scheduling may become an issue if there is an unusually high amount of operation and maintenance work required in Cochrane. To mitigate this, NOW Inc. has the ability to schedule crews to work in different Towns as required, approve overtime work, or bring in contract resources as necessary. However, crews are often isolated from each other due to road closures between Towns.

The budgeted amounts include provision for the replacement of high risk corner poles in 2017 and other high risk poles in the subsequent years. The number of poles replaced using the budgeted amounts depends on whether any of the identified poles are supporting an overhead transformer, since the transformer will be replaced at the same time as the pole under the same budget. The number of pole replacements may also fluctuate if additional poles require immediate replacement due to safety concerns or if there is a high number of pole failures in a given year. NOW Inc. has tried to mitigate this risk in its project planning process by identifying high risk corner poles (which are under the most physical strain) for replacement in 2017.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is poles as the end of their service life due to failure or failure risk, as identified during the pole inspection process.

The secondary drivers of this project include safety, as poles at risk of failing also pose a safety risk. Reliability is another driver, since the replacement of deteriorated poles decreases the probability of pole failure during severe weather, which would cause an outage. Finally, avoiding future costs is also a driver, as most proactive replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can be overtime hours.

b) Priority:
This project replaces aging poles at the end of its service life and is scored in safety, reliability, and efficiency. Poles replaced as part of a pole replacement program are the very worst poles identified during inspections and are assumed to be the most likely to fail, but age demographics indicate that the poles in Cochrane are in better condition than the other two Towns. The program is ranked eighth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	8	0	0	0	8	4	
Weight	10	8	7	6	5	4	
Weighted Score	80	0	0	0	40	16	136

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- spot pole replacements; and
- overhead rebuild.

The first project alternative is a "do nothing" approach. Poles which are identified for replacement during NOW Inc.'s inspection process are at the end of their service life either having already failed or posing a failure risk. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

The second alternative, the spot pole replacements, is the current planned project. The benefits in safety, reliability, and cost reduction are achieved as described in part (a) above, while the costs are less for a single pole replacement rather than a complete overhead rebuild. This is the optimal approach.

The third approach is to plan an overhead rebuild project to replace the poles identified. NOW Inc. has planned a separate overhead rebuild project on parts of the 4.16/2.4 kV system in the Town of Cochrane, which replaces the poles, pole-mounted transformers, and overhead conductors over a geographic area. This separate program identifies poles for replacement outside of the overhead rebuild, whereby planning an overhead rebuild would not be timely enough to replace a single pole identified during inspection and adjacent poles are not necessarily in a condition that would warrant replacement. A complete overhead rebuild for each pole replacement would also require significant capital funding, making this option not feasible.

2. Safety
The replacement of poles which pose a failure risk eliminates a safety hazard to the public and employees.

3. Cyber-security, Privacy
N/A

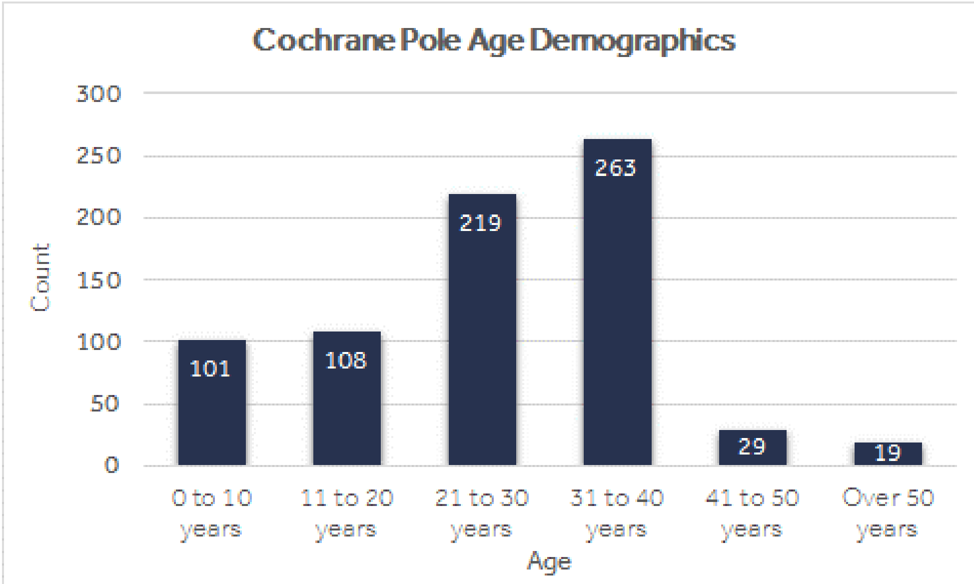
4. Co-ordination, Interoperability
Any third party attachments will be re-attached to the new pole. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
N/A

C. Category-Specific Requirements

Consequence of Failure
Based on a TUL of 45 years, some poles in Cochrane have exceeded TUL, while many more are approaching TUL, as shown below in the pole age demographics for the Town of Cochrane. Inspections identify individual poles for replacement, which are those in the worst condition.



The failure of a pole always poses a safety risk, especially since NOW Inc.'s entire service area is classified as urban rather than rural. The reliability consequences depend upon the location of the pole, among other factors. The failure of a pole close to the substation would affect the greatest number of customers, while the failure of a pole carrying only secondary conductors or a single phase lateral affects less customers.

The failure of a pole also increases system O&M costs. Unplanned pole change-outs usually take longer to replace, as the downed pole must first be located and the work may need to be done at night. A failed poled may also break the conductors, which are not usually replaced as part of the pole replacement program.

Project/Program Timing Factors
Pole replacement programs do not generally have timing objectives, as individual work orders for pole change-outs are scheduled and completed under the program funds. The number of poles replaced depends on the quantity of the poles with overhead transformers.

Impact to System O&M Costs
NOW Inc.'s pole inspection program identifies the worst poles for replacement in its pole replacement programs. If these poles are not replaced, they will likely fail, therefore without this program system O&M costs would increase.

Reliability/Safety Factors
One of the drivers of this program is safety; poles at risk of failure pose a safety risk to employees and the public. Another driver for this program is reliability; poles replaced as part of this program would likely fail and cause an outage without intervention.

Cost-benefit Analysis
The benefits of this project are the mitigation of safety risks, reduced outage probability, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR2 Project/Program Description

This is an ongoing capital program to replace individual poles that are identified during NOW Inc.'s inspection process. This particular program covers poles in the Town of Kapuskasing. In the case where a pole requiring replacement is supporting an overhead transformer, then the transformer is also replaced. Insulators and hardware attachments are replaced, but conductors are not replaced as part of this program.

Poles that were installed in the 1950s are failing at a higher rate. This replacement program focuses on these high risk poles. Pole replacements in the Town of Kapuskasing are also made as part of the voltage conversion project (see SS1A to SS1E).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital costs for this program are shown in the table below. Historical spending on pole replacements fluctuates due to poles being replaced under the voltage conversion projects instead of this program. Historical spending was also less from 2013 to 2015 since pole replacements were carried out by a fibre-optic company seeking third party attachment (at no cost to NOW Inc.).

Historical Capital Costs ($ '000)					Future Capital Costs ($ '000)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
67,997	2,013	14,050	8,103	55,000	55,000	55,000	55,000	55,000	55,000

Start Date
N/A

In-service Date
N/A

Customer Attachments
Poles are identified for replacement during inspections, therefore the customer attachments cannot be known at this time.

Load
If the pole is supporting an overhead transformer, then the transformer is also replaced.

Risks/Mitigation
Pole replacements are budgeted based on the need to replace poles at the end of their service life in each Town. Crew scheduling may become an issue if there is an unusually high amount of operation and maintenance work required in Kapuskasing. To mitigate this, NOW Inc. has the ability to schedule crews to work in different Towns as required, approve overtime work, or bring in contract resources as necessary. However, crews are often isolated from each other due to road closures between Towns.

The budgeted amounts include provision for the replacement of eight to ten poles each year of the forecast period. The number of poles replaced each year depends on whether any of the identified poles are supporting an overhead transformer, since the transformer will be replaced at the same time as the pole under the same budget. The number of pole replacements may also fluctuate if additional poles require immediate replacement due to safety concerns.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is poles as the end of their service life due to failure or failure risk, as identified during the pole inspection process.

The secondary drivers of this project include safety, as poles at risk of failing also pose a safety risk. Reliability is another driver, since the replacement of deteriorated poles decreases the probability of pole failure during severe weather, which would cause an outage. Finally, avoiding future operations and maintenance costs is also a driver, as replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can be overtime hours.

b) Priority:

This project replaces aging poles at the end of its service life and is scored in safety, reliability, and efficiency. Poles replaced as part of a pole replacement program are the very worst poles identified during inspections and are assumed to be the most likely to fail, and age demographics indicate that the poles in Kapuskasing are in better condition than those in Iroquois Falls, but worse condition than those in Cochrane. The program is ranked seventh out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	9.6	0	0	0	9.6	4.8	
Weight	10	8	7	6	5	4	
Weighted Score	96	0	0	0	48	19.2	163.2

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- spot pole replacements; and
- overhead rebuild.

The first project alternative is a "do nothing" approach. Poles which are identified for replacement during NOW Inc.'s inspection process are at the end of their service life either having already failed or posing a failure risk. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

The second alternative, the spot pole replacements, is the current planned project. The benefits in safety, reliability, and cost reduction are achieved as described in part (a) above, while the costs are less for a single pole replacement rather than a complete overhead rebuild. This is the optimal approach.

The third approach is to plan an overhead rebuild project to replace the poles identified. NOW Inc. has planned a separate voltage conversion project in the Town of Kapuskasing, replacing the 4.16/2.4 kV system with a 25/14.4 kV system. Many of the poles replaced as a part of the voltage conversion project are at the end of their service life. This separate program identifies individual poles for replacement outside of the voltage conversion, whereby planning an overhead rebuild would not be timely enough to replace a single pole identified during inspection and adjacent poles are not necessarily in a condition that would warrant replacement. A complete overhead rebuild for each pole replacement would also require significant capital funding, making this option not feasible.

2. Safety
The replacement of poles which pose a failure risk eliminates a safety hazard to the public and employees.

3. Cyber-security, Privacy
N/A

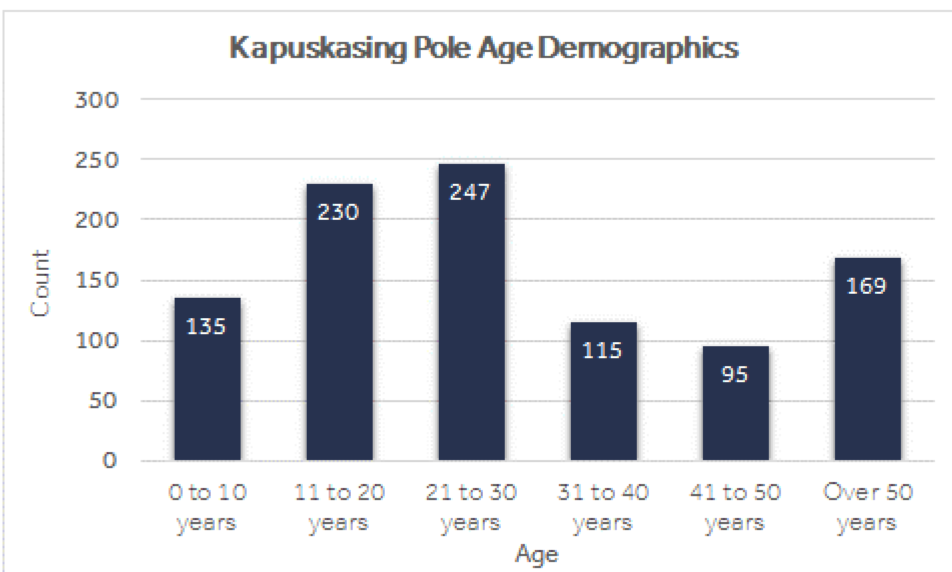
4. Co-ordination, Interoperability
Any third party attachments will be re-attached to the new pole. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
N/A

C. Category-Specific Requirements

Consequence of Failure
Based on a TUL of 45 years, many poles in Kapuskasing have exceeded TUL, while more are approaching TUL, as shown below in the pole age demographics for the Town of Kapuskasing. Inspections identify individual poles for replacement, which are those in the worst condition.



The failure of a pole always poses a safety risk, especially since NOW Inc.'s entire service area is classified as urban rather than rural. The reliability consequences depend upon the location of the pole, among other factors. The failure of a pole close to the substation would affect the greatest number of customers, while the failure of a pole carrying only secondary conductors or a single phase lateral affects less customers.

The failure of a pole also increases system O&M costs. Unplanned pole change-outs usually take longer to replace, as the downed pole must first be located and the work may need to be done at night. A failed pole may also break the conductors, which are not usually replaced as part of the pole replacement program.

Project/Program Timing Factors

Pole replacement programs do not generally have timing objectives, as individual work orders for pole change-outs are scheduled and completed under the program funds. The number of poles replaced using the specified budget each year depends on the quantity of the poles at the end of their service life which support overhead transformers, since the transformer is also replaced under the same scope. $55,000 allows for the replacement of eight to ten poles per year depending on the number of overhead transformers.

Impact to System O&M Costs

NOW Inc.'s pole inspection program identifies the worst poles for replacement in its pole replacement programs. If these poles are not replaced, they will likely fail, therefore without this program system O&M costs would increase.

Reliability/Safety Factors

One of the drivers of this program is safety; poles at risk of failure pose a safety risk to employees and the public. Another driver for this program is reliability; poles replaced as part of this program would likely fail and cause an outage without intervention.

Cost-benefit Analysis

The benefits of this project are the mitigation of safety risks, reduced outage probability, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR3 Project/Program Description

This is an ongoing capital program to replace individual poles that are identified during NOW Inc.'s inspection process. This particular program covers poles in the Town of Iroquois Falls. In the case where a pole requiring replacement is supporting an overhead transformer, then the transformer is also replaced. Insulators and hardware attachments are replaced, but conductors are not replaced as part of this program.

Poles that were installed in the 1950s are failing at a higher rate. This replacement program focuses on these high risk poles. Pole replacements in the Town of Iroquois Falls are also made as part of the voltage conversion project (see SS2A to SS2E).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital costs for this program are shown in the table below. Historical spending on this program was less from 2013 to 2015 since more poles were replaced as part of the voltage conversion project these years.

Historical Capital Costs ($ '000)					Future Capital Costs ($ '000)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
16,557	8,323	3,229	419	27,500	55,000	55,000	55,000	55,000	55,000

Start Date
N/A

In-service Date
N/A

Customer Attachments
Poles are identified for replacement during inspections, therefore the customer attachments cannot be known at this time.

Load
If the pole is supporting an overhead transformer, then the transformer is also replaced.

Risks/Mitigation
Pole replacements are budgeted based on the need to replace poles at the end of their service life in each Town. Crew scheduling may become an issue if there is an unusually high amount of operation and maintenance work required in Iroquois Falls. To mitigate this, NOW Inc. has the ability to schedule crews to work in different Towns as required, approve overtime work, or bring in contract resources as necessary. However, crews are often isolated from each other due to road closures between Towns. NOW Inc. is also searching for an additional apprentice who will work in Iroquois Falls.

The budgeted amounts include provision for the replacement of eight to ten poles each year of the forecast period. The number of poles replaced each year depends on whether any of the identified poles are supporting an overhead transformer, since the transformer will be replaced at the same time as the pole under the same budget. The number of pole replacements may also fluctuate if additional poles require immediate replacement due to safety concerns.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is poles at the end of their service life due to failure or failure risk, as identified during the pole inspection process.

The secondary drivers of this project include safety, as poles at risk of failing also pose a safety risk. Reliability is another driver, since the replacement of deteriorated poles decreases the probability of pole failure during severe weather, which would cause an outage. Finally, avoiding future operations and maintenance costs is also a driver, as replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can be overtime hours.

b) Priority:

This project replaces aging poles at the end of its service life and is scored in safety, reliability, and efficiency. Poles replaced as part of a pole replacement program are the very worst poles identified during inspections and are assumed to be the most likely to fail, and age demographics indicate that the poles in Iroquois Falls are in the worst condition of the three Towns. The program is ranked sixth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	11.2	0	0	0	11.2	5.6	
Weight	10	8	7	6	5	4	
Weighted Score	112	0	0	0	56	22.4	190.4

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- spot pole replacements; and
- overhead rebuild.

The first project alternative is a "do nothing" approach. Poles which are identified for replacement during NOW Inc.'s inspection process are at the end of their service life either having already failed or posing a failure risk. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

The second alternative, the spot pole replacements, is the current planned project. The benefits in safety, reliability, and cost reduction are achieved as described in part (a) above, while the costs are less for a single pole replacement rather than a complete overhead rebuild. This is the optimal approach.

The third approach is to plan an overhead rebuild project to replace the poles identified. NOW Inc. has planned a separate voltage conversion project in the Town of Iroquois Falls, replacing the 2.4 kV delta system with a 12.5/7.2 kV system. Many of the poles replaced as a part of the voltage conversion project are at the end of their service life. This separate program identifies individual poles for replacement outside of the voltage conversion, whereby planning an overhead rebuild would not be timely enough to replace a single pole identified during inspection and adjacent poles are not necessarily in a condition that would warrant replacement. A complete overhead rebuild for each pole replacement would also require significant capital funding, making this option not feasible.

2. Safety
The replacement of poles which pose a failure risk eliminates a safety hazard to the public and employees.

3. Cyber-security, Privacy
N/A

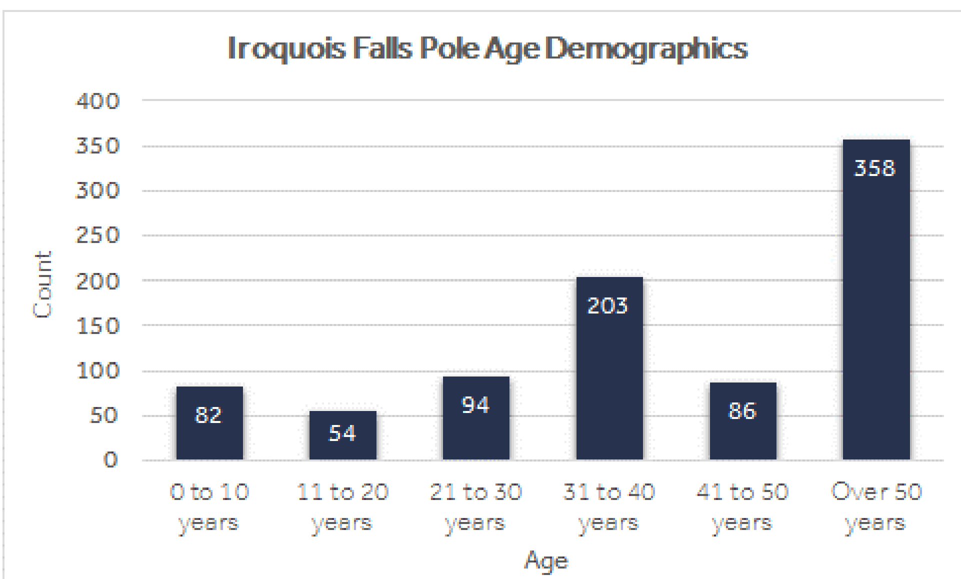
4. Co-ordination, Interoperability
Any third party attachments will be re-attached to the new pole. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
N/A

C. Category-Specific Requirements

Consequence of Failure
Based on a TUL of 45 years, a significant number of poles in Iroquois Falls have exceeded TUL, while more are approaching TUL, as shown below in the pole age demographics for the Town of Iroquois Falls. Inspections identify individual poles for replacement, which are those in the worst condition.



The failure of a pole always poses a safety risk, especially since NOW Inc.'s entire service area is classified as urban rather than rural. The reliability consequences depend upon the location of the pole, among other factors. The failure of a pole close to the substation would affect the greatest number of customers, while the failure of a pole carrying only secondary conductors or a single phase lateral affects less customers.

The failure of a pole also increases system O&M costs. Unplanned pole change-outs usually take longer to replace, as the downed pole must first be located and the work may need to be done at night. A failed poled may also break the conductors, which are not usually replaced as part of the pole replacement program.

Project/Program Timing Factors
Pole replacement programs do not generally have timing objectives, as individual work orders for pole change-outs are scheduled and completed under the program funds. The number of poles replaced depends on the quantity of the poles with overhead transformers.

Impact to System O&M Costs
NOW Inc.'s pole inspection program identifies the worst poles for replacement in its pole replacement programs. If these poles are not replaced, they will likely fail, therefore without this program system O&M costs would increase.

Reliability/Safety Factors
One of the drivers of this program is safety; poles at risk of failure pose a safety risk to employees and the public. Another driver for this program is reliability; poles replaced as part of this program would likely fail and cause an outage without intervention.

Cost-benefit Analysis
The benefits of this project are the mitigation of safety risks, reduced outage probability, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR4A Project/Program Description

This is an overhead rebuild project in the Town of Cochrane, will replace existing 35- and 40-foot wood poles with 45-foot wood poles and rebuild the 4.16/2.4 kV feeder. The existing poles are too short creating clearance issues and starting to show signs of deterioration. The replacement of #6 copper conductors with 1/0 ACSR will reduce the probability of conductors breaking during high winds or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages.

This project will replace approximately 700 m of three-phase line, which comprises 10 poles, 5 single-phase transformers, and 1 three-phase transformer bank. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

Poles that were installed in the 1950s are failing at a higher rate. These high risk poles are included for replacement in the Cochrane overhead rebuild projects. The overhead rebuild in 2018 will target the downtown area in Cochrane, where spans are short., and overtime work will be done on Sundays to avoid outages for local businesses (which close on Sundays).

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; these are replaced with over varieties during overhead rebuilds.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for overhead rebuilds in Cochrane are presented in the table below, with the relevant year (2017) in bold. Spending over the historical period fluctuates with the project scope each year: 2012 and 2015 was mainly secondary work (which is less expensive). The 2018 project has a higher budget than other years since the downtown area will be rebuilt, necessitating overtime work on Sundays to avoid outages for local businesses. Project costs also trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
13,839	129,232	38,660	7,334	50,000	**90,000**	180,000	130,000	135,000	140,000

Start Date
March 1, 2017

In-service Date
November 30, 2017

Customer Attachments
Yes

Load
- 5 single-phase transformers
- 1 three-phase transformer bank

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The increased pole heights improve clearance issues for third party attachments and the public.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Other drivers of this project include improving system efficiency, as increasing the conductor size and replacing 40-year-old transformers will reduce line losses. Finally, this project is expected to avoid future costs, as the existing poles and transformers have reached or exceeded TUL and are expected to require increased crew roll-outs without intervention.

b) Priority:
This project replaces aging substandard poles, small conductors, and overhead transformers that have reached their TUL. The small conductors will be replaced with a standard size and pole heights will be increased, which will improve clearances. Based on age demographics, the poles in Cochrane are in better condition than the other two Towns. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked fourth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	12	0	2	0	9	8	
Weight	10	8	7	6	5	4	
Weighted Score	120	0	14	0	45	32	211

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;

- rebuild the 4.16/2.4 kV overhead feeder;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- replace the 4.16/2.4 kV feeder with a 25 kV feeder.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The substandard pole heights will continue to create clearance issues that require work-arounds for third party attachments and to not meet public clearance standards. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and/or require increased crew roll-outs. Energy losses will be higher for the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, the 4.16/2.4 kV feeder rebuild, is the current planned project. This project mitigates the existing clearance and energy loss issues, as well as the potential reliability issues and O&M costs. This is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth project alternative is to replace the line section with a 25 kV feeder. This approach is not required since future demand can be met with the existing 4.16/2.4 kV system. The 25 kV line would reduce line losses compared to a 4.16/2.4 kV line, but would require a tap to the nearest 25 kV feeder and transformers rated for 25 kV; therefore, this option is more expensive.

2. Safety
Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Consequence of Failure
The poles in this area approaching their TUL, while the transformers have already reached TUL. Without replacement, the poles and transformers would continue to deteriorate, and their probability of failure would increase. This is expected to unfavourably affect NOW Inc.'s reliability and O&M costs. The line section in this project scope contains 5 single-phase transformer and 1 three-phase transformer, all of which would lose power in case of a failure along this section of the line.

In addition, the existing conductors are #6 copper and, if not replaced with larger conductors, may break during adverse weather or line maintenance. This is also expected to unfavourably affect NOW Inc.'s reliability and O&M costs.

Project/Program Timing Factors
Overhead rebuild projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and employing contract resources, where necessary.

Impact to System O&M Costs
The existing assets are of approximately 40 years old. There are consequence such as poles breaking, conductor breaking, and transformer failure if these assets are not replaced. These consequences increase system O&M costs of the utility along with other issues such as safety, reliability and efficiency. The replacement of poles, conductors and transformers with new assets reduces the future maintenance and trouble call costs for the assets in the project scope, but inspection costs remain unchanged.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

Cost-benefit Analysis
The benefits of this project are improved line clearances, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR4B Project/Program Description

This is an overhead rebuild project in the Town of Cochrane, will replace existing 35- and 40-foot wood poles with 45-foot wood poles and rebuild the 4.16/2.4 kV feeder. The existing poles are too short creating clearance issues and starting to show signs of deterioration. The replacement of #6 copper conductor with 1/0 ACSR will reduce the probability of conductors breaking during high winds or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages.

This project will replace approximately 900 m of three-phase line, which comprises 18 poles and 6 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

Poles that were installed in the 1950s are failing at a higher rate. These high risk poles are included for replacement in the Cochrane overhead rebuild projects. The overhead rebuild in 2018 will target the downtown area in Cochrane, where spans are short., and overtime work will be done on Sundays to avoid outages for local businesses (which close on Sundays).

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; these are replaced with over varieties during overhead rebuilds.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital expenditures for overhead rebuilds in Cochrane are presented in the table below, with the relevant year (2018) in bold. Spending over the historical period fluctuates with the project scope each year: 2012 and 2015 was mainly secondary work (which is less expensive). The 2018 project has a higher budget than other years since the downtown area will be rebuilt, necessitating overtime work on Sundays to avoid outages for local businesses. Project costs also trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
13,839	129,232	38,660	7,334	50,000	90,000	**180,000**	130,000	135,000	140,000

Start Date
March 1, 2018

In-service Date
November 30, 2018

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation
Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The increased pole heights improve clearance issues for third party attachments and the public.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Other drivers of this project include improving system efficiency, as increasing the conductor size and replacing 40-year-old transformers will reduce line losses. Finally, this project is expected to avoid future operations and maintenance costs, as the existing poles and transformers have reached or exceeded TUL and are expected to require increased crew roll-outs without intervention.

b) Priority:
This project replaces aging substandard poles, small conductors, and overhead transformers that have reached their TUL. The small conductors will be replaced with a standard size and pole heights will be increased, which will improve clearances. Based on age demographics, the poles in Cochrane are in better condition than the other two Towns. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked fourth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	12	0	2	0	9	8	
Weight	10	8	7	6	5	4	
Weighted Score	120	0	14	0	45	32	211

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- rebuild the 4.16/2.4 kV overhead feeder;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- replace the 4.16/2.4 kV feeder with a 25 kV feeder.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The substandard pole heights will continue to create clearance issues that require work-arounds for third party attachments and to not meet public clearance standards. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and/or require increased crew roll-outs. Energy losses will be higher for the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, the 4.16/2.4 kV feeder rebuild, is the current planned project. This project mitigates the existing clearance and energy loss issues, as well as the potential reliability issues and O&M costs. This is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth project alternative is to replace the line section with a 25 kV feeder. This approach is not required since future demand can be met with the existing 4.16/2.4 kV system. The 25 kV line would reduce line losses compared to a 4.16/2.4 kV line, but would require a tap to the nearest 25 kV feeder and transformers rated for 25 kV; therefore, this option is more expensive.

2. Safety

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Consequence of Failure
The poles in this area approaching their TUL, while the transformers have already reached TUL. Without replacement, the poles and transformers would continue to deteriorate, and their probability of failure would increase. This is expected to unfavourably affect NOW Inc.'s reliability and O&M costs. The line section in this project scope contains 6 single-phase transformer, all of which would lose power in case of a failure along this section of the line.

In addition, the existing conductors are #6 copper and, if not replaced with larger conductors, may break during adverse weather or line maintenance. This is also expected to unfavourably affect NOW Inc.'s reliability and O&M costs.

Project/Program Timing Factors
Overhead rebuild projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and employing contract resources, where necessary.

Impact to System O&M Costs
The existing assets are of approximately 40 years old. There are consequence such as poles breaking, conductor breaking, and transformer failure if these assets are not replaced. These consequences increase system O&M costs of the utility along with other issues such as safety, reliability and efficiency. The replacement of poles, conductors and transformers with new assets reduces the future maintenance and trouble call costs for the assets in the project scope, but inspection costs remain unchanged.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

Cost-benefit Analysis
The benefits of this project are improved line clearances, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR4C Project/Program Description

This is an overhead rebuild project in the Town of Cochrane, will replace existing 35- and 40-foot wood poles with 45-foot wood poles and rebuild the 4.16/2.4 kV feeder. The existing poles are too short creating clearance issues and starting to show signs of deterioration. The replacement of #6 copper conductor with 1/0 ACSR will reduce the probability of conductors breaking during high winds or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages.

This project will replace approximately 900 m of three-phase line, which comprises 18 poles and 6 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

Poles that were installed in the 1950s are failing at a higher rate. These high risk poles are included for replacement in the Cochrane overhead rebuild projects. The overhead rebuild in 2018 will target the downtown area in Cochrane, where spans are short., and overtime work will be done on Sundays to avoid outages for local businesses (which close on Sundays).

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; these are replaced with over varieties during overhead rebuilds.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for overhead rebuilds in Cochrane are presented in the table below, with the relevant year (2019) in bold. Spending over the historical period fluctuates with the project scope each year: 2012 and 2015 was mainly secondary work (which is less expensive). The 2018 project has a higher budget than other years since the downtown area will be rebuilt, necessitating overtime work on Sundays to avoid outages for local businesses. Project costs also trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
13,839	129,232	38,660	7,334	50,000	90,000	180,000	**130,000**	135,000	140,000

Start Date
March 1, 2019

In-service Date
November 30, 2019

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The increased pole heights improve clearance issues for third party attachments and the public.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Other drivers of this project include improving system efficiency, as increasing the conductor size and replacing 40-year-old transformers will reduce line losses. Finally, this project is expected to avoid future operations and maintenance costs, as the existing poles and transformers have reached or exceeded TUL and are expected to require increased crew roll-outs without intervention.

b) Priority:
This project replaces aging substandard poles, small conductors, and overhead transformers that have reached their TUL. The small conductors will be replaced with a standard size and pole heights will be increased, which will improve clearances. Based on age demographics, the poles in Cochrane are in better condition than the other two Towns. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked fourth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	12	0	2	0	9	8	
Weight	10	8	7	6	5	4	
Weighted Score	120	0	14	0	45	32	211

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- rebuild the 4.16/2.4 kV overhead feeder;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- replace the 4.16/2.4 kV feeder with a 25 kV feeder.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The substandard pole heights will continue to create clearance issues that require work-arounds for third party attachments and to not meet public clearance standards. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and/or require increased crew roll-outs. Energy losses will be higher for the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, the 4.16/2.4 kV feeder rebuild, is the current planned project. This project mitigates the existing clearance and energy loss issues, as well as the potential reliability issues and O&M costs. This is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth project alternative is to replace the line section with a 25 kV feeder. This approach is not required since future demand can be met with the existing 4.16/2.4 kV system. The 25 kV line would reduce line losses compared to a 4.16/2.4 kV line, but would require a tap to the nearest 25 kV feeder and transformers rated for 25 kV; therefore, this option is more expensive.

2. Safety
Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Consequence of Failure
The poles in this area approaching their TUL, while the transformers have already reached TUL. Without replacement, the poles and transformers would continue to deteriorate, and their probability of failure would increase. This is expected to unfavourably affect NOW Inc.'s reliability and O&M costs. The line section in this project scope contains 4 single-phase transformer, all of which would lose power in case of a failure along this section of the line.

In addition, the existing conductors are #6 copper and, if not replaced with larger conductors, may break during adverse weather or line maintenance. This is also expected to unfavourably affect NOW Inc.'s reliability and O&M costs.

Project/Program Timing Factors
Overhead rebuild projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and employing contract resources, where necessary.

Impact to System O&M Costs
The existing assets are of approximately 40 years old. There are consequence such as poles breaking, conductor breaking, and transformer failure if these assets are not replaced. These consequences increase system O&M costs of the utility along with other issues such as safety, reliability and efficiency. The replacement of poles, conductors and transformers with new assets reduces the future maintenance and trouble call costs for the assets in the project scope, but inspection costs remain unchanged.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

Cost-benefit Analysis
The benefits of this project are improved line clearances, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR4D Project/Program Description

This is an overhead rebuild project in the Town of Cochrane, will replace existing 35- and 40-foot wood poles with 45-foot wood poles and rebuild the 4.16/2.4 kV feeder. The existing poles are too short creating clearance issues and starting to show signs of deterioration. The replacement of #6 copper conductor with 1/0 ACSR will reduce the probability of conductors breaking during high winds or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages.

This project will replace approximately 900 m of three-phase line, which comprises 18 poles and 6 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

Poles that were installed in the 1950s are failing at a higher rate. These high risk poles are included for replacement in the Cochrane overhead rebuild projects. The overhead rebuild in 2018 will target the downtown area in Cochrane, where spans are short., and overtime work will be done on Sundays to avoid outages for local businesses (which close on Sundays).

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; these are replaced with over varieties during overhead rebuilds.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for overhead rebuilds in Cochrane are presented in the table below, with the relevant year (2020) in bold. Spending over the historical period fluctuates with the project scope each year: 2012 and 2015 was mainly secondary work (which is less expensive). The 2018 project has a higher budget than other years since the downtown area will be rebuilt, necessitating overtime work on Sundays to avoid outages for local businesses. Project costs also trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
13,839	129,232	38,660	7,334	50,000	90,000	180,000	130,000	**135,000**	140,000

Start Date
March 1, 2020

In-service Date
November 30, 2020

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The increased pole heights improve clearance issues for third party attachments and the public.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Other drivers of this project include improving system efficiency, as increasing the conductor size and replacing 40-year-old transformers will reduce line losses. Finally, this project is expected to avoid future operations and maintenance costs, as the existing poles and transformers have reached or exceeded TUL and are expected to require increased crew roll-outs without intervention.

b) Priority:
This project replaces aging substandard poles, small conductors, and overhead transformers that have reached their TUL. The small conductors will be replaced with a standard size and pole heights will be increased, which will improve clearances. Based on age demographics, the poles in Cochrane are in better condition than the other two Towns. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked fourth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	12	0	2	0	9	8	
Weight	10	8	7	6	5	4	
Weighted Score	120	0	14	0	45	32	211

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- rebuild the 4.16/2.4 kV overhead feeder;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- replace the 4.16/2.4 kV feeder with a 25 kV feeder.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The substandard pole heights will continue to create clearance issues that require work-arounds for third party attachments and to not meet public clearance standards. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and/or require increased crew roll-outs. Energy losses will be higher for the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, the 4.16/2.4 kV feeder rebuild, is the current planned project. This project mitigates the existing clearance and energy loss issues, as well as the potential reliability issues and O&M costs. This is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth project alternative is to replace the line section with a 25 kV feeder. This approach is not required since future demand can be met with the existing 4.16/2.4 kV system. The 25 kV line would reduce line losses compared to a 4.16/2.4 kV line, but would require a tap to the nearest 25 kV feeder and transformers rated for 25 kV; therefore, this option is more expensive.

2. Safety
Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

<u>Consequence of Failure</u>
The poles in this area approaching their TUL, while the transformers have already reached TUL. Without replacement, the poles and transformers would continue to deteriorate, and their probability of failure would increase. This is expected to unfavourably affect NOW Inc.'s reliability and O&M costs. The line section in this project scope contains 4 single-phase transformers, all of which would lose power in case of a failure along this section of the line.

In addition, the existing conductors are #6 copper and, if not replaced with larger conductors, may break during adverse weather or line maintenance. This is also expected to unfavourably affect NOW Inc.'s reliability and O&M costs.

<u>Project/Program Timing Factors</u>
Overhead rebuild projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and employing contract resources, where necessary.

<u>Impact to System O&M Costs</u>
The existing assets are of approximately 40 years old. There are consequence such as poles breaking, conductor breaking, and transformer failure if these assets are not replaced. These consequences increase system O&M costs of the utility along with other issues such as safety, reliability and efficiency. The replacement of poles, conductors and transformers with new assets reduces the future maintenance and trouble call costs for the assets in the project scope, but inspection costs remain unchanged.

<u>Reliability/Safety Factors</u>
One of the drivers of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

<u>Cost-benefit Analysis</u>
The benefits of this project are improved line clearances, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR4E Project/Program Description

This is an overhead rebuild project in the Town of Cochrane, will replace existing 35- and 40-foot wood poles with 45-foot wood poles and rebuild the 4.16/2.4 kV feeder. The existing poles are too short creating clearance issues and starting to show signs of deterioration. The replacement of #6 copper conductors with 1/0 ACSR will reduce the probability of conductors breaking during high winds or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages.

This project will replace approximately 900 m of three-phase line, which comprises 18 poles and 6 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

Poles that were installed in the 1950s are failing at a higher rate. These high risk poles are included for replacement in the Cochrane overhead rebuild projects. The overhead rebuild in 2018 will target the downtown area in Cochrane, where spans are short., and overtime work will be done on Sundays to avoid outages for local businesses (which close on Sundays).

Many poles in Cochrane are short compared to modern construction standards, and third parties cannot attach to the pole without the use of pole-top extensions for NOW Inc.'s lines. A number of the poles in Cochrane are southern yellow pine, which are known to suffer premature rot; these are replaced with over varieties during overhead rebuilds.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for overhead rebuilds in Cochrane are presented in the table below, with the relevant year (2021) in bold. Spending over the historical period fluctuates with the project scope each year: 2012 and 2015 was mainly secondary work (which is less expensive). The 2018 project has a higher budget than other years since the downtown area will be rebuilt, necessitating overtime work on Sundays to avoid outages for local businesses. Project costs also trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
13,839	129,232	38,660	7,334	50,000	90,000	180,000	130,000	135,000	**140,000**

Start Date
March 1, 2021

In-service Date
November 30, 2021

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The increased pole heights improve clearance issues for third party attachments and the public.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Other drivers of this project include improving system efficiency, as increasing the conductor size and replacing 40-year-old transformers will reduce line losses. Finally, this project is expected to avoid future operations and maintenance costs, as the existing poles and transformers have reached or exceeded TUL and are expected to require increased crew roll-outs without intervention.

b) Priority:
This project replaces aging substandard poles, small conductors, and overhead transformers that have reached their TUL. The small conductors will be replaced with a standard size and pole heights will be increased, which will improve clearances. Based on age demographics, the poles in Cochrane are in better condition than the other two Towns. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked fourth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	12	0	2	0	9	8	
Weight	10	8	7	6	5	4	
Weighted Score	120	0	14	0	45	32	211

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- rebuild the 4.16/2.4 kV overhead feeder;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- replace the 4.16/2.4 kV feeder with a 25 kV feeder.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The substandard pole heights will continue to create clearance issues that require work-arounds for third party attachments and to not meet public clearance standards. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and/or require increased crew roll-outs. Energy losses will be higher for the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, the 4.16/2.4 kV feeder rebuild, is the current planned project. This project mitigates the existing clearance and energy loss issues, as well as the potential reliability issues and O&M costs. This is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth project alternative is to replace the line section with a 25 kV feeder. This approach is not required since future demand can be met with the existing 4.16/2.4 kV system. The 25 kV line would reduce line losses compared to a 4.16/2.4 kV line, but would require a tap to the nearest 25 kV feeder and transformers rated for 25 kV; therefore, this option is more expensive.

2. Safety

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Consequence of Failure

The poles in this area approaching their TUL, while the transformers have already reached TUL. Without replacement, the poles and transformers would continue to deteriorate, and their probability of failure would increase. This is expected to unfavourably affect NOW Inc.'s reliability and O&M costs. The line section in this project scope contains 4 single-phase transformers, all of which would lose power in case of a failure along this section of the line.

In addition, the existing conductors are #6 copper and, if not replaced with larger conductors, may break during adverse weather or line maintenance. This is also expected to unfavourably affect NOW Inc.'s reliability and O&M costs.

Project/Program Timing Factors

Overhead rebuild projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and employing contract resources, where necessary.

Impact to System O&M Costs

The existing assets are of approximately 40 years old. There are consequence such as poles breaking, conductor breaking, and transformer failure if these assets are not replaced. These consequences increase system O&M costs of the utility along with other issues such as safety, reliability and efficiency. The replacement of poles, conductors and transformers with new assets reduces the future maintenance and trouble call costs for the assets in the project scope, but inspection costs remain unchanged.

Reliability/Safety Factors

One of the drivers of this project is reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 1/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Completion of this project will improve safety by:

- replacing short (substandard) poles, which will improve clearances for third party attachments and the public;
- replacing 40-year-old poles, which will decrease the probability of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 1/0 ACSR, which will decrease the probability of conductors breaking in the event adverse weather or when the crews are working on the poles.

Cost-benefit Analysis

The benefits of this project are improved line clearances, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR5 Project/Program Description

This project replaces glass insulators with new silicone insulators and replaces a frosted structure at Cochrane DS. Glass insulators in general are prone to flashovers due to contamination and/or electrolytic film development. The glass insulators at Cochrane DS will be replace with new silicone insulators that will have improved hydrophobicity and will be less prone to contamination due to salt spray, reducing the likelihood of a flashover.

The steel structure in question supports the 4.16/2.4 kV conductors. The most recent inspection identified concerning frost damage on the structure. The structure will be replaced with a new galvanized steel structure.

The completion of this project will mitigate safety and reliability concerns, and will mitigate future system O&M costs.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital expenditures for substation feeder upgrades at Cochrane DS are presented in the table below, with the relevant year (2017) in bold.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
11,206	-	686	-	25,000	**50,000**	-	-	-	-

Start Date
2017

In-service Date
2017

Customer Attachments
Downstream feeder

Load
- 1 feeder

Risks/Mitigation
Typical risks to completing capital work at a substation include scheduled outage impacts for downstream customers. The work is scheduled to minimize outage impacts.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is assets at the end of their service life due to failure risk. The existing glass insulators are likely to flashover. The steel structure is frosted and is at risk to buckle.

The secondary driver of this project is reliability, as an insulator flashover or a structure collapse would both likely cause an outage.

Other drivers of this project include safety and operational efficiency. The damaged structure is more likely to fall and poses a safety hazard to NOW Inc. staff or contractors who work in the substation. The proactive replacement of the insulators and structure improves operational efficiency, since it is cheaper to replace all of the insulators at once and planned replacements are faster than reactive replacements.

b) Priority:

This project replaces and insulators and a frosted structure at Cochrane DS and was scored in safety, reliability, and efficiency. The project is ranked fifth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	6	0	0	0	20	10	
Weight	10	8	7	6	5	4	
Weighted Score	60	0	0	0	100	40	200

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- replace the glass insulators and frosted structure;
- replace the glass insulators only;
- replace the frosted structure only; and
- rebuild the entire substation.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. It is probable that one or more insulators may flash over and that the frosted structure will collapse without intervention. The risks without project completion fall into the categories of safety, reliability, and operational efficiency.

The second alternative, the replacement of the glass insulators and frosted structure, is the current planned project. This project replaces assets at the end of their service life while eliminating potential safety, reliability, and efficiency concerns. This is the optimal approach.

The third alternative is to replace only the glass insulators. In this case, the frosted structure would still remain and its structural failure is probable. This is a potential safety, reliability, and operational efficiency concern.

The fourth alternative is to replace only the frosted structure. In this case, the old glass insulators would remain in place and are likely to flashover. This is a potential safety, reliability, and operational efficiency concern.

The fifth approach is to completely rebuild the Cochrane substation. The substation is in acceptable condition and is expected to continue reliable operation following the replacement of the insulators and frosted structure, as well as the refurbishment of one of the transformer banks (as a separate project). Rebuilding the entire substation would not utilize its remaining life and is much more expensive, so is not recommended.

<u>2. Safety</u>
Completion of this project will improve safety by:

- replacing a frosted structure which poses a safety risk to NOW Inc. staff and contractors working inside the substation; and
- replacing glass insulators which could flash over when someone is inside the substation.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The new construction will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

<u>6. Environmental Benefits</u>
N/A

C. Category-Specific Requirements

Consequence of Failure
The glass insulators at Cochrane DS are more prone to flashovers due to contamination and electrolytic film development. Without replacement, the insulators would continue to deteriorate, and the probability of a flashover would increase. A flashover at insulator in the substation could affect one or both of the 4.16/2.4 kV feeders.

The most recent inspection of the structure in question at Cochrane DS identified concerning frost damage on the structure. Without replacement, the structure would continue to deteriorate, and the probability of a failure would increase. A failure of the structure would affect the entire 4.16/2.4 kV feeder.

Project/Program Timing Factors
Capital projects in substations are scheduled to minimize scheduled outage impacts to customers.

Impact to System O&M Costs
Without the planned project, it is probable that the existing glass insulators will flash over and the frosted structure will buckle. Either of these events would increase NOW Inc.'s system O&M costs.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of old glass insulators with new silicone insulators decreases the probability of a flashover. Replacing the frosted steel structure reduces the probability of an outage due to the structure collapsing.

Completion of this project will improve safety by:

- replacing a frosted structure which poses a safety risk to NOW Inc. staff and contractors working inside the substation; and
- replacing glass insulators which could flash over when someone is inside the substation.

Cost-benefit Analysis
The benefits of this project are improved safety, reduced outage probability, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR6 Project/Program Description

This project replaces the 4.16/2.4 kV substation transformer bank T2 at Cochrane DS. The transformer bank consists of three 1 MVA transformers that were installed in 1953 and are over 60 years old. The cooling fins exhibit severe rusting and the foundation is cracked. The foundation will be replaced when the new transformer bank is installed. The completion of this project will mitigate safety, environmental, and reliability concerns and will mitigate future system O&M costs.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital expenditures for substation transformer replacements at Cochrane DS are presented in the table below.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
-	-	-	-	-	-	50,000	75,000	-	-

Start Date
2018

In-service Date
2019

Customer Attachments
2 downstream feeders

Load
2 downstream feeders (2.8 MVA peak)

Risks/Mitigation
Typical risks to completing capital work at a substation include scheduled outage impacts for downstream customers. The T1 bank in parallel is rated up to 3 MVA and is capable of delivering power to both feeders even on peak load. Furthermore the work is scheduled to minimize outage impacts.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is a substation transformer bank at the end of its service life due to failure risk. The existing substation transformer bank is 63 years old and requires life extension in order to continue reliable operation. The cooling fins exhibit severe rusting and the foundation is cracked.

The secondary driver of this project is reliability, as the replacement activities will decrease the likelihood of a power interruption and an outage would affect a large number of customers.

Other drivers of this project include operational efficiency and the environment. The proactive replacement of the substation transformer bank avoids costly maintenance on the transformers and is more cost efficient than an emergency, unplanned replacement. The replacement mitigates a transformer failure to prevent oil leaking into the environment.

b) Priority:

This project replaces a 63-year-old substation transformer bank at Cochrane DS, which otherwise has a high probability of failure. The project is scored in safety, environment, reliability, and efficiency, and is ranked tenth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	1	0	4	0	10	5	
Weight	10	8	7	6	5	4	
Weighted Score	10	0	28	0	50	20	108

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- replace the transformer bank
- refurbish the transformer bank; and
- rebuild the entire substation.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. It is probable that the transformer bank would fail without a replacement, which would require a costly emergency repair and would constitute a lengthy outage if the second transformer bank is unable to pick up the load. The main risks without project completion fall into the categories of the environment, reliability, and operational efficiency.

The second alternative, the replacement of the substation transformer bank, is the current planned project. The transformer bank is over 60 years old and a refurbishment would do little to extend its life. The cracked foundation must be rebuilt coincident with the transformer replacements. This is the optimal approach.

The third alternative is to refurbish the transformer bank. As previously mentioned, there is little remaining life to be extracted from the transformer bank due to a life extension. Furthermore the requirement to replace the concrete foundation supports a replacement rather than a refurbishment; so this option is not recommended.

Finally, the fourth alternative is to completely rebuild the Cochrane substation. The replacement of the transformer bank could coincide with the replacement of the insulators and frosted structure, as well as the rest of the substation equipment. However, the rest of the substation is in acceptable condition and rebuilding the entire substation would not utilize its remaining life and would be much more expensive. Furthermore the parallel transformer bank set-up supports replacing banks one at a time; so this option is not recommended.

2. Safety

Safety is not a major driver, since a transformer failure causing a safety concern is an extremely low probability event. However, replacing the transformer bank before it fails does yield some safety benefits.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
The new construction will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The replacement of the substation transformer bank reduces the likelihood of oil leaking into the environment.

C. Category-Specific Requirements

Consequence of Failure
The substation transformer bank is 63 years old. The cooling fins exhibit severe rusting and the foundation is cracked. Without intervention, it is expected that an outage would occur. It is expected that the other transformer bank T1 could pick up both feeder in case of an unplanned outage, but this transformer bank is close to 60 years old and also has a significant probability of failure. The main drawback of an unplanned replacement is the higher cost of a reactive replacement.

Project/Program Timing Factors
Capital projects in substations are scheduled to minimize scheduled outage impacts to customers.

Impact to System O&M Costs
Without the planned project, it is probable that the transformer would fail and require emergency repair or replacement, which would increase NOW Inc.'s system O&M costs.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of the substation transformer bank mitigates the possibility of it failing and causing an outage if the second transformer bank cannot pick up the load.

Safety is not a major driver of this project, since a transformer failure causing a safety concern is an extremely low probability event. However, refurbishing the transformer bank to reduce its probability of failure does yield some safety benefits.

Cost-benefit Analysis
The benefits of this project are improved safety, mitigation of potential environmental damage, reduced outage probability, and avoidance of future system O&M costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR7 Project/Program Description

This project replaces the primary (12.5/7.2 kV) switchgear and underground cables at the Detroyes substation in Iroquois Falls. This substation was constructed in 1966 and has two distribution feeders. Potheads are the most problematic and unreliable component of cables and the pothead in question is showing signs of deterioration. The manufacturer has indicated that replacement is needed within five years and it will be monitored until it is replaced.

Work on the primary side of the transformer is required to accompany the replacements. The completion of this project will mitigate safety, environmental, and reliability concerns and will mitigate future system O&M costs.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital expenditures for substation primary side replacements at Detroyes DS are presented in the table below.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
-	-	-	-	-	-	-	-	50,000	-

Start Date
2020

In-service Date
2020

Customer Attachments
2 downstream feeders

Load
2 feeders

Risks/Mitigation
The risk of asset failure before its scheduled replacement is the biggest risk to this project as planned. The replacement year was selected based on discussions with the manufacturer, who indicated the pothead should be replaced within five years. The pothead will be monitored to mitigate the failure risk going forward.

Other typical risks to completing capital work at a substation include scheduled outage impacts for downstream customers; the work is scheduled to minimize outage impacts. Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload. NOW Inc. is also searching for an additional apprentice who will work in Iroquois Falls.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is assets at the end of their service life due to failure risk. The substation is 50 years old and the lead pothead on the primary side is showing signs of deterioration. The pothead is the most unreliable component of a cable and is prone to particularly violent failures, and cannot be repaired since it is lead-filled. Therefore the 12.5/7.2 kV switchgear and underground cables will be replaced.

The secondary driver of this project is reliability, as the replacement will decrease the likelihood of a power interruption and an outage would affect a large number of customers.

Safety is a driver for this project since a pothead failure can be violent and dangerous. Other drivers of this project include operational efficiency and the environment. The proactive replacement is more cost efficient than a reactive replacement and mitigates additional outage restoration costs. The pothead replacement will mitigate the environmental leak.

b) Priority:

This project replaces the primary side switchgear and underground cables at the Detroyes DS in Iroquois Falls, in order to replace the leaking lead pothead. The project is scored in safety, environment, reliability, and efficiency, and is ranked ninth out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	4	0	1	0	10	8	
Weight	40	8	7	6	5	4	
Weighted Score	40	0	7	0	50	32	129

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- replace the primary switchgear and cables;
- maintain the pothead; and
- rebuild the entire substation.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. Potheads are particularly prone to failures, which can be violent and dangerous when they occur. The main risks without project completion fall into the categories of safety, environment, reliability, and operational efficiency.

The second alternative, the replacement of the primary switchgear and cables, is the current planned project. The replacement will mitigate the failure risk of the pothead and prevent further environmental works. This is the optimal approach.

The third alternative is to maintain the pothead. The pothead is lead-filled so this is not a possible approach.

Finally, the fourth alternative is to completely rebuild the Detroyes substation. The rest of the substation is in acceptable condition; a complete substation rebuild would not utilize its remaining life (especially that of the substation transformer) and would be much more expensive, so is not recommended.

2. Safety

Cable potheads are particularly prone to failures, which can be violent and dangerous. The proactive replacement of the primary switchgear and underground cables mitigates the safety concern due to a failure.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
The new construction will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The replacement of the leaking pothead will alleviate the environmental leak.

C. Category-Specific Requirements

Consequence of Failure
The substation is 50 years old and the pothead on the primary side is leaking. The pothead is the most unreliable component of a cable and its failure is very likely. Without intervention, it is expected that an outage would occur, which would affect every customer served from Detroyes DS.

Project/Program Timing Factors
Capital projects in substations are scheduled to minimize scheduled outage impacts to customers.

Impact to System O&M Costs
Without the planned project, it is probable that the pothead would fail and require an emergency replacement of the primary switchgear and cables, which would increase NOW Inc.'s system O&M costs.

Reliability/Safety Factors
One of the drivers of this project is reliability. The replacement of the pothead mitigates a failure at the cable or switchgear, which would cause a major power outage.

Pothead failures can be violent and dangerous, making safety a driver for this project. The replacement of the primary switchgear and cables mitigates the safety concern.

Cost-benefit Analysis
The benefits of this project are improved safety, mitigation of potential environmental damage, reduced outage probability, and avoidance of future system O&M costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SR8 Project/Program Description

With the completion of the voltage conversion in sections of Iroquois Falls from 2.4 kV delta to 12.5/7.2 kV, the existing 2.4 kV delta station (Mill Gate DS) can be removed from service and the site restored. The delta system does not have a reference to ground and will not trip in case of a ground fault. The decommissioning of the substation will reduce system O&M costs in the future. Other benefits of removing a substation from service can be categorized as environmental and reliability.

The decommissioning will take place once all of the customer attachments and load have been moved from the 2.4 kV delta system onto the existing 12.5/7.2 kV system. Therefore it is requisite that the Iroquois Falls voltage conversion be completed before the decommissioning of Mill Gate DS.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures
The historical and future capital expenditures for substation system renewal at Mill Gate DS are presented in the table below.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
-	-	-	-	-	-	-	-	-	75,000

Start Date
2021

In-service Date
2021

Customer Attachments
N/A

Load
N/A

Risks/Mitigation
The most prominent risk to the completion of this project as planned is the timely completion of the voltage conversion project in Iroquois Falls. All of the customers currently served by the 2.4 kV delta system must be moved on the 12/5/7.2 kV system before the substation can be decommissioned.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload. NOW Inc. is also searching for an additional apprentice who will work in Iroquois Falls.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is a substation at the end of its service life due to obsolescence. With the completion of the 2.4 kV delta conversion to 12.5/7.2 kV in Iroquois Falls, the 2.4 kV delta substation will no longer be useful. The substation is over 40 years old and the delta side has no reference to ground. The site will be restored once the substation is decommissioned.

The secondary driver for this project is cost efficiency, since eliminating the substation will reduce future system O&M costs (i.e. substation maintenance and inspections).

Safety is a driver for this project since the delta side of the substation has no reference to ground and will not trip in case of a downstream ground fault.

Other drivers of this project include reliability and the environment. The elimination of a substation reduces the number of system components that could fail and cause an outage and the elimination of a substation transformer reduces the likelihood of an oil leak on NOW Inc.'s system.

b) Priority:

This project decommissions the 2.4 kV delta substation (Mill Gate DS) and restores the site. The project is scored in safety, environment, reliability, and efficiency, and is ranked third out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	10	0	4	0	10	10	
Weight	10	8	28	6	5	4	
Weighted Score	100	0	7	0	50	40	218

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing; and
- decommission the substation.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. If the substation is left in place, the site cannot be restored and inspections will still be required in accordance with the *Distribution System Code*. The project alleviates potential risks in safety, the environment, and reliability, and reduces future system O&M costs.

The second alternative, the decommissioning of Mill Gate DS and restoration of the site, is the current planned project. The substation will no longer be useful once the 2.4 kV delta system is converted to 12.5/7.2 kV and its decommissioning will reduce future system O&M costs. This is the optimal approach.

2. Safety
The delta side of the substation has no reference to ground and will not trip in case of a downstream ground fault, making safety a driver for this project. Eliminating the substation will mitigate this safety concern.

3. Cyber-security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits
The elimination of a substation transformer reduces the probability of an oil leak on NOW Inc.'s system.

C. Category-Specific Requirements

Consequence of Failure
With the completion of the conversion of the 2.4 kV delta system in Iroquois Falls to 12.5/7.2 kV, the 2.4 kV delta substation (Mill Gate DS) will no longer serve any customers or load and will not have any useful purpose.

Project/Program Timing Factors
Capital projects in substations are scheduled to minimize scheduled outage impacts to customers. As previously mentioned, the most prominent risk to the completion of this project as planned is the timely completion of the voltage conversion project in Iroquois Falls. All of the customers currently served by the 2.4 kV delta system must be moved on the 12/5/7.2 kV system before the substation can be decommissioned.

Impact to System O&M Costs
The decommissioning of the substation will reduce future system O&M costs (i.e. substation maintenance and inspections).

Reliability/Safety Factors
One of the drivers of this project is reliability. The elimination of a substation reduces the number of system components that could fail and cause an outage.

Safety is a driver for this project since the delta side of the substation has no reference to ground and will not trip in case of a downstream ground fault.

Cost-benefit Analysis
The benefits of this project are improved safety, mitigation of potential environmental damage, reduced outage probability, and the reduction of future system O&M costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS1A Project/Program Description

This project is a voltage conversion from 4.16/2.4 kV to 25/14.4 kV in the town of Kapuskasing. This project is necessary in order to remove a 4.16/2.4 kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion this project will bring improved safety and system efficiency, and reduced operating costs.

This project will replace approximately 1000 m of three-phase line, which comprises 20 poles and 7 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for the Kapuskasing voltage conversion are shown in the table below, with the relevant year (2017) in bold. Historical spending was higher in 2013 and 2014 due to primary work being completed in these two years, with the respective secondary work completed in 2015. Project costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
103,372	205,501	203,393	94,251	140,000	**175,000**	200,000	205,000	215,000	220,000

Start Date
March 1, 2017

In-service Date
November 30, 2017

Customer Attachments
Yes

Load
- 7 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is reduced operating and maintenance cost. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a 4.16/2.4 kV station from service, thus avoiding future maintenance costs of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole breaking during high winds. Furthermore, the replacement of conductors and transformers decreases the failure risk.

Other drivers of this project include improved overall system efficiency. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV, and replacing conductors and 40-year-old transformers will reduce line losses.

Finally, this project is expected to bring improved safety, as the replacement of deteriorated poles decreases the probability of poles breaking during high wind and replacement of conductors decreases the chances of conductor breaking in the event of storm or when crews are working.

b) Priority:

This project upgrades the 4.16/2.4 kV system to 25/14.4 kV and replaces aging poles, conductors, and overhead transformers. Based on age demographics, the poles in Kapuskasing are in worse condition than those in Cochrane, but better condition than those in Iroquois Falls. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked second out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	5.8	0	6	0	7.8	22.4	
Weight	10	8	7	6	5	4	
Weighted Score	58	0	42	0	39	89.6	228.6

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 4.16/2.4 kV to 25/14.4 kV;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- rebuild 4.16/2.4 kV

The first project alternative is a “do nothing” approach, which will not yield any of the project benefits. The 4.16 kV station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and increase the number of trouble calls. Finally, energy losses will be higher on the 4.16/2.4 kV, especially due to the 40-year-old assets.

The second alternative, upgrade 4.16/2.4 kV to 25/14.4 kV, is the current planned project. This project mitigates the reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a 4.16/2.4 kV station, which is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to rebuild the 4.16/2.4 kV feeder. In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. Although, rebuilding the 4.16/2.4 kV replaces aging infrastructure, it will not lead NOW Inc. to decommission 4.16 kV station and to avoid maintenance cost of the station.

<u>2. Safety</u>
Completion of this project will improve safety by replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the other drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

<u>6. Environmental Benefits</u>
The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include O&M costs and reliability. This project reduces future replacement and maintenance costs of a 4.16 kV station to eventually be removed from service. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, the upgraded 25/14.4 kV system can accommodate more customers than the existing 4.16/2.4 kV which will eventually reduce the operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 4.16/2.4 kV to 25/14.4 kV and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and the probability of failure of conductors and transformers are minimized by the replacement. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its 4.16/2.4 kV station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using contract resources, when necessary.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS1B Project/Program Description

This project is a voltage conversion from 4.16/2.4 kV to 25/14.4 kV in the town of Kapuskasing. This project is necessary in order to remove a 4.16/2.4 kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion this project will bring improved safety and system efficiency, and reduced operating costs.

This project will replace approximately 1100 m of three-phase line, which comprises 16 poles and 6 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for the Kapuskasing voltage conversion are shown in the table below, with the relevant year (2018) in bold. Historical spending was higher in 2013 and 2014 due to primary work being completed in these two years, with the respective secondary work completed in 2015. Project costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
103,372	205,501	203,393	94,251	140,000	175,000	**200,000**	205,000	215,000	220,000

Start Date
March 1, 2018

In-service Date
November 30, 2018

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is reduced operating and maintenance cost. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a 4.16/2.4 kV station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole breaking during high winds. Furthermore, the replacement of conductors and transformers decreases the failure risk.

Other drivers of this project include improved overall system efficiency. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV, and replacing conductors and 40-year-old transformers will reduce line losses.

Finally, this project is expected to bring improved safety, as the replacement of deteriorated poles decreases the probability of poles breaking during high wind and replacement of conductors decreases the chances of conductor breaking in the event of storm or when crews are working.

b) Priority:

This project upgrades the 4.16/2.4 kV system to 25/14.4 kV and replaces aging poles, conductors, and overhead transformers. Based on age demographics, the poles in Kapuskasing are in worse condition than those in Cochrane, but better condition than those in Iroquois Falls. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked second out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	5.8	0	6	0	7.8	22.4	
Weight	10	8	7	6	5	4	
Weighted Score	58	0	42	0	39	89.6	228.6

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 4.16/2.4 kV to 25/14.4 kV;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- rebuild 4.16/2.4 kV

The first project alternative is a “do nothing” approach, which will not yield any of the project benefits. The 4.16 kV station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages and increase the number of trouble calls. Finally, energy losses will be higher on the 4.16/2.4 kV, especially due to the 40-year-old assets.

The second alternative, upgrade 4.16/2.4 kV to 25/14.4 kV, is the current planned project. This project mitigates the reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a 4.16/2.4 kV station, which is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to rebuild the 4.16/2.4 kV feeder. In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. Although, rebuilding the 4.16/2.4 kV replaces aging infrastructure, it will not lead NOW Inc. to decommission 4.16 kV station and to avoid maintenance cost of the station.

2. Safety

Completion of this project will improve safety by replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the other drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include O&M costs and reliability. This project reduces future replacement and maintenance costs of a 4.16 kV station to eventually be removed from service. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, the upgraded 25/14.4 kV system can accommodate more customers than the existing 4.16/2.4 kV which will eventually reduce the operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 4.16/2.4 kV to 25/14.4 kV and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and the probability of failure of conductors and transformers are minimized by the replacement. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its 4.16/2.4 kV station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using contract resources, when necessary.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS1C Project/Program Description

This project is a voltage conversion from 4.16/2.4 kV to 25/14.4 kV in the town of Kapuskasing. This project is necessary in order to remove a 4.16/2.4 kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion this project will bring improved safety and system efficiency, and reduced operating costs.

This project will replace approximately 1100 m of three-phase line, which comprises 16 poles and 6 single-phase transformers. The average age of the existing infrastructure is 50 years, which exceeds the TUL of overhead transformers (40 years) and wood poles (45 years).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for the Kapuskasing voltage conversion are shown in the table below, with the relevant year (2019) in bold. Historical spending was higher in 2013 and 2014 due to primary work being completed in these two years, with the respective secondary work completed in 2015. Project costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	**2019**	2020	2021
103,372	205,501	203,393	94,251	140,000	175,000	200,000	**205,000**	215,000	220,000

Start Date
March 1, 2019

In-service Date
November 30, 2019

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is reduced operating and maintenance cost. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a 4.16/2.4 kV station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole breaking during high winds. Furthermore, the replacement of conductors and transformers decreases the failure risk.

Other drivers of this project include improved overall system efficiency. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV, and replacing conductors and 50-year-old transformers will reduce line losses.

Finally, this project is expected to bring improved safety, as the replacement of deteriorated poles decreases the probability of poles breaking during high wind and replacement of conductors decreases the chances of conductor breaking in the event of storm or when crews are working.

b) Priority:

This project upgrades the 4.16/2.4 kV system to 25/14.4 kV and replaces aging poles, conductors, and overhead transformers. Based on age demographics, the poles in Kapuskasing are in worse condition than those in Cochrane, but better condition than those in Iroquois Falls. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked second out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	5.8	0	6	0	7.8	22.4	
Weight	10	8	7	6	5	4	
Weighted Score	58	0	42	0	39	89.6	228.6

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 4.16/2.4 kV to 25/14.4 kV;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- rebuild 4.16/2.4 kV

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The 4.16 kV station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have

exceeded TUL, they are expected to cause customer outages and increase the number of trouble calls. Finally, energy losses will be higher on the 4.16/2.4 kV, especially due to the 50-year-old assets.

The second alternative, upgrade 4.16/2.4 kV to 25/14.4 kV, is the current planned project. This project mitigates the reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a 4.16/2.4 kV station, which is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to rebuild the 4.16/2.4 kV feeder. In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. Although, rebuilding the 4.16/2.4 kV replaces aging infrastructure, it will not lead NOW Inc. to decommission 4.16 kV station and to avoid maintenance cost of the station.

<u>2. Safety</u>
Completion of this project will improve safety by replacing the poles that are approximately 50 years old with new poles, which decreases the chances of poles breaking due to deterioration.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the other drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

<u>6. Environmental Benefits</u>
The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include O&M costs and reliability. This project reduces future replacement and maintenance costs of a 4.16 kV station to eventually be removed from service. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, the upgraded 25/14.4 kV system can accommodate more customers than the existing 4.16/2.4 kV which will eventually reduce the operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 4.16/2.4 kV to 25/14.4 kV and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and the probability of failure of conductors and transformers are minimized by the replacement. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its 4.16/2.4 kV station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using contract resources, when necessary.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS1D Project/Program Description

This project is a voltage conversion from 4.16/2.4 kV to 25/14.4 kV in the town of Kapuskasing. This project is necessary in order to remove a 4.16/2.4 kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion this project will bring improved safety and system efficiency, and reduced operating costs.

This project will replace approximately 1100 m of three-phase line, which comprises 16 poles and 6 single-phase transformers. The average age of the existing infrastructure is 50 years, which exceeds the TUL of overhead transformers (40 years) and wood poles (45 years).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for the Kapuskasing voltage conversion are shown in the table below, with the relevant year (2020) in bold. Historical spending was higher in 2013 and 2014 due to primary work being completed in these two years, with the respective secondary work completed in 2015. Project costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
103,372	205,501	203,393	94,251	140,000	175,000	200,000	205,000	**215,000**	220,000

Start Date
March 1, 2020

In-service Date
November 30, 2020

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is reduced operating and maintenance cost. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a 4.16/2.4 kV station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole breaking during high winds. Furthermore, the replacement of conductors and transformers decreases the failure risk.

Other drivers of this project include improved overall system efficiency. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV, and replacing conductors and 50-year-old transformers will reduce line losses.

Finally, this project is expected to bring improved safety, as the replacement of deteriorated poles decreases the probability of poles breaking during high wind and replacement of conductors decreases the chances of conductor breaking in the event of storm or when crews are working.

b) Priority:

This project upgrades the 4.16/2.4 kV system to 25/14.4 kV and replaces aging poles, conductors, and overhead transformers. Based on age demographics, the poles in Kapuskasing are in worse condition than those in Cochrane, but better condition than those in Iroquois Falls. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked second out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	5.8	0	6	0	7.8	22.4	
Weight	10	8	7	6	5	4	
Weighted Score	58	0	42	0	39	89.6	228.6

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 4.16/2.4 kV to 25/14.4 kV;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- rebuild 4.16/2.4 kV

The first project alternative is a “do nothing” approach, which will not yield any of the project benefits. The 4.16 kV station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have

exceeded TUL, they are expected to cause customer outages and increase the number of trouble calls. Finally, energy losses will be higher on the 4.16/2.4 kV, especially due to the 50-year-old assets.

The second alternative, upgrade 4.16/2.4 kV to 25/14.4 kV, is the current planned project. This project mitigates the reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a 4.16/2.4 kV station, which is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to rebuild the 4.16/2.4 kV feeder. In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. Although, rebuilding the 4.16/2.4 kV replaces aging infrastructure, it will not lead NOW Inc. to decommission 4.16 kV station and to avoid maintenance cost of the station.

2. Safety

Completion of this project will improve safety by replacing the poles that are approximately 50 years old with new poles, which decreases the chances of poles breaking due to deterioration.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the other drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include O&M costs and reliability. This project reduces future replacement and maintenance costs of a 4.16 kV station to eventually be removed from service. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, the upgraded 25/14.4 kV system can accommodate more customers than the existing 4.16/2.4 kV which will eventually reduce the operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 4.16/2.4 kV to 25/14.4 kV and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and the probability of failure of conductors and transformers are minimized by the replacement. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its 4.16/2.4 kV station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using contract resources, when necessary.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS1E Project/Program Description

This project is a voltage conversion from 4.16/2.4 kV to 25/14.4 kV in the town of Kapuskasing. This project is necessary in order to remove a 4.16/2.4 kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion this project will bring improved safety and system efficiency, and reduced operating costs.

This project will replace approximately 1100 m of three-phase line, which comprises 16 poles and 6 single-phase transformers. The average age of the existing infrastructure is 50 years, which exceeds the TUL of overhead transformers (40 years) and wood poles (45 years).

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

The historical and future capital expenditures for the Kapuskasing voltage conversion are shown in the table below, with the relevant year (2021) in bold. Historical spending was higher in 2013 and 2014 due to primary work being completed in these two years, with the respective secondary work completed in 2015. Project costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
103,372	205,501	203,393	94,251	140,000	175,000	200,000	205,000	215,000	**220,000**

Start Date
March 1, 2021

In-service Date
November 30, 2021

Customer Attachments
Yes

Load
- 6 single-phase transformers

Risks/Mitigation

Although the risks to completing an overhead rebuild project as planned are small, typical risks include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

Another typical risk is the management of NOW Inc.'s workforce, which may be called to do emergency repairs during the scheduled construction window. If needed, NOW Inc. employs contract resources to manage potential staffing overload.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is reduced operating and maintenance cost. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a 4.16/2.4 kV station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

The secondary driver of this project is reliability. The replacement of deteriorated poles decreases the probability of pole breaking during high winds. Furthermore, the replacement of conductors and transformers decreases the failure risk.

Other drivers of this project include improved overall system efficiency. The voltage conversion from 4.16/2.4 kV to 25/14.4 kV, and replacing conductors and 50-year-old transformers will reduce line losses.

Finally, this project is expected to bring improved safety, as the replacement of deteriorated poles decreases the probability of poles breaking during high wind and replacement of conductors decreases the chances of conductor breaking in the event of storm or when crews are working.

b) Priority:

This project upgrades the 4.16/2.4 kV system to 25/14.4 kV and replaces aging poles, conductors, and overhead transformers. Based on age demographics, the poles in Kapuskasing are in worse condition than those in Cochrane, but better condition than those in Iroquois Falls. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked second out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	5.8	0	6	0	7.8	22.4	
Weight	10	8	7	6	5	4	
Weighted Score	58	0	42	0	39	89.6	228.6

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 4.16/2.4 kV to 25/14.4 kV;
- replace the 4.16/2.4 kV overhead feeder with an underground feeder; and
- rebuild 4.16/2.4 kV

The first project alternative is a “do nothing” approach, which will not yield any of the project benefits. The 4.16 kV station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have

exceeded TUL, they are expected to cause customer outages and increase the number of trouble calls. Finally, energy losses will be higher on the 4.16/2.4 kV, especially due to the 50-year-old assets.

The second alternative, upgrade 4.16/2.4 kV to 25/14.4 kV, is the current planned project. This project mitigates the reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a 4.16/2.4 kV station, which is the optimal approach.

The third approach is to replace the 4.16/2.4 kV feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to rebuild the 4.16/2.4 kV feeder. In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. Although, rebuilding the 4.16/2.4 kV replaces aging infrastructure, it will not lead NOW Inc. to decommission 4.16 kV station and to avoid maintenance cost of the station.

2. Safety

Completion of this project will improve safety by replacing the poles that are approximately 50 years old with new poles, which decreases the chances of poles breaking due to deterioration.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the other drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include O&M costs and reliability. This project reduces future replacement and maintenance costs of a 4.16 kV station to eventually be removed from service. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, the upgraded 25/14.4 kV system can accommodate more customers than the existing 4.16/2.4 kV which will eventually reduce the operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 4.16/2.4 kV to 25/14.4 kV and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and the probability of failure of conductors and transformers are minimized by the replacement. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its 4.16/2.4 kV station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using contract resources, when necessary.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS2A Project/Program Description

This project is a delta to wye conversion in the town of Iroquois Falls, will upgrade from 2.4 kV delta system to 12.5/7.2 kV wye. This project is necessary in order to remove a delta station from service and to replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion this project will bring improved safety and system efficiency.

This project will replace approximately 1000 m of three-phase line, which comprises 12 poles, 6 single-phase transformers, and 1 three-phase pad-mounted transformer. The average age of the existing infrastructure is 40 years, which is the TUL of overhead and pad-mounted transformers and approaching the TUL of wood poles (45 years).

The voltage conversion of the delta system is completed from the outside in. The innermost areas have the oldest poles and higher span lengths due to the wider lots.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Historical and future capital expenditures for the Iroquois Falls delta to wye conversion are shown in the table below, with the relevant year (2017) in bold. Since the voltage conversion of the delta system is completed from the outside in, the project costs are higher over the forecast period due to the increased line lengths due to wider lots in the scoped areas. Project costs are also higher due the inclusion of a padmount transformer replacement and its associated cables each year of the forecast period. In general, costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
81,730	63,936	31,322	83,829	87,000	**140,000**	155,000	165,000	170,000	180,000

Start Date
March 1, 2017

In-service Date
November 30, 2017

Customer Attachments
Yes

Load
- 6 single-phase transformers
- 1 three-phase pad mounted transformer

Risks/Mitigation

The delta to wye conversion process will be carried out with precautions, following ESA safe work procedures. Dedicated crews will be hired for the conversion work and therefore minimizing any risks.

Other typical risks for overhead rebuild projects include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault.

The secondary driver of this project is the reduction of future operating and maintenance cost. The voltage conversion from 2.4 kV delta to 12.5/7.2 kV wye can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a delta station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

Other drivers of this project include reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 3/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Finally, this project is expected to improve overall system efficiency, as the 12.5/7.2 kV system is capable of delivering the same power at a lower current than the 2.4 kV delta system; therefore reducing line losses. Increasing the conductor size and replacing 40-year-old transformers will also reduce line losses.

b) Priority:

This project upgrades the 2.4 kV delta system to 12.5/7.2 kV wye and replaces aging poles, small conductors, and overhead transformers that have reached their TUL. Based on age demographics, the poles in Iroquois Falls are in the worst condition of the three Towns. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked first out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	17.6	0	6	0	10.6	24.8	
Weight	10	8	7	6	5	4	
Weighted Score	176	0	42	0	53	99.2	370.2

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 2.4 kV delta to 12.5/7.2 kV wye;
- replace the 2.4 kV delta overhead feeder with an underground feeder; and

- replace the 2.4 kV delta with 4.16/2.4 kV wye.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4 kV delta system, especially due to the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, upgrade 2.4 kV delta to 12.5/7.2 kV wye, is the current planned project. This project mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

The third approach is to replace the 2.4 kV delta feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to replace the 2.4 kV delta feeder with a 4.16/2.4 kV wye feeder. Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

<u>2. Safety</u>
Completion of this project will improve safety by:

- converting from delta to wye; which is safer since delta has no reference to ground and will not trip if a phase inadvertently comes into contact with a ground point,
- replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 3/0 ACSR, which decreases the possibility of the conductor breaking in the event of a storm.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include reliability and operating costs. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, this project reduces future replacement and maintenance costs of a delta station to eventually be removed from service. The upgraded 12.5/7.2 kV system can accommodate more customers than the existing 2.4 kV delta system which eventually reduce operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 2.4 kV delta to 12.5/7.2 kV wye and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and mechanical strength of conductors will be increased to withstand conductor breaking in the event of storm. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its delta station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using dedicated crews for the delta conversion.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS2B Project/Program Description

This project is a delta to wye conversion in the town of Iroquois Falls, will upgrade from 2.4 kV delta system to 12.5/7.2 kV wye. This project is necessary in order to remove a delta station from service and to replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion this project will bring improved safety and system efficiency.

This project will replace approximately 1000 m of three-phase line, which comprises 20 poles, 5 single-phase transformers, and 1 three-phase bank. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

The voltage conversion of the delta system is completed from the outside in. The innermost areas have the oldest poles and higher span lengths due to the wider lots.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Historical and future capital expenditures for the Iroquois Falls delta to wye conversion are shown in the table below, with the relevant year (2018) in bold. Since the voltage conversion of the delta system is completed from the outside in, the project costs are higher over the forecast period due to the increased line lengths due to wider lots in the scoped areas. Project costs are also higher due the inclusion of a padmount transformer replacement and its associated cables each year of the forecast period. In general, costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
81,730	63,936	31,322	83,829	87,000	140,000	**155,000**	165,000	170,000	180,000

Start Date
March 1, 2018

In-service Date
November 30, 2018

Customer Attachments
Yes

Load
- 5 single-phase transformers
- 1 three-phase transformer bank
- 1 three-phase padmount transformer

Risks/Mitigation

The delta to wye conversion process will be carried out with precautions, following ESA safe work procedures. Dedicated crews will be hired for the conversion work and therefore minimizing any risks.

Other typical risks for overhead rebuild projects include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault.

The secondary driver of this project is reduced operating and maintenance cost. The voltage conversion from 2.4 kV delta to 12.5/7.2 kV wye can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a delta station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

Other drivers of this project include reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 3/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Finally, this project is expected to improve overall system efficiency, as the 12.5/7.2 kV system is capable of delivering the same power at a lower current than the 2.4 kV delta system; therefore reducing line losses. Increasing the conductor size and replacing 40-year-old transformers will also reduce line losses.

b) Priority:

This project upgrades the 2.4 kV delta system to 12.5/7.2 kV wye and replaces aging poles, small conductors, and overhead transformers that have reached their TUL. Based on age demographics, the poles in Iroquois Falls are in the worst condition of the three Towns. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked first out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	17.6	0	6	0	10.6	24.8	
Weight	10	8	7	6	5	4	
Weighted Score	176	0	42	0	53	99.2	370.2

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 2.4 kV delta to 12.5/7.2 kV wye;
- replace the 2.4 kV delta overhead feeder with an underground feeder; and

- replace the 2.4 kV delta with 4.16/2.4 kV wye.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4 kV delta system, especially due to the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, upgrade 2.4 kV delta to 12.5/7.2 kV wye, is the current planned project. This project mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

The third approach is to replace the 2.4 kV delta feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to replace the 2.4 kV delta feeder with a 4.16/2.4 kV wye feeder. Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

2. Safety

Completion of this project will improve safety by:

- converting from delta to wye; which is safer since delta has no reference to ground and will not trip if a phase inadvertently comes into contact with a ground point,
- replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 3/0 ACSR, which decreases the possibility of the conductor breaking in the event of a storm.

3. Cyber-security, Privacy

N/A

4. Co-ordination, Interoperability

The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

5. Economic Development

One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include reliability and operating costs. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, this project reduces future replacement and maintenance costs of a delta station to eventually be removed from service. The upgraded 12.5/7.2 kV system can accommodate more customers than the existing 2.4 kV delta system which eventually reduce operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 2.4 kV delta to 12.5/7.2 kV wye and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and mechanical strength of conductors will be increased to withstand conductor breaking in the event of storm. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its delta station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using dedicated crews for the delta conversion.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS2C Project/Program Description

This project is a delta to wye conversion in the town of Iroquois Falls, will upgrade from 2.4 kV delta system to 12.5/7.2 kV wye. This project is necessary in order to remove a delta station from service and to replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion this project will bring improved safety and system efficiency.

This project will replace approximately 900 m of three-phase line, which comprises 15 poles, and 5 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

The voltage conversion of the delta system is completed from the outside in. The innermost areas have the oldest poles and higher span lengths due to the wider lots.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Historical and future capital expenditures for the Iroquois Falls delta to wye conversion are shown in the table below, with the relevant year (2019) in bold. Since the voltage conversion of the delta system is completed from the outside in, the project costs are higher over the forecast period due to the increased line lengths due to wider lots in the scoped areas. Project costs are also higher due the inclusion of a padmount transformer replacement and its associated cables each year of the forecast period. In general, costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
81,730	63,936	31,322	83,829	87,000	140,000	155,000	**165,000**	170,000	180,000

Start Date
March 1, 2019

In-service Date
November 30, 2019

Customer Attachments
Yes

Load
- 5 single-phase transformers
- 1 three-phase padmount transformer

Risks/Mitigation

The delta to wye conversion process will be carried out with precautions, following ESA safe work procedures. Dedicated crews will be hired for the conversion work and therefore minimizing any risks.

Other typical risks for overhead rebuild projects include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault.

The secondary driver of this project is reduced operating and maintenance cost. The voltage conversion from 2.4 kV delta to 12.5/7.2 kV wye can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a delta station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

Other drivers of this project include reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 3/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Finally, this project is expected to improve overall system efficiency, as the 12.5/7.2 kV system is capable of delivering the same power at a lower current than the 2.4 kV delta system; therefore reducing line losses. Increasing the conductor size and replacing 40-year-old transformers will also reduce line losses.

b) Priority:

This project upgrades the 2.4 kV delta system to 12.5/7.2 kV wye and replaces aging poles, small conductors, and overhead transformers that have reached their TUL. Based on age demographics, the poles in Iroquois Falls are in the worst condition of the three Towns. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked first out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	17.6	0	6	0	10.6	24.8	
Weight	10	8	7	6	5	4	
Weighted Score	176	0	42	0	53	99.2	370.2

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 2.4 kV delta to 12.5/7.2 kV wye;
- replace the 2.4 kV delta overhead feeder with an underground feeder; and

- replace the 2.4 kV delta with 4.16/2.4 kV wye.

The first project alternative is a “do nothing” approach, which will not yield any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4 kV delta system, especially due to the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, upgrade 2.4 kV delta to 12.5/7.2 kV wye, is the current planned project. This project mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

The third approach is to replace the 2.4 kV delta feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to replace the 2.4 kV delta feeder with a 4.16/2.4 kV wye feeder. Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

<u>2. Safety</u>
Completion of this project will improve safety by:

- converting from delta to wye; which is safer since delta has no reference to ground and will not trip if a phase inadvertently comes into contact with a ground point,
- replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 3/0 ACSR, which decreases the possibility of the conductor breaking in the event of a storm.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include reliability and operating costs. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, this project reduces future replacement and maintenance costs of a delta station to eventually be removed from service. The upgraded 12.5/7.2 kV system can accommodate more customers than the existing 2.4 kV delta system which eventually reduce operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 2.4 kV delta to 12.5/7.2 kV wye and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and mechanical strength of conductors will be increased to withstand conductor breaking in the event of storm. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its delta station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using dedicated crews for the delta conversion.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS2D Project/Program Description

This project is a delta to wye conversion in the town of Iroquois Falls, will upgrade from 2.4 kV delta system to 12.5/7.2 kV wye. This project is necessary in order to remove a delta station from service and to replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion this project will bring improved safety and system efficiency.

This project will replace approximately 900 m of three-phase line, which comprises 15 poles and 5 single-phase transformers. The average age of the existing infrastructure is 40 years, which is the TUL of overhead transformers and approaching the TUL of wood poles (45 years).

The voltage conversion of the delta system is completed from the outside in. The innermost areas have the oldest poles and higher span lengths due to the wider lots.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Historical and future capital expenditures for the Iroquois Falls delta to wye conversion are shown in the table below, with the relevant year (2020) in bold. Since the voltage conversion of the delta system is completed from the outside in, the project costs are higher over the forecast period due to the increased line lengths due to wider lots in the scoped areas. Project costs are also higher due the inclusion of a padmount transformer replacement and its associated cables each year of the forecast period. In general, costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($)					Future Capital Costs ($)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
81,730	63,936	31,322	83,829	87,000	140,000	155,000	165,000	**170,000**	180,000

Start Date
March 1, 2020

In-service Date
November 30, 2020

Customer Attachments
Yes

Load
- 5 single-phase transformers
- 1 three-phase padmount transformer

Risks/Mitigation

The delta to wye conversion process will be carried out with precautions, following ESA safe work procedures. Dedicated crews will be hired for the conversion work and therefore minimizing any risks.

Other typical risks for overhead rebuild projects include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault.

The secondary driver of this project is reduced operating and maintenance cost. The voltage conversion from 2.4 kV delta to 12.5/7.2 kV wye can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a delta station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

Other drivers of this project include reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 3/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Finally, this project is expected to improve overall system efficiency, as the 12.5/7.2 kV system is capable of delivering the same power at a lower current than the 2.4 kV delta system; therefore reducing line losses. Increasing the conductor size and replacing 40-year-old transformers will also reduce line losses.

b) Priority:

This project upgrades the 2.4 kV delta system to 12.5/7.2 kV wye and replaces aging poles, small conductors, and overhead transformers that have reached their TUL. Based on age demographics, the poles in Iroquois Falls are in the worst condition of the three Towns. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked first out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	17.6	0	6	0	10.6	24.8	
Weight	10	8	7	6	5	4	
Weighted Score	176	0	42	0	53	99.2	370.2

c) Analysis of Project and Project Alternatives:

The alternatives to this project include:

- do nothing;
- upgrade 2.4 kV delta to 12.5/7.2 kV wye;
- replace the 2.4 kV delta overhead feeder with an underground feeder; and

- replace the 2.4 kV delta with 4.16/2.4 kV wye.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4 kV delta system, especially due to the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, upgrade 2.4 kV delta to 12.5/7.2 kV wye, is the current planned project. This project mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

The third approach is to replace the 2.4 kV delta feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to replace the 2.4 kV delta feeder with a 4.16/2.4 kV wye feeder. Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

<u>2. Safety</u>
Completion of this project will improve safety by:

- converting from delta to wye; which is safer since delta has no reference to ground and will not trip if a phase inadvertently comes into contact with a ground point,
- replacing the poles that are approximately 40 years old with new poles, which decreases the chances of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 3/0 ACSR, which decreases the possibility of the conductor breaking in the event of a storm.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include reliability and operating costs. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, this project reduces future replacement and maintenance costs of a delta station to eventually be removed from service. The upgraded 12.5/7.2 kV system can accommodate more customers than the existing 2.4 kV delta system which eventually reduce operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 2.4 kV delta to 12.5/7.2 kV wye and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and mechanical strength of conductors will be increased to withstand conductor breaking in the event of storm. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its delta station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using dedicated crews for the delta conversion.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

SS2E Project/Program Description

This project is a delta to wye conversion in the town of Iroquois Falls, will upgrade from 2.4 kV delta system to 12.5/7.2 kV wye. This project is necessary in order to remove a delta station from service and to replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion this project will bring improved safety and system efficiency.

This project will replace approximately 1000 m of three-phase line, which comprises 16 poles and 5 single- phase transformers. The average age of the existing infrastructure is 45 years, which is the TUL of wood poles and exceeded the TUL of overhead transformers (40 years).

The voltage conversion of the delta system is completed from the outside in. The innermost areas have the oldest poles and higher span lengths due to the wider lots.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Historical and future capital expenditures for the Iroquois Falls delta to wye conversion are shown in the table below, with the relevant year (2021) in bold. Since the voltage conversion of the delta system is completed from the outside in, the project costs are higher over the forecast period due to the increased line lengths due to wider lots in the scoped areas. Project costs are also higher due the inclusion of a padmount transformer replacement and its associated cables each year of the forecast period. In general, costs trend upward over the forecast period due to projected transformer cost increases.

Historical Capital Costs ($ '000)					Future Capital Costs ($ '000)				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
81,730	63,936	31,322	83,829	87,000	140,000	155,000	165,000	170,000	**180,000**

Start Date
March 1, 2021

In-service Date
November 30, 2021

Customer Attachments
Yes

Load
- 5 single-phase transformers
- 1 three-phase padmount transformer

Risks/Mitigation

The delta to wye conversion process will be carried out with precautions, following ESA safe work procedures. Dedicated crews will be hired for the conversion work and therefore minimizing any risks.

Other typical risks for overhead rebuild projects include management of the design and approval process to ensure that there are no objections to the line location plans. To mitigate this, the project design process accommodates road authority review and approval (municipal consent) of overhead line locations.

REG Investment
N/A

Leave to Construct
N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:
The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault.

The secondary driver of this project is reduced operating and maintenance cost. The voltage conversion from 2.4 kV delta to 12.5/7.2 kV wye can accommodate more customers, and the completion of this project will bring NOW Inc. closer to removing a delta station from service, thus avoiding maintenance cost of that station. Also, with the replacement of aging poles, conductors and transformers, future unplanned failure risk and replacement cost will be avoided.

Other drivers of this project include reliability. The replacement of deteriorated poles decreases the probability of pole failure during high winds. Furthermore, the conductor size is being increased from #6 copper to 3/0 ACSR, which will decreases the possibility of conductor breaking in the event of adverse weather or during line maintenance.

Finally, this project is expected to improve overall system efficiency, as the 12.5/7.2 kV system is capable of delivering the same power at a lower current than the 2.4 kV delta system; therefore reducing line losses. Increasing the conductor size and replacing 45-year-old transformers will also reduce line losses.

b) Priority:
This project upgrades the 2.4 kV delta system to 12.5/7.2 kV wye and replaces aging poles, small conductors, and overhead transformers that have reached their TUL. Based on age demographics, the poles in Iroquois Falls are in the worst condition of the three Towns. The project will eventually lead to the decommissioning of a substation. The five-year project was scored in safety, environment, reliability, and efficiency, and is ranked first out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	17.6	0	6	0	10.6	24.8	
Weight	10	8	7	6	5	4	
Weighted Score	176	0	42	0	53	99.2	370.2

c) Analysis of Project and Project Alternatives:
The alternatives to this project include:

- do nothing;
- upgrade 2.4 kV delta to 12.5/7.2 kV wye;
- replace the 2.4 kV delta overhead feeder with an underground feeder; and

- replace the 2.4 kV delta with 4.16/2.4 kV wye.

The first project alternative is a "do nothing" approach, which will not yield any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4 kV delta system, especially due to the #6 copper conductors and the 45-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

The second alternative, upgrade 2.4 kV delta to 12.5/7.2 kV wye, is the current planned project. This project mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

The third approach is to replace the 2.4 kV delta feeder with an underground feeder. This option is much more expensive, so is not recommended.

The fourth alternative is to replace the 2.4 kV delta feeder with a 4.16/2.4 kV wye feeder. Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

<u>2. Safety</u>
Completion of this project will improve safety by:

- converting from delta to wye; which is safer since delta has no reference to ground and will not trip if a phase inadvertently comes into contact with a ground point,
- replacing the poles that are approximately 45 years old with new poles, which decreases the chances of poles breaking due to deterioration; and
- increasing the conductor size from #6 copper to 3/0 ACSR, which decreases the possibility of the conductor breaking in the event of a storm.

<u>3. Cyber-security, Privacy</u>
N/A

<u>4. Co-ordination, Interoperability</u>
The completion of this project will make it easier for third party attachment to obtain new attachment permits in this section and to perform maintenance work on their existing attachments. The new construction will meet USF standards for overhead line design and will be built to satisfy the requirements of *O. Reg. 22/04 – Electrical Distribution Safety*.

<u>5. Economic Development</u>
One of the drivers of this project is reliability and a reliable supply of electricity is conducive of economic development.

6. Environmental Benefits

The replacement of transformers which are past their TUL will mitigate the potential for oil leaks into the environment. The new transformers will meet the latest energy efficiency standards.

C. Category-Specific Requirements

Customer Benefits

This project has significant impact on customers, as the project drivers include reliability and operating costs. Completion of this project will reduce unplanned outages, which reduces overtime cost. Also, this project reduces future replacement and maintenance costs of a delta station to eventually be removed from service. The upgraded 12.5/7.2 kV system can accommodate more customers than the existing 2.4 kV delta system which eventually reduce operating cost per customer.

Regional Planning

N/A

Advanced Technology, Interoperability, Cyber-security

The new transformers installed as part of this project will use the latest technology to meet modern energy efficiency standards.

Reliability, Efficiency, Safety, Co-ordination Benefits

This project will improve safety, overall system efficiency, operations, and maintenance by upgrading from 2.4 kV delta to 12.5/7.2 kV wye and replacing poles and conductors.

The failure risk of poles will be eliminated by replacing deteriorated poles, and mechanical strength of conductors will be increased to withstand conductor breaking in the event of storm. The voltage conversion, conductor upgrades, and transformer replacements will reduce line losses. This project brings NOW Inc. closer to decommissioning its delta station, which will eventually reduce O&M costs.

Timing/Priority Factors

Overhead upgrade projects generally achieve timing objectives. Possible risks to the project timeline include obtaining municipal consent and potential construction crew work overloads. These risks are mitigated by obtaining road authority review and using dedicated crews for the delta conversion.

Cost-benefit Analysis

The benefits of this project are improved safety, reduced outage probability, reduced line losses, and avoidance of future system O&M and trouble call costs. As indicated in the analysis of project alternatives – B.1.(c) – the project as scoped is the preferred trade-off between costs and benefits.

GP1 Project/Program Description

Computer software investments are made into operating system software in support of day-to-day business operations. In 2017, computer software investments have been planned to update NOW Inc.'s GIS, OMS, and CIS to improve operational efficiency and in response to customer feedback.

The GIS upgrades are a continuation of an ongoing digitization project to move NOW Inc.'s paper records into a computer system. The GIS will facilitate improved project planning and knowledge transfer for employee turnover.

The OMS upgrades have been planned in response to an opportunity to improve operational efficiency by reducing crew rolling hours in response to outages, and also in response to customer requests for better communication in the event of an outage.

Finally, the existing CIS will no longer be supported by the vendor due to its non-compliance with OESP (the new version is fully compliant). The CIS upgrades have been planned in response to this and in response to customer requests for paperless billing. The timing of the CIS upgrade coincides with the replacement of its server (in 2016) to save the $20,000 that would otherwise be spent installing the existing CIS onto the new server.

A. General Information on the Project/Activity

Historical and Future Capital Expenditures

Comparative expenditures in computer software over the historical and forecast period are shown in the table below, with the relevant year (2017) in bold. These costs have been broken down to their respective software system.

	Historical Capital Costs ($)					Future Capital Costs ($)				
	2012	2013	2014	2015	2016	**2017**	2018	2019	2020	2021
OS Software	-	-	-	-	-	**-**	5,000	5,000	5,000	5,000
GIS Upgrades	-	-	87,493	160,557	120,914	**-**	-	-	-	-
OMS Upgrades	-	-	-	-	-	**40,000**	-	-	-	-
CIS Upgrades	-	-	-	-	-	**75,000**	-	-	-	-
Total	-	-	87,493	160,557	120,914	**115,000**	5,000	5,000	5,000	5,000

Start Date
1 January 2017

In-service Date
31 December 2017

Customer Attachments
N/A

Load
N/A

Risks/Mitigation

The costs and benefits of a computer software upgrade largely depend on the offerings of the available vendors. The GIS is already being phased into service, but an OMS has yet to be chosen and the fault locating and outage reporting capabilities, as well as costs differ between vendors. NOW Inc. will mitigate this risk by meeting with multiple vendors, viewing product demos, and consulting with other utilities that have recently updated their GIS, OMS, or CIS.

Funding is also a risk for the computer software upgrades, as this is the lowest ranked project in NOW Inc.'s budget and would be the first to be deferred if funding was cut. NOW Inc. has planned its computer software investments based on opportunities to improve operational efficiency and feedback from its customers. In case the approved funding level does not permit the CIS upgrade, the current CIS will have to be re-installed onto a new server at an additional cost of $20,000; as the existing server is at the end of its life and a new one was installed in 2016.

There is also a regulatory risk that paperless billing will become mandatory in Ontario, in which case the cost of re-installing the existing CIS onto a new server would have been unnecessary. The existing CIS is not compliant with OESP and will no longer be supported by the software vendor. To mitigate this risk, NOW Inc. is planning to upgrade its CIS.

REG Investment

N/A

Leave to Construct

N/A

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

The main driver of the GIS and OMS upgrades is the opportunity to improve operational efficiency. The GIS upgrade will allow for improved project planning and facilitate knowledge transfer once NOW Inc.'s current staff leave the workforce. The new OMS will be able to estimate the fault location in order to reduce crew time spent restoring outages.

Secondary drivers for the OMS upgrade include improved reliability, as outages can be restored quicker. The OMS upgrade is also driven by customer feedback requesting more information on outages, and will be incorporated into an enhanced outage reporting system, depending on the vendor capability.

The primary driver of the CIS upgrade is customer feedback. Customers have asked for paperless billing and more information on conserving energy and reducing their electricity bill, which the new CIS will facilitate.

Secondary drivers for the CIS upgrades include regulatory compliance and reducing costs. As previously mentioned, the existing CIS does not comply with OESP and will no longer be supported by the software vendor. As also mentioned, the server which hosts the current CIS is at the end of its service life and requires replacement. If the CIS is mot upgraded at the same time, then the existing CIS must be re-installed onto the new server at additional cost. This additional cost would be avoided if the CIS upgrade were to correspond with the new server, as planned.

b) Priority:

The project was scored in regulatory, due to possible mandatory paperless billing, reliability, due to faster outage restoration time, and efficiency, due to streamlined project planning and fewer crew hours during outage restoration. The project is ranked eleventh out of the eleven planned projects/programs based on the scoring below.

Criteria	Safety	Regulatory	Environment	Load Growth	Reliability	Efficiency	Total Score
Score	0	2	0	0	5	10	
Weight	10	8	7	6	5	4	
Weighted Score	0	16	0	0	25	40	81

c) Analysis of Project and Project Alternatives:
This project involves three separate systems, the GIS, OMS, and CIS, which are discussed separately below.

The alternatives to the GIS upgrade are:

- do nothing; and
- upgrade the GIS.

The first project alternative is a "do nothing" approach. The amount spent on the GIS upgrades in previous years would not yield the expected benefits, implying this is not a feasible option. NOW Inc. would neither realize the benefits of improved project planning nor the ability to effectively transfer knowledge to its future workforce.

The second alternative, to upgrade the GIS, is the current planned project. The benefits in operational efficiency and knowledge transfer are achieved with the new software. This is the optimal approach.

The alternatives to the OMS upgrade are:

- do nothing; and
- implement an OMS.

The first project alternative is a "do nothing" approach. Cost savings and improved reliability due to faster outage location and restoration would not be achieved. NOW Inc. would not have the ability to report outage information, as requested by its customers.

The second alternative, to implement an OMS, is the current planned project. The benefits in operational efficiency and reliability are achieved with the new software. NOW Inc. will be able to report detailed information on outages to its customers through various media depending on the software vendor. This is the optimal approach.

The alternatives to the CIS upgrade are:

- do nothing;
- replace the server and upgrade the CIS; and
- replace the server and re-install the existing CIS.

The first project alternative is a "do nothing" approach. The server on which the CIS is installed is at the end of its service life and has to be replaced, else it will fail and bring down the CIS. This is not a viable option.

The second alternative, to upgrade the CIS, is the current planned project. NOW Inc. will be able to implement paperless billing at the request of its customers, which will likely also meet regulatory requirements for paperless billing in the future. Since the server also needs to be replaced, upgrading the CIS at the same time will avoid the cost of re-installing the current CIS on the new server. This is the optimal approach.

The third alternative, to replace the server and re-install the existing CIS, costs less than upgrading the CIS, but NOW Inc. would not be able to switch to paperless billing. If paperless billing were made mandatory in the future, then the cost of re-installing the current CIS onto the new server would be wasted.

<u>2. Safety</u>
This investment will not have any effect on health and safety protections and performance

<u>3. Cyber-security, Privacy</u>
The vendor-issued software will comply with NERC cyber-security and grid protection requirements, and will conform to all applicable laws, standards, and best utility practices pertaining to customer privacy as part of the purchasing requirements.

<u>4. Co-ordination, Interoperability</u>
The three systems contemplated in this project, the GIS, OMS, and CIS, are well-known and established tools in the electrical utility industry. NOW Inc. has already selected the GIS based on meetings with vendors and co-ordination with other electrical utilities in Ontario. Selection of the OMS and CIS will also be based on meetings with vendors and co-ordination with similarly-sized utilities in Ontario.

Investment into the GIS enables improved project planning in the future and facilitates knowledge transfer when NOW Inc.'s current staff retires. Investment into the OMS enables faster and more efficient outage restoration in the future and addresses customer requests for improved outage information. Investment into the CIS enables paperless billing at the request of NOW Inc.'s customers, and which may become a mandatory regulatory requirement in the future.

<u>5. Economic Development</u>
Investments into the OMS will allow for faster outage restoration times and a reliable supply of electricity is conducive of economic growth. The ability to accurately report outages and expected restoration times will benefit local residents and businesses who rely on electricity.

<u>6. Environmental Benefits</u>
Upgrading the CIS will allow NOW Inc. to implement paperless billing. Less paper and mailing service usage will benefit the environment.

C. Category-Specific Requirements

Cost-benefit Analysis
As described in B.1(c), *Analysis of Project and Project Alternatives*, the proposed project plan to upgrade the GIS, OMS, and CIS is the optimal approach. Upgrades to the GIS are the final phase of an ongoing project and implementing an OMS and upgrading the CIS are both largely due to feedback from NOW Inc.'s customer survey. Upgrades to the GIS will improve operational efficiency through streamlined project planning and will facilitate knowledge transfer to NOW Inc.'s future staff. The implementation of an OMS will allow for faster and more efficient outage restoration and improved outage reporting to customers. The upgrade of the CIS will allow NOW Inc. to transition to paperless billing as requested by customers, and will offset the cost of re-installing the existing CIS onto the new server.

The exact costs and benefits depend on the level of funding approved in NOW Inc.'s distribution rates and on the solutions available from software vendors. Accordingly, no quantitative analysis has been performed at this time due to the number of variables outside of NOW Inc.'s control.

Appendix B: North and East of Sudbury Needs Screening Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra Qasim Raza
Independent Electricity System Operator	Chris Reali Philip Woo
Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the North & East of Sudbury region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by Working Group participants.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2026. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers
The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.

B. 500/115kV Autotransfomers
The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit

C. 230/115 kV Autotransformers
The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit

D. Transmission Lines & Ratings
The 500kV, 230kV transmission lines are adequate over the study period.

Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.

E. 230 kV and 115 kV Connection Facilities
The 230kV and 115kV connection facilities in this region are adequate over the study period.

F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS
The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus

G. Ansonville T2 or D3K Outages
With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

System Reliability, Operation and Restoration Review

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the North & East of Sudbury Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 Regional Issue / Trigger

The NA for the North & East of Sudbury Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The North & East of Sudbury Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

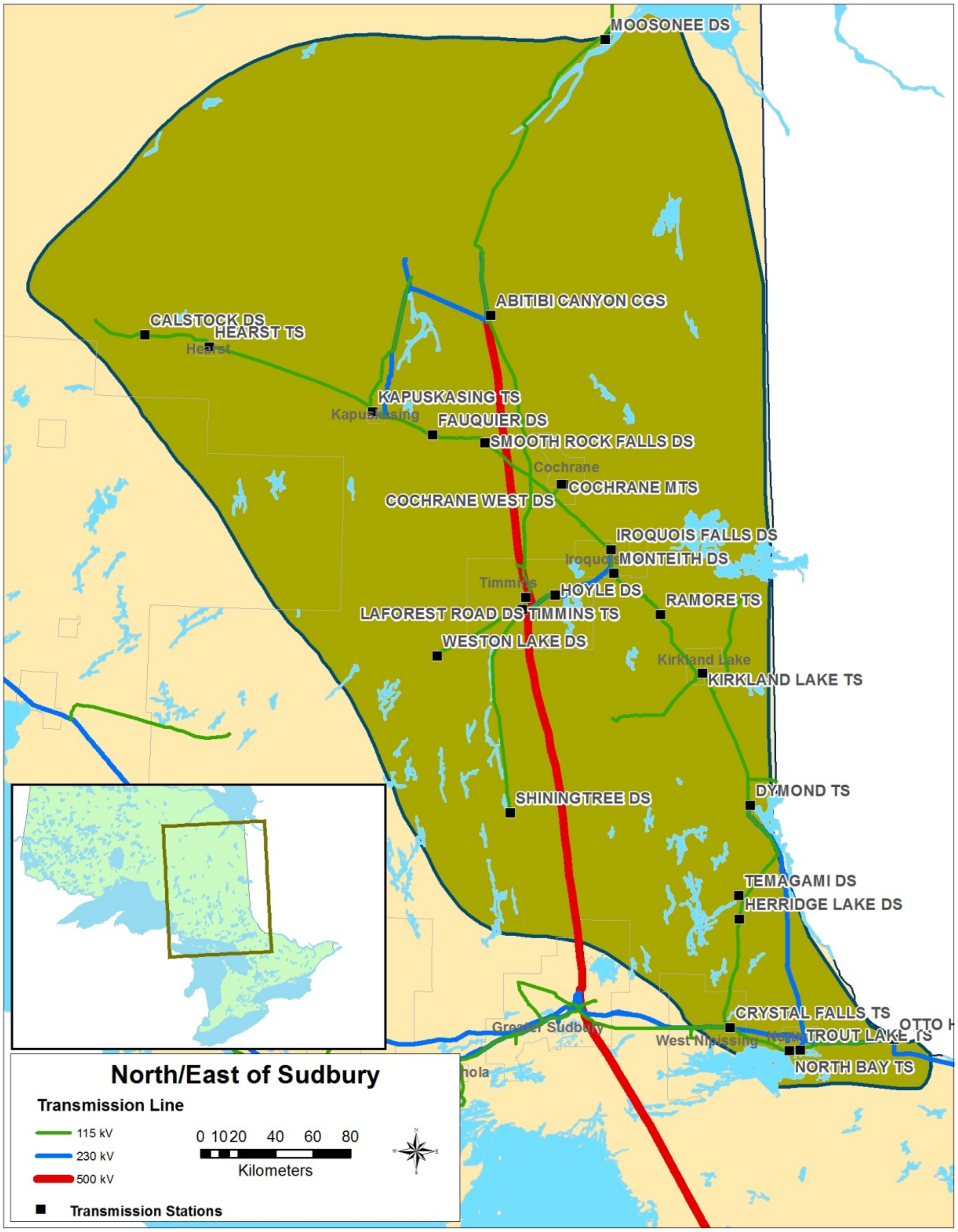


Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

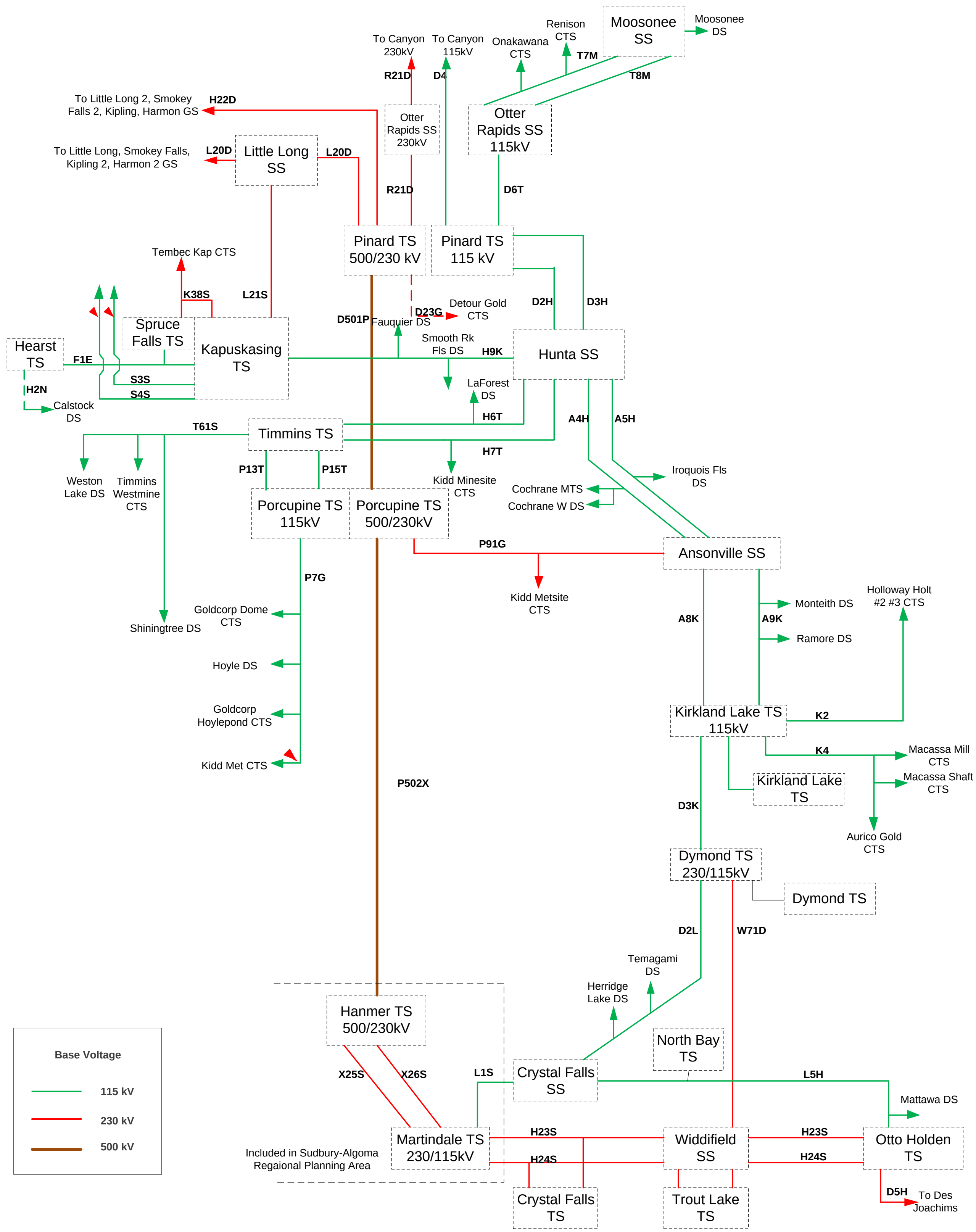


Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, Working Group participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 Needs Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region’s LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
   - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
   - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings.
   - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
   - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
   - With two elements out of service, no more than 600 MW of load is lost by configuration.
   - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

6.1 500/230kV Autotransfomers

The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers

The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings

The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 SYSTEM RELIABILITY, OPERATION AND RESTORATION

7.1 Performance

The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration

Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 Aging Infrastructure and Replacement of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

<u>Timmins TS / Kirkland Lake TS – Voltage Regulation Issues</u>

11 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

12 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Appendix C: Renewable Energy Generation Investments Plan

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

Northern Ontario Wires Inc.
2017 Cost of Service Application

12 May 2016

TABLE OF CONTENTS

1 INTRODUCTION

Northern Ontario Wires Inc. ("**NOW Inc.**") is preparing to file a Cost of Service ("**COS**") Application for the prospective rate year of 2017. In accordance with the Ontario Energy Board ("**OEB**") *Filing Requirements for Electricity Transmission and Distribution Applications*, NOW Inc. has prepared this Renewable Energy Generation ("**REG**") Investments Plan to accompany its Distribution System Plan ("**DSP**") and COS Application.

This REG Investments Plan provides information on NOW Inc.'s ability to accommodate new REG connections to its distribution system. The purpose of this REG Investments Plan is to inform the Independent Electricity System Operator ("**IESO**") that it has not identified any REG investments in its DSP and to request the IESO to provide a letter commenting on this information.

Section 2 of this REG Investments Plan provides background information regarding NOW Inc.'s distribution system. Section 3 lists the existing and proposed REG connections. Section 4 contains the system assessment to identify constraints. Finally, Section 5 summarizes that there are no proposed investments to facilitate new REG connections.

2 NORTHERN ONTARIO WIRE INC.'S DISTRIBUTION SYSTEM

NOW Inc. is a local distribution company holding Distribution License ED-2003-0018, which owns and operates electrical infrastructure, serving customers in the Town of Cochrane, the Town of Iroquois Falls, and the Town of Kapuskasing. As mandated by the *Electricity Act, 1998*, NOW Inc. was incorporated in 1999 during the amalgamation of the Cochrane Public Utilities Commission and the Iroquois Falls Hydro Electric Commission. In the year 2000, NOW Inc. purchased the assets of Kapuskasing Wires Inc. The Corporation of the Town of Cochrane is the sole shareholder of NOW Inc.

NOW Inc.'s service area totals 28 square kilometres, all of which is classified as urban. The three towns have a combined population of approximately 18,100; NOW Inc. serves 6,101 customers as of the 2015 year-end customer count.

NOW Inc. owns a total of six distribution substation ("**DS**"). In Cochrane, NOW Inc. receives power at 115 kV from Hydro One Networks Inc. ("**HONI**") and steps it down to 25/14.4 kV and 4.16/2.4 kV.

In Iroquois Falls, NOW Inc. receives power from the HONI-owned Iroquois Falls DS feeders F1 and F2 at 12.5/7.2 kV. NOW Inc. owns two DS in Iroquois falls which step power down to 4.16/2.4 kV and one DS which steps power down to 2.4 kV delta. NOW Inc. is in the process of converting its 2.4 kV delta system to 12.5/7.2 kV, at which point it will retire the 12.5/7.5-2.4 kV delta DS.

In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4 kV. NOW Inc. owns one DS in Kapuskasing which steps power down to 4.16/2.4 kV. NOW Inc. is in the process of upgrading the 4.16/2.4 kV system in Kapuskasing to 25/14.4 kV, which will eliminate the need for a DS in Kapuskasing.

3 Existing and Proposed Connections

The existing REG connections within NOW Inc.'s service territory under the Feed-in Tariff ("**FIT**") Program, all fall under the category of microFIT (10 kW or less). All of the installed REG are solar photovoltaics ("**PV**"). There are currently thirteen microFIT connections with a cumulative capacity of 127.97 kW, as listed in Table 1.

Table 1: List of installed REG connections.

Address	City	Type	Installation Date	Feeder	Capacity (kW)
14 Ash St.	Kapuskasing	Solar PV	Apr. 6, 2010	M2	9.8
459 Eleventh Ave.	Cochrane	Solar PV	July 17, 2010	EAST	10
438 Eleventh Ave.	Cochrane	Solar PV	Sep. 3, 2012	EAST	10
444 Eleventh Ave.	Cochrane	Solar PV	May 19, 2011	EAST	10
80 Cedar Street	Kapuskasing	Solar PV	Aug. 26, 2011	M2	10
Millview Road	Kapuskasing	Solar PV	Apr. 2, 2012	M2	10
499 Fourth Street	Cochrane	Solar PV	Apr. 10, 2012	EAST	10
364 Eleventh Ave.	Cochrane	Solar PV	June 19, 2012	EAST	10
58 Algonquin Rd	Cochrane	Solar PV	Apr. 25, 2013	EAST	10
31 Mateev Ave.	Kapuskasing	Solar PV	June 5, 2013	M2	8.17
531 Cedar Str.	Kapuskasing	Solar PV	Jan. 11, 2012	M2	10
201 Murdock	Kapuskasing	Solar PV	Jan. 17, 2012	M2	10
533 Niagara	Kapuskasing	Solar PV	July 19, 2012	M2	10

There are no proposed REG connections and NOW Inc. has not forecast for any additional FIT or microFIT connections over the five-year planning period of its DSP (2017 to 2021) due to upstream capacity constraints at the HONI-owned Timmins TS.

4 System Assessment to Identify Constraints

There are no constraints on NOW Inc.'s distribution system that would prevent the connection of new REG installations. However, there is currently no capability to connect new REG projects in NOW Inc.'s service territory due to upstream capacity constraints at the HONI-owned Timmins TS.

5 Proposed Investments to Facilitate New Connections

Since the REG connection capacity in NOW Inc.'s service territory is constrained by upstream restrictions at HONI's Timmins TS, no investments have been proposed to facilitate new REG connections over the years 2017 to 2021. NOW Inc. will continue to consult with HONI in order to enable new REG connections in its service category. To that end, HONI is initiating the regional planning process for the North/East of Sudbury region, which NOW Inc. is a part of, and will prepare the Needs Screening for the region.

Appendix D: IESO Comment Letter on Renewable Energy Generation Investments Plan

IESO Letter of Comment

Northern Ontario Wires Inc.

Renewable Energy Generation Investment Plan

May 27, 2016

Independent Electricity System Operator

Introduction

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

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

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

Northern Ontario Wires Inc. – Distribution System Plan

On May 16, 2016, the IESO received Northern Ontario Wires Inc.'s ("NOW Inc.") Renewable Energy Generation Investment Plan ("Plan") for the 5-year period 2017-2021. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

With respect to existing and proposed REG connections, Table 1 of the Plan illustrates that NOW Inc. has connected 13 microFIT projects totalling 127.97 kW of capacity.

Section 4 of the Plan indicates that although there are no constraints on the distribution system to prevent additional REG connections, NOW Inc. is limited by upstream capacity constraints. Specifically, on page 2, NOW Inc. indicates that "[t]here are no proposed REG connections and NOW Inc. has not forecast for any additional FIT or microFIT connections over the five-year planning period of its DSP (2017 to 2021) due to upstream capacity constraints at the HONI-owned Timmins TS."

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

According to the IESO's information as of April 30, 2016, the IESO has offered contracts to 13 microFIT projects totalling 127.97 kW of capacity.

The Transmission Availability Table ("TAT Table") available on the IESO's FIT website confirms that there is currently no availability at Timmins TS.:
http://fit.powerauthority.on.ca/sites/default/files/version4/FIT-4-TS-TAT-table-final-July-9-2015.pdf

The REG connections information in NOW Inc.'s Plan is therefore consistent with that of the IESO.

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

For regional planning purposes, NOW Inc.'s distribution system is located in the North and East of Sudbury Region (Group 3). This region includes Hydro One Networks Inc. ("Hydro One" or "HONI") (Distribution and Transmission), Greater Sudbury Hydro Inc., Hearst Power Distribution Company Limited, North Bay Hydro Distribution Ltd., and Northern Ontario Wires Inc.

Regional planning for the North and East of Sudbury Region commenced in October 2015 with the information gathering process and the development of the Needs Assessment Report which was completed by Hydro One on April 15, 2016. As determined by the Needs Assessment working group, of which NOW Inc. was a part, no further regional coordination is required, as the voltage regulation issues at Timmins TS affecting NOW Inc. can be best addressed by a wires solution through local planning led by Hydro One. NOW Inc. indicates that because of the upstream restrictions at Timmins TS, no investments are proposed over the planning period, and states its intention to consult with Hydro One in order to enable REG connections (section 5).

The regional planning process for this region is now complete and will be undertaken again when the next 5-year planning cycle commences, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

The IESO appreciates the opportunity to comment on the Renewable Energy Generation Investment Information provided by Northern Ontario Wires Inc. as part of its 2017-2021 Distribution System Plan.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Appendix E: Substation Oil Analysis Report

SIEMENS

Customer Services Division

Prepared for:

Dan Bouchier.

Regarding:

2015 Oil Analysis for
Northern Ontario Wires

Prepare By:	John Love
Technician:	John love
Date of Report:	August 7, 2015
Job Number:	41171263

Table of Contents

1.0 Scope of Work

Siemens Industrial Services group performed the following work on June, 2015:

- Oil sampling and visual inspections were performed on (12) Transformers in Cochrane.
- Oil sampling and visual inspections were performed on (5) Transformers in Iroquois Falls.
- Oil sampling and visual inspections were performed on (1) Transformers in Kapuskasing.

2.0 Summary of Oil Tests

2.1 Inspection and Oil Analysis of (17) Transformers

Insulating Oil Sampling and Analysis

All samples were taken according to ASTM standards (ASTM D923, ASTM D3613) and the analysis was performed by an independent laboratory.

The following tests were performed as part of our transformer insulating oil analysis:

ASTM D877 Liquid Dielectric Test

The dielectric breakdown voltage of an insulating liquid is a measure of the liquid's ability to withstand electric stress without failure. It serves to indicate the presence of contaminating agents such as water, dirt, moist cellulose fibers or conductive particles in the liquid. One or more of these may be present in significant concentrations when low dielectric breakdown values are found by test. However, high dielectric breakdown voltage does not indicate the absence of all contaminants; it may merely indicate that the concentrations of contaminants that are present in the liquid between the electrodes are not large enough to harmfully affect the average breakdown voltage of the liquid when tested by this method.

ASTM D971 Interfacial Tension

This test results in a reliable indication of the presence of hydrophilic compounds. When certain contaminants such as soaps, paints, varnishes and oxidation products are present in the oil, the film strength of the oil is weakened, thus requiring less force to rupture. For oils in service, a decreasing value indicates the accumulation of contaminants, oxidation products, or both. It is a precursor of objectionable products that may attack the insulation and interfere with the cooling of transformer windings.

ASTM D974 Neutralization Number

The acid number of oil is a measure of the amount of acidic materials present. As oils age in service, the acidity, and therefore the acid number, increases. Used oil having a high acid number indicates the oil is either oxidized or contaminated with materials such as varnish, paint, or other foreign matter. This test serves as an indicator of the potential of the oil to form sludge.

ASTM D 1500 Color

Color change in an insulating oil can be attributed to the deterioration of the liquid by oxidation and/or the effect of insulating material on the liquid. This color change is an indication of the condition of the insulating liquid, but the color test alone is not a reliable test. A color change indicates that further investigation is required. The color of insulating liquids are expressed by a set of color numbers, zero to eight.

ASTM D1533 Moisture Content

Its water content has harmful effects on the electrical characteristics of an insulating liquid. A high water content may make a dielectric liquid unsuitable for some applications because a deterioration in properties such as dielectric breakdown voltage may occur. This test is suitable for use in acceptance specifications, in control of processing and evaluating the condition of dielectric liquids in service.

.

ASTM D-924, Power Factor (Dissipation Factor)

Power Factor is a measure of the dielectric losses in an insulating fluid due to heat dissipation when the fluid is placed in an electrical AC field. A low dissipation factor indicates low dielectric losses. Power factor is a means of evaluating the quality of the insulating fluid. When used in conjunction with other oil quality tests, the power factor can be useful in complementing the description of the state of the fluid insulation

ASTM D35612 Dissolved Gas Analysis

Gas analysis is based upon the fact that both electrical insulating oil and cellulose insulation breakdown under abnormal thermal or electrical stress. The results of these stresses are both volatile and non-volatile gases, known as fault gases.

Gas analysis is the technique that identifies fault gases, relates their quality, generation rate and relevant ratios, to type and severity of fault.

Increased frequency or periodic testing will significantly increase the value and accuracy of fault gas analysis.

Typical fault gases*:*

Hydrogen, H_2
Methane, CH_2
Ethane, C_2H_6
Ethylene, C_2H_4
Acetylene, C_2H_2
Carbon Monoxide, CO
Carbon Dioxide, CO_2

Typical types of transformer problems that can be detected are:

Thermal Degradation
Low Operational Temperature
High Operational Temperature, Hot spot
Arcing
Partial Discharges
Degradation of Paper Insulation

All typical limit values have been derived from transformer age, industry standards and insulating liquid capacity. Although some values may exceed the safe limits, it may only become a concern if the generation rate is significant. Our report would indicate if immediate re-sampling was required to determine this rate.

The importance of periodic oil and gas analysis should not be underestimated. Analysis of the fault gases formed can give information on the condition of the transformer, without the need for a costly internal inspection. Various items form general conductor overheating, circulating current to serious arcing problems can be determined from this form of testing.

3.0 Observations and Recommendations

Test results obtained from the Weidmann Diagnostics Solutions laboratory in Burlington, ON. Test standards as indicated on the report forms.

3.1 Transformer Main Kapuskasing

3.1.1 Diagnostics

Hydrogen: Condition 2 Indications of partial discharge activity (100 ppm).
Carbon Monoxide: Condition 2 Indications of overheated cellulose insulation (350 ppm).
Exceeds limit for in-service oil (25 dynes/cm min).

3.1.2 Recommendations

Retest annually and continue normal operation

3.2 Detroyes LTC Iroquois Falls

3.2.1 Diagnostics

Moisture in Oil: Exceeds limit for equipment > 69 kV for in-service oil - kV not provided (25 ppm max).

3.2.2 Recommendations

Plan a shutdown to investigate ingress of moisture.

3.3 Transformer Abitibi Iroquois Falls

3.3.1 Diagnostics

Carbon Monoxide: Condition 2 Indications of overheated cellulose insulation (350 ppm).
Carbon Dioxide: Condition 2 Indications of overheated cellulose insulation (2500 ppm).
Interfacial Tension: Exceeds limit for in-service oil (25 dynes/cm min).
Moisture in Oil: Exceeds limit for in service oil (35ppm max)

3.3.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.4 Abitibi LTC Iroquois Falls

3.4.1 Diagnostics

Moisture in Oil: Exceeds limit for in-service oil (30 ppm max).

3.4.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.5 Transformer Cambridge Iroquois Falls

3.5.1 Diagnostics

Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570ppm).
TDCG: Condition 2 Levels exceed normal concentrations. Fault may be present (720 ppm).
Power Factor: Exceeds limit for in-service oil (0.5% max).

3.5.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.6 Transformer Regulator Cochrane

3.6.1 Diagnostics

Interfacial Tension: Exceeds limit for in-service oil (25 dynes/cm min).

3.6.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.7 T1-LTC Cochrane

3.7.1 Diagnostics

Moisture in Oil: Exceeds limit for in-service oil (25 ppm max).

3.7.2 Recommendations

Plan a shutdown to investigate ingress of moisture.

3.8 Transformer T REG MAIN

3.8.1 Diagnostics

Moisture in Oil: Exceeds limit for in-service oil (35 ppm max).

3.8.2 Recommendations

Plan a shutdown to investigate ingress of moisture

3.9 Transformer T1C Cochrane

3.9.1 Diagnostics

Interfacial Tension: Exceeds limit for in-service oil (30 dynes/cm min).

3.9.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.10 Transformer T1B Cochrane

3.10.1 Diagnostics

Interfacial Tension: Exceeds limit for in-service oil (30 dynes/cm min).

3.10.2 Recommendations

Continue normal operation. Resample for testing within one year.

3.11 Transformer T1A Cochrane

3.11.1 Diagnostics

Interfacial Tension: Exceeds limit for in-service oil (30 dynes/cm min).

3.11.2 Recommendations

Continue normal operation. Resample for testing within one year.

4.0 APPENDIX

4.1 Oil Test Results

4.1 OIL TEST RESULTS

Table of Contents
Job #41171263 IF

PAGE

Customer Northern Ontario Wires
User Northern Ontario Wires
Plant Iroquois Falls

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Abitibi POSITION Main Gate

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 261784

SPECIFICATION NO. KVA 2,000 / / TYPE ON5 CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE 5.3 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1420 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 12,000 ◉ DELTA ○ WYE RATED CURRENT 96 / / AMPERES

SECONDARY VOLTAGE 4,000 / 2,309 ○ DELTA ◉ WYE RATED CURRENT 289 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/25/2011	11/18/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006	6/1/2005
PARTICLES	TRACE	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	30	47	46	42	28					
INTERFACIAL TENSION (D/CM)	18.99	19.36	18.92	18.54	20					
ACIDITY (MG KOH/G)	0.195	0.189	0.214	0.293	.168					
ASTM COLOR NO.	L2.0	L2.0	L2.0	0	1.5					
PCB CONTENT (PPM)				3.4						
E.P.A. CLASSIFICATION				1260						
POWER FACTOR (%)	0.081	0.089	0.089	0.110	.085					
WATER CONTENT (PPM)	37	28	17	38						
SPECIFIC GRAVITY	0.8701	0.8704		0.876	.874					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/25/2011	11/18/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006	6/1/2005
* HYDROGEN (H2)	28	23	17	16	32					
* METHANE (CH4)	6	6	6	5	6					
* ETHANE (C2H6)	4	3	4	4	1					
* ETHYLENE (C2H4)	8	6	7	8	7					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	288	358	349	302	312					
CARBON DIOXIDE (CO2)	2,512	2,811	2,716	2,157	2,935					
NITROGEN (N2)	67,218	64,685	70,229	51,488	65,751					
OXYGEN (O2)	25,858	21,483	23,715	18,691	21,410					
TOTAL GAS	95,922	89,375	97,043	72,671	90,454					
TOTAL COMBUSTIBLE GAS	334	396	383	335	358					

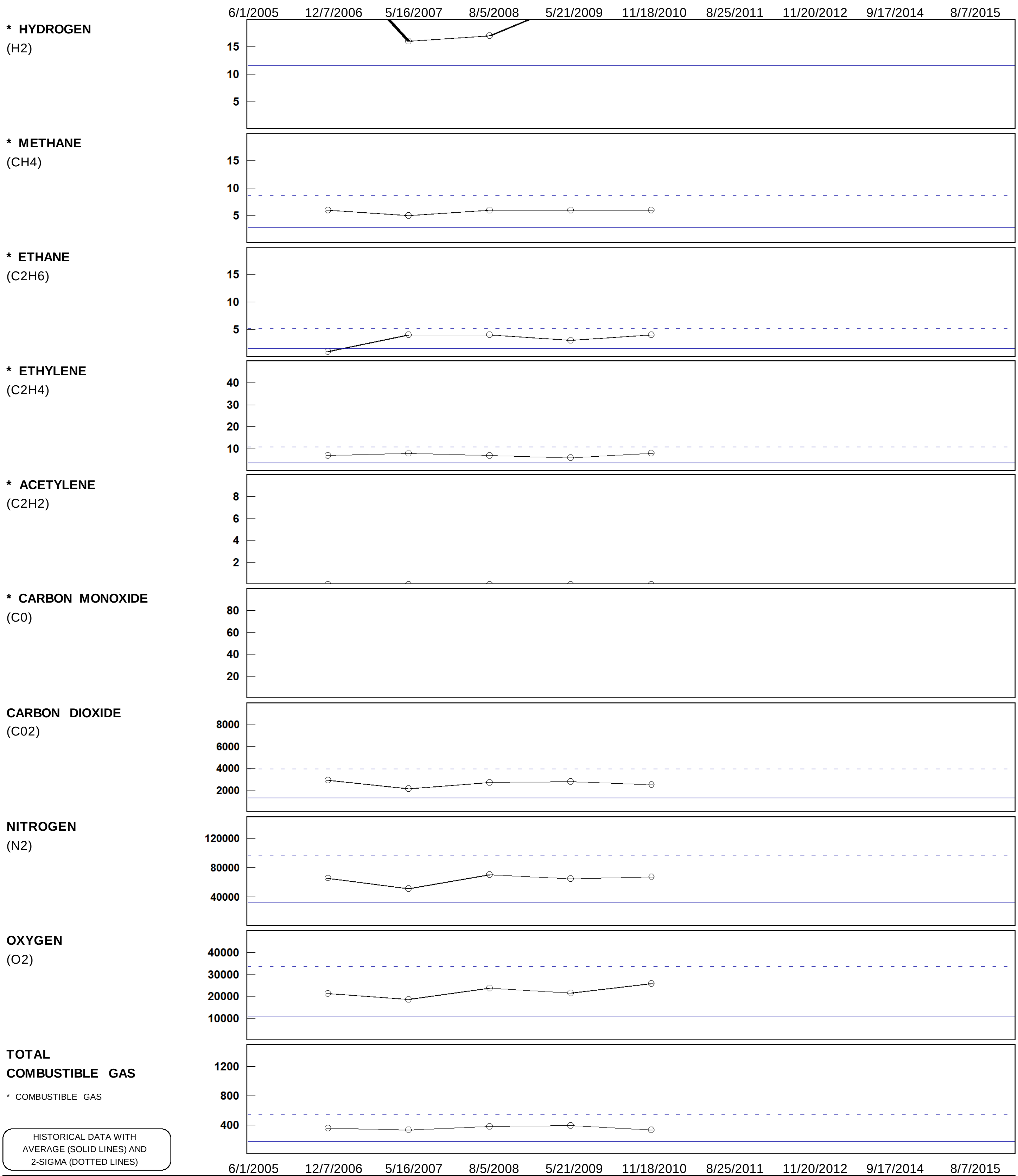
* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0	PAGE	
SUBSTATION	Abitibi	POSITION	Main Gate
JOB #	41171263 IF		
SERIAL NO.	261784		



REVISED 2/11/2013

SIEMENS

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Abitibi	POSITION	Main Gate	JOB #	41171263 IF
SERIAL NO.	261784				

DIELECTRIC STRENGTH
(KV)

INTERFACIAL TENSION
(D/CM)

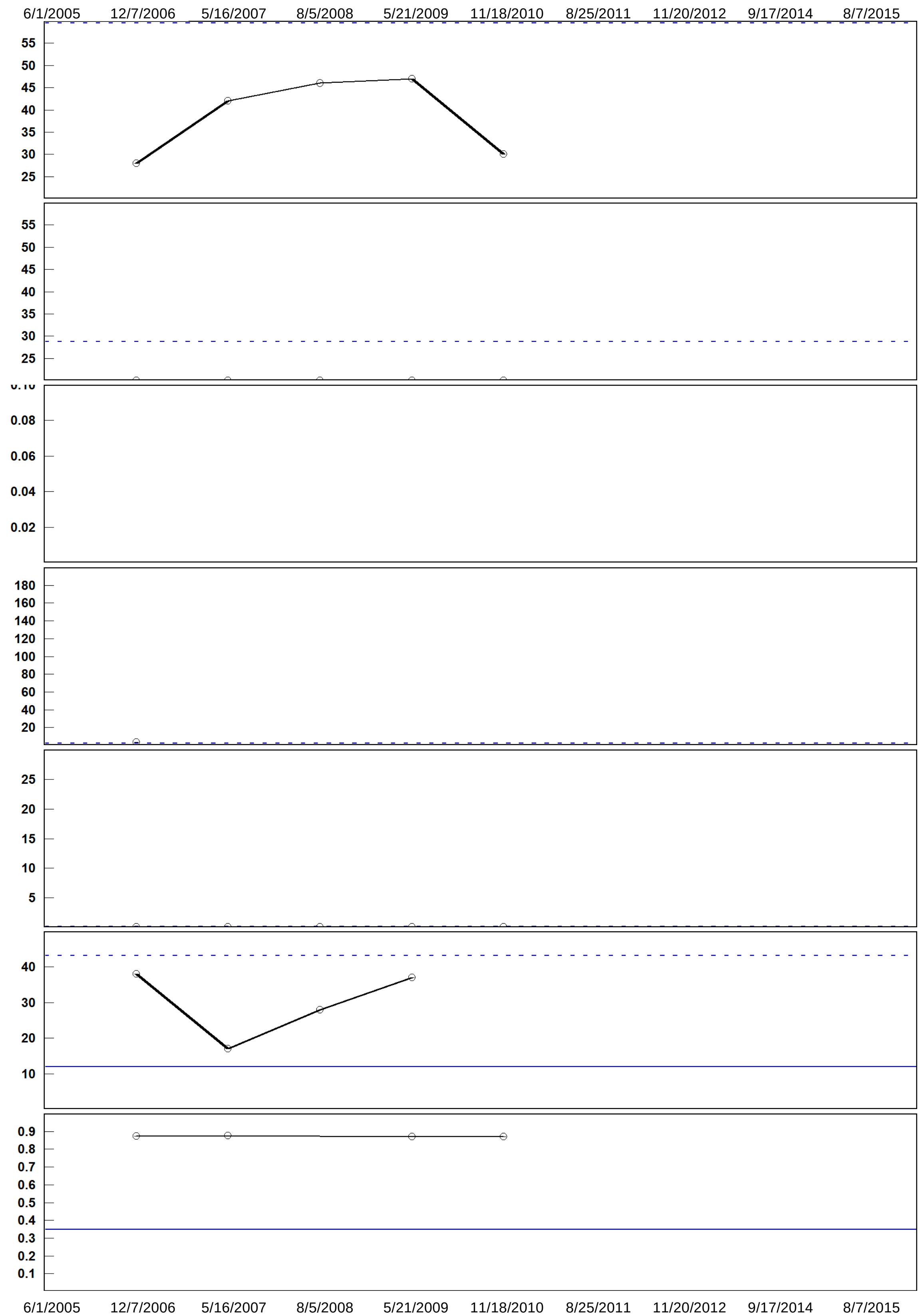
ACIDITY
(MG KOH/G)

PCB CONTENT
(PPM)

POWER FACTOR
(%)

WATER CONTENT
(PPM)

SPECIFIC GRAVITY



HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT ANALYSIS

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Abitibi POSITION Main Gate

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 261784

SPECIFICATION NO. KVA 2,000 / / TYPE ON5 CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE 5.3 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1420 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 12,000 ◉ DELTA ○ WYE RATED CURRENT 96 / / AMPERES

SECONDARY VOLTAGE 4,000 / 2,309 ○ DELTA ◉ WYE RATED CURRENT 289 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

TEST RESULTS

			ASTM
PARTICLES	TRACE		D-1524
DIELECTRIC STRENGTH	30	kV	D-877
INTERFACIAL TENSION	18.99	D/CM	D-971
ACIDITY	0.195	MG KOH/G	D-974
ASTM COLOR NO.	L2.0		D-1500
PCB CONTENT		PPM	D-4059
E.P.A. CLASSIFICATION			
POWER FACTOR	0.081	%	D-924
WATER CONTENT	37	PPM	D-1533B
SPECIFIC GRAVITY	0.8701		D-287

TRANSFORMER INSPECTION

TEMPERATURE GUAGE PRESENT READING °C

TEMPERATURE GUAGE HIGH READING °C

PRESSURE/VACUUM GUAGE READING #

PAINT CONDITION

GASKETS

BUSHINGS

LIQUID LEVEL

DISSOLVED GAS ANALYSIS ASTM D-3612C

* HYDROGEN	(H2)	28	PPM
* METHANE	(CH4)	6	PPM
* ETHANE	(C2H6)	4	PPM
* ETHYLENE	(C2H4)	8	PPM
* ACETYLENE	(C2H2)	0	PPM
* CARBON MONOXIDE	(CO)	288	PPM
CARBON DIOXIDE	(CO2)	2,512	PPM
NITROGEN	(N2)	67,218	PPM
OXYGEN	(O2)	25,858	PPM
TOTAL GAS		95,922	PPM
TOTAL COMBUSTIBLE GAS		334	PPM
EQUIVALENT TCG READING		0.3182	%

* COMBUSTIBLE GAS

PLUMBING TABLE

	P	S	OTHER
TOP			
BOTTOM			
VENT			
ACCESS PORT			
SAMPLE VALVE			

ANALYSIS OF TEST RESULTS

CONDITION	SERVICE
○ EXCELLENT	☐ NO SERVICE REQUIRED
○ GOOD	☐ RETEST IN ____ MONTHS:
○ INVESTIGATE	☐ SERVICE REQUIRED
○ POOR	☐ SERVICE IMMEDIATELY
○ FAILED UNIT	☐ REFER TO COMMENTS

COMMENTS:

DEFICIENCIES:

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

57100, REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Abitibi POSITION Main Gate - LTC

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 261784

SPECIFICATION NO. KVA 2,000 / / TYPE ONS CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE 5.3 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1420 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 12,000 ◉ DELTA ○ WYE RATED CURRENT 96 / / AMPERES

SECONDARY VOLTAGE 4,000 / 2,309 ○ DELTA ◉ WYE RATED CURRENT 289 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/25/2011	11/18/2010					
PARTICLES	TRACE	CLR&SPRK	TRACE	MODERATE						
DIELECTRIC STRENGTH (kV)	26	41	32	40						
INTERFACIAL TENSION (D/CM)	18.81	19.22	18.75	18.8						
ACIDITY (MG KOH/G)	0.225	0.211	0.232	.335						
ASTM COLOR NO.	L1.5	1.5	L1.5	L1.5						
PCB CONTENT (PPM)										
E.P.A. CLASSIFICATION										
POWER FACTOR (%)	0.065	0.076	0.065	.057						
WATER CONTENT (PPM)	40	34	27	45						
SPECIFIC GRAVITY	0.8594	0.8593	0.8595	.864						

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/25/2011	11/18/2010					
* HYDROGEN (H2)	66	102	103	169	173					
* METHANE (CH4)	3	4	3	4	4					
* ETHANE (C2H6)	1	1	1	1	2					
* ETHYLENE (C2H4)	6	5	5	7	7					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	143	176	154	249	219					
CARBON DIOXIDE (CO2)	1,524	1,576	1,382	1,608	2,621					
NITROGEN (N2)	66,443	69,825	54,368	64,284	61,956					
OXYGEN (O2)	27,835	26,688	20,675	23,304	19,838					
TOTAL GAS	96,021	98,377	76,691	89,626	84,820					
TOTAL COMBUSTIBLE GAS	219	288	266	430	405					

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

REVISED 2/11/2013

SIEMENS

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Abitibi	POSITION	Main Gate - LTC	JOB #	41171263 IF
SERIAL NO.	261784				

* HYDROGEN (H2)

* METHANE (CH4)

* ETHANE (C2H6)

* ETHYLENE (C2H4)

* ACETYLENE (C2H2)

* CARBON MONOXIDE (C0)

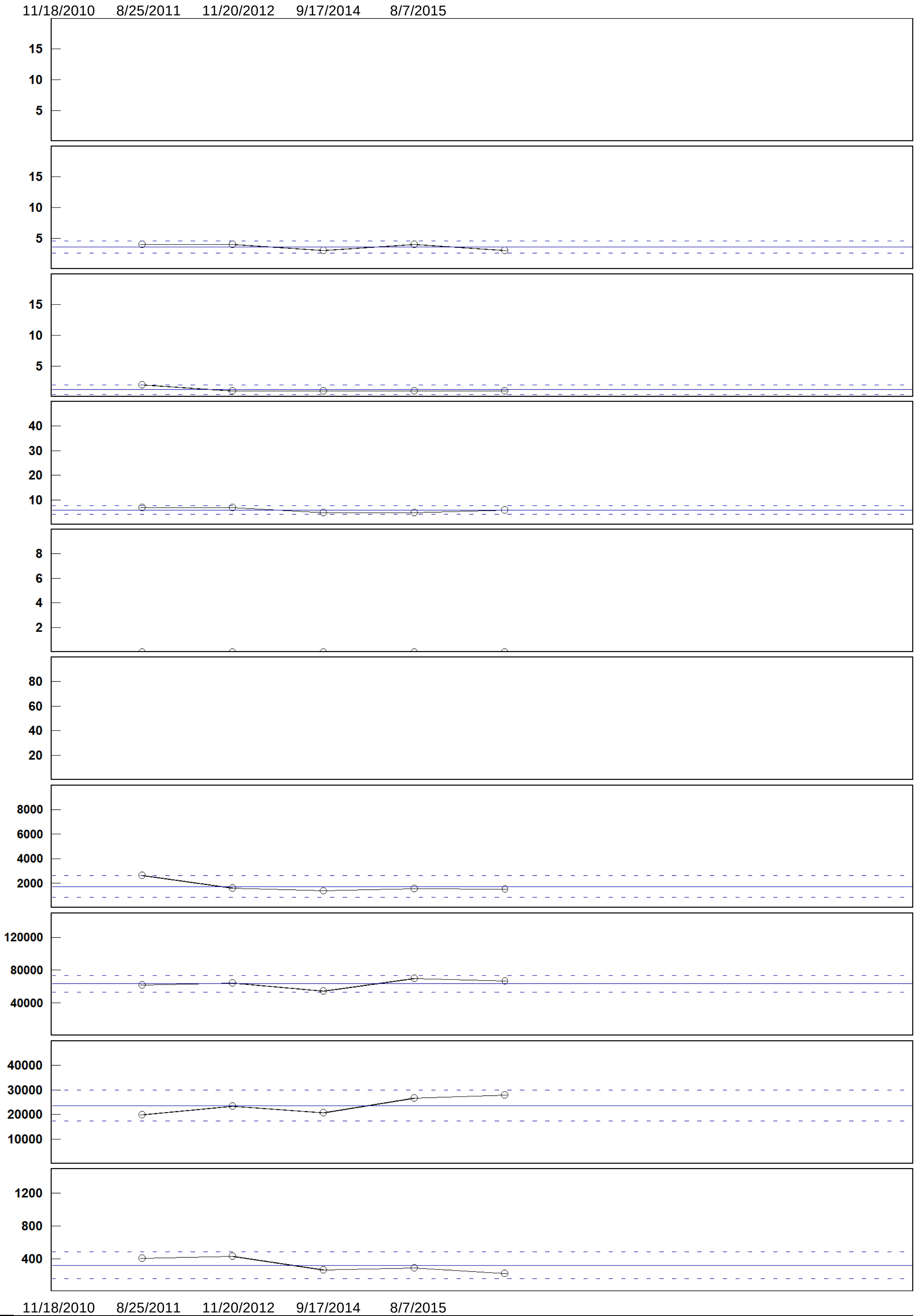
CARBON DIOXIDE (C02)

NITROGEN (N2)

OXYGEN (O2)

TOTAL COMBUSTIBLE GAS

* COMBUSTIBLE GAS



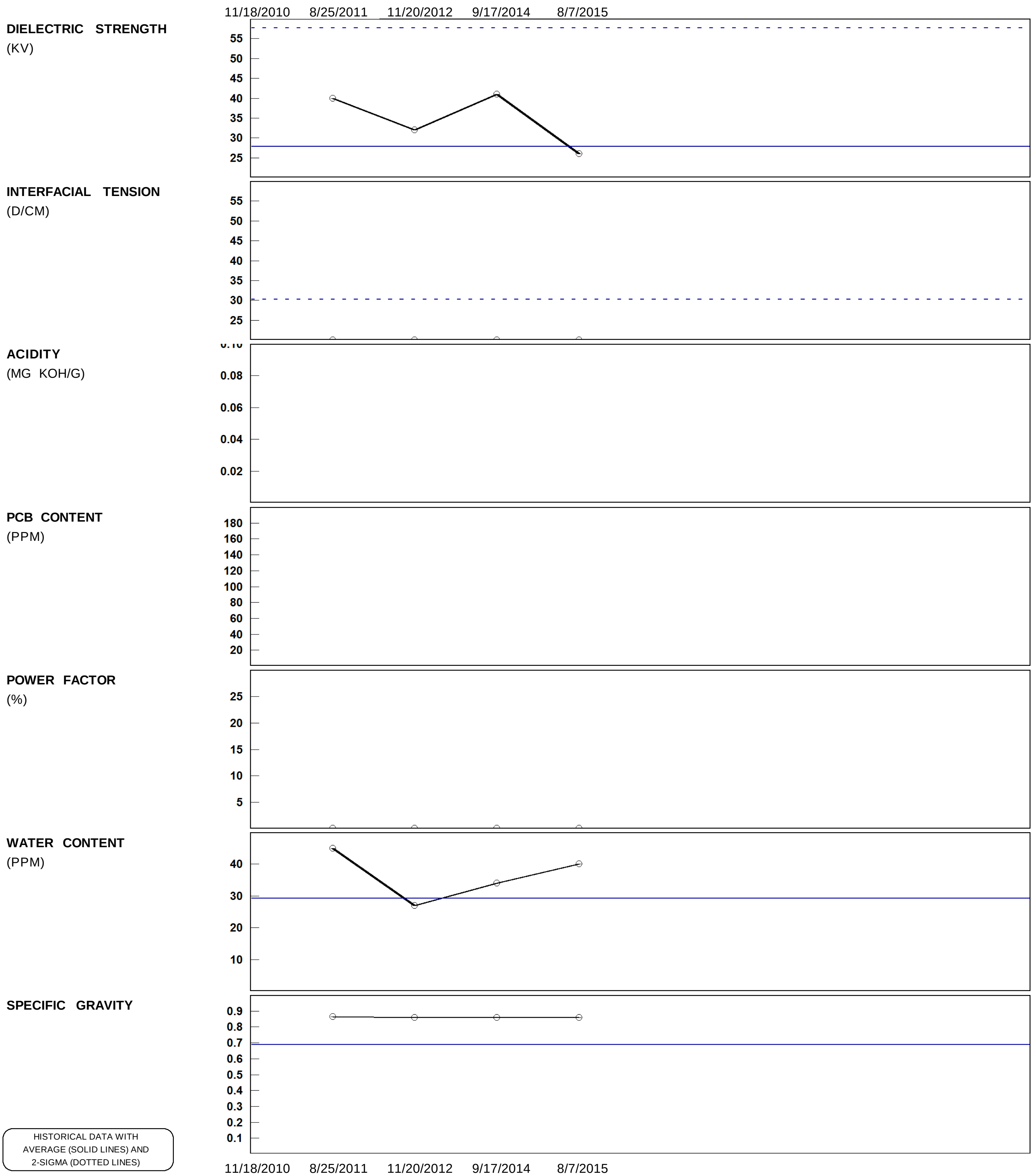
HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Abitibi	POSITION	Main Gate - LTC	JOB #	41171263 IF
SERIAL NO.	261784				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT ANALYSIS

SIEMENS

CUSTOMER: Northern Ontario Wires — PAGE:

PLANT: Iroquois Falls — SUBSTATION: Abitibi — POSITION: Main Gate - LTC

TEST DATE: 8/7/2015 — AMBIENT TEMPERATURE: °C — HUMIDITY: % — JOB #: 41171263 IF

NAMEPLATE DATA

MANUFACTURER: Ferranti Packard — SERIAL NO.: 261784

SPECIFICATION NO.: — KVA: 2,000 / / — TYPE: ONS — CLASS:

PHASE: 3 — TEMPERATURE RISE: 55 °C — IMPEDANCE: 5.3 % — B.I.L. RATING: kV PRI. kV SEC.

COOLANT: OIL — CAPACITY: 1420 gallons — TOTAL WEIGHT: 33100

WINDING POLARITY: SUBTRACTIVE — WINDING MATERIAL: — K FACTOR: NA

PRIMARY VOLTAGE: 12,000 — ◉ DELTA ○ WYE — RATED CURRENT: 96 / / AMPERES

SECONDARY VOLTAGE: 4,000 / 2,309 — ○ DELTA ◉ WYE — RATED CURRENT: 289 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING: VOLTS — # FANS: — TAP CHANGER: ◉ INTERNAL ○ EXTERNAL — DRY TYPE ☐

TEST RESULTS

			ASTM
PARTICLES	TRACE		D-1524
DIELECTRIC STRENGTH	26	kV	D-877
INTERFACIAL TENSION	18.81	D/CM	D-971
ACIDITY	0.225	MG KOH/G	D-974
ASTM COLOR NO.	L1.5		D-1500
PCB CONTENT		PPM	D-4059
E.P.A. CLASSIFICATION			
POWER FACTOR	0.065	%	D-924
WATER CONTENT	40	PPM	D-1533B
SPECIFIC GRAVITY	0.8594		D-287

TRANSFORMER INSPECTION

TEMPERATURE GUAGE PRESENT READING: °C

TEMPERATURE GUAGE HIGH READING: °C

PRESSURE/VACUUM GUAGE READING: #

PAINT CONDITION:

GASKETS:

BUSHINGS:

LIQUID LEVEL:

DISSOLVED GAS ANALYSIS — ASTM D-3612C

* HYDROGEN	(H2)	66	PPM
* METHANE	(CH4)	3	PPM
* ETHANE	(C2H6)	1	PPM
* ETHYLENE	(C2H4)	6	PPM
* ACETYLENE	(C2H2)	0	PPM
* CARBON MONOXIDE	(CO)	143	PPM
CARBON DIOXIDE	(CO2)	1,524	PPM
NITROGEN	(N2)	66,443	PPM
OXYGEN	(O2)	27,835	PPM
TOTAL GAS		96,021	PPM
TOTAL COMBUSTIBLE GAS		219	PPM
EQUIVALENT TCG READING		0.8594	%

* COMBUSTIBLE GAS

PLUMBING TABLE

	P	S	OTHER
TOP			
BOTTOM			
VENT			
ACCESS PORT			
SAMPLE VALVE			

ANALYSIS OF TEST RESULTS

CONDITION

- ○ EXCELLENT
- ○ GOOD
- ○ INVESTIGATE
- ○ POOR
- ○ FAILED UNIT

SERVICE

- ☐ NO SERVICE REQUIRED
- ☐ RETEST IN ____ MONTHS:
- ☐ SERVICE REQUIRED
- ☐ SERVICE IMMEDIATELY
- ☐ REFER TO COMMENTS

COMMENTS:

DEFICIENCIES:

SAMPLED BY: John Love — TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Cambridge POSITION Main

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 2305235

SPECIFICATION NO. KVA 2,000 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE 5.4 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 267 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 12,000 ◉ DELTA ○ WYE RATED CURRENT 96 / / AMPERES

SECONDARY VOLTAGE 4,160 / 2,402 ○ DELTA ◉ WYE RATED CURRENT 278 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	11/28/2011	8/25/2011	11/18/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006
PARTICLES	ND	CLR&SPRK	TRACE							
DIELECTRIC STRENGTH (kV)	49	53	48		39					
INTERFACIAL TENSION (D/CM)	36.69	37.35	36.67		36.36	38.7				
ACIDITY (MG KOH/G)	0.018	0.009	0.014		0.034					
ASTM COLOR NO.	L2.0	L2.0	L2.0		1.5	1.5				
PCB CONTENT (PPM)					2.6					
E.P.A. CLASSIFICATION					1254/1260					
POWER FACTOR (%)	0.605	0.613	0.574		0.508	0.625				
WATER CONTENT (PPM)	3	4	3		5	5				
SPECIFIC GRAVITY	0.8795	0.8795	0.8797		0.884					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	11/28/2011	8/25/2011	11/18/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006
* HYDROGEN (H2)	1	3	1	5	5					
* METHANE (CH4)	15	15	11	14	13					
* ETHANE (C2H6)	3	3	2	3	3					
* ETHYLENE (C2H4)	19	17	15	20	18	14				
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	696	732	586	678	658					
CARBON DIOXIDE (CO2)	2,308	2,374	1,880	1,330	2,084					
NITROGEN (N2)	76,190	80,036	68,799	71,166	81,357					
OXYGEN (O2)	1,066	744	2,380	1,113	967					
TOTAL GAS	80,298	83,924	73,674	74,329	85,105					
TOTAL COMBUSTIBLE GAS	734	770	615	720	697					

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

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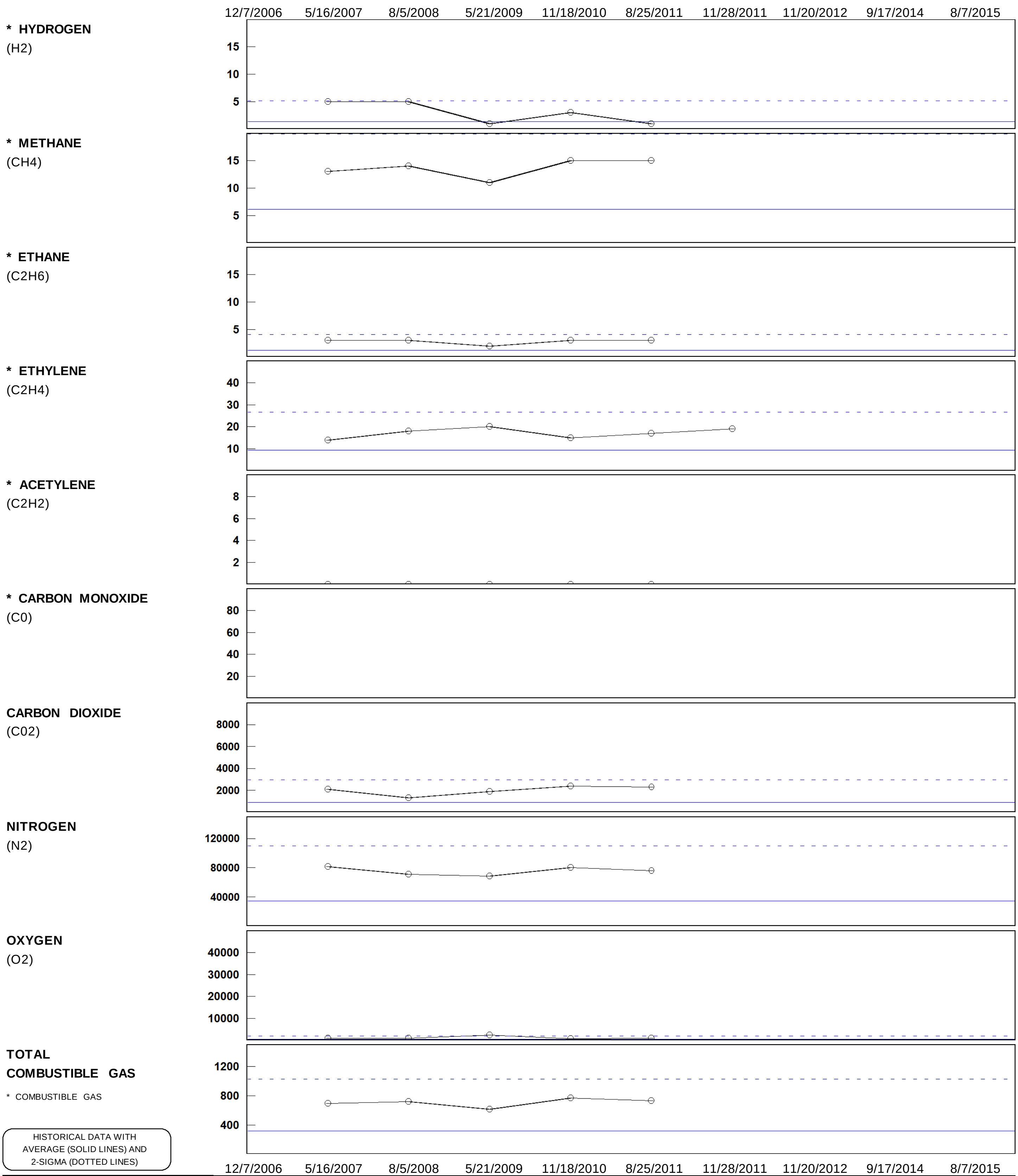
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Cambridge	POSITION	Main	JOB #	41171263 IF
SERIAL NO.	2305235				



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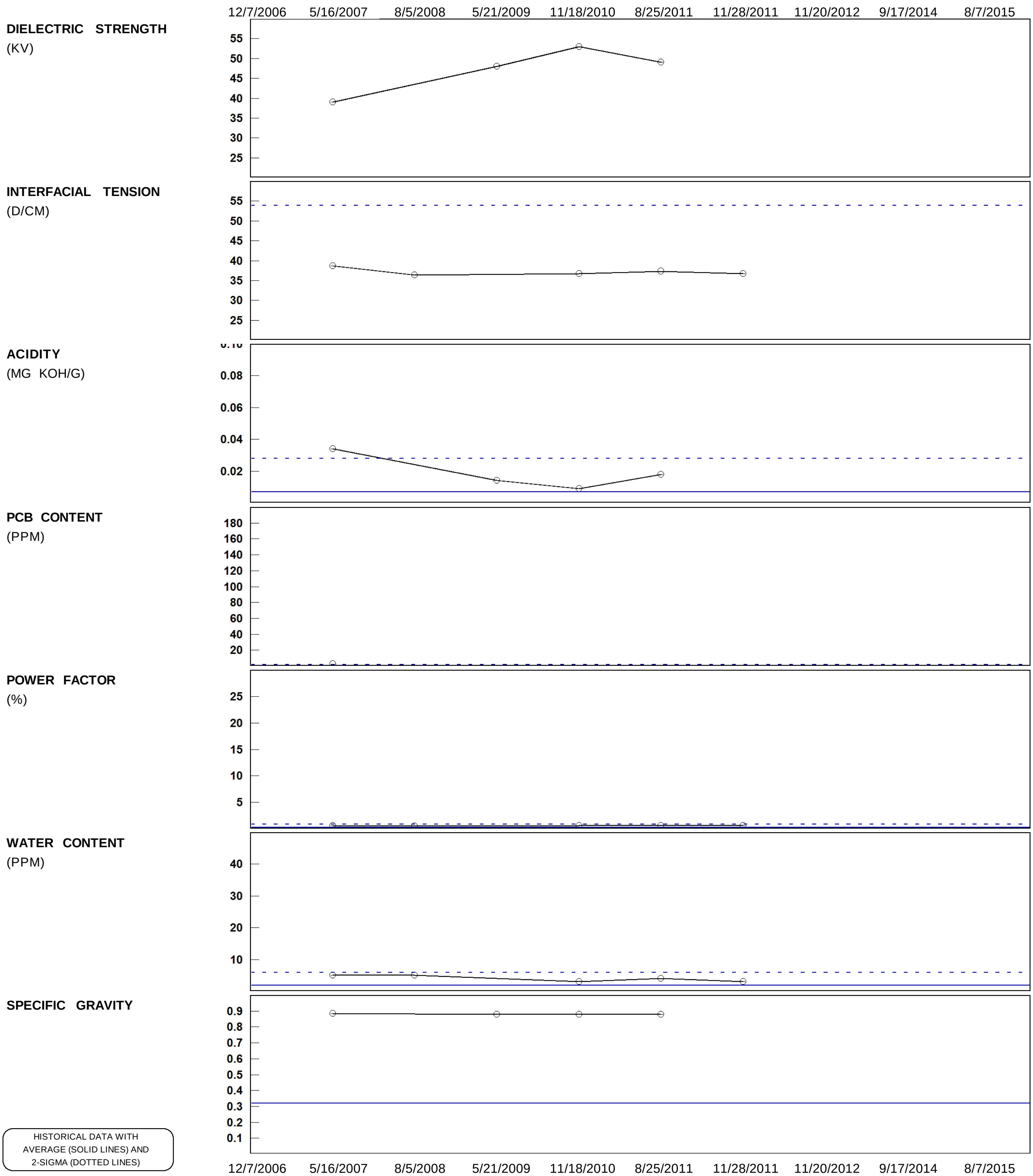
TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Cambridge	POSITION	Main	JOB #	41171263 IF
SERIAL NO.	2305235				



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TRANSFORMER LIQUID COOLANT ANALYSIS

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Cambridge POSITION Main

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 2305235

SPECIFICATION NO. KVA 2,000 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE 5.4 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 267 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 12,000 ◉ DELTA ○ WYE RATED CURRENT 96 / / AMPERES

SECONDARY VOLTAGE 4,160 / 2,402 ○ DELTA ◉ WYE RATED CURRENT 278 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

TEST RESULTS

			ASTM
PARTICLES	ND		D-1524
DIELECTRIC STRENGTH	49	kV	D-877
INTERFACIAL TENSION	36.69	D/CM	D-971
ACIDITY	0.018	MG KOH/G	D-974
ASTM COLOR NO.	L2.0		D-1500
PCB CONTENT		PPM	D-4059
E.P.A. CLASSIFICATION			
POWER FACTOR	0.605	%	D-924
WATER CONTENT	3	PPM	D-1533B
SPECIFIC GRAVITY	0.8795		D-287

TRANSFORMER INSPECTION

TEMPERATURE GUAGE PRESENT READING °C

TEMPERATURE GUAGE HIGH READING °C

PRESSURE/VACUUM GUAGE READING #

PAINT CONDITION

GASKETS

BUSHINGS

LIQUID LEVEL

DISSOLVED GAS ANALYSIS — ASTM D-3612C

* HYDROGEN	(H2)	1	PPM
* METHANE	(CH4)	15	PPM
* ETHANE	(C2H6)	3	PPM
* ETHYLENE	(C2H4)	19	PPM
* ACETYLENE	(C2H2)	0	PPM
* CARBON MONOXIDE	(CO)	696	PPM
CARBON DIOXIDE	(CO2)	2,308	PPM
NITROGEN	(N2)	76,190	PPM
OXYGEN	(O2)	1,066	PPM
TOTAL GAS		80,298	PPM
TOTAL COMBUSTIBLE GAS		734	PPM
EQUIVALENT TCG READING		0.659	%

* COMBUSTIBLE GAS

PLUMBING TABLE

	P	S	OTHER
TOP			
BOTTOM			
VENT			
ACCESS PORT			
SAMPLE VALVE			

ANALYSIS OF TEST RESULTS

CONDITION	SERVICE
○ EXCELLENT	☐ NO SERVICE REQUIRED
○ GOOD	☐ RETEST IN ___ MONTHS:
○ INVESTIGATE	☐ SERVICE REQUIRED
○ POOR	☐ SERVICE IMMEDIATELY
○ FAILED UNIT	☐ REFER TO COMMENTS

COMMENTS:

DEFICIENCIES:

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Detroyes POSITION Main

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 12577

SPECIFICATION NO. KVA 2,000 / / TYPE ON5 CLASS

PHASE 3 TEMPERATURE RISE °C IMPEDANCE 5 % B.I.L. RATING kV PRI. kV SEC.

COOLANT CAPACITY 1320 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE ◉ DELTA ○ WYE RATED CURRENT / / AMPERES

SECONDARY VOLTAGE / 0 ○ DELTA ◉ WYE RATED CURRENT / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	9/25/2011	12/3/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006	1/6/2005
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	34	51	46	39	52					
INTERFACIAL TENSION (D/CM)	37.8	37.07	37.46	37.48	39.9					
ACIDITY (MG KOH/G)	0.014	0.006	0.005	0.011	0.009					
ASTM COLOR NO.	L1.0	L1.0	1.5	0.5	0.5					
PCB CONTENT (PPM)				2.9						
E.P.A. CLASSIFICATION				1260						
POWER FACTOR (%)	0.010	0.024	0.024	0.009	0.030					
WATER CONTENT (PPM)	16	11	7	19	7					
SPECIFIC GRAVITY	0.8549	0.8546	0.854	0.859	0.858					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	9/25/2011	12/3/2010	5/21/2009	8/5/2008	5/16/2007	12/7/2006	1/6/2005
* HYDROGEN (H2)	8	5	4	9	10					
* METHANE (CH4)	1	1	1	53	1					
* ETHANE (C2H6)	0	0	0	0	0					
* ETHYLENE (C2H4)	2	1	2	2	1					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	36	44	51	1	57					
CARBON DIOXIDE (CO2)	841	830	813	659	891					
NITROGEN (N2)	68,235	63,714	58,817	52,887	65,424					
OXYGEN (O2)	34,115	30,383	28,623	28,230	30,997					
TOTAL GAS	103,238	94,978	88,311	81,841	97,381					
TOTAL COMBUSTIBLE GAS	47	51	58	65	69					

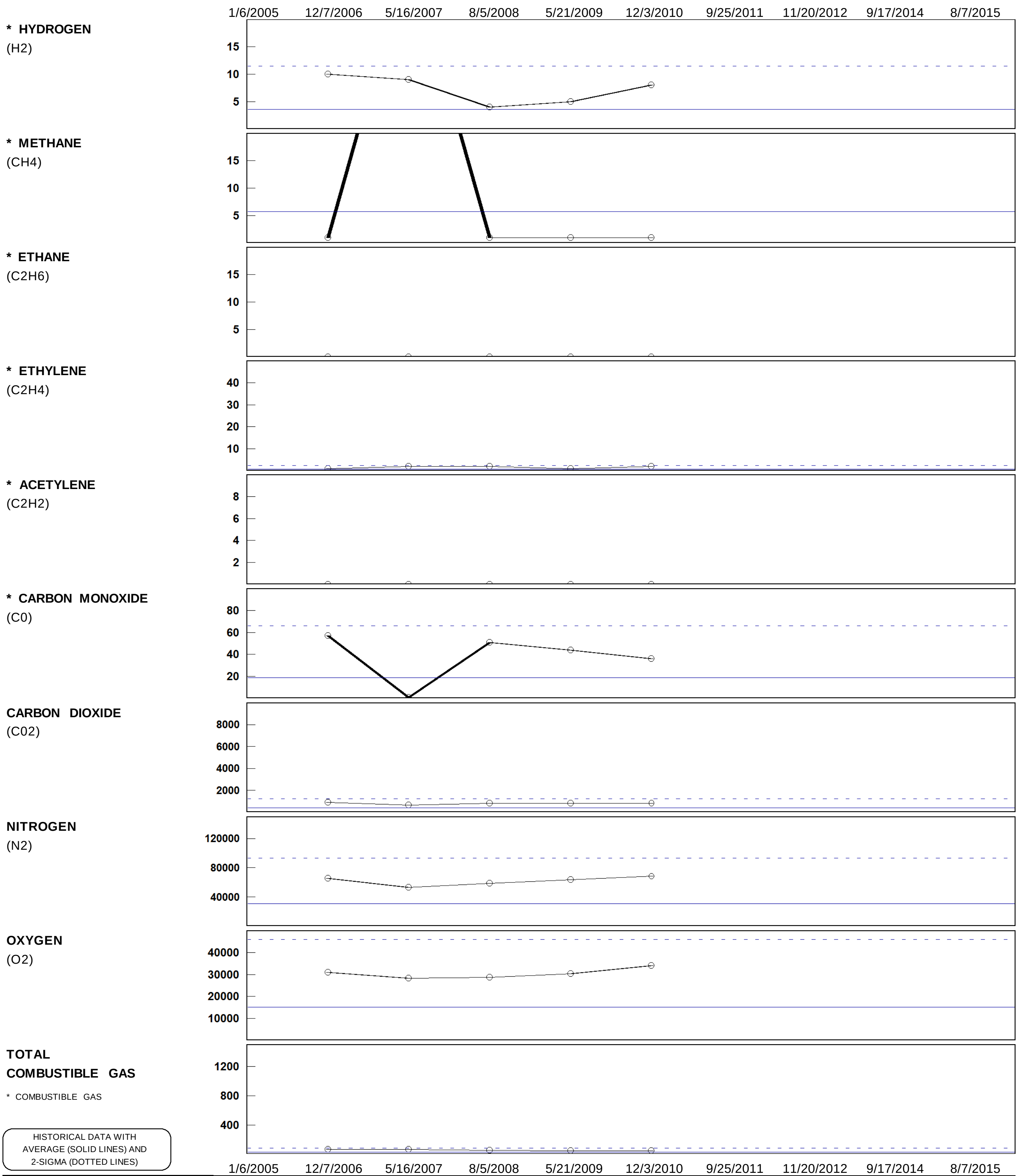
* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Detroyes	POSITION	Main	JOB #	41171263 IF
SERIAL NO.	12577				

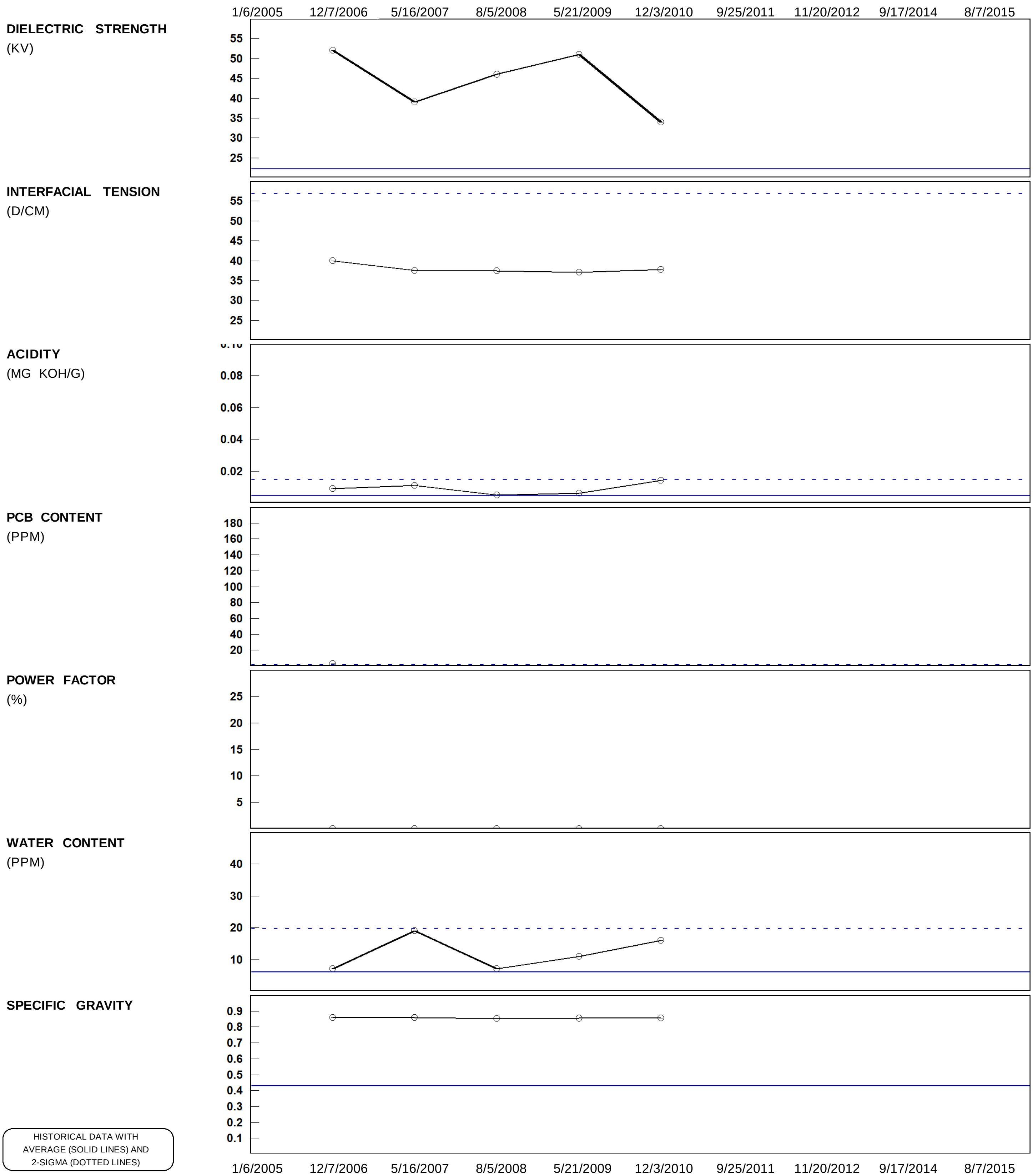


REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Detroyes	POSITION	Main	JOB #	41171263 IF
SERIAL NO.	12577				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT ANALYSIS

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Detroyes POSITION Main

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 12577

SPECIFICATION NO. KVA 2,000 / / TYPE ON5 CLASS

PHASE 3 TEMPERATURE RISE °C IMPEDANCE 5 % B.I.L. RATING kV PRI. kV SEC.

COOLANT CAPACITY 1320 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE ● DELTA ○ WYE RATED CURRENT / / AMPERES

SECONDARY VOLTAGE / 0 ○ DELTA ● WYE RATED CURRENT / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ● INTERNAL ○ EXTERNAL DRY TYPE ☐

TEST RESULTS

			ASTM
PARTICLES	ND		D-1524
DIELECTRIC STRENGTH	34	kV	D-877
INTERFACIAL TENSION	37.8	D/CM	D-971
ACIDITY	0.014	MG KOH/G	D-974
ASTM COLOR NO.	L1.0		D-1500
PCB CONTENT		PPM	D-4059
E.P.A. CLASSIFICATION			
POWER FACTOR	0.010	%	D-924
WATER CONTENT	16	PPM	D-1533B
SPECIFIC GRAVITY	0.8549		D-287

TRANSFORMER INSPECTION

TEMPERATURE GUAGE PRESENT READING °C

TEMPERATURE GUAGE HIGH READING °C

PRESSURE/VACUUM GUAGE READING #

PAINT CONDITION

GASKETS

BUSHINGS

LIQUID LEVEL

DISSOLVED GAS ANALYSIS

ASTM D-3612C

* HYDROGEN	(H2)	8	PPM
* METHANE	(CH4)	1	PPM
* ETHANE	(C2H6)	0	PPM
* ETHYLENE	(C2H4)	2	PPM
* ACETYLENE	(C2H2)	0	PPM
* CARBON MONOXIDE	(CO)	36	PPM
CARBON DIOXIDE	(CO2)	841	PPM
NITROGEN	(N2)	68,235	PPM
OXYGEN	(O2)	34,115	PPM
TOTAL GAS		103,238	PPM
TOTAL COMBUSTIBLE GAS		47	PPM
EQUIVALENT TCG READING		0.0465	%

* COMBUSTIBLE GAS

PLUMBING TABLE

	P	S	OTHER
TOP			
BOTTOM			
VENT			
ACCESS PORT			
SAMPLE VALVE			

ANALYSIS OF TEST RESULTS

CONDITION	SERVICE
○ EXCELLENT	☐ NO SERVICE REQUIRED
○ GOOD	☐ RETEST IN ___ MONTHS:
○ INVESTIGATE	☐ SERVICE REQUIRED
○ POOR	☐ SERVICE IMMEDIATELY
○ FAILED UNIT	☐ REFER TO COMMENTS

COMMENTS:

DEFICIENCIES:

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Iroquois Falls SUBSTATION Detroyes POSITION Main-LTC

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 IF

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 12577

SPECIFICATION NO. KVA 4,000 / / TYPE ON5 CLASS

PHASE 3 TEMPERATURE RISE °C IMPEDANCE % B.I.L. RATING kV PRI. kV SEC.

COOLANT CAPACITY 1320 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE ◉ DELTA ○ WYE RATED CURRENT / / AMPERES

SECONDARY VOLTAGE / 0 ○ DELTA ◉ WYE RATED CURRENT / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/25/2011	12/3/2010					
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	15	51	45	38	45					
INTERFACIAL TENSION (D/CM)	41.19	39.92	40.9	40.82	42.9					
ACIDITY (MG KOH/G)	0.011	0.005	0.005	0.010	0.006					
ASTM COLOR NO.	L1.0	L1.0	L1.0	0	1					
PCB CONTENT (PPM)										
E.P.A. CLASSIFICATION										
POWER FACTOR (%)	15	0.017	0.006	0.001	0.026					
WATER CONTENT (PPM)	51	31	18	39	15					
SPECIFIC GRAVITY	0.8636	0.8644	0.8659	0.871	0.871					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/25/2011	12/3/2010					
* HYDROGEN (H2)	353	83	46	140	69					
* METHANE (CH4)	2	1	1	1	1					
* ETHANE (C2H6)	0	0	0	0	0					
* ETHYLENE (C2H4)	1	0	0	0	0					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	10	4	3	13	3					
CARBON DIOXIDE (CO2)	1,009	470	480	440	539					
NITROGEN (N2)	61,610	63,861	62,093	62,792	63,919					
OXYGEN (O2)	27,826	31,095	31,318	32,365	31,645					
TOTAL GAS	90,811	95,514	93,941	95,751	96,176					
TOTAL COMBUSTIBLE GAS	366	88	50	154	73					

* COMBUSTIBLE GAS

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TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Detroyes	POSITION	Main-LTC	JOB #	41171263 IF
SERIAL NO.	12577				

*** HYDROGEN**
(H2)

*** METHANE**
(CH4)

*** ETHANE**
(C2H6)

*** ETHYLENE**
(C2H4)

*** ACETYLENE**
(C2H2)

*** CARBON MONOXIDE**
(C0)

CARBON DIOXIDE
(C02)

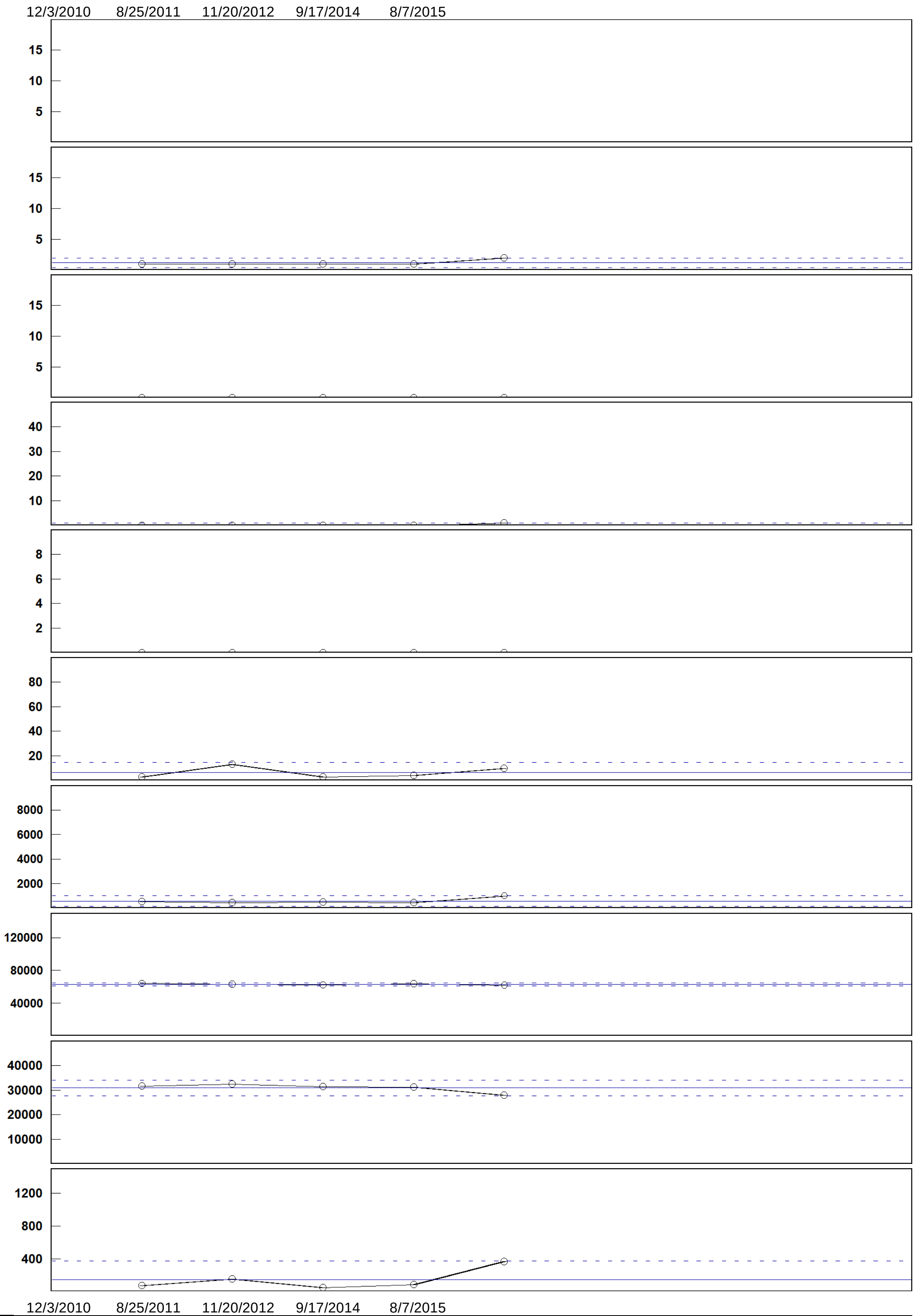
NITROGEN
(N2)

OXYGEN
(O2)

TOTAL COMBUSTIBLE GAS

* COMBUSTIBLE GAS

HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

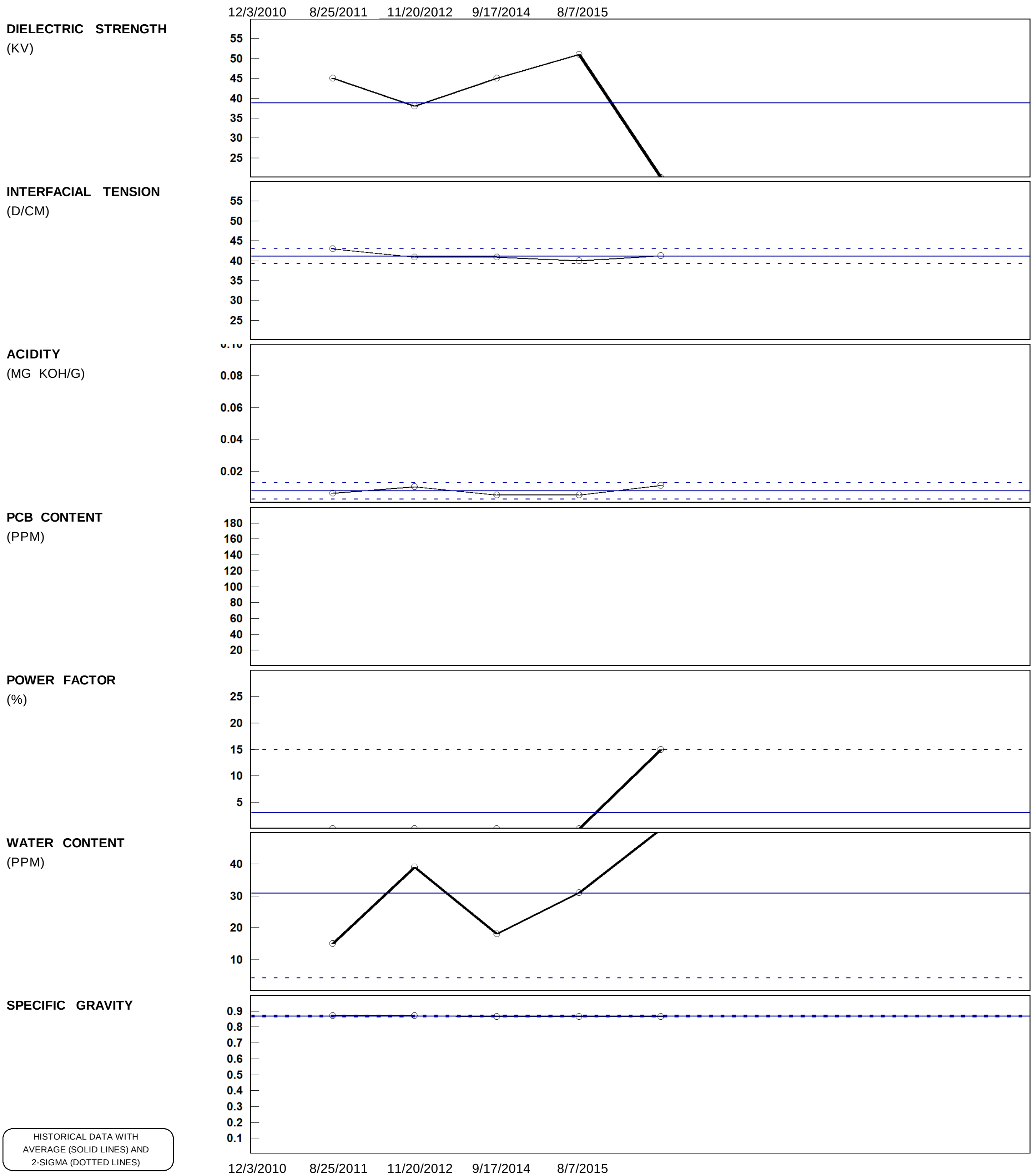


REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Detroyes	POSITION	Main-LTC	JOB #	41171263 IF
SERIAL NO.	12577				



TRANSFORMER LIQUID COOLANT ANALYSIS

SIEMENS

CUSTOMER: Northern Ontario Wires — PAGE:

PLANT: Iroquois Falls — SUBSTATION: Detroyes — POSITION: Main-LTC

TEST DATE: 8/7/2015 — AMBIENT TEMPERATURE: °C — HUMIDITY: % — JOB #: 41171263 IF

NAMEPLATE DATA

MANUFACTURER: Ferranti Packard — SERIAL NO.: 12577

SPECIFICATION NO.: — KVA: 4,000 / / — TYPE: ON5 — CLASS:

PHASE: 3 — TEMPERATURE RISE: °C — IMPEDANCE: % — B.I.L. RATING: kV PRI. kV SEC.

COOLANT: — CAPACITY: 1320 gallons — TOTAL WEIGHT: 33100

WINDING POLARITY: SUBTRACTIVE — WINDING MATERIAL: — K FACTOR: NA

PRIMARY VOLTAGE: — ◉ DELTA ○ WYE — RATED CURRENT: / / AMPERES

SECONDARY VOLTAGE: / 0 — ○ DELTA ◉ WYE — RATED CURRENT: / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING: VOLTS — # FANS: — TAP CHANGER: ◉ INTERNAL ○ EXTERNAL — DRY TYPE ☐

TEST RESULTS

TEST RESULTS			ASTM
PARTICLES	ND		D-1524
DIELECTRIC STRENGTH	15	kV	D-877
INTERFACIAL TENSION	41.19	D/CM	D-971
ACIDITY	0.011	MG KOH/G	D-974
ASTM COLOR NO.	L1.0		D-1500
PCB CONTENT		PPM	D-4059
E.P.A. CLASSIFICATION			
POWER FACTOR	15	%	D-924
WATER CONTENT	51	PPM	D-1533B
SPECIFIC GRAVITY	0.8636		D-287

TRANSFORMER INSPECTION

TEMPERATURE GUAGE PRESENT READING: °C

TEMPERATURE GUAGE HIGH READING: °C

PRESSURE/VACUUM GUAGE READING: #

PAINT CONDITION

GASKETS

BUSHINGS

LIQUID LEVEL

DISSOLVED GAS ANALYSIS — ASTM D-3612C

* HYDROGEN	(H2)	353	PPM
* METHANE	(CH4)	2	PPM
* ETHANE	(C2H6)	0	PPM
* ETHYLENE	(C2H4)	1	PPM
* ACETYLENE	(C2H2)	0	PPM
* CARBON MONOXIDE	(CO)	10	PPM
CARBON DIOXIDE	(CO2)	1,009	PPM
NITROGEN	(N2)	61,610	PPM
OXYGEN	(O2)	27,826	PPM
TOTAL GAS		90,811	PPM
TOTAL COMBUSTIBLE GAS		366	PPM
EQUIVALENT TCG READING		0.8021	%

* COMBUSTIBLE GAS

PLUMBING TABLE

	P	S	OTHER
TOP			
BOTTOM			
VENT			
ACCESS PORT			
SAMPLE VALVE			

ANALYSIS OF TEST RESULTS

CONDITION	SERVICE
○ EXCELLENT	☐ NO SERVICE REQUIRED
○ GOOD	☐ RETEST IN ____ MONTHS:
○ INVESTIGATE	☐ SERVICE REQUIRED
○ POOR	☐ SERVICE IMMEDIATELY
○ FAILED UNIT	☐ REFER TO COMMENTS

COMMENTS:

DEFICIENCIES:

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SIEMENS

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Job #41171263 KAP

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User Northern Ontario Wires
Plant Kapuskasing

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Kapuskasing SUBSTATION Kap - Main POSITION Main

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263 KAP

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 12086

SPECIFICATION NO. KVA 5,000 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 65 °C IMPEDANCE 5.31 % B.I.L. RATING kV PRI. kV SEC.

COOLANT Oil CAPACITY 990 gallons TOTAL WEIGHT 33100

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 25,000 ◉ DELTA ○ WYE RATED CURRENT 115 / / AMPERES

SECONDARY VOLTAGE 4,160 / 2,402 ○ DELTA ◉ WYE RATED CURRENT 694 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	10/16/2014	11/20/2012	11/28/2011	8/15/2011	11/17/2010	5/21/2009	7/5/2008	8/22/2006	
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	36	61	50		41	50				
INTERFACIAL TENSION (D/CM)	22.74	22.98	23.49		23.17	25				
ACIDITY (MG KOH/G)	0.119	0.108	0.138		0.185	0.104				
ASTM COLOR NO.	L3.0	L1.5	2.5		0	2				
PCB CONTENT (PPM)					15					
E.P.A. CLASSIFICATION					1260					
POWER FACTOR (%)	0.074	0.087	0.068		0.051	0.049				
WATER CONTENT (PPM)	25	18	14		32	16				
SPECIFIC GRAVITY	0.8856	0.886	0.8863		0.89	0.89				

DISSOLVED GAS ANALYSIS	8/7/2015	10/16/2014	11/20/2012	11/28/2011	8/15/2011	11/17/2010	5/21/2009	7/5/2008	8/22/2006	
* HYDROGEN (H2)	102	133	113	144	147	149				
* METHANE (CH4)	3	4	3	4	4	4				
* ETHANE (C2H6)	1	0	1	1	1	1				
* ETHYLENE (C2H4)	5	3	3	4	4	2				
* ACETYLENE (C2H2)	0	0	0	0	0	0				
* CARBON MONOXIDE (CO)	359	454	405	447	458	399				
CARBON DIOXIDE (CO2)	2,003	21,633	1,971	1,382	1,908	2,098				
NITROGEN (N2)	62,987	62,956	53,419	56,312	55,895	62,601				
OXYGEN (O2)	16,289	10,911	8,581	10,702	5,596	10,037				
TOTAL GAS	81,749	96,094	64,496	68,996	64,013	75,291				
TOTAL COMBUSTIBLE GAS	470	594	525	600	614	555				

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

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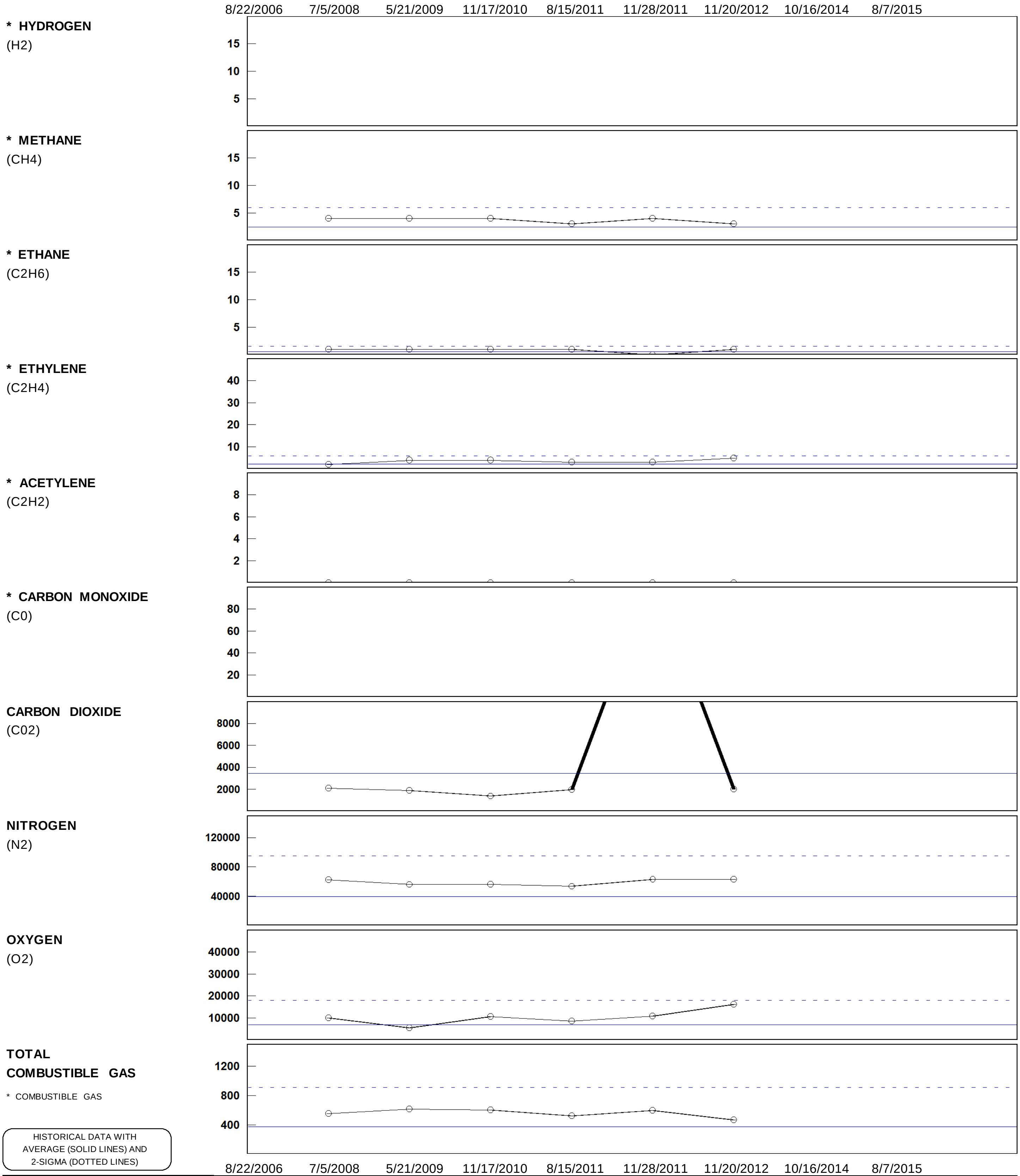
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Kap - Main	POSITION	Main	JOB #	41171263 KAP
SERIAL NO.	12086				



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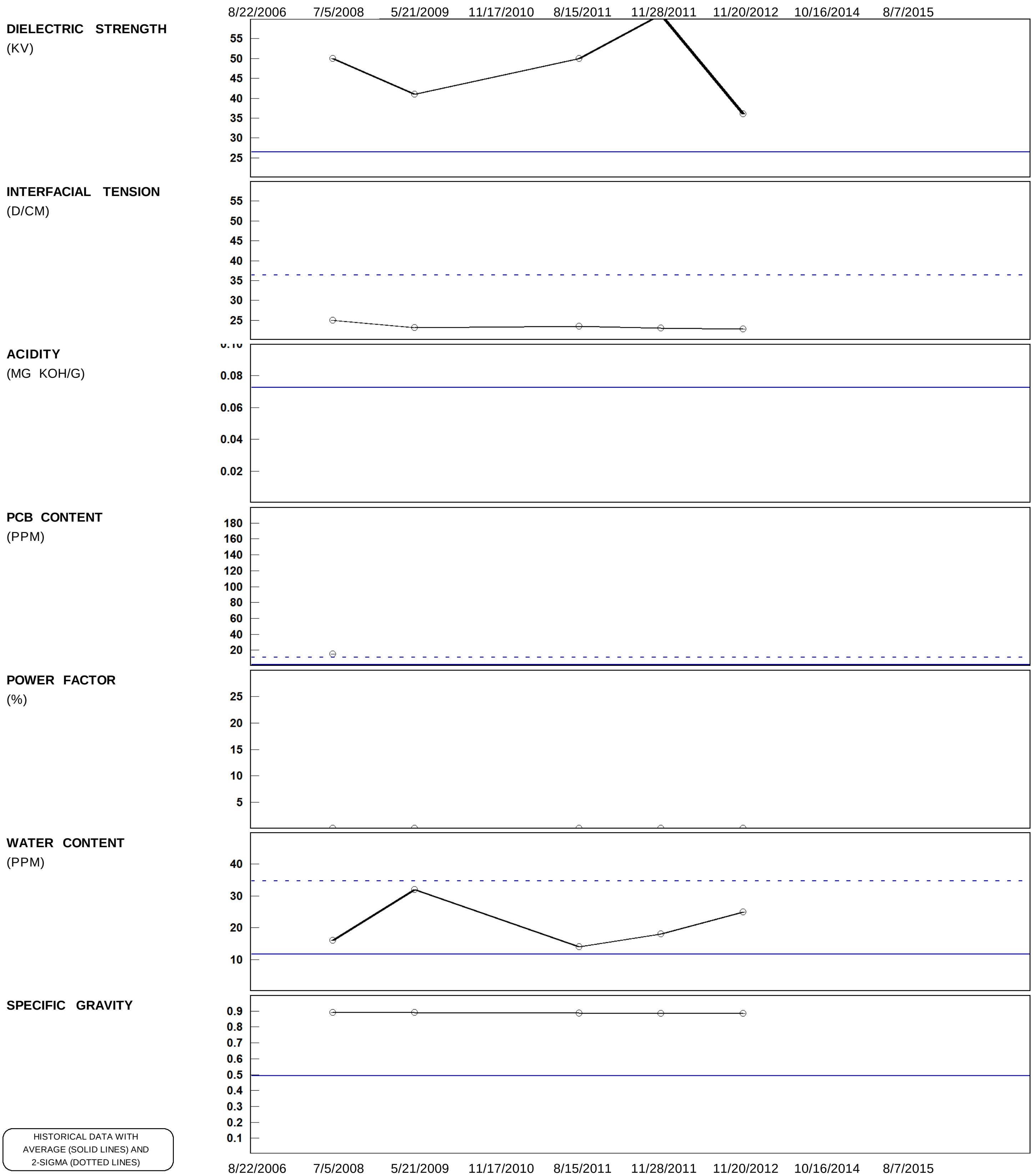
TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Kap - Main	POSITION	Main	JOB #	41171263 KAP
SERIAL NO.	12086				



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SIEMENS

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Plant Cochrane

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane- 25KV T1

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER CGE SERIAL NO. 288692

SPECIFICATION NO. KVA 7,500 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 65 °C IMPEDANCE 8.3 % B.I.L. RATING 550 kV PRI. 150 kV SEC.

COOLANT Oil CAPACITY 3095 Gallons TOTAL WEIGHT 72400

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 115,000 ◉ DELTA ○ WYE RATED CURRENT 38 / / AMPERES

SECONDARY VOLTAGE 24,940 / 14,399 ○ DELTA ◉ WYE RATED CURRENT 174 / / AMPERES

TAP VOLTAGES 132,000 129,250 12,650 123,750 121,000 118,250 115,500

TAP CONNECTIONS 1 2 3 4 5 6 7

TAP SETTING VOLTS # FANS TAP CHANGER: ○ INTERNAL ◉ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/6/2015	9/17/2014	1/16/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/15/2008	5/16/2007	7/11/2006
PARTICLES	ND	CLR&SPRK		TRACE						
DIELECTRIC STRENGTH (kV)	38	50		47		54				
INTERFACIAL TENSION (D/CM)	30.1	30.74		29.72		37.9				
ACIDITY (MG KOH/G)	0.041	0.033		0.036		0.016				
ASTM COLOR NO.	L1.5	1.5		1.5		1.5				
PCB CONTENT (PPM)					35					
E.P.A. CLASSIFICATION					1254					
POWER FACTOR (%)	0.066	0.040		0.027		0.023				
WATER CONTENT (PPM)	11	8		9						
SPECIFIC GRAVITY	0.8623	0.8623		0.8623		0.865				

DISSOLVED GAS ANALYSIS	8/6/2015	9/17/2014	1/16/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/15/2008	5/16/2007	7/11/2006
* HYDROGEN (H2)	6	4		0		13				
* METHANE (CH4)	2	2		3		5				
* ETHANE (C2H6)	0	0		1		1				
* ETHYLENE (C2H4)	12	12		14		12				
* ACETYLENE (C2H2)	0	0		0		0				
* CARBON MONOXIDE (CO)	167	229		354		618				
CARBON DIOXIDE (CO2)	1,418	1,552		2,335		2,288				
NITROGEN (N2)	65,276	62,296		57,968		77,617				
OXYGEN (O2)	29,048	27,020		22,654		24,265				
TOTAL GAS	95,929	91,115	0	83,329		104,819				
TOTAL COMBUSTIBLE GAS	187	247	0	372		649				

* COMBUSTIBLE GAS

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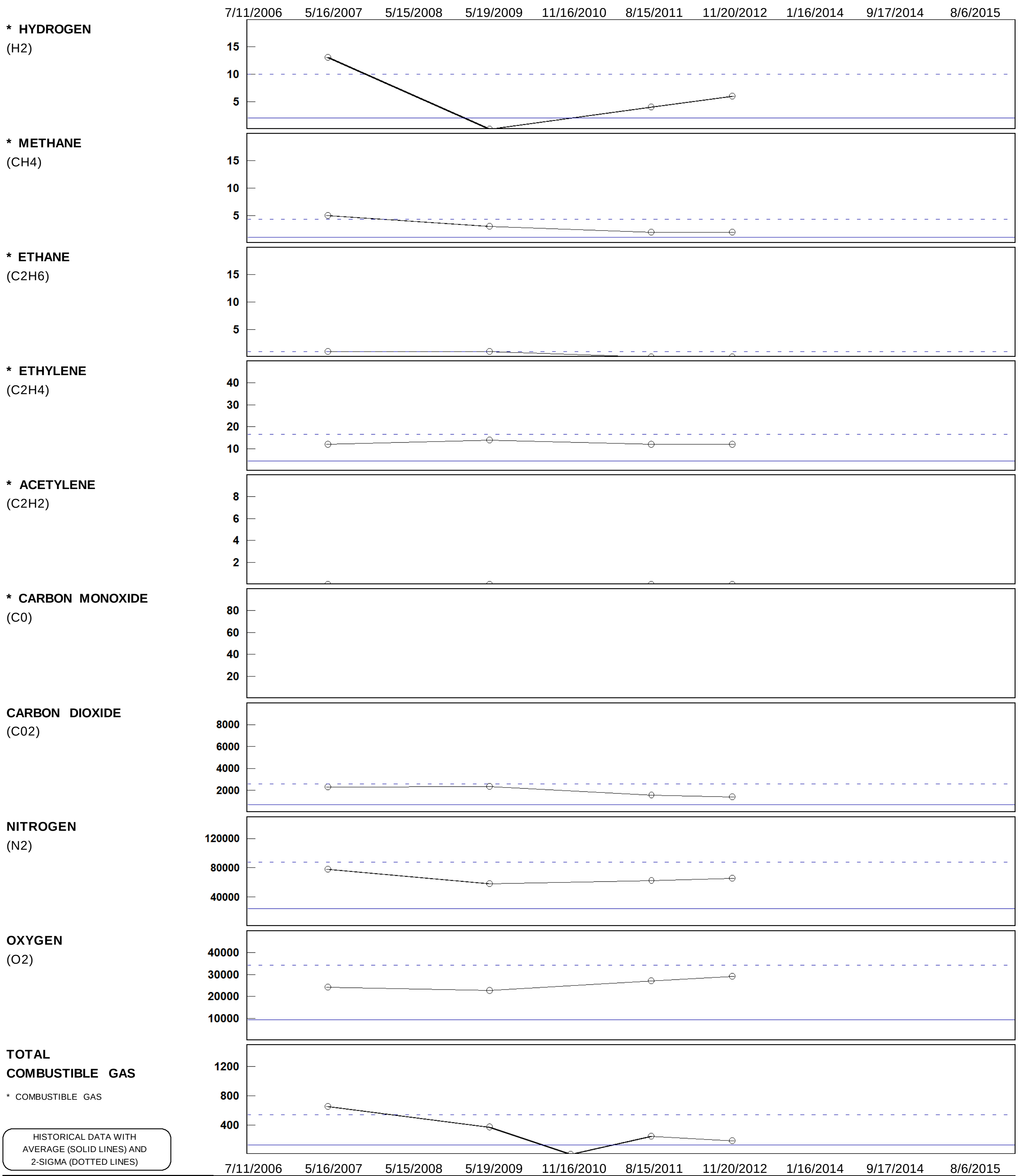
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T1	JOB #	41171263
SERIAL NO.	288692				



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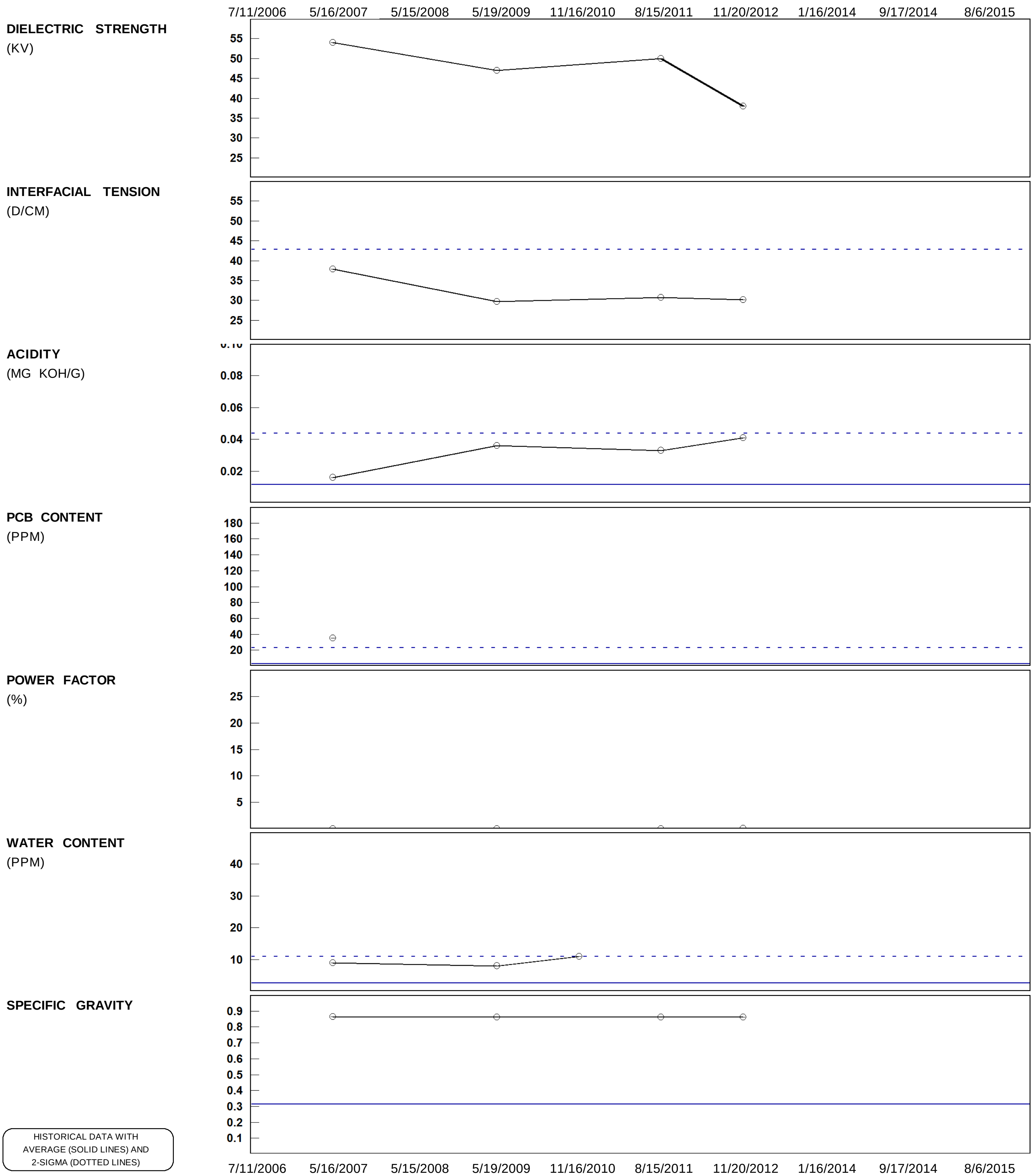
TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T1	JOB #	41171263
SERIAL NO.	288692				



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TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane- 25KV T1-LTC

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER CGE SERIAL NO. 288692

SPECIFICATION NO. KVA 7,500 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 65 °C IMPEDANCE 8.3 % B.I.L. RATING 550 kV PRI. 150 kV SEC.

COOLANT Oil CAPACITY 3095 Gallons TOTAL WEIGHT 72400

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 115,000 ◉ DELTA ○ WYE RATED CURRENT 38 / / AMPERES

SECONDARY VOLTAGE 24,940 / 14,399 ○ DELTA ◉ WYE RATED CURRENT 174 / / AMPERES

TAP VOLTAGES	132,000	129,250	12,650	123,750	121,000	118,250	115,500	
TAP CONNECTIONS	1	2	3	4	5	6	7	

TAP SETTING VOLTS # FANS TAP CHANGER: ○ INTERNAL ◉ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/9/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
PARTICLES	Light	Carbon	CLOUDY							
DIELECTRIC STRENGTH (kV)	29	36	31	36	35					
INTERFACIAL TENSION (D/CM)	14.35	15.01	15.32	18.21	45.8					
ACIDITY (MG KOH/G)	0.511	0.480	0.437	0.355	0.005					
ASTM COLOR NO.	L2.5	2.0	L2.5	1.5	0.5					
PCB CONTENT (PPM)										
E.P.A. CLASSIFICATION										
POWER FACTOR (%)	0.172	0.179	0.223	0.288	0.004					
WATER CONTENT (PPM)	53	51	41	69	13					
SPECIFIC GRAVITY	0.8646	0.8649	0.8646	0.866	0.879					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/9/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
* HYDROGEN (H2)	505	339	370	773	187					
* METHANE (CH4)	24	11	44	35	45					
* ETHANE (C2H6)	12	0	4	87	3					
* ETHYLENE (C2H4)	40	11	79	35	86					
* ACETYLENE (C2H2)	265	130	631	118	608					
* CARBON MONOXIDE (CO)	255	228	166	358	8					
CARBON DIOXIDE (CO2)	1,598	1,351	981	1,549	267					
NITROGEN (N2)	67,426	65,002	63,730	54,854	71,206					
OXYGEN (O2)	12,250	13,021	17,148	0	30,197					
TOTAL GAS	82,375	80,093	83,153	57,809	102,607					
TOTAL COMBUSTIBLE GAS	1,101	719	1,294	1,406	937					

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

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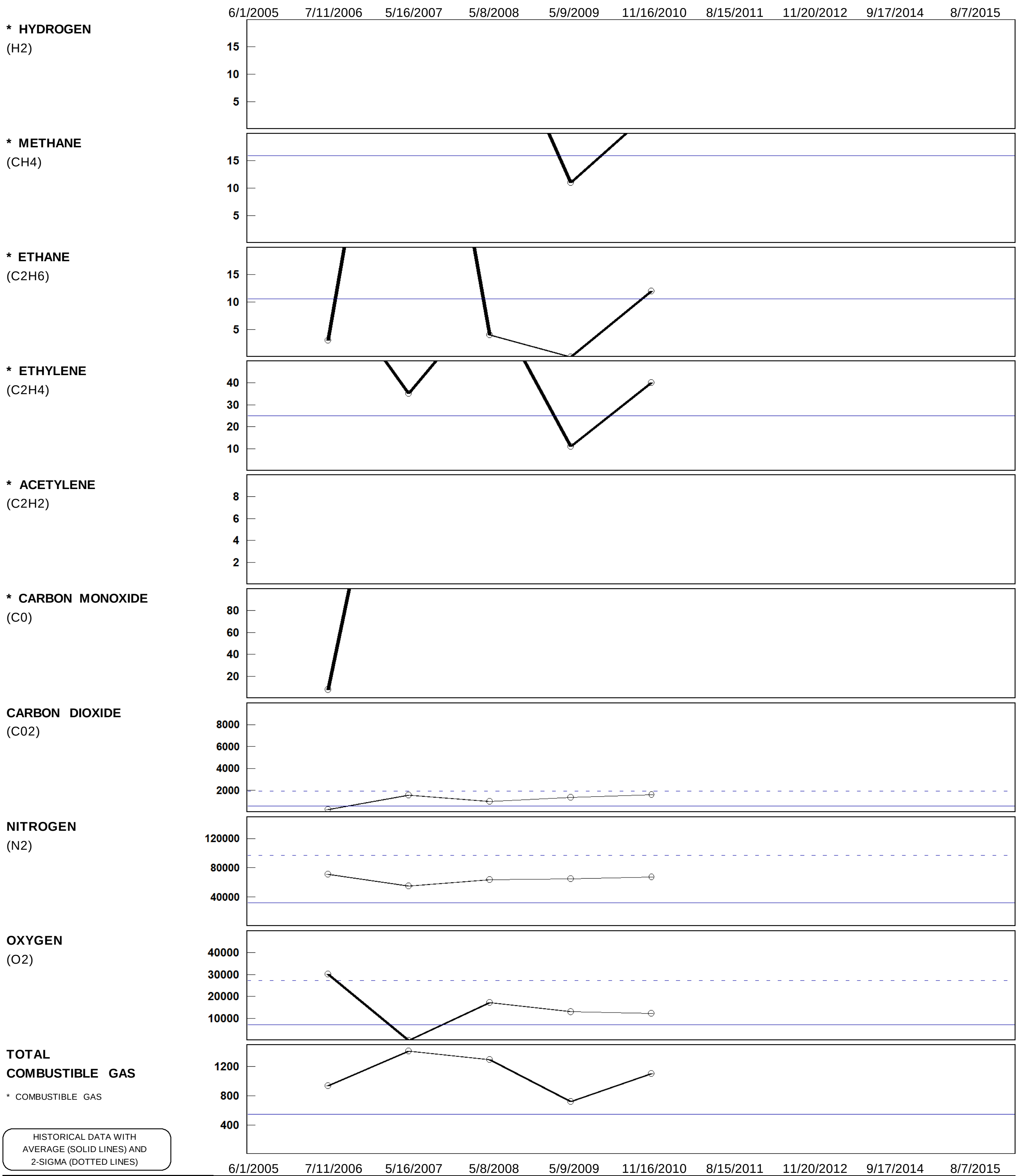
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T1-LTC	JOB #	41171263
SERIAL NO.	288692				



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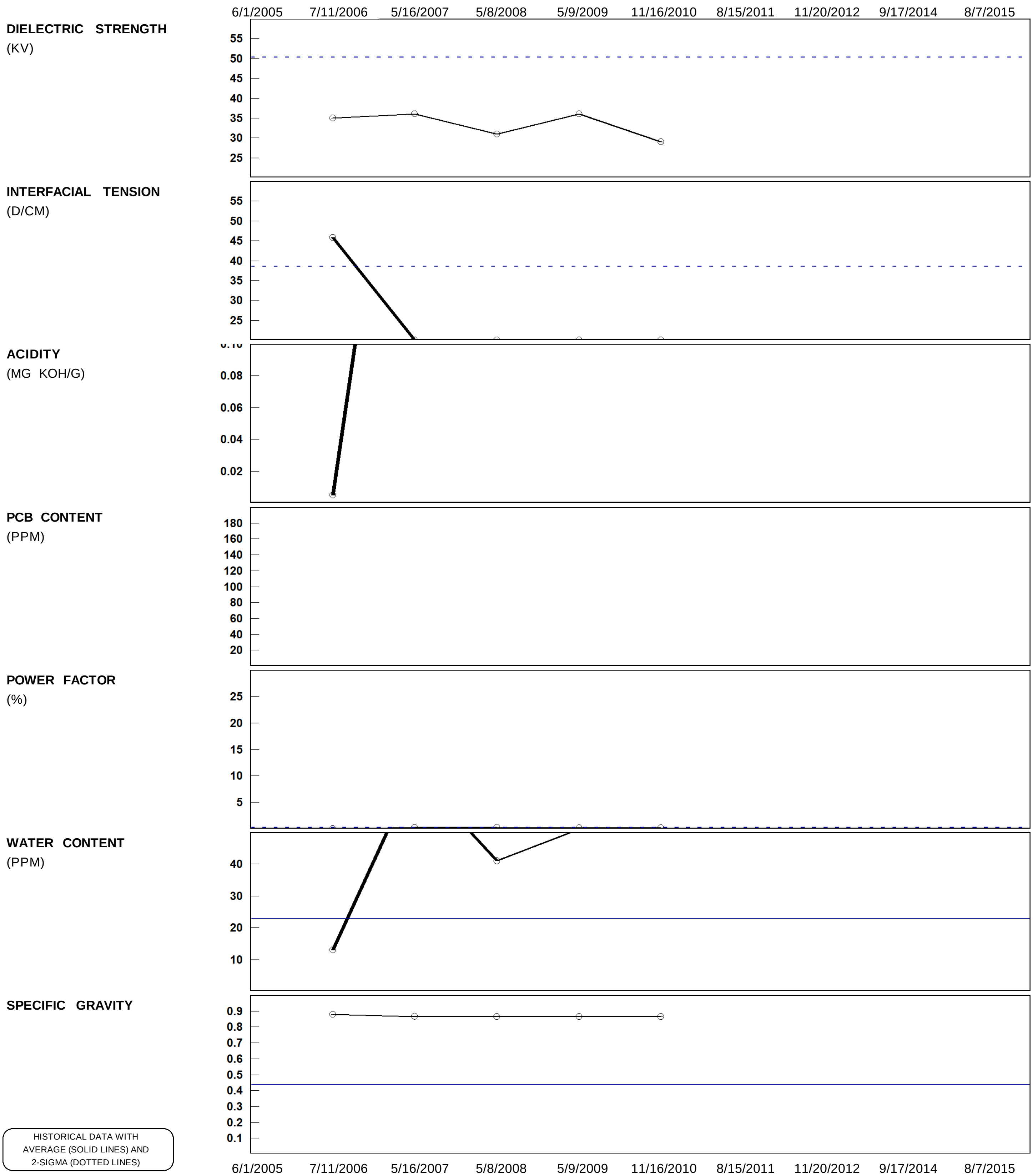
TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T1-LTC	JOB #	41171263
SERIAL NO.	288692				



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TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane- 25KV T2

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER CGE SERIAL NO. 288693

SPECIFICATION NO. KVA 7,500 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 65 °C IMPEDANCE 8.3 % B.I.L. RATING 550 kV PRI. 150 kV SEC.

COOLANT Oil CAPACITY 3095 Gallons TOTAL WEIGHT 72400

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 115,000 ◉ DELTA ◯ WYE RATED CURRENT 38 / / AMPERES

SECONDARY VOLTAGE 24,940 / 14,399 ◯ DELTA ◉ WYE RATED CURRENT 174 / / AMPERES

TAP VOLTAGES	132,000	129,250	12,650	123,750	121,000	118,250	115,500	
TAP CONNECTIONS	1	2	3	4	5	6	7	

TAP SETTING VOLTS # FANS TAP CHANGER: ◯ INTERNAL ◉ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/17/2006	6/1/2005
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	39	52	40	37	51					
INTERFACIAL TENSION (D/CM)	36.64	36.87	36.72	36.29	32.3					
ACIDITY (MG KOH/G)	0.024	0.020	0.011	0.034	0.033					
ASTM COLOR NO.	L1.5	L1.5	L1.5	0	1.5					
PCB CONTENT (PPM)										
E.P.A. CLASSIFICATION				254/1260/124						
POWER FACTOR (%)	0.010	0.023	0.008	0.023	0.015					
WATER CONTENT (PPM)	9	6	3	12	5					
SPECIFIC GRAVITY	0.8612	0.8614	0.8607	0.866	0.866					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/17/2006	6/1/2005
* HYDROGEN (H2)	6	3	1	5	8					
* METHANE (CH4)	3	3	2	3	4					
* ETHANE (C2H6)	1	0	0	0	1					
* ETHYLENE (C2H4)	13	10	6	10	13					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	294	311	187	338	455					
CARBON DIOXIDE (CO2)	1,697	1,713	1,224	1,898	1,791					
NITROGEN (N2)	67,228	62,676	49,927	52,105	72,863					
OXYGEN (O2)	30,326	27,182	22,906	23,013	22,896					
TOTAL GAS	99,568	91,898	74,253	77,372	98,031					
TOTAL COMBUSTIBLE GAS	317	327	196	356	481					

* COMBUSTIBLE GAS

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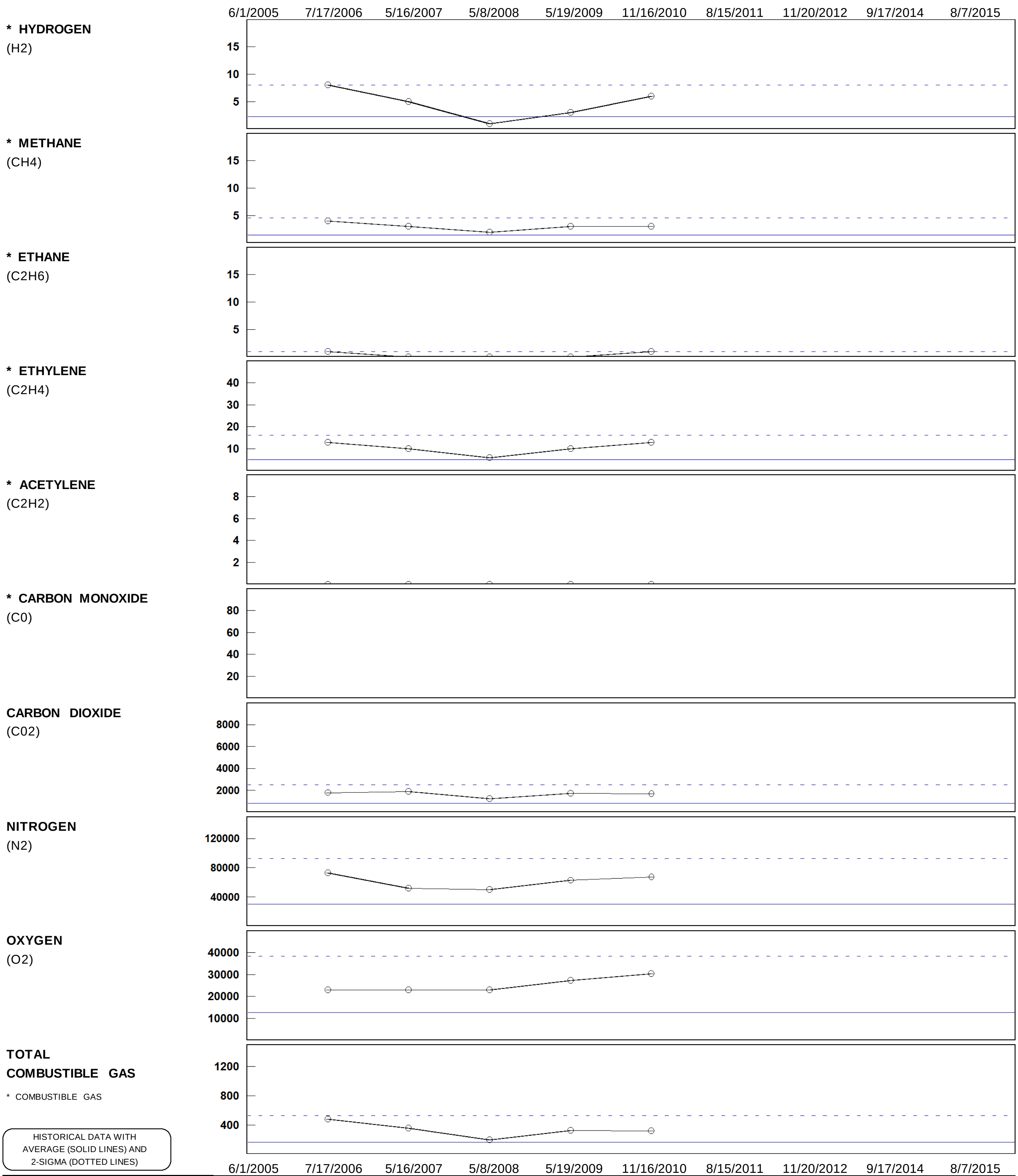
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T2	JOB #	41171263
SERIAL NO.	288693				



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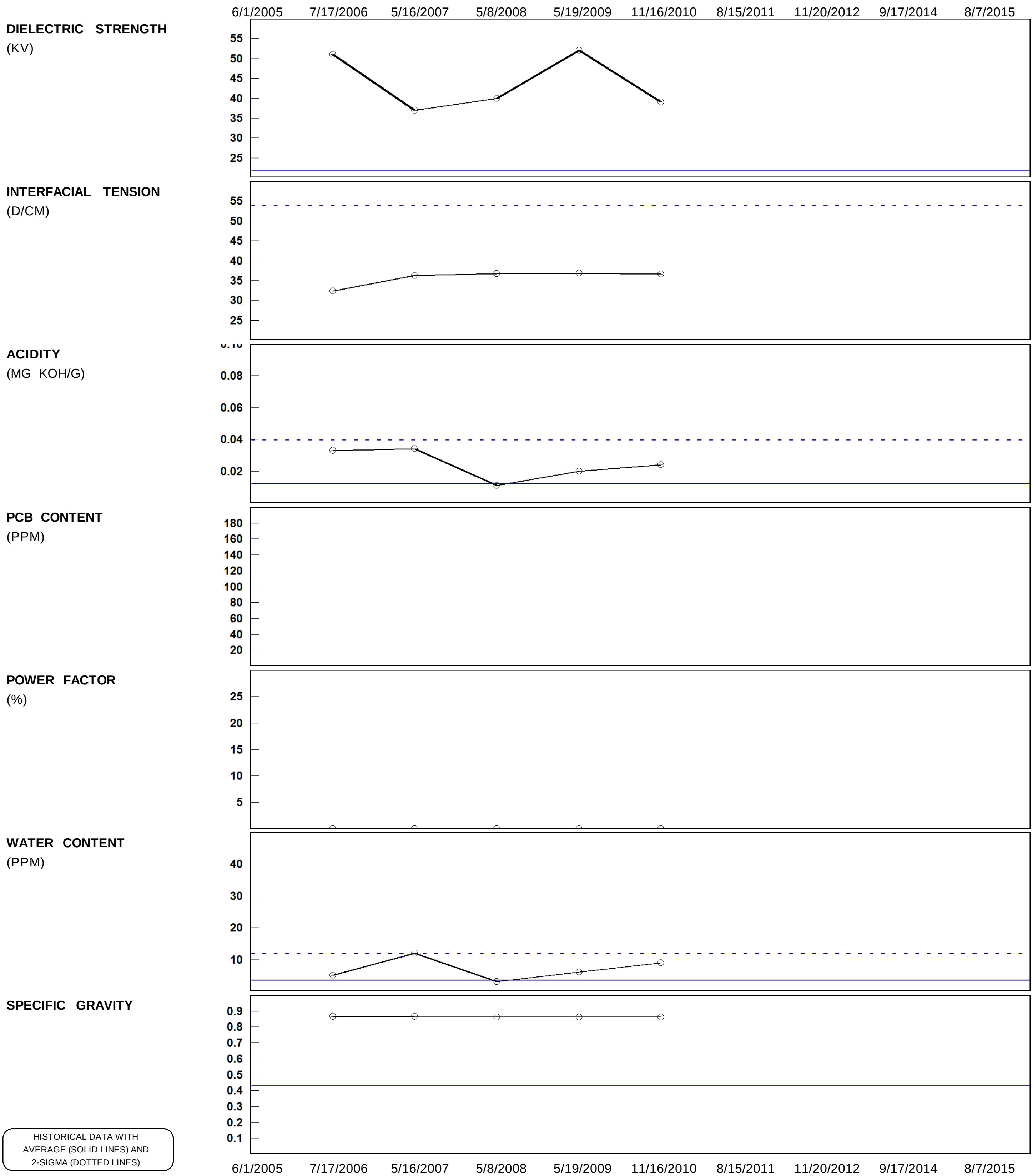
TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T2	JOB #	41171263
SERIAL NO.	288693				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane- 25KV T2-LTC

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER SERIAL NO.

SPECIFICATION NO. KVA / / TYPE CLASS

PHASE 3 TEMPERATURE RISE °C IMPEDANCE % B.I.L. RATING kV PRI. kV SEC.

COOLANT CAPACITY LITERS TOTAL WEIGHT

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE ● DELTA ○ WYE RATED CURRENT / / AMPERES

SECONDARY VOLTAGE / 0 ○ DELTA ● WYE RATED CURRENT / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ● INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY										
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	39	52	40	37	51					
INTERFACIAL TENSION (D/CM)	36.64	36.87	36.72	36.29	32.3					
ACIDITY (MG KOH/G)	0.024	0.020	0.011	0.034	0.033					
ASTM COLOR NO.	L1.5	L1.5	L1.5	0	1.5					
PCB CONTENT (PPM)										
E.P.A. CLASSIFICATION				254/1260/124						
POWER FACTOR (%)	0.010	0.023	0.008	0.023	0.015					
WATER CONTENT (PPM)	9	6	3	12	5					
SPECIFIC GRAVITY	0.8612	0.8614	0.8607	0.866	0.866					

DISSOLVED GAS ANALYSIS										
* HYDROGEN (H2)	6	3	1	5	8					
* METHANE (CH4)	3	3	2	3	4					
* ETHANE (C2H6)	1	0	0	0	1					
* ETHYLENE (C2H4)	13	10	6	10	13					
* ACETYLENE (C2H2)	0	0	0	0	0					
* CARBON MONOXIDE (CO)	294	311	187	338	455					
CARBON DIOXIDE (CO2)	1,697	1,713	1,224	1,898	1,791					
NITROGEN (N2)	67,228	62,676	49,927	52,105	72,863					
OXYGEN (O2)	30,326	27,182	22,906	23,013	22,896					
TOTAL GAS	99,568	91,898	74,253	77,372	98,031					
TOTAL COMBUSTIBLE GAS	317	327	196	356	481					

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

REVISED 2/11/2013

SIEMENS

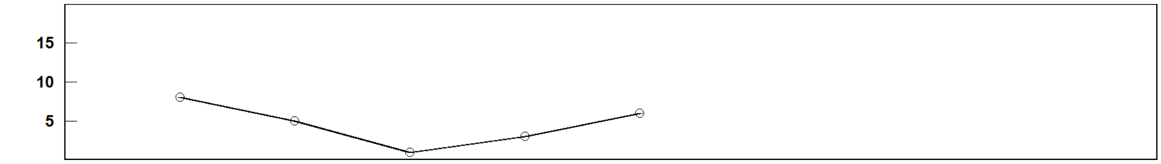
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

USER Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0 PAGE

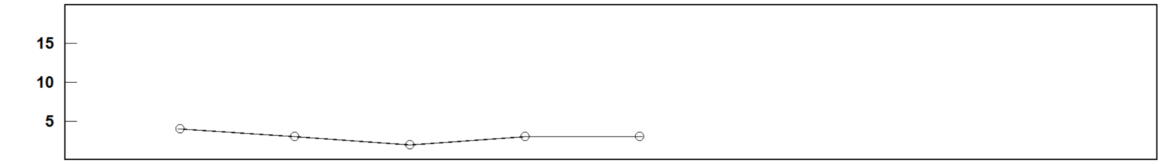
SUBSTATION Main POSITION Cochrane- 25KV T2-LTC JOB # 41171263

SERIAL NO.

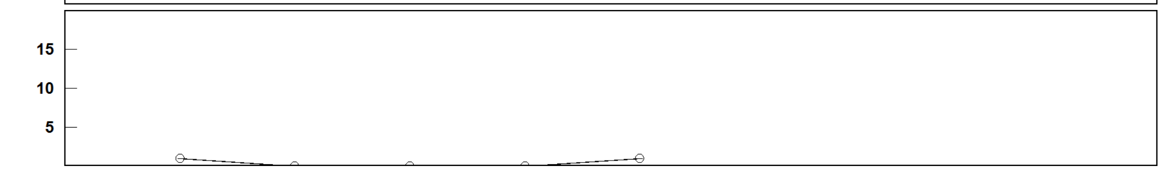
*** HYDROGEN**
(H2)



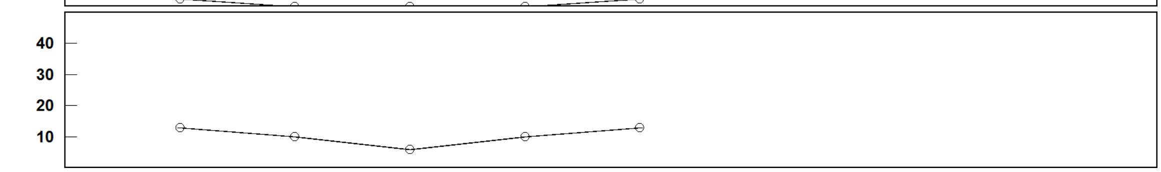
*** METHANE**
(CH4)



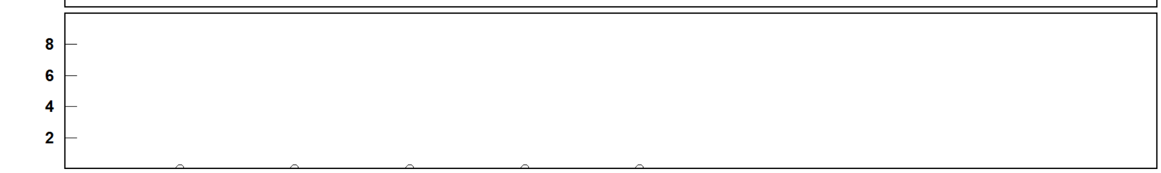
*** ETHANE**
(C2H6)



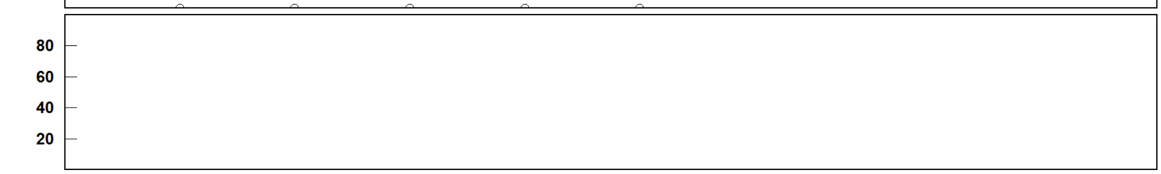
*** ETHYLENE**
(C2H4)



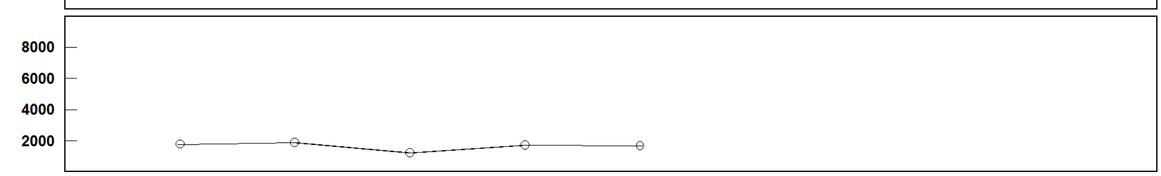
*** ACETYLENE**
(C2H2)



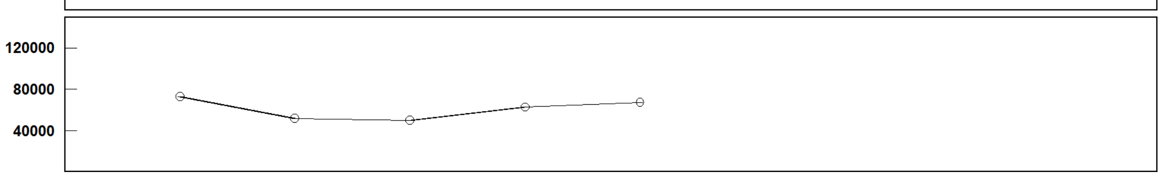
*** CARBON MONOXIDE**
(C0)



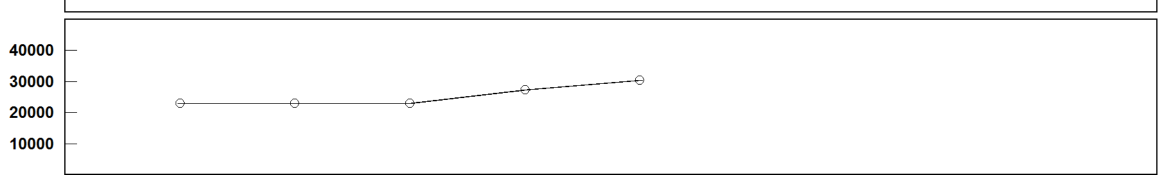
CARBON DIOXIDE
(C02)



NITROGEN
(N2)

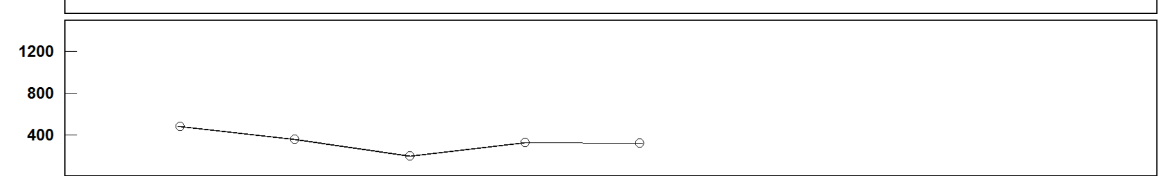


OXYGEN
(O2)



TOTAL COMBUSTIBLE GAS

* COMBUSTIBLE GAS



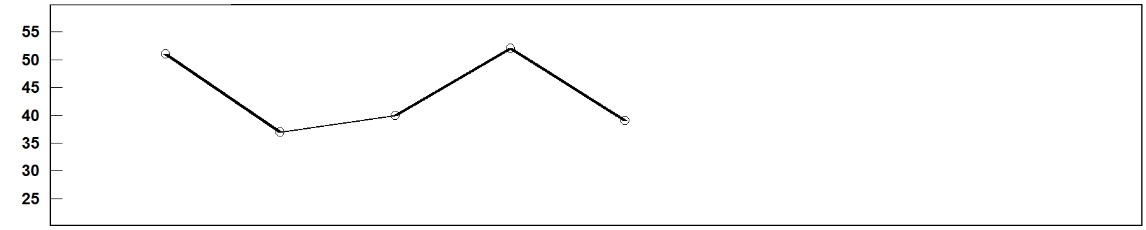
HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

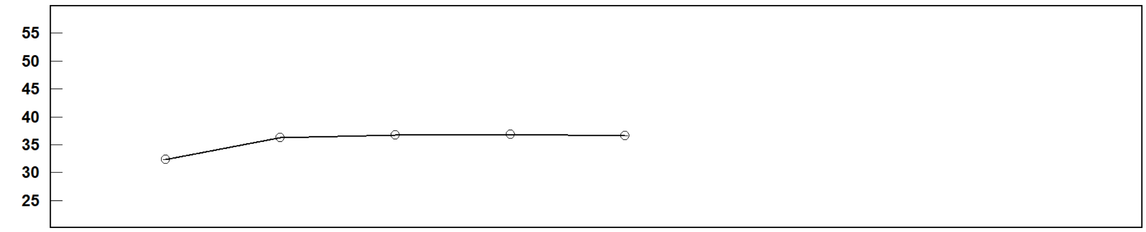
SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane- 25KV T2-LTC	JOB #	41171263
SERIAL NO.					

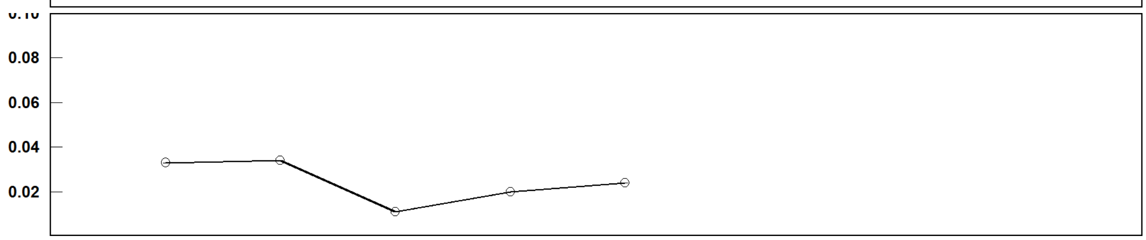
DIELECTRIC STRENGTH
(KV)



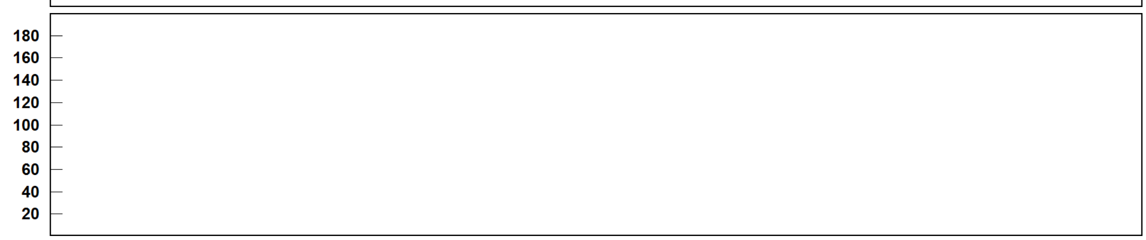
INTERFACIAL TENSION
(D/CM)



ACIDITY
(MG KOH/G)

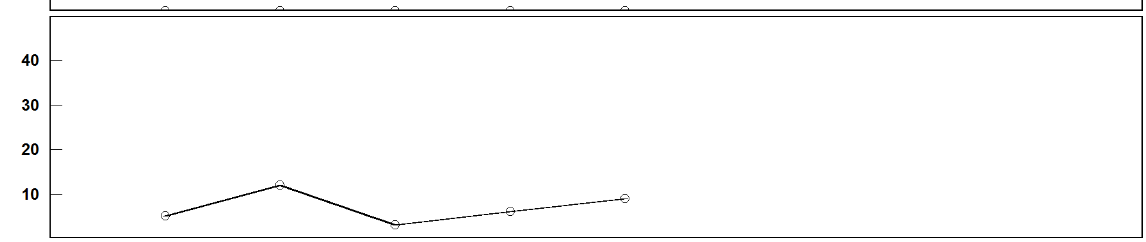


PCB CONTENT
(PPM)

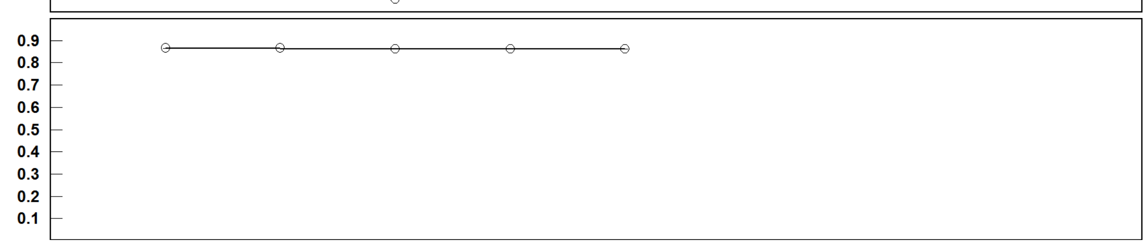


POWER FACTOR
(%)

WATER CONTENT
(PPM)



SPECIFIC GRAVITY



HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane-Regulator

TEST DATE 8/6/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 269579

SPECIFICATION NO. KVA 5,200 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE % B.I.L. RATING kV PRI. kV SEC.

COOLANT Oil CAPACITY 558 Gallons TOTAL WEIGHT 5250

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 4,160 ◉ DELTA ○ WYE RATED CURRENT 722 / / AMPERES

SECONDARY VOLTAGE 2,400 / 1,386 ○ DELTA ◉ WYE RATED CURRENT 1,251 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/6/2015	9/17/2014	11/20/2012	11/28/2011	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006
PARTICLES	ND	CLR&SPRK	MODERATE							
DIELECTRIC STRENGTH (kV)	51	51	36			51				
INTERFACIAL TENSION (D/CM)	18.03	18.03	18.17			19.8				
ACIDITY (MG KOH/G)	0.190	0.190	0.203			0.165				
ASTM COLOR NO.	L2.0	L2.0	L2.0			2.0				
PCB CONTENT (PPM)					54					
E.P.A. CLASSIFICATION					1260					
POWER FACTOR (%)	0.246	0.246	0.243			0.254				
WATER CONTENT (PPM)	32	32	24			25				
SPECIFIC GRAVITY	0.883	0.883	0.8834			0.887				

DISSOLVED GAS ANALYSIS	8/6/2015	9/17/2014	11/20/2012	11/28/2011	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006
* HYDROGEN (H_2)	73	73	44	57		63				
* METHANE (CH_4)	2	2	1	2		1				
* ETHANE (C_2H_6)	1	1	1	2		2				
* ETHYLENE (C_2H_4)	2	2	3	4		3				
* ACETYLENE (C_2H_2)	0	0	1	2		0				
* CARBON MONOXIDE (CO)	45	45	24	45		34				
CARBON DIOXIDE (CO_2)	1,281	1,281	1,052	752		737				
NITROGEN (N_2)	63,186	63,186	56,933	54,533		67,642				
OXYGEN (O_2)	28,276	28,276	27,593	30,098		26,574				
TOTAL GAS	92,866	92,866	85,652	85,495	0	95,056				
TOTAL COMBUSTIBLE GAS	123	123	74	112	0	103				

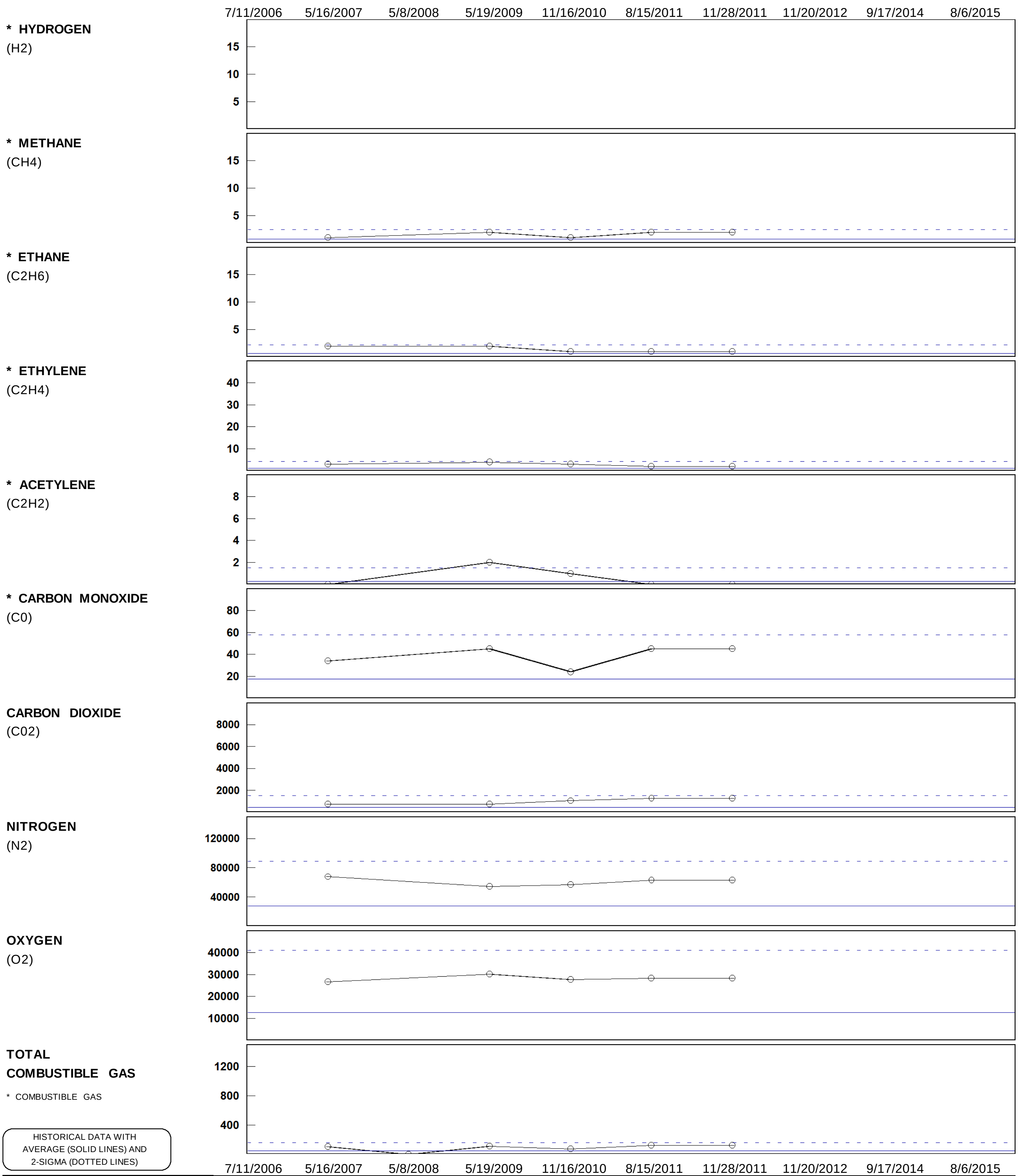
* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-Regulator	JOB #	41171263
SERIAL NO.	269579				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-Regulator	JOB #	41171263
SERIAL NO.	269579				

DIELECTRIC STRENGTH (KV)

INTERFACIAL TENSION (D/CM)

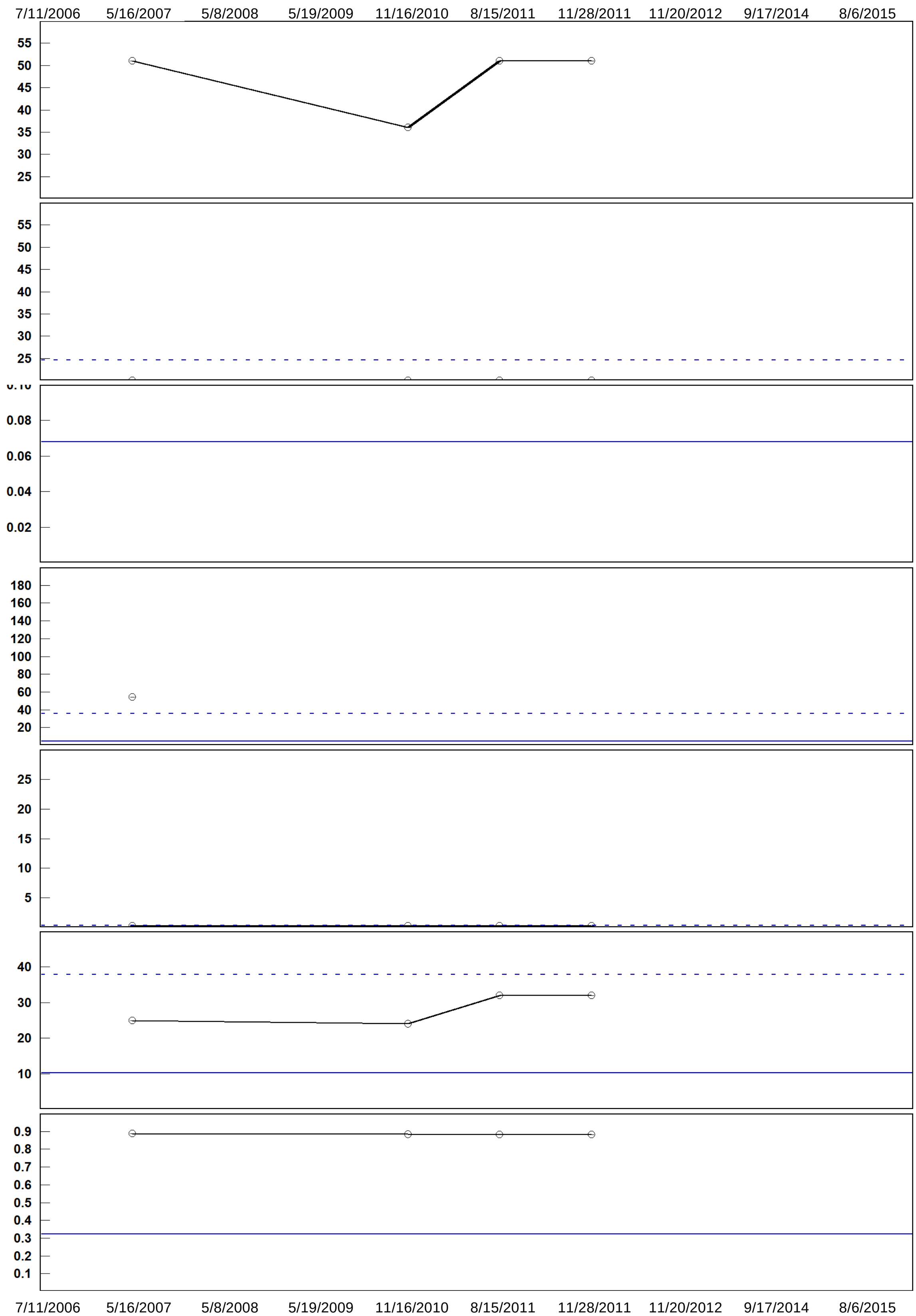
ACIDITY (MG KOH/G)

PCB CONTENT (PPM)

POWER FACTOR (%)

WATER CONTENT (PPM)

SPECIFIC GRAVITY



HISTORICAL DATA WITH AVERAGE (SOLID LINES) AND 2-SIGMA (DOTTED LINES)

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TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane-Regulator-LTC

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER Ferranti Packard SERIAL NO. 269579

SPECIFICATION NO. KVA 5,200 / / TYPE ONAN CLASS

PHASE 3 TEMPERATURE RISE 55 °C IMPEDANCE % B.I.L. RATING kV PRI. kV SEC.

COOLANT Oil CAPACITY 72 Gallons TOTAL WEIGHT 5250

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 4,160 ◉ DELTA ○ WYE RATED CURRENT 722 / / AMPERES

SECONDARY VOLTAGE 2,400 / 1,386 ○ DELTA ◉ WYE RATED CURRENT 1,251 / / AMPERES

TAP VOLTAGES

TAP CONNECTIONS

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	40	45	41	36	57					
INTERFACIAL TENSION (D/CM)	25.08	24.94	25.15	24.98	27.1					
ACIDITY (MG KOH/G)	0.072	0.070	0.073	0.125	0.055					
ASTM COLOR NO.	L3.0	L3.0	L2.5	0	2.5					
PCB CONTENT (PPM)	29									
E.P.A. CLASSIFICATION										
POWER FACTOR (%)	0.229	0.189	0.287	0.177	0.212					
WATER CONTENT (PPM)	29	26	19	34	2.5					
SPECIFIC GRAVITY	0.8639	0.8645	0.8647	0.869	0.868					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
* HYDROGEN (H2)	1	0	1	11	2					
* METHANE (CH4)	2	1	1	1	1					
* ETHANE (C2H6)	1	0	0	0	0					
* ETHYLENE (C2H4)	6	2	2	6	4					
* ACETYLENE (C2H2)	11	1	2	3	4					
* CARBON MONOXIDE (CO)	33	28	9	81	26					
CARBON DIOXIDE (CO2)	602	622	329	632	360					
NITROGEN (N2)	63,829	63,457	44,560	59,883	68,530					
OXYGEN (O2)	29,698	29,636	21,288	26,876	29,017					
TOTAL GAS	94,183	93,747	66,192	87,493	97,944					
TOTAL COMBUSTIBLE GAS	54	32	15	102	37					

* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

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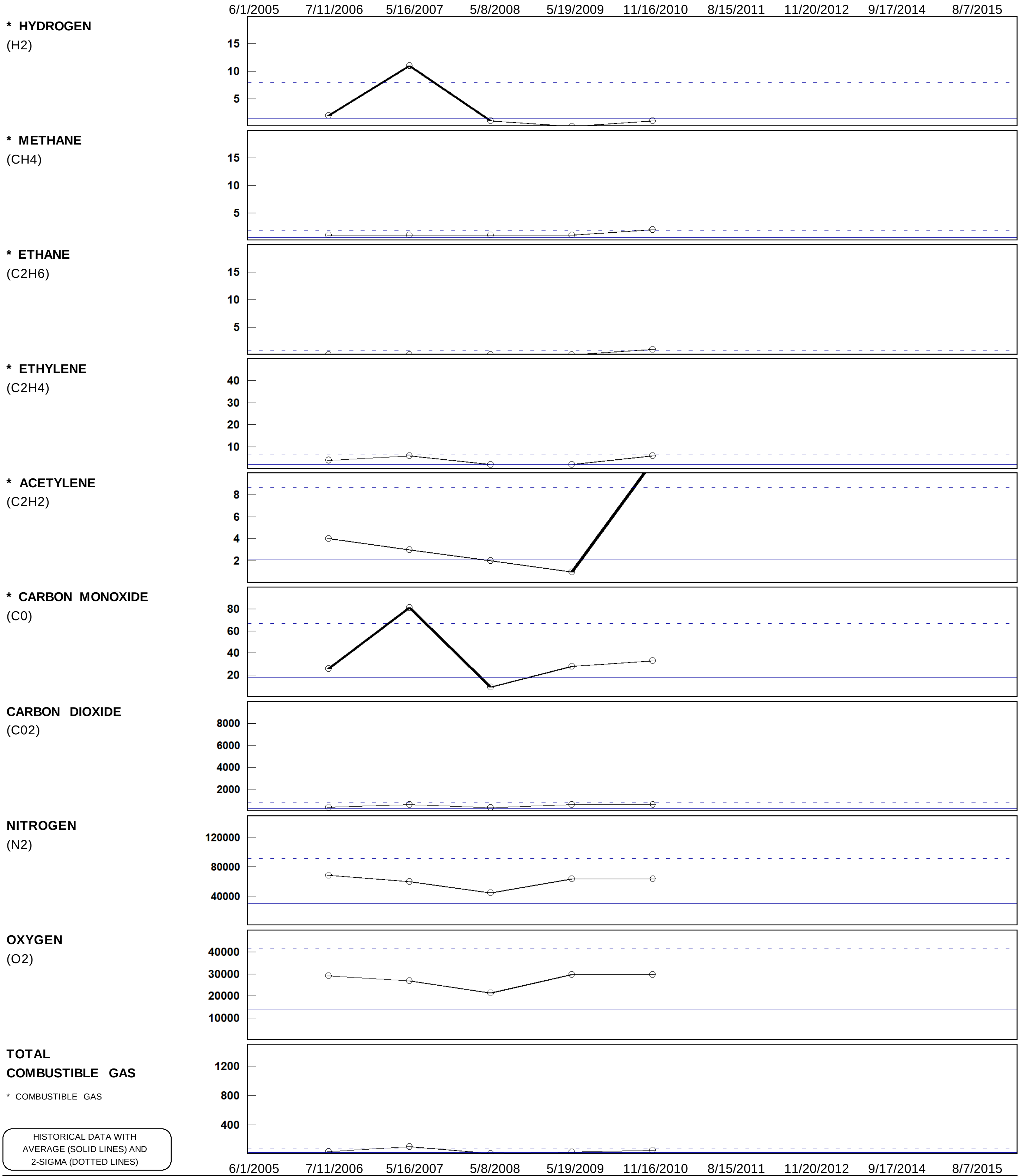
TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-Regulator-LTC	JOB #	41171263
SERIAL NO.	269579				

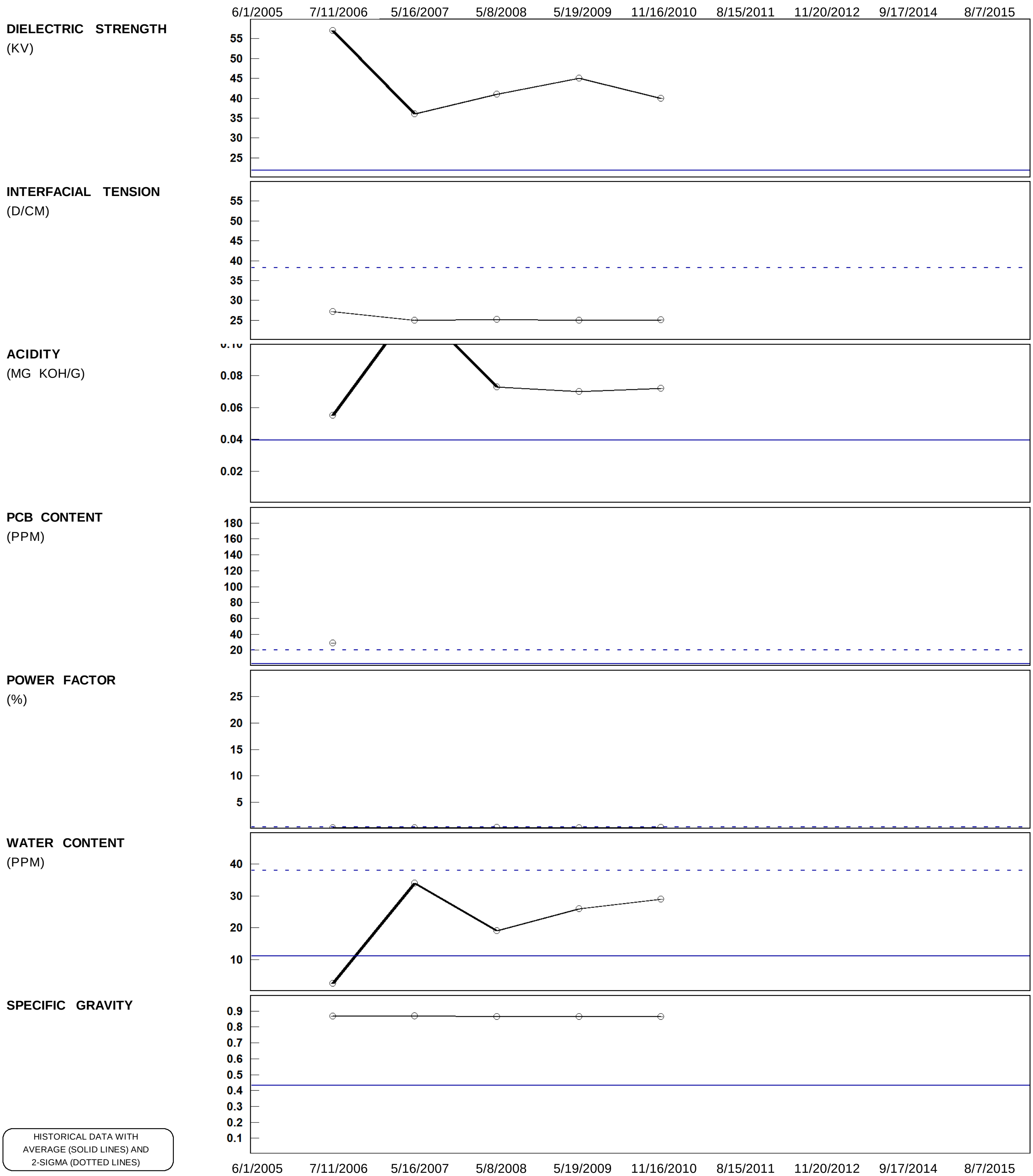


REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-Regulator-LTC	JOB #	41171263
SERIAL NO.	269579				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane-T1B

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER English Electric SERIAL NO. 203108

SPECIFICATION NO. KVA 1,000 / / TYPE ONAN CLASS

PHASE 1 TEMPERATURE RISE 55 °C IMPEDANCE 9.25 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1225 GALLONS TOTAL WEIGHT 25450

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 110,000 RATED CURRENT 9 / / AMPERES

SECONDARY VOLTAGE 2,400 0 RATED CURRENT 417 / / AMPERES

TAP VOLTAGES 121,000 118,250 115,500 112,750 110,000

TAP CONNECTIONS I II III IV V

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
PARTICLES	ND	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	36	45	44							
INTERFACIAL TENSION (D/CM)	23.77	24.8	23.25							
ACIDITY (MG KOH/G)	0.131	0.104	0.105							
ASTM COLOR NO.	L2.0	L2.0	L2.0							
PCB CONTENT (PPM)				5						
E.P.A. CLASSIFICATION				1260						
POWER FACTOR (%)	0.104	0.108	0.108							
WATER CONTENT (PPM)	15	12	8							
SPECIFIC GRAVITY	0.8481	0.8482	0.848							

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
* HYDROGEN (H2)	23	22	16							
* METHANE (CH4)	4	4	3							
* ETHANE (C2H6)	2	2	2							
* ETHYLENE (C2H4)	8	6	5							
* ACETYLENE (C2H2)	0	0	0							
* CARBON MONOXIDE (CO)	213	219	198							
CARBON DIOXIDE (CO2)	1,892	1,930	1,775							
NITROGEN (N2)	69,279	65,711	57,085							
OXYGEN (O2)	27,981	27,558	24,673							
TOTAL GAS	99,402	95,452	83,757	0						
TOTAL COMBUSTIBLE GAS	250	253	224	0						

* COMBUSTIBLE GAS

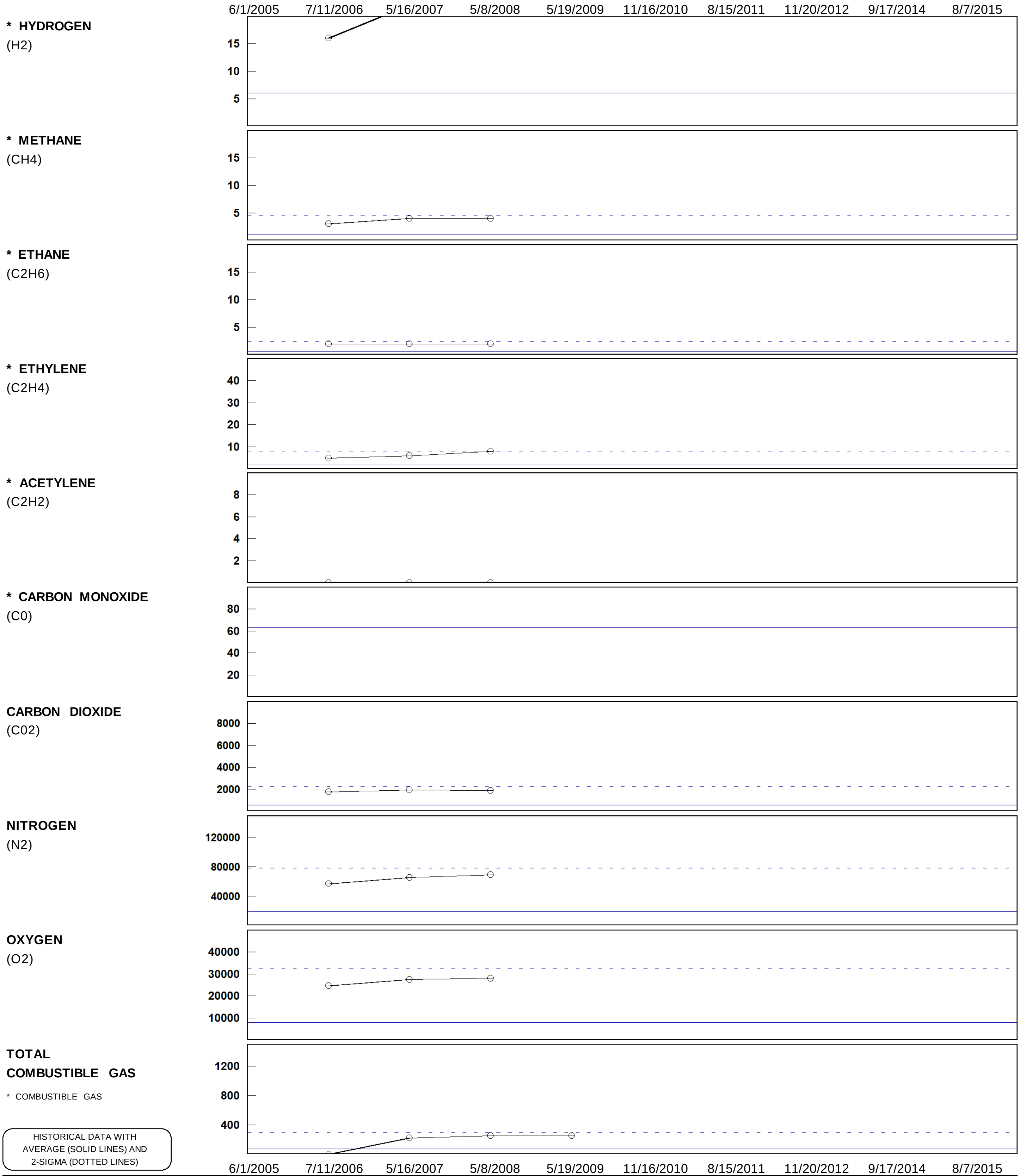
SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T1B	JOB #	41171263
SERIAL NO.	203108				

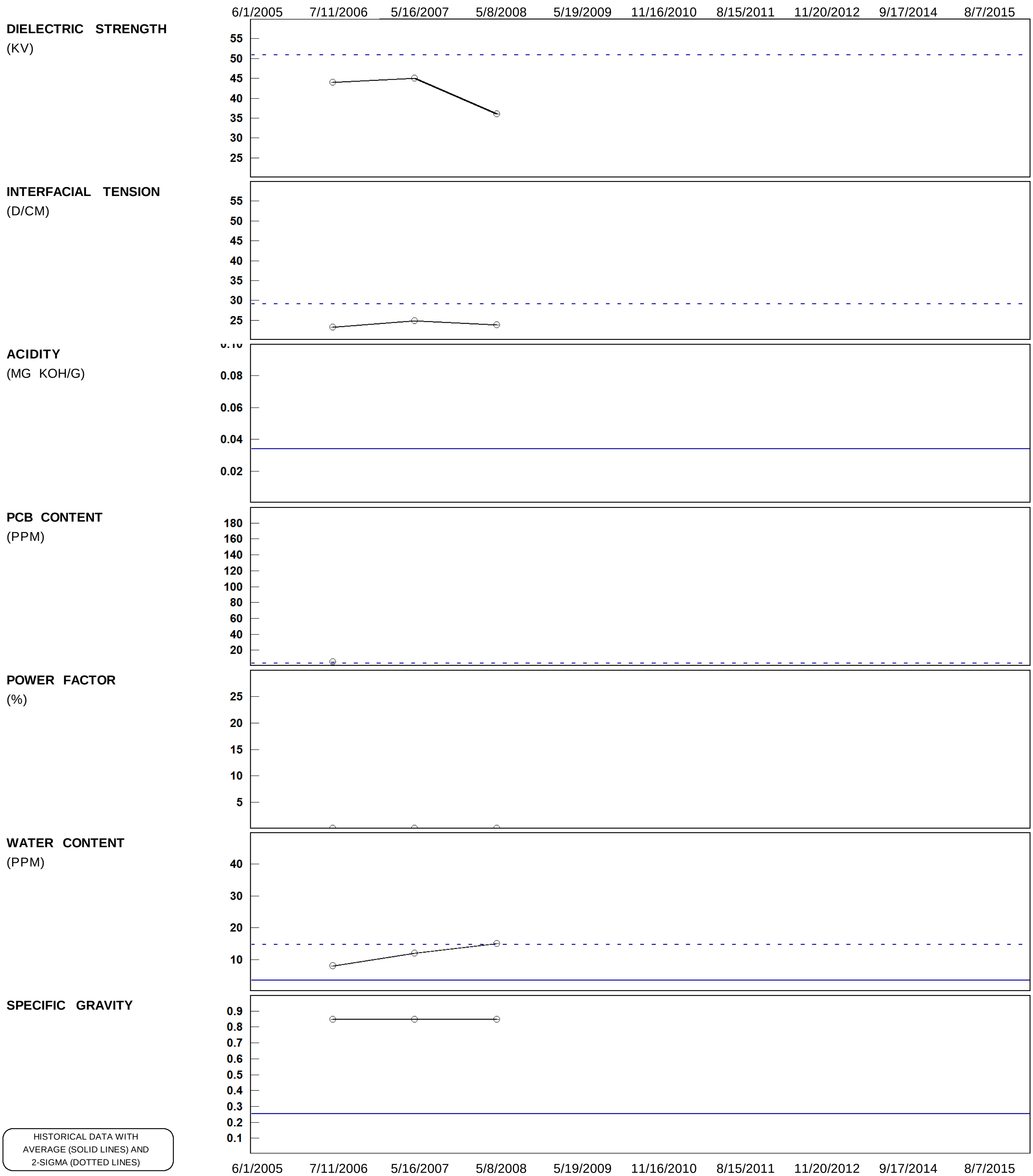


REVISED 2/11/2013

SIEMENS

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T1B	JOB #	41171263
SERIAL NO.	203108				



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TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane-T2A

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER English Electric SERIAL NO. 286604

SPECIFICATION NO. KVA 1,000 / / TYPE ONAN CLASS

PHASE 1 TEMPERATURE RISE 55 °C IMPEDANCE 8.66 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1225 GALLONS TOTAL WEIGHT 25450

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 110,000 RATED CURRENT 9 / / AMPERES

SECONDARY VOLTAGE 2,400 0 RATED CURRENT 417 / / AMPERES

TAP VOLTAGES 121,000 118,250 115,500 112,750 110,000

TAP CONNECTIONS I II III IV V

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
PARTICLES	TRACE	CLR&SPRK	CLR&SPRK							
DIELECTRIC STRENGTH (kV)	28	45	49		49					
INTERFACIAL TENSION (D/CM)	33.41	33.73	33.18		34.3					
ACIDITY (MG KOH/G)	0.039	0.032	0.037		0.031					
ASTM COLOR NO.	L2.0	1.5	L1.5		1.5					
PCB CONTENT (PPM)				18						
E.P.A. CLASSIFICATION				1260						
POWER FACTOR (%)	0.053	0.029	0.014		0.009					
WATER CONTENT (PPM)	19	12	10		11					
SPECIFIC GRAVITY	0.8828	0.8828	0.883		0.887					

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006	6/1/2005
* HYDROGEN (H2)	1	3	1		5					
* METHANE (CH4)	2	1	1		1					
* ETHANE (C2H6)	0	0	0		0					
* ETHYLENE (C2H4)	2	2	2		2					
* ACETYLENE (C2H2)	0	0	0		0					
* CARBON MONOXIDE (CO)	47	63	54		64					
CARBON DIOXIDE (CO2)	912	1,001	920		667					
NITROGEN (N2)	61,303	64,717	56,494		69,962					
OXYGEN (O2)	31,097	31,244	27,417		29,571					
TOTAL GAS	93,364	97,031	84,889	0	100,272					
TOTAL COMBUSTIBLE GAS	52	69	58	0	72					

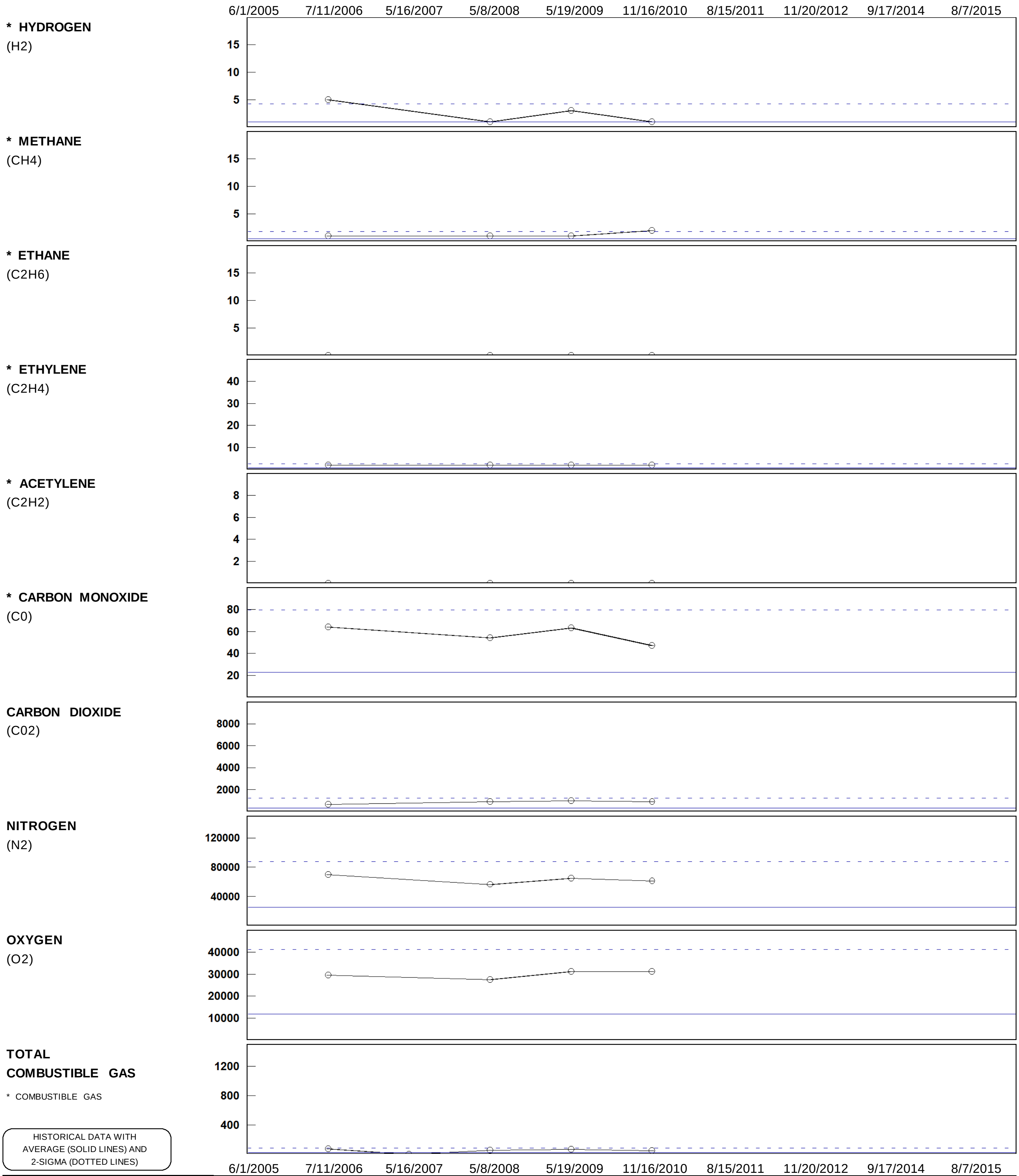
* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

SIEMENS

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T2A	JOB #	41171263
SERIAL NO.	286604				

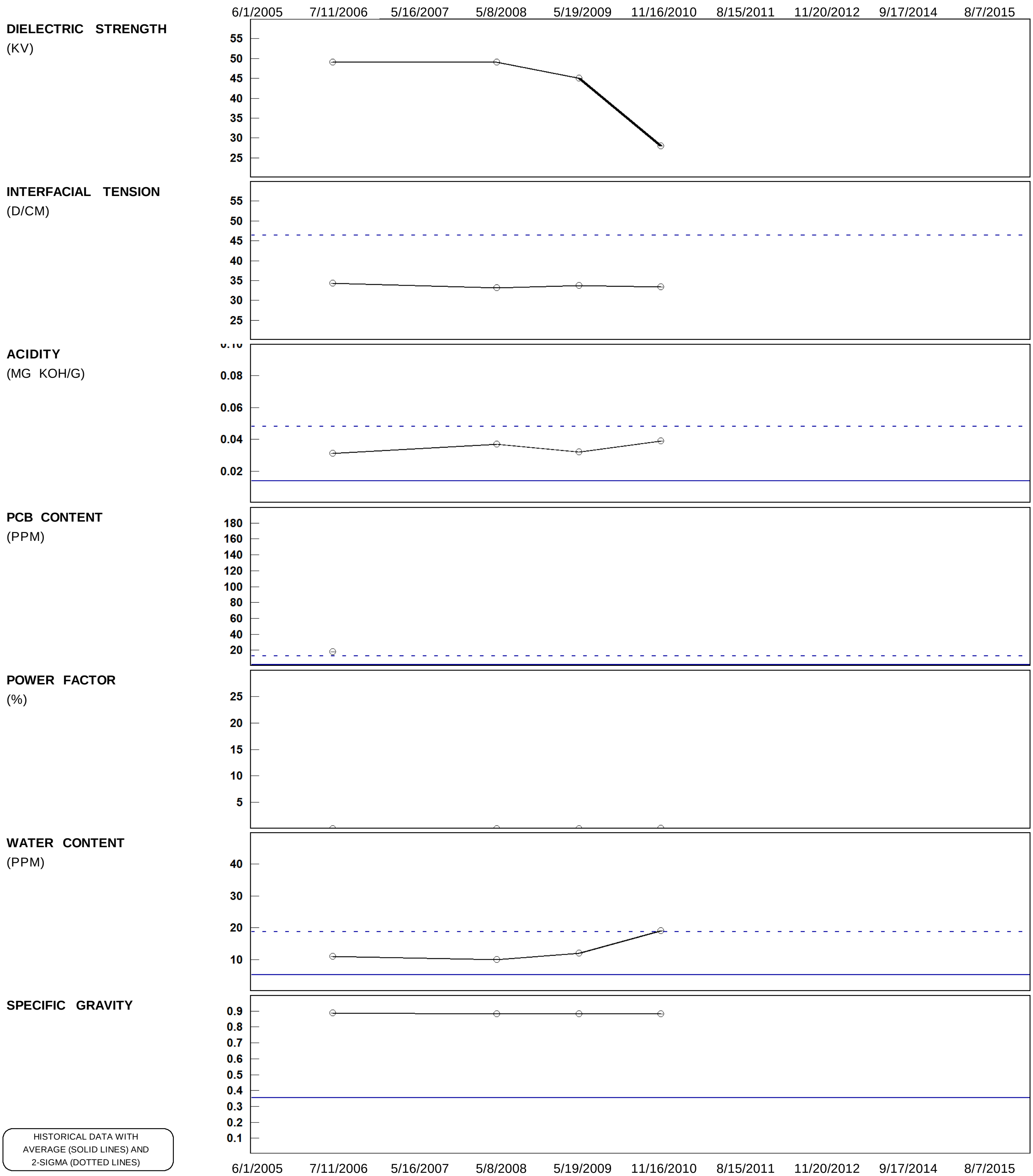


REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T2A	JOB #	41171263
SERIAL NO.	286604				



REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING

SIEMENS

CUSTOMER Northern Ontario Wires PAGE

PLANT Cochrane SUBSTATION Main POSITION Cochrane-T2C

TEST DATE 8/7/2015 AMBIENT TEMPERATURE °C HUMIDITY % JOB # 41171263

NAMEPLATE DATA

MANUFACTURER English Electric SERIAL NO. 258423

SPECIFICATION NO. KVA 1,000 / / TYPE ONAN CLASS

PHASE 1 TEMPERATURE RISE 55 °C IMPEDANCE 9.35 % B.I.L. RATING kV PRI. kV SEC.

COOLANT OIL CAPACITY 1225 GALLONS TOTAL WEIGHT 25450

WINDING POLARITY SUBTRACTIVE WINDING MATERIAL K FACTOR NA

PRIMARY VOLTAGE 110,000 RATED CURRENT 9 / / AMPERES

SECONDARY VOLTAGE 2,400 0 RATED CURRENT 417 / / AMPERES

TAP VOLTAGES 121,000 118,250 115,500 112,750 110,000

TAP CONNECTIONS I II III IV V

TAP SETTING VOLTS # FANS TAP CHANGER: ◉ INTERNAL ○ EXTERNAL DRY TYPE ☐

FLUID QUALITY	8/7/2015	9/17/2014	1/16/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006
PARTICLES	TRACE	CLR&SPRK	CLR&SPRK	CLR&SPRK						
DIELECTRIC STRENGTH (kV)	39	47	47	51	38	48				
INTERFACIAL TENSION (D/CM)	33.49	33.35	32.89	33.09	33.11	35.1				
ACIDITY (MG KOH/G)	0.044	0.035	0.049	0.033	0.046	0.024				
ASTM COLOR NO.	L1.5	L1.5	L1.5	L1.5	0	1.5				
PCB CONTENT (PPM)					5.3					
E.P.A. CLASSIFICATION					1260					
POWER FACTOR (%)	0.026	0.039	0.056	0.020	0.24	0.023				
WATER CONTENT (PPM)	13	9	11	7	14	8				
SPECIFIC GRAVITY	0.8738	0.874	0.8737	0.874	0.878	0.878				

DISSOLVED GAS ANALYSIS	8/7/2015	9/17/2014	1/16/2014	11/20/2012	8/15/2011	11/16/2010	5/19/2009	5/8/2008	5/16/2007	7/11/2006
* HYDROGEN (H_2)	8	3	4	5	5	4				
* METHANE (CH_4)	2	2	1	1	1	1				
* ETHANE (C_2H_6)	0	0	0	0	0	0				
* ETHYLENE (C_2H_4)	3	2	4	2	3	2				
* ACETYLENE (C_2H_2)	0	0	0	0	0	0				
* CARBON MONOXIDE (CO)	59	68	69	66	67	70				
CARBON DIOXIDE (CO_2)	1,041	1,054	1,128	1,005	774	627				
NITROGEN (N_2)	64,596	61,607	65,212	60,708	57,308	71,902				
OXYGEN (O_2)	32,332	29,550	31,677	29,161	29,932	29,984				
TOTAL GAS	98,041	92,286	98,095	90,948	88,090	102,590				
TOTAL COMBUSTIBLE GAS	72	75	78	74	76	77				

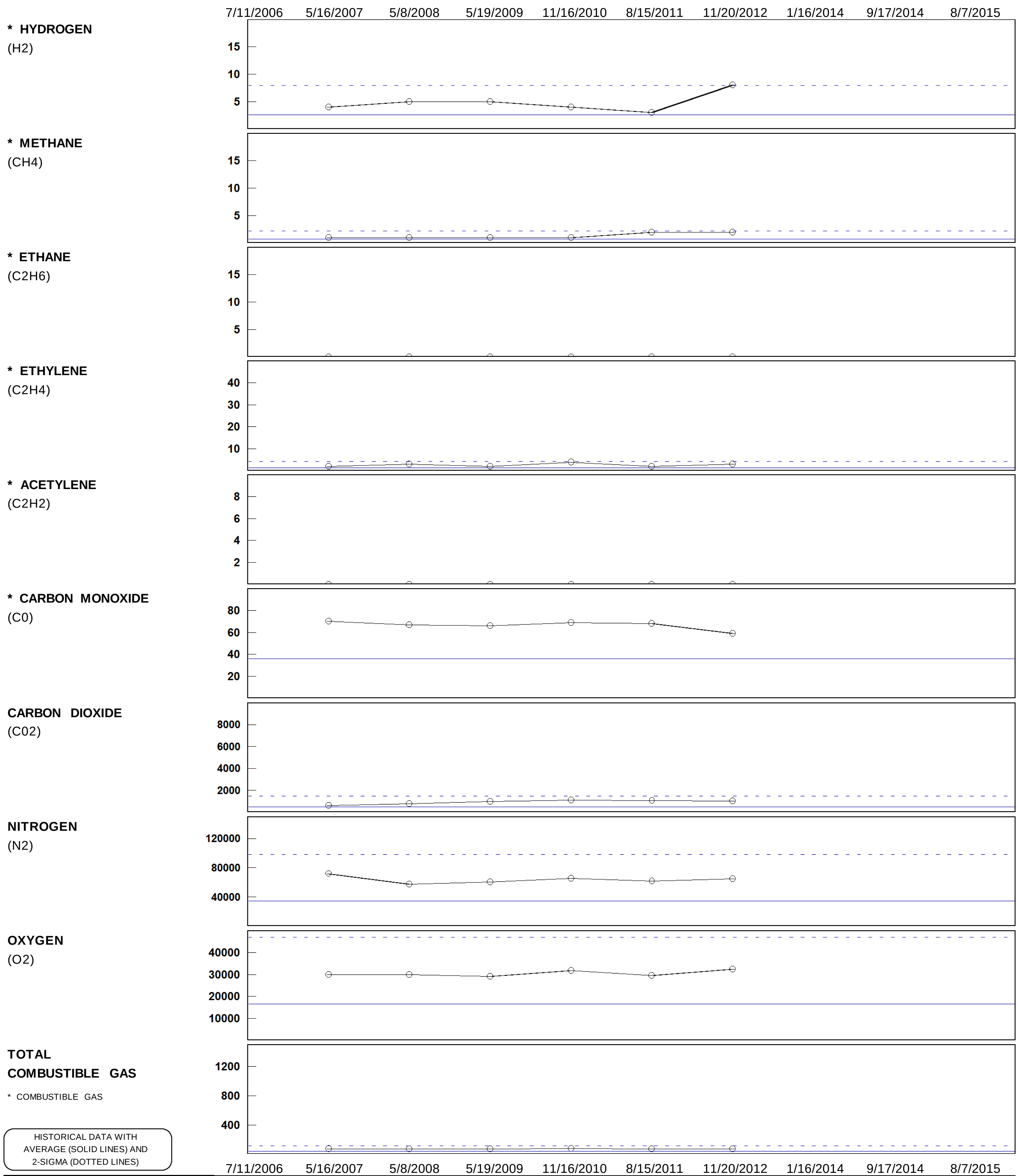
* COMBUSTIBLE GAS

SAMPLED BY: John Love TESTED BY: WEIDMANN - ACTI

SIEMENS

TRANSFORMER LIQUID COOLANT TRENDING
DISSOLVED GAS ANALYSIS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T2C	JOB #	41171263
SERIAL NO.	258423				

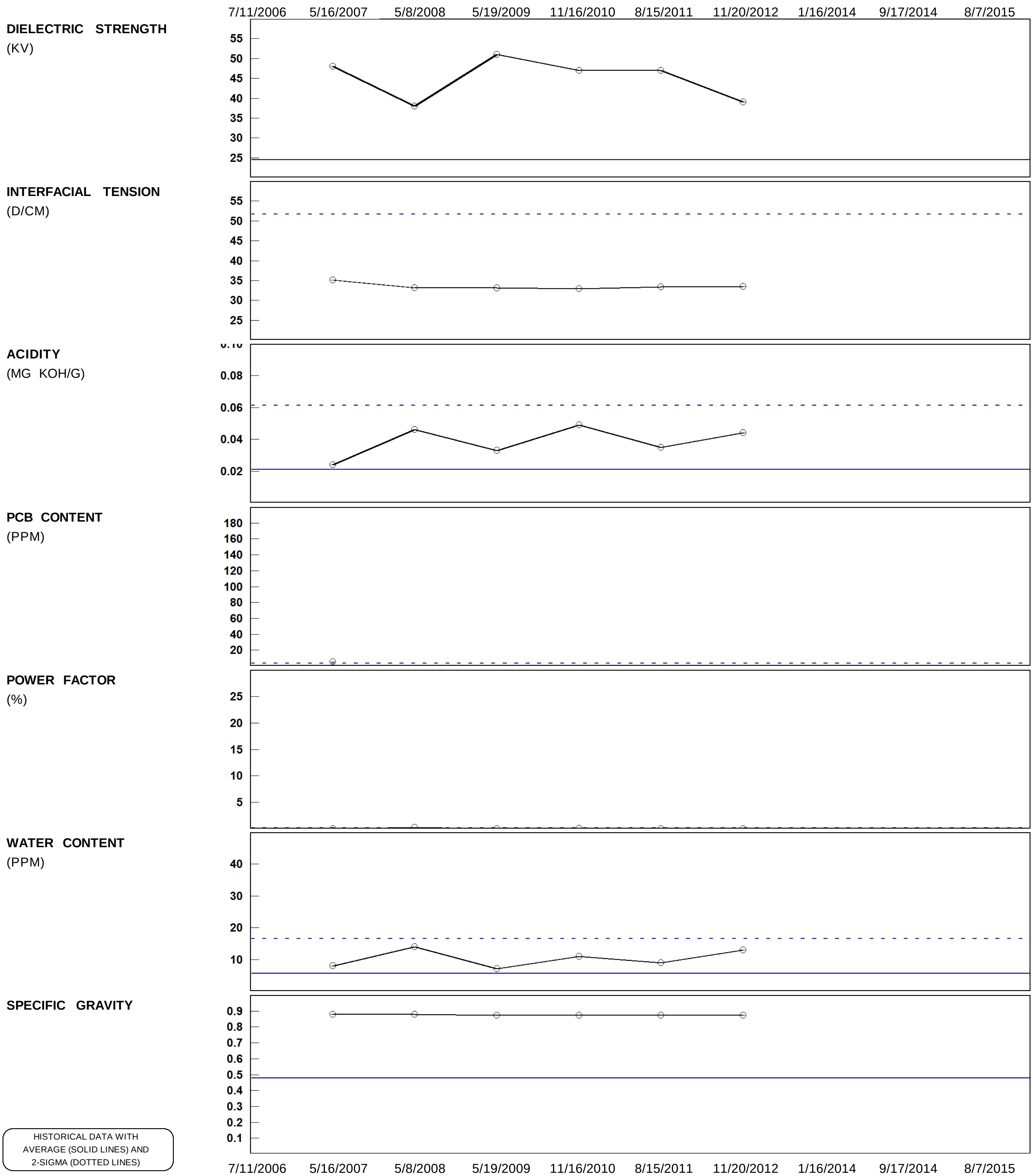


REVISED 2/11/2013

TRANSFORMER LIQUID COOLANT TRENDING
FLUID QUALITY

SIEMENS

USER	Northern Ontario Wires; 153 Sixth Ave; PO Box 640; Cochrane ON Canada P0L 1C0			PAGE	
SUBSTATION	Main	POSITION	Cochrane-T2C	JOB #	41171263
SERIAL NO.	258423				



REVISED 2/11/2013

File Number:	EB-2016-0096
Exhibit:	2
Tab:	2
Schedule:	1
Attachment:	2
Page:	1
Date:	26-Aug-16

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

First year of Forecast Period: *2017*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2012			**2013**			**2014**			**2015**			**2016**			**2017**	**2018**	**2019**	**2020**	**2021**
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Var**					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access		-	--	-	40	--		8	--		58	--	15		-100.0%	15	15	20	20	20
System Renewal		283	--	333	245	-26.4%		112	--		179	--	213		-100.0%	355	395	370	350	380
System Service		185	--	179	269	50.3%		235	--		178	--	227		-100.0%	315	355	370	385	400
General Plant		363	--	213	254	19.2%		366	--		171	--	248		-100.0%	143	33	33	33	33
TOTAL EXPENDITURE	-	831	--	725	808	11.4%	864	721	-16.6%	536	586	9.3%	703	-	-100.0%	828	798	793	788	833
System O&M		$ 1,102	--		$ 1,232	--		$ 1,237	--		$ 1,128	--	$ 1,209		-100.0%	$ 1,513	$ 1,586	$ 1,626	$ 1,668	$ 1,711

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

File Number:	EB-2016-0096
Exhibit:	2
Tab:	2
Schedule:	1
Attachment:	3
Page:	1
Date:	26-Aug-16

Appendix 2-AA
Capital Projects Table

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**
System Access						
Metering		40,344	8,210	5,089	15,000	15,000
Sub-Total	0	40,344	8,210	5,089	15,000	15,000
System Renewal						
Pole Changes- Cochrane	80,318	105,504	49,270	58,096	55,000	105,000
Pole Changes- Kapuskasing	67,997	2,013	14,050	8,103	55,000	55,000
Pole Changes-Iroquois Falls	16,557	8,323	3,229	419	27,500	55,000
Cochrane - 5 kV Upgrade - Laneway	13,839	129,232				
Cochrane - 11th Ave Relocate Upgr	87,623					
Cochrane - Primary 11th and Maple			38,660	7,334		
Cochrane Lakefront Rebuild					50,000	
Cochrane 5 - kV Upgrade						90,000
Cochrane Substation Feeder	11,206		686		25,000	50,000
IF - Pole Changes				52,253		
Cochrane Pole Changes				29,665		
Kapuskasing Pole Changes				9,232		
Sub-Total	277,540	245,072	105,895	165,102	212,500	355,000
System Service						
Kapuskasing 5kV to 25kV Conversi	103,372	205,501	203,393	94,251	140,000	175,000
Iroqois Falls 2.4 to 12kV Upgrade	81,730	63,936	31,322	83,829	87,000	140,000
Sub-Total	185,102	269,437	234,715	178,080	227,000	315,000
General Plant						
Transportation Equipment	218,112	224,313	261,375		85,000	
Computer Hardware	3,982		1,800	6,000	30,000	10,000
Computer Software			87,493	160,557	120,914	115,000
Buildings	116,245	17,535	10,228	1,165		
Sub-Total	338,339	241,848	360,896	167,722	235,914	125,000
Miscellaneous	29,314	12,485	11,550	69,777	12,500	17,500
Total	**830,295**	**809,186**	**721,266**	**585,770**	**702,914**	**827,500**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**830,295**	**809,186**	**721,266**	**585,770**	**702,914**	**827,500**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Cochrane Office: (705) 272-6669
Iroquois Falls Office: (800) 619-6722
Kapuskasing Office: (800) 619-6722
customercare@nowinc.ca

Northern Ontario WIRES inc.

153 Sixth Avenue - 153 Sixième Rue
P.O. Box 640 - C.P. 640
Cochrane, Ontario P0L 1C0

February 9, 2016

Electrical Safety Authority
155 A Matheson Blvd. W.
Suite 202
Mississauga, ON L5R 3L5

Att: General Manager of Technical Services & Compliance

Dear Sir:

Re: NOW Annual Audit Report 2015

Please find enclosed a copy of our recent annual audit performed by Mr. Leslie Stoch, P. Eng., from Acumen Engineered Solutions International Inc. This audit was completed on January 20, 2016 at our facilities here in Cochrane, Ontario.

The report contains no non-compliant issues and one opportunity for improvement wherein evidence is needed to show that construction is being carried out in accordance with NOW's certified standard designs. We have immediately implemented this recommendation, as all construction projects, including pole changes will now require a sign-off indicating that work is in accordance with these standards.

Moreover, we also are enclosing a copy of the Annual Declaration of Compliance, which I trust will be found to be in order and we look forward to any further correspondence you deem appropriate to these matters.

Best regards,

Dan Boucher
General Manager

Cc: D. Lamarche, Purchasing Manager

Cochrane Office: (705) 272-6669
Iroquois Falls Office: (800) 619-6722
Kapuskasing Office: (800) 619-6722
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Northern Ontario WIRES inc.

153 Sixth Avenue - 153 Sixième Rue
P.O. Box 640 - C.P. 640
Cochrane, Ontario P0L 1C0

Annual Declaration of Compliance

The Declaration of Compliance is submitted by *Northern Ontario Wires Inc.* in accordance with Ontario Regulation 22/04, Section 14 for the period *January 1, 2015* to *December 31, 2015.*

I, Dan Boucher, of or on behalf of, *Northern Ontario Wires Inc.* hereby state that, to the best of my knowledge and belief and having made reasonable inquiries, *Northern Ontario Wires Inc.* has complied with the following Sections of Ontario Regulation 22/04:

1. Section 3 – Same, change of ownership;
2. Section 9 – Deviations from required standards;
3. Section 10 - Proximity to distribution lines;
4. Section 11 – Disconnection of unused lines;
5. Section 12 – Reporting of serious electrical incidents.

Northern Ontario Wires Inc. shall provide ESA with such additional information relating to the review and validation process as is considered necessary by ESA to support this Annual Declaration of Compliance.

Signature

General Manager

Title or Professional Designation

February 9, 2016

Date

AESI

www.aesi-inc.com
aesi@aesi-inc.com

January 21, 2016

Mr. Dan Boucher,
General Manager and Electrical Superintendent,
Northern Ontario Wires Inc.,
153 Sixth Ave.,
Cochrane, ON
P0L 1C0

Dear Dan:

Please find enclosed, two copies of my report for the OR 22/04 audit performed on January 20, 2016. Overall, Northern Ontario Wires is in compliance with OR 22/04. No noncompliances were found. The report does note one opportunity for improvement and lists a number of general observations.

ESA will request that you submit your audit report for review. Along with submission of the report, you will be asked to provide a plan that includes actions and a timetable to address any identified issues. The audit findings may be reviewed with ESA at a follow up meeting and any issues that require action will be addressed.

Thank you for your hospitality. I very much enjoyed working with you and your staff. I found everyone I encountered helpful, forthcoming with information and generous with his or her valuable time.

Please contact me if you have any questions on this report or require any additional information.

Yours truly,

Les.

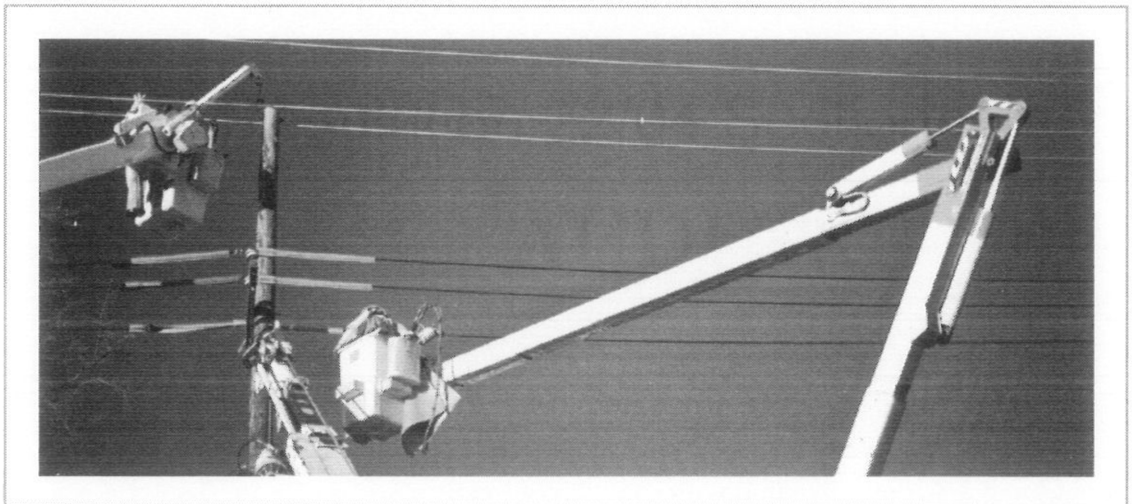
Leslie Stoch, P.Eng.

775 Main Street E
Suite 1B
Milton, Ontario
Canada L9T 3Z3
P · 905.875.2075
F · 905.875.2062

1990 Lakeside Pkwy
Suite 250
Tucker, Georgia
USA 30084
P ·

AUDIT REPORT

Ontario Regulation 22/04 Sections 4 to 8



Client
Northern Ontario Wires Inc.

Date
January 20, 2016

Prepared by
L. Stoch and Associates

AESI

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Audit Report
January 1 – December 31, 2015
Ontario Regulation 22/04
Sections 4 to 8

Northern Ontario Wires Inc.,
153 Sixth Ave.,
Cochrane, ON P0L 1C0

Prepared by: Leslie Stoch **Date:** Jan. 21/16

L. Stoch, P.Eng.

Reviewed by: ____________ **Date:** Feb 8/16

Description and Scope of Audit

An OR 22/04 audit of Northern Ontario Wires Inc. was carried out on January 20, 2016 by Les Stoch of L. Stoch and Associates. Its purpose was to assess the extent of compliance with respect to Sections 4 to 8 of Ontario Regulation 22/04, to measure whether the distributor has appropriate processes in place to comply with the safety standards set out in the regulation and whether the organization correctly follows its processes. The audit period covered was January 1 to December 31, 2015.

Northern Ontario Wires Inc. distributes electricity in the Municipalities of Cochrane, Kapuskasing and Iroquois Falls, serving over 6000 residential, commercial and industrial customers. The scope of this audit involved processes concerning 5 municipal substations 2400 volts to 25 kV, overhead and underground primary and secondary lines. The distributor employs 14 staff.

The audit plan, shown in the attached audit checklist/report covers the distributor's policies and procedures concerning OR 22/04. Standard auditing methods and procedures were used including interviews with personnel, examining documents and records and observing work in progress on a relevant sample of work activities.

Although the emphasis of this audit was directed toward noncompliances and aspects that should be considered for improvement, nothing in this report should be construed as criticism of neither the distributor's staff nor the services provided.

Auditor Qualifications and Experience

Leslie Stoch is a professional electrical engineer, qualified quality management system auditor and consultant. Since 1993, he provides electrical engineering services under a PEO Certificate of Authorization, and quality management consulting services for organizations working toward ISO 9000 registration. He is a member of Professional Engineers Ontario, the American Society for Quality, the International Association of Electrical Inspectors and the Ontario Electrical League.

His electrical industry experience includes 21 years with Electrical Inspection, Ontario Hydro in electrical engineering and management positions. He is a past member of the Ontario Provincial Advisory Committee, developing recommendations on Ontario's electrical code. Through Dalhousie University, he provides professional development and training seminars on the electrical code and code-related subjects across Canada.

Auditor Independence

L. Stoch and Associates declares itself to be independent from Northern Ontario Wires Inc. and the work to be audited, and free of any potential threats to the auditor's independence including self-interest, self-review, advocacy, familiarity and intimidation.

Executive Overview

An audit of Northern Ontario Wires was performed on January 20, 2016 to verify the organization's extent of compliance with Ontario Regulation 22/04, to identify any gaps and to evaluate the effectiveness of procedures in place for compliance purposes.

The audit covered the organization's existing processes and new ones developed in response to the regulation. Overall, the distributor's processes are in compliance with the regulation. No noncompliances were found. One opportunity for improvement and a number of general comments are included in this report.

The previous audit report included one opportunity for improvement – that the LDC purchased rebuilt transformers, but had not documented its procedure for approval of used equipment. This issue arose due to a misunderstanding. The LDC's equipment approval procedure specifies that only new equipment may be returned to stock. The LDC has declared that it does not purchase rebuilt transformers, only new ones.

Northern Ontario Wires is a successful organization, concerned about public safety and protecting the public from any harm that might result from its operations. The dedication of its employees was clearly evident throughout the audit.

Noncompliances

- No noncompliances were found.

Opportunity for Improvement

- One opportunity for improvement was noted. Eastlink is presently upgrading their fibre wire system throughout Cochrane. The LDC is performing extensive make ready work including numerous pole replacements. No evidence of the standards employed were found in Work Orders or other construction records. Evidence is needed to show that construction is being carried out in accordance with the LDC's certified standard designs.

General Observations

- The LDC's major equipment has been recorded and approved in equipment specifications. Other approved equipment has been listed. No evidence of approval could be found for the equipment list. Evidence of approval by a competent person is needed.

- The LDC's demarcation point is at the customer's property line. Therefore, all work on construction private property is the customer's responsibility, designed by the customer's engineer and inspected by ESA.

- Construction plans submitted by Eastlink and CTS displayed certificates of approval and P.Eng. seals.

- No new equipment was approved in 2015.

- No plans from external engineers or subdivision developers were received in 2014.

- No third party attachment projects were completed within the audit period.

- To date, no certificates of inspection have been received for fibre wire installation work by Eastlink. The General Manager is taking action to ensure that work is inspected signed off more promptly.

Management Response to ESA

The Electrical Safety Authority will ask the distributor to submit a copy of this audit report. Management will be asked to prepare a response to the audit findings, including actions on any identified issues, along with a timetable to address each situation. An action plan should be submitted to ESA along with the audit report.

ESA will respond directly to Northern Ontario Wires on receiving the distributor's report. An audit review meeting with ESA may take place. The audit findings listed in the report will be reviewed, and any items that require action will be addressed along with the distributor's action plan and any timelines.

If any corrective actions are required, the LDC will be asked to submit a report on progress in addressing any issues identified in the audit and action plan.

Opening Meeting

An opening meeting was held on January 20, 2016 with the following persons present:

Dan Boucher
Les Stoch

Closing Meeting

A closing meeting was held on January 20, 2016 with the following persons present:

Dan Boucher
Les Stoch

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment **up to 750 volts not part of distribution** to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Street lighting installed and maintained for municipality of Cochrane and LED lighting conversion - inspected by ESA • Substation lighting and batteries checked during regular substation inspections Inspection and PM records available		X		
4(4)	A maintenance and inspection program for **overhead primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management	Inspection and PM overhead systems: • Lines patrolled with thermal imaging annually by LDC, recorded in Deficiency Records (no deficiencies found in 2015) – maintenance and repairs recorded in Service Orders • Poles and equipment identified and entered in GIS • Poles replaced based on age and condition • Voltage upgrades - 4160 V to 12.5 kV in Kapuskasing and 2400 V to 25 kV in Iroquois Falls • Tree trimming scheduled based on observations during line patrols, recorded in Service Orders • Porcelain insulation replacements when needed • PCB testing and elimination program Inspection and PM records available		X		
4(5)	A maintenance, inspection and testing program for **underground primary and secondary distribution** lines to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM underground systems: • Underground system inspected annually and IR inspection, recorded in Underground Plant Inspection Reports • Equipment identified and entered in GIS • PCB testing and elimination program • Transformer pad replacements program Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
4(6)	A maintenance, inspection and testing program for **distribution stations** to ensure proper operation and safety • Maintenance schedule • Asset management • Maintenance records	Inspection and PM substations: • Monthly substation inspections recorded in Monthly Substation Report plus H & S committee inspections • Thermal imaging by LDC using hand held equipment • Stations shut down when necessary • Vegetation control by contractor • PCB testing and elimination complete • Annual oil sampling and gas analysis Inspection and PM records available		X		
6	Distribution equipment approved when approved by **certification or field inspection;** or approved under **Rule of Distributor** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P.Eng. • Approval records • Non-major equipment – Good Utility Practice • Receiving inspection • Pre-regulation equipment	The LDC is a member of the USF Group. The Equipment Approval process is documented in a Purchasing Policies document. Approved major equipment specifications identify applicable standards. New types of equipment are approved by the Purchasing Manager and the General Manager. All tenders through NEDBC are approved by the General Manager. Observations: • No new equipment was approved in 2015. • Equipment other than major equipment is specified in an approved equipment list. No evidence of approval was found for the equipment list. Evidence of equipment approval is needed.		X		
6(1)(a)	**Specifying** equipment approved by **certification or field evaluation**	Personnel are aware of the need to specify approved equipment.		X		

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6(1(a)	**Checking** that supplied ancillary equipment ordered is approved by **certification or field evaluation**.	Personnel are aware of the need to check for equipment approval markings.		X		
6(1)(b)	**Major distribution equipment** approval under **Rule of the Distributor**: • Documented approval process • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P.Eng., competent person and no undue hazard; or • Supporting record of approvals • Certified tests reviewed by a competent person • Composite & wood poles	The equipment approval procedure is documented. Major equipment is approved under a Rule of the Distributor. Approved specifications identify standards to be met. Certified test data is available in hard copy and accessible on the USF web-site.		X		
6(1)(b)	**Re-Use of Major Equipment** • Documented process identifies competent person • Used major equipment approved by competent person or a P.Eng. and no undue hazard • Competent person records no undue hazard • Testing or repair – competent person records no undue hazard • Must fail safely • Otherwise approve as new	The LDC does not generally re-use equipment returned from the field. A Return to Inventory Approval form has been developed for use when equipment is to be re-used and approved by a competent person. Observations: • The LDC does not normally re-use equipment returned from the field. The LDC's equipment approval procedure specifies that only unused equipment can be returned to stock. • No equipment is sent out for repairs or refurbishment by others.		X		

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	**Non-major Equipment** approval under **Rule of the Distributor** (no undue hazards): • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards. • GUP may include successful use in comparable systems • Supporting documentation • Composite cross-arms	The equipment approval procedure is documented. Non-major equipment may be approved when in conformance to a recognized standard or under Good Utility Practice after a minimum 2-year trial period. Observation – The LDC's approved equipment is listed by USF. No non-major equipment was being assessed at time of the audit.		X		
6(1)(b)	Equipment is **specified** to meet **Rule of Distributor** standards (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	The LDC is a member of USF and the North East District Buying Consortium (NEDBC). Group tendering is done through the NEDBC. Specifications are provided to the vendors who also have access to the USF equipment list. Purchase orders specify the manufacturers' part numbers, equipment description and ratings.		X		
6(1)(b)	Supplied equipment **meets Rule of Distributor** requirements • Inspection procedure • Dealing with vendor noncompliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition.		X		
6(2)	**Inspection and testing** of equipment supplied based on **Rule of Distributor** requirements (Inspection and testing records)	The distributor has not developed any unique standards and relies on existing industry standards.	X			

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6(2)	**Determining inspection and testing methods** for equipment supplied to distributor (Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)	The LDC has not developed any unique inspection or testing methods.	X			
6(1)(a) 6(2)	Dealing with **vendor noncompliance**	Nonconforming shipments are quarantined, vendors are contacted and equipment is returned if necessary.		X		
7	Plans: • Prepared by a P.Eng.; and/or • Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a P.Eng. or ESA • Plans by subdivision developers • Plans by external consultants • Temporary power plans • Deviation of approval	The distributor's USF standard design drawings have been certified by ESA. The standards are normally referenced in the plans drawn up by the General Manager. Plans are reviewed with Lines prior to construction. Standards binders are carried in field vehicles. No deviations from the standards have been made to date. Observation – Eastlink is in process of upgrading their fibre wire installations throughout Cochrane. The LDC is doing extensive make ready work including the replacement of poles. No evidence of the standards applied was found in Work Orders and other construction records. Evidence is needed to show that construction was carried out in accordance with the USF certified standards.			X	
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction	Approved plans or standard designs are provided except for like-for-like, emergency and legacy construction. Plans are reviewed by the Lead Hand and General Manager before issuing to the field so as to minimize field changes. Observations: • No engineering plans were produced internally or by others in 2015. • The LDC's demarcation point is at each customer's property line. Therefore, all work on private property is the customer's responsibility and inspected by ESA,		X		

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
7	Ensure third party attachments are: • Authorized; and • No adverse affect on distribution system safety • Engineering plans certified by LDC or third party P.Eng. (no gaps in certification) • Certified third party standards – evidence of certification • Third party generation • Bell Canada plans • Solar panels & DAS installations	Third party attachers are Eastlink, Bell Aliant and CTS. On submitting an application, the third party surveys the subject line and the LDC provides any required make ready work. Plans submitted by the third party are reviewed and approved by the General Manager. Observations: • Plans received from Eastlink for a fibre wire installation is underway throughout Cochrane. Plans displayed certificates of approval and P.Eng. seals. • Plans received from CTS for installation along 4^{th} Street, Cochrane displayed a certificate of approval and P.Eng. seal. Construction has not yet begun.		X		
7	Up-to-date copies of internal specifications and identified standards available to approving P.Eng. – examples: • Electrical Safety Code • CSA Std. O/H Systems • CSA Std. U/G Systems • National Electrical Safety Code • Equipment Standards	The LDC has hard copy and/or electronic access to all necessary codes and standards including equipment standards.		X		
7	Ensure P.Eng. memberships valid and current	The LDC does not employ a P.Eng.	X			
7	Identify competencies of identified <u>competent persons</u> and ensure they have the required competencies (training records, position descriptions, resumes)	Qualifications of identified competent staff reviewed and confirmed.		X		
7(1)(a)	Installations based on plans by a P.Eng.: • Reviewed and approved by a P.Eng; or • Reviewed and Approved by ESA	Installations are based on standards reviewed and approved by ESA.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Noncompliance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by the General Manager. Observation – No construction plans were produced in 2015.		X		
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications **reviewed and approved** by a <u>P.Eng. or ESA</u> (Signatures, stamps)	USF standard designs and specifications are reviewed and approved by ESA.		X		
7(3) 7(5)	Plans, standard design drawings and specifications **certified** by a <u>P.Eng. or ESA</u> (Plans, drawings, specifications, certificates)	USF standard design drawings are certified by ESA.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction • Retained and available to ESA • Retained for minimum of one year after audit • Electronic storage	Plans are maintained in project files indexed by year, location and municipal grids. Project files contain • Marked up and as-built plans • Material lists • Partial/Final Certificates • Daily Work Order/Tailboard Sheets • Correspondence • Service Orders and Work Orders • Standards • Locates		X		
8(1)	Construction verification program: • Approved by ESA • When approved • <u>Qualified persons</u> list up-to-date • Any changes approved	The CVP is approved by ESA and qualified persons list maintained up-to-date. Field personnel understand the need to complete partial and final certificates of inspection. Line construction is signed off on Service Orders. Work Order/Tailboard Sheets are completed and work signed off daily.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on: • Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Noncompliances noted in record of inspection	Approved plans are provided except for like-for-like, emergency and legacy work and approved equipment is supplied. The General Manager reviews each project with lines personnel prior to construction.		X		
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	All construction is inspected and approved before use.		X		
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • Metering • Cutoff and reconnection • Customer service • NC's rectified • No undue hazard statement (how?) • Inspection record and certificate	Like-for-like, emergency, legacy and metering work is inspected and confirmed safe by competent persons. Metering work and service upgrades are signed off to confirm no undue hazards in Service Orders and Meter Install Sheets. Cutoffs, reconnections preventive maintenance, tree trimming and emergency repairs are signed off in Service Orders and Work Orders. Service Orders are also employed to record line patrol observations, power outages and trouble calls.		X		

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P.Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are normally carried out by qualified staff identified in the CVP.		X		
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Noncompliances rectified • Stamped, signed or initialed • Inspection verification program followed	Records of inspection provide all required information on what was inspected, identify the inspector and include: • Marked up and as-built plans • Partial/Final Certificates • Work Order/Tailboard Sheets • Service Orders • Meter Install Sheets		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature or initials • Like-for-like and legacy construction no undue hazards	Certificates of inspection provide all necessary information on what was inspected and identify the inspector. Certificates include: • Partial/Final Certificates • Work Order/Tailboard Sheets • Service Orders		X		
8(7)	Certificates and records of inspection available to ESA and: • Who maintains records and certificates • Covers all applicable construction • Signed and dated • Progressive inspections and sampling process certificates	Certificates and records of inspection are available in project files or other departments as applicable.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
	Competent and qualified persons trained on CV program and process for updating • All identified in CVP	Competent and qualified staff has received CVP training and occasional refresher training. Qualifications of competent and qualified staff reviewed and confirmed. Observation – CVP refresher training was not provided in 2015. Annual refresher training is suggested to ensure that personnel are aware of any changes. CVP training records should be provided.		X		
	Third party contractors trained and listed in the CVP	Construction work is presently not contracted out.	X			
	Sampling program developed	No inspection sampling is done.	X			
	Process for resolving noncompliances and design changes	Noncompliances and field proposals for design changes are discussed with the General Manager. If agreed to, plans are marked up and GIS updated.		X		
	Third party construction by contractors • Approved plan followed	Electrical and civil construction work on private property is performed by the owners' contractors. Work by contractors is inspected by ESA. None was completed within the audit period.		X		
	Third party attachment – communications and community antenna systems: • Meets safety requirements • Noncompliances and variations resolved • Inspection by P.Eng. or person qualified in CVP • Certificate and record of inspection	Third party attachment inspections are performed by the third parties' consulting engineers. Observations: • No third party attachment projects were completed within the audit period. • To date, no fibre wire installations by Eastlink have been signed off. The General Manager is taking action to ensure that work is inspected and signed off more promptly.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Noncompliance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Safety communications Interest and input from the Board	The distributor promotes public safety in the following ways: • Public safety information on distributor's web-site (safety tips, tree trimming and power outages). • The web-site is in process of being updated • Emergency preparedness planning with the municipality and mutual assistance arrangements with other LDC's • Participation with Utility Safety Professionals – IHSA Safety Groups, EUSA, IAPA • Distributor regularly provides annual safety reports to the Board with quarterly summaries • Board members attend the LDC's annual safety breakfast • EUSA awards – bronze medallion • Newspaper articles on power outages and child safety • Electrical safety included with conservation messages Records available		X		

TILTRAN
POWER SERVICES
A SPARKPOWER COMPANY

July 14, 2016

Customer: Northern Ontario Wires
143 6th Ave.
Cochrane ON

Attention: Dan Boucher

Re: Site Inspection, Oil Samples Report - Our Ref: 16-00020
Site: Customer: Northern Ontario Wires, 143 6th Ave. Cochrane Ont.

Dear Dan

A summary of the site findings is listed below for your review. All findings are referenced to the Ontario Electrical Safety Code (OESC).

Findings:

Iroquois Falls Deetroyes Sub

- [OESC Rule # 26-306] - Barb wire is not in adequate condition, multiple stand offs are broken.

- [OESC Rule #36-304(5)] – The ground surface covering layer shall exist throughout the station.

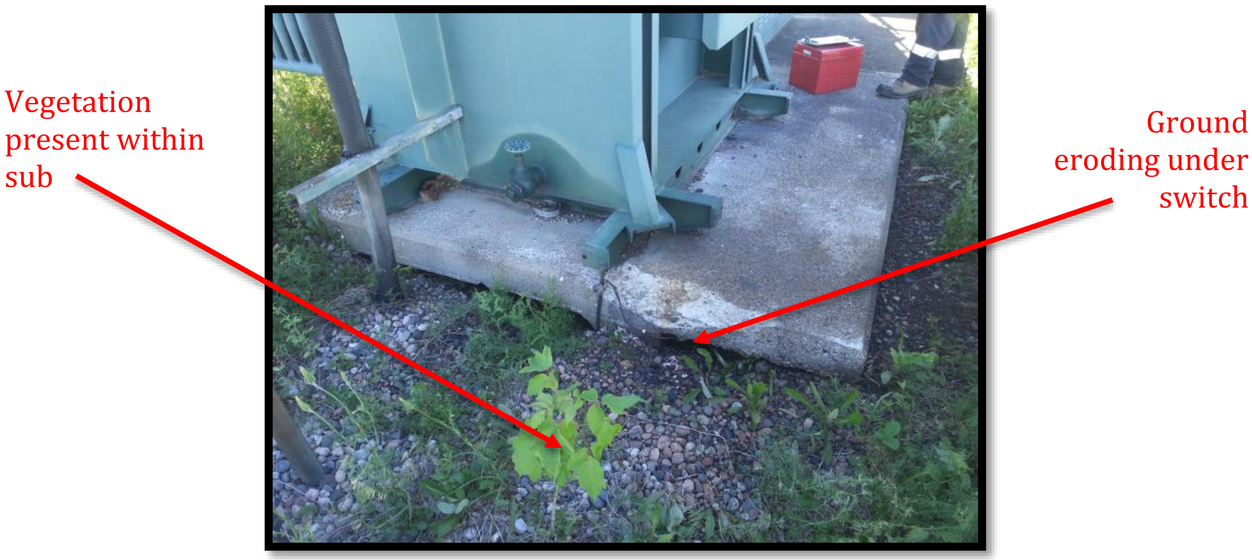
- [OESC Rule # 2-112, 2-300, 2-400] – Enclosures are to be rust free and properly sealed to prevent water entry.

- Tap changer as well as oil filled cable tap box are leaking.

Iroquois Falls Mill Gate Sub

- [OESC Rule # 26-306] – No Barbwire exists around sub.
- [OESC Rule # 36-312] – No fence/barbwire bonding exists.

- [OESC Rule #36-304(5)] – The ground surface covering layer shall exist throughout the station. No vegetation shall exist within the fenced area.



- Tap changer is leaking oil.

Iroquois Falls Cambridge Sub

- Substation is in adequate condition.

Cochrane Main Sub

- [OESC Rule # 26-312(3)] Bottom of fence fabric must be within 50mm of the ground surface.

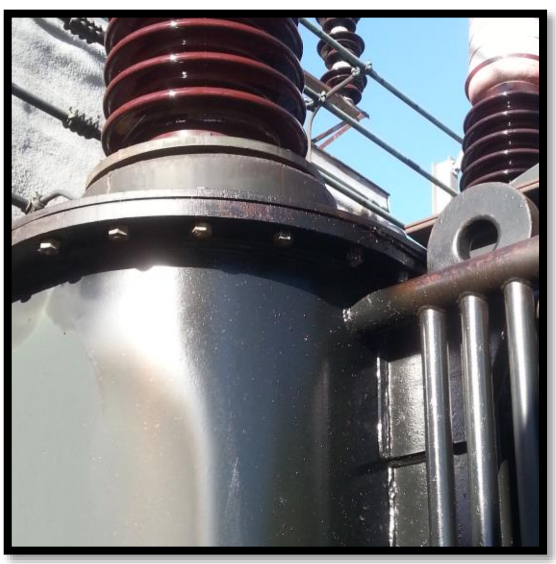
Large spaces
beneath fence

[OESC Rule #36-304(5)] – The ground surface covering layer shall exist throughout the station. No vegetation shall exist within the fenced area.

Large amounts of vegetation present.

No Gravel present in substation

- Transformer "T1C" HV bushing is leaking.



- "28T2" and "28T3" fans did not appear to be operational. "28T3" fan control temperature probe has been removed and replaced with stand alone temperature gauge.

Kapuskasing Main Sub

- Oil level gauge on conservator is broken and requires replacement.

- [OESC Rule # 26-312(3)] - Ground errosion has caused fence fabric to become greater than 50mm from the ground.

- Recommend topping up gravel with proper type throughout substation.

- [OESC Rule # 36-312] – Fence bonding is not present around substation.

If you have any questions/concerns please do not hesitate to contact us. Please give us a call should you wish us to provide you pricing and services for any or all of the recommended repairs listed in this report. We look forward to being of continued service to **Northern Ontario Wire.**

Sincerely,

Adam Johnson

Electrician 309A
Maintenance and Technical Services
Phone: (519) 842-6458 (ext.4210)
Fax: (519) 842-7688
Cell: (519) 521-0121

NOW Fleet - 2015

Unit #	Year	Make	Model	Description	Plate No.	Serial No./V.I.N.	G/L#	Kms as of 05/14	Town	Pic
510	1962	WEST	RH4	REEL TRAILER	V72702	362850	5255-1510	-	Kap	510
511	1982	TJWE	PT4	POLE TRAILER	35277H	2042131	5255-1513	-	Cochrane	511
513	1991	HMDE	TY	REEL TRAILER	J94829	FILE-147907685	5255-1511	-	Ifalls	513
516	2005	BANDIT	65XL	CHIPPER	-		5255-1516	391	Cochrane	516
517	2006	DODGE	DAKOTA	PICKUP	4589RX	1D7HW22K26S683981	5255-1517	180,276	Cochrane	517
519	2008	FORD	DRW	DUMP TRUCK	9730YC	1FDAF57R68EA18999	5255-1519	37,000	Cochrane	519
520	2007	INTL	40S	DIGGER	4499VC	1HTMMAAN57H434919	5255-1520	21,654	Cochrane	520
521	2008	FORD	C0F	PICKUP	7253WJ	1FTRF14WX8KD43411	5255-1521	122,514	Ifalls	521
522	2008	INTL	70S	BUCKET TRUCK	1358WJ	1HTWGAZR48J652951	5255-1522	41,259	Cochrane	522
523	2008	BRIN	UNK	POLE TRAILER	H8310B	1L9MP40148G085368	5255-1523	-	Kap	523
524	2010	CHEV	SILVERADO	PICKUP	1297YL	1GCPKPE0XAZ141472	5255-1524	119,423	Cochrane	524
525	2010	DODGE	CARAVAN	VAN	BHSV845	2D4RN4DE0AR258115	5255-1525	135,468	Cochrane	525
526	2011	FRHT	FM2	BUCKET TRUCK	6869ZL	1FVHCYBS1BHAZ4392	5255-1526	22,314	Kap	526
527	2011	CHEV	SILVERADO	PICKUP	9918ZF	1GCRKPE0XBZ272458	5255-1527	114,059	Dan B.	527
528	2011	BROOKS BRO.	PTB112 XL-10KHD-E	POLE TRAILER	J44320	1B9BS1125BM274032	5255-1528	-	Ifalls	528
529	2011	KW	CON	DIGGER DERRICK	AA38652	2NKHHM7X4BM293010	5255-1529	15,763	Kap	529
530	2012	FRHT	FM2	BUCKET TRUCK	AB55466	1FVHCYBS4CHBN5784	5255-1530	14,444	Ifalls	530
RT531	2012	BROOKS BRO.	SLR	REEL TRAILER	K547OC	1B9US0820CM274207	5255-1531	-	Ifalls	531
532	2013	CHEV	SILVERADO	4 X 4 PICKUP	AD17876	1GC1KVCG2DF170030	5255-1532	35,718	Kap	532
RT533	2013	BROOKS BRO.	SLRT	REEL TRAILER	13453C	1B9US0826DM274214	1-4-5255-3010		Cochrane	533
534	2013	SKYLIFT	SUPER 6000	MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		KAP	534
535	2013	COMMERCIAL	TRAILER	TRAILER FOR MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		Kap	535
536	2013	FRHT	C4047 PG	DIGGER TEREX	AF50482	1FVACYCYXEHFN7347	1-4-5255-3010	22,514	IFALLS	536
537	2016	DODGE	RTR	4 X 4 PICKUP	AN30973	1C6RR7FG6GS285111	1-4-5255-3010	3000	Cochrane	537

Fleet Evaluation Matrix for 2015

Factor	Description of Evaluation Criteria					Small Trucks						Large Trucks							Other Equipment									
						# 517	# 521	# 524	# 525	# 527	532	# 519	# 520	# 522	# 526	# 529	# 530	# 536	# 510	# 511	# 513	# 516	# 523	# 528	# 531	# 533	# 534	# 535
Age	One point for each year of service based on "in service" date					8	7	5	5	4	2	7	8	7	4	4	3	1	50	30	21	10	7	4	3	2	2	2
Mileage	One point for each 16,093 kilometers (10,000 miles) of use					11	8	7	9	7	2	2	1	3	1	1	1	1	0	0	0	1	0	0	0	0	0	0
	1 Point	*2 Points*	*3 Points*	*4 Points*	*5 Points*																							
Type of Service	**Light duty** Small Vehicles: Engineering or Administration use Large Vehicles: on road use only and lightly loaded.	n/a	**Medium duty** Small Vehicles: trucks used by trades which are commonly loaded; Large Vehicles: mainly on road use and with average payload.	n/a	**Heavy duty** Small & Large Vehicles: trades use and commonly loaded for road and off road use	3	3	3	1	3	1	5	5	5	5	5	5	5	5	5	3	3	5	5	5	5	5	5
Reliability	Repair once every 3 months or less	n/a	Repair two or three times in 3-month period	n/a	Repair two or more times per month on average	5	1	1	3	1	1	1	3	1	1	1	1	0	1	1	1	1	1	1	1	0	0	0
Maintenance and Repair Costs	Accumulated cost as compared to original purchase cost is ≤ 20%	Accumulated costs as compared to original purchase cost is > 20% & ≤ 47%	Accumulated costs as compared to original purchase cost is > 47% & ≤ 74%	Accumulated costs as compared to original purchase cost is > 74% & ≤ 100%	Accumulated costs as compared to original purchase cost is ≥ 100%	2	1	1	2	1	0	1	1	0	0	1	0		0	0	0	0	0	0	0	0	0	0
Take into consideration body condition, rust, interior condition, anticipated repairs and accident history.																												
Condition	**Excellent** Truck has no signs of deterioration and is close to like new condition	**Very Good** Truck is no longer in new condition but is still in very good shape	**Good** Truck has signs of regular use	**Fair** Truck is showing signs of early deterioration with advanced signs of rust and worn interior components.	**Poor** Truck has signs of rust perforation, seat covers are worn thru and repairs have been postponed due to age and cost benefit.	4	4	3	3	3	1	2	3	2	2	2	1		5	4	4	2	3	2	1	1	1	1
Total Score						33	24	20	23	19	7	18	21	18	13	14	11	7	61	40	29	17	16	12	10	8	8	**8**

Scoring Results	
Point Ranges	**Action**
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Schedule Detailed Evaluation
Over 27	Needs Immediate Consideration Perform Detailed Evaluation

Fleet Replacement Schedule

Unit #	Year	In Service Date mm/dd/yy	Original Book Value	Description	Score	2013	2014	2015	2016	2017	2018	2019	2020
Small Trucks (8 Year Cycle)													
517	2006	5/23/2006	$ 28,305.47	Dodge Dakota ST Club	33								
521	2008	5/23/2008	$ 27,313.43	Ford F150 4X4 SS REG	24								
524	2010	5/7/2010	$ 29,218.00	Chev Silverado	20								
525	2010	3/26/2010	$ 27,683.00	Dodge Grand Caravan SE Wagon	23								
527	2011	2/16/2011	$ 31,706.00	Chev Silverado 1500	19								
532	2013	3/4/2013	$ 37,323.47	Chev Silverado 2500	7								
Large Trucks (15 Year Cycle)													
519	2008	2/22/2010	$ 54,329.00	Ford F550 4X4 Dump Box	18								
520	2007	9/4/2007	$ 202,295.00	International Digger Derrick	21								
522	2008	1/6/2009	$ 220,800.00	International Bucket Truck w/ Altec	18								
526	2011	4/6/2011	$ 276,423.00	Freightliner M2-106 Bucket Truck	13								
529	2011	11/15/2011	$ 220,005.00	Kenworth T300 4X2 Digger Derrick	14								
530	2012	3/26/2012	$ 281,345.00	Freightliner Bucket Truck w/ Posi-Plus	11								
536	2013	12/9/2014	$ 295,353.75	Freightliner/Digger Terex	7								
Other Equipment (As Required based on Condition)													
510	1962	xx/xx/xx	?	Cable (Reel) Trailer	61								
511	1991	xx/xx/xx	?	Pole Trailer	40								
513	1982	xx/xx/xx	?	Cable (Reel) Trailer	29								
516	2005	11/15/2005	$ 15,114.60	Bandit Chipper Model 65XL	17								
523	2008	2009	$ 20,142.00	Pole Trailer	16								
528	2011	5/17/2011	$ 15,012.00	Brooks Bros. Pole Trailer PTB112XL-10KHD-	12								
531	2012	6/27/2012	$ 20,767.00	Brooks Bros. Reel Trailer SLR	10								
533	2013	5/27/2013	$ 21,022.50	Brooks Bros. SLRT-7208 reel trailer	8								
534	2013	5/30/2013	$ 163,914.00	Skylift Mini-Derrick super 6000	8								
535	2013	5/30/2013		Trailer for Mini-Derrick	8								
Total													

Scoring Results	
Point Ranges	**Action**
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Schedule Detailed Evaluation
Over 27	Needs Immediate Consideration Perform Detailed Evaluation

CAPITALIZATION OVERVIEW

NOW's capital assets are recorded and recognized at cost, and include direct labour and benefits, materials, fleet and contractor costs, which are incurred during the development, implementation, or construction phase of the asset.

Certain capital assets may be funded or paid by a customer or third party developer through capital contributions. Under IFRS, the capital contributions that are recognized as deferred revenue have been reclassified as a reduction to rate base under Transition to International Financial Reporting Standards, EB-2008-0408, July 28, 2009.

Under CGAAP, NOW had the option to capitalize interest based on the OEB's prescribed allowance for funds used during construction ("AFUDC"). Under IFRS, NOW can use its actual borrowing costs as the basis for determining the amount of interest to be capitalized for qualifying assets and will include this amount in capital asset additions.

Under IFRS, an entity must present and record separately from property, plant, and equipment ("PP&E") those assets that are within the scope of International Accounting Standard 38 Intangible Assets ("IAS 38").

The Board Report Transition to International Financial Reporting Standards, EB-2008-0408, July 28, 2009 states the following:

"IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue requirement. This reclassification is also necessary to preserve continuity of the rate base."

Based on the above, for IFRS, NOW has included intangible assets as PP&E for rate setting purposes. The major differences between IFRS and CGAAP with respect to the accounting for PP&E and intangible assets are outlined below.

Opening Balances

The International Accounting Standards Board ("IASB") amended "IFRS 1 – First-time adoption of IFRS" in May, 2010 to allow rate-regulated entities to use the previous accounting net book value as the IFRS cost on the date of transition to IFRS. This is referred to as the deemed cost exemption.

NOW has elected to use the deemed cost election under IFRS 1 for opening balance sheet values for its capital assets. Based on paragraph D8B of IFRS 1, entities with operations subject to rate regulations may hold items of PP&E or intangible assets where the carrying amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization in accordance with IFRS.

In this case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRS as deemed cost. For the purposes of paragraph D8B, operations are subject to rate regulation if they provide goods or services to customers at prices (i.e., rates) established by an authorized body empowered to establish rates that bind the customers, and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services, and to earn a specified return. Based on the definition above, NOW qualifies for this exemption. Under this exemption the deemed cost at the date of transition becomes the new IFRS cost basis. Therefore, on January 1, 2014, the opening accumulated depreciation is $nil under IFRS and the opening cost equates to the closing CGAAP net book value ("NBV").

The capital contribution adjustment represents the adjustment to net book value of distribution system assets. The accumulated customer contribution balance has been set to zero as at January 1, 2014 for IFRS, as the cumulative balance has been offset against the costs of related capital assets for which the contribution was received. In 2015, customer contributions were recorded as deferred revenue under IFRS.

IAS 16.43 requires an entity to depreciate separately each part of an item of PP&E that has a cost that is significant in relation to the total cost of the item. This requirement means that the total cost of a PP&E item should either be allocated to each significant part (where acquired as a whole) or (if constructed) the cost should be capitalized according to the significant part.

Change of Capitalization Policy

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS.

Based on the Board Report, the Board requires utilities to adhere to IFRS capitalization accounting requirements for rate-making and regulatory reporting purposes after the date of adoption of IFRS, and that a utility is required to file a copy of its capitalization policy, as part of its first cost of service rate filing after adopting IFRS.

In light of all the above, NOW, in conjunction with its IFRS advisor and auditor, performed a thorough analysis of all costs that were being capitalized under CGAAP in order to determine if they were eligible for capitalization under IFRS. These costs included materials, labour, benefits, truck, subcontractor, overhead, customer contributions, and borrowing costs. The analysis conducted by NOW has been summarized as follows:

Material Cost

These costs include stocked items taken from warehouse and issued out to each project as well as direct materials which are purchased and delivered to the job site directly. These costs represent the purchase price and initial delivery/handling costs of the materials.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management, hence there is no impact on the amount of material costs being capitalized for IFRS.

Labour Costs

The labour costs that are capitalized to PP&E comprise of engineering, design, linemen, construction, and supervision time with working timesheets which record the nature of the actions and activities being undertaken and time spent on each task by each type of employee. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Therefore, there will be no impact on the amount of labour costs being capitalized under IFRS relating to this cost category.

Benefit Costs

Employee benefit costs represent the costs associated with employee pensions, vacations, sick leave, etc. For each hour of regular time recorded, via a timesheet, directly to a capital project, benefits are automatically allocated according to where the time is coded. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. NOW has determined there will be no impact on the amount of employee benefit costs being capitalized under IFRS.

Labour Burden

Under CGAAP, a fixed percentage of overhead and administration costs, referred to as “labour burden”, could be allocated to direct labour costs, and forms part of the cost of an asset. These costs include the labour costs, related benefits and other general administrative costs of the senior operations management and directors that cannot be attributed to a specific project. NOW Inc. did not practice this under CGAAP. Therefore, NOW has confirmed that labour burden will not be capitalized under IFRS and therefore these costs will continue to be expensed in the period incurred.

Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers and other fleet equipment. Some of these costs include depreciation expense of the fleet vehicles, fuel costs, repairs, and parts, insurance and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance (mechanics and other garage staff) as tracked via timesheets. Each vehicle has an individual work order and all the above costs related to the maintenance of that vehicle are accumulated under the work order, and therefore all the costs are directly attributable. A fleet rate is determined on an annual basis for each vehicle group by dividing the annual costs accumulated for each vehicle type by their annual usage. 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. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. NOW has determined there will be no impact on the amount of transportation costs being capitalized under IFRS.

Third Party Costs

Sub-contractor costs are incurred when NOW engages a third party to perform services. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. NOW has determined there will be no impact on the amount of third party costs being capitalized under IFRS.

Capitalization of Borrowing Costs

IAS 23 Borrowing Costs establishes the criteria for the recognition of interest on borrowings as a component of the carrying amount of an acquired or self-constructed item of capital assets. Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset.

Under CGAAP, rate regulated entities were permitted to include an allowance for funds used during construction ("AFUDC") in the cost of an asset that is acquired, constructed, or developed over time. NOW will no longer be able to capitalize AFUDC under IFRS but will be required to capitalize interest as per IAS 23. IAS 23 states that an entity can capitalize borrowing costs only on qualifying assets. A qualifying asset is an asset that takes a substantial period of time to complete. NOW has defined a substantial period of time as being greater than six months, and will capitalize borrowing costs for every qualifying asset or project that is expected to take longer than six months to be completed. Since NOW's debt is acquired on an arm's length basis, the actual borrowing costs are used. The amount of borrowing costs eligible for capitalization is determined by applying a capitalization rate to the expenditures on qualifying assets.

Customer Contributions

Under CGAAP, NOW recorded customer contributions as an offset to the cost of capital asset and amortized as part of the net capital asset. Under IFRS, NOW cannot capitalize these customer contributions as part of its net capital assets, but instead will defer the contributions as a liability and amortize them as revenue.

According to the Board Report:

"For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates".

Consistent with the Board's guidance, NOW is recording customer contributions received after January 1, 2014 as deferred revenue and amortizing them as revenue over the life of the related asset. Customer contributions received prior to this date have been netted against the cost of the related asset as a result of deemed cost election chosen for IFRS 1. For the purpose of this Application, capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

Policies and Procedures			
Department	Northern Ontario Wires Inc.	Issued	
Section	General	Effective:	Sept 18, 2008
Subject:	**CAPITALIZATION POLICY**	Page:	1 of 1
Approved by:		Revised:	

1. POLICY

1.1 Northern Ontario Wires Inc. shall implement a Capitalization policy as required.

2. PURPOSE

2.1 The purpose of capitalizing expenditures is to provide for an equitable allocation of cost among existing and future customers.

3. SCOPE

3.1 A capital expenditure is defined as any significant expenditure incurred to acquire, construct or develop land, buildings, plant, engineering structures, machinery and equipment expected to provide future economic benefits to the company and its customers. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. A "betterment" includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset's useful life. Capital assets include electric plant, transmission, generation and distribution facilities, meters, vehicles, office furniture, computer equipment and other equipment.

4. PROCEDURE

4.1 Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

4.2 Whether capital assets are purchased or constructed by the Corporation they are stated at cost and include contracted services, material, labour, engineering costs and overheads, including associated interest costs.

4.3 Betterments Versus Repairs

As noted previously a betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved.

4.4 A repair is defined as the cost incurred in the maintenance of the service potential of a capital asset.

CAPITALIZATION OF OVERHEAD

Both IFRS and CGAAP treatment for PP&E is to recognized the asset initially at cost. The difference in the standards relate to the type of cost inputs that can be included in the acquisition amount.

Costs incurred for the following purposes are typically capitalized:

- purchase, construction and commissioning of specific assets providing future economic benefits;
- design and development of specific assets that will provide future economic benefits;
- additions to existing assets; and
- betterments that result in improvement of capacity, efficiency, or useful life

Expenditures that can be capitalized as PP&E or intangible assets under IFRS include direct labour, direct materials and supplies, transportation costs, directly attributable external costs, professional fees and permits. Indirect expenditures that can be capitalized include directly attributable borrowing costs, tools and transport and work equipment used in the capital project, indirect depreciation of dedicated equipment, and directly attributable indirect costs. There are some prohibitions that cannot be capitalized including general and administrative overhead and training costs.

Due to the potential differences resulting from a change in accounting policies from CGAAP to IFRS, NOW Inc. performed a review with the assistance of a third party IFRS consultant BDO along with discussions with the external auditors.

Labour Overhead Rates

NOW Inc. does not utilize fixed overhead rates for allocating burden to capital or operating projects. NOW Inc. converted its accounting system which enables the direct allocation of employee burden to specific accounts based on how the time is allocated on the time sheet. As such, actual costs are allocated without an overhead rate.

Indirect costs including other payroll obligations including vacations, statutory holidays, banked time and sick time are allocated according to the allocation of hours worked in a year. The cost driver to allocate indirect costs is hours worked which aligns with the directly attributable rate.

Fleet Expenses

The costs associating with running the fleet have been analyzed by the IFRS consultant and been audited at 2015 year end. Directly attributable expenses are allocated based on the actual vehicle hours charged to projects.

Other Overhead

The costs associated with other positions that support purchasing including finance and accounts payable have no portion allocated to capital. Although necessary to acquire assets in order to put in service, this cost is deemed indirect, and not attributed to capital.

Burden Rates

NOW Inc. burden rates are based on identifiable and discrete cost drivers that vary according to direct labour and material changing.

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Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Bridge Year	2017 Test Year
Operations	$ 675,428	$ 811,967	$ 679,307	$ 680,311	$ 880,631
Maintenance	$ 706,035	$ 550,324	$ 571,047	$ 655,327	$ 762,556
Customer Service	$ 1,072,708	$ 584,730	$ 752,020	$ 714,670	$ 746,564
Administration	$ 1,252,523	$ 646,500	$ 515,318	$ 751,526	$ 648,087
Total OM&A Before Capitalization (B)	$ 3,706,694	$ 2,593,520	$ 2,517,691	$ 2,801,833	$ 3,037,838

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	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Bridge Year	2017 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
employee benefits	$ 70,224	$ 70,183	$ 71,100	$ 73,233	$ 75,430	Yes	No material change in capitalization
Materials and fleet costs	$ 78,950	$ 54,820	$ 51,373	$ 52,914	$ 54,502	Yes	No material change in capitalization
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs							
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 149,174	$ 125,003	$ 122,473	$ 126,147	$ 129,932		

% of Capitalized OM&A (=A/B)	4%	5%	5%	5%	4%		

COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

NOW Inc. is limited by Hydro One Inc. constraints that do not allow for any FIT projects to be connected in its service area. There are currently thirteen (13) MicroFIT customers with only one application in 2015.

NOW's distribution system does not have constraints and with the lack of upstream capacity, NOW Inc. does not propose any eligible investment for the connection of qualifying generation facilities.

NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

NOW Inc. does not currently anticipate any projects that require the Advance Capital Module. Should an unanticipated project that would require ICM treatment become known, NOW Inc. will propose such project in a subsequent application.

ADDITION OF ICM ASSETS TO RATE BASE

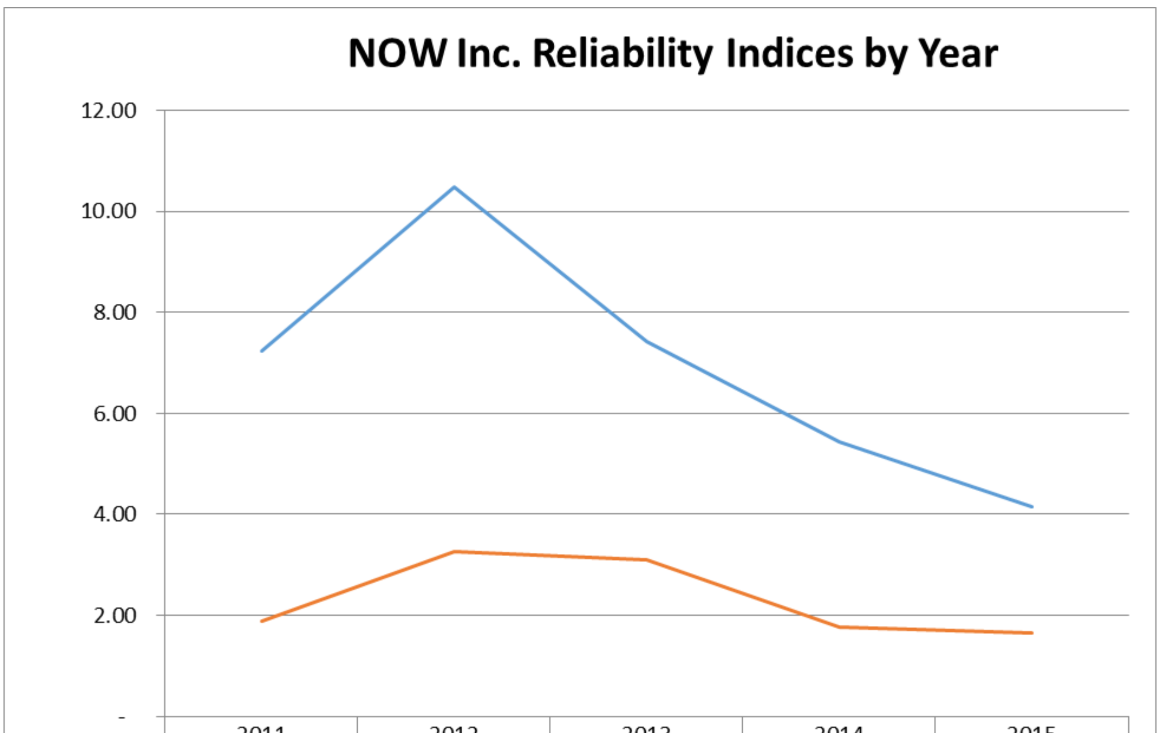
NOW Inc. does not have any prior approved ACM or ICM projects from a prior application.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Reliability Performance

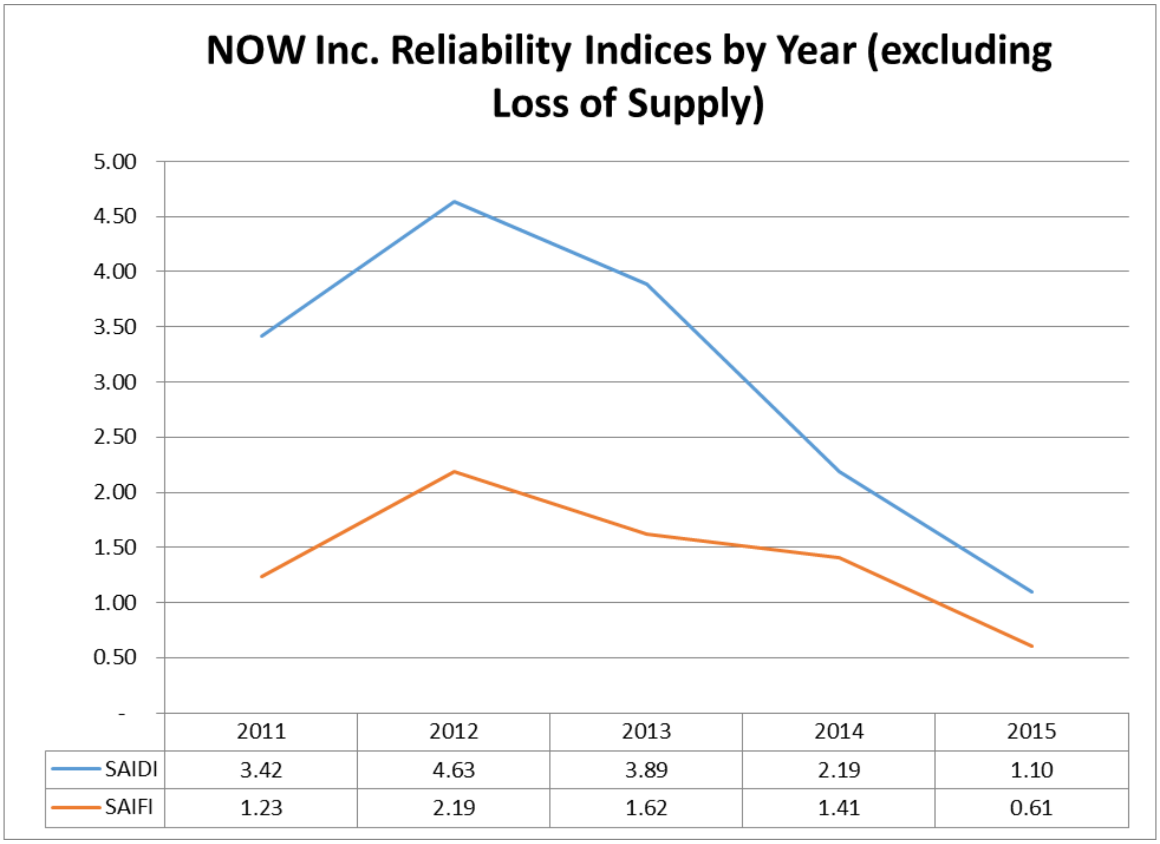
NOW Inc. tracks service reliability statistics SAIDI (System Average Interruption Duration Index) and SAIFI (System Average interruption Frequency Index) including and excluding loss of supply related incidents. NOW Inc. had developed its target indices based on an average of the previous 5 years (2011-2015) in accordance with the OEB's Report of the Board (EB-2014-0189) Setting System Reliability Performance objectives, dated August 25, 2015.

Figure 1



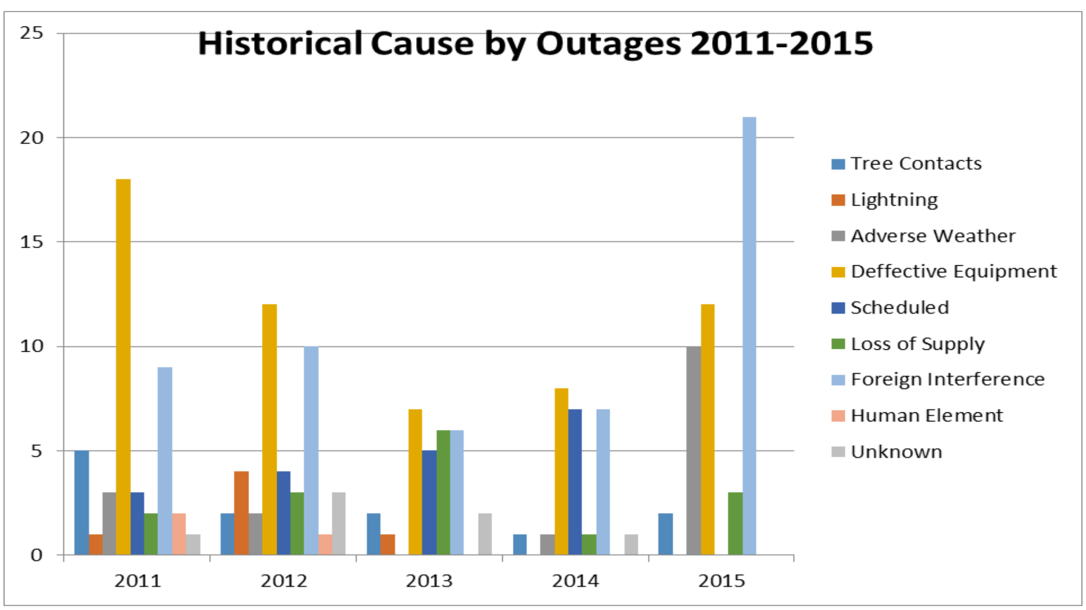
	2011	2012	2013	2014	2015
SAIDI	7.23	10.49	7.43	5.44	4.16
SAIFI	1.89	3.27	3.10	1.77	1.66

Figure 2



	2011	2012	2013	2014	2015
SAIDI	3.42	4.63	3.89	2.19	1.10
SAIFI	1.23	2.19	1.62	1.41	0.61

Figure 3



NOW Inc. is committed to the reliability of the distribution system and has set 2017 target indices for SAIDI and SAIFI as follows:

Figure 4 – Current and Proposed Reliability Targets

Excluding Loss of Supply	Proposed Targets
SAIDI	3.75
SAIFI	1.70
	Current Targets (2013)
SAIDI	2.75-4.63
SAIFI	1.23-2.19

In order to meet these targets NOW Inc. will need to continue to invest in capital and maintenance programs. In particular, the capital programs noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets helps to remove the risk to reliability and safety which would otherwise be unacceptable.

2011

During the year, NOW Inc. customers experienced eighteen (18) incidents of defective equipment, representing 40% of the outages for that year. After these incidents, NOW Inc. increased its line patrols of its overhead lines.

2012

In 2012 NOW Inc. experienced three incidents of Loss of Supply as well as four scheduled outages in order perform upgrades and repairs to the distribution system.

2013

In 2013, NOW Inc. experienced six incidents of Loss of Supply as well as five scheduled outages in order to perform upgrades and repairs to the distribution system. Historically, these figures tend to be higher than the norm, the average Loss of Supply being between 1-3, and the average number of scheduled outages being 2-4. Given that these aren't the norms, NOW Inc. is comfortable with the targets as set on the current 2015 Scorecard.

2014

NOW Inc. experienced the least amount of outages in 2014, with the primary cause being defective equipment followed by 7 scheduled outages and foreign interference.

2015

During this year, NOW Inc. experienced 21 interruptions due to foreign interference, primarily animals (crows, squirrels, etc.). This represents 43% of the interruptions that occurred in 2015. As a result, NOW Inc. is installing animal guards in order to mitigate these causes for outages.

Also in 2015, NOW Inc. experienced a number of weather related incidents due to high winds. Together with the foreign interference, these two causes account for almost two thirds of the outages.

A summary of NOW Inc. Service Quality and Reliability Measures is provided in E2/T2/S7/Att1 (OEB Appendix 2-G). This information is consistent with the Scorecard.

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Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
SAIDI	7.230	10.490	7.430	5.440	4.160	3.420	4.630	3.890	2.190	1.100	7.230	10.490	7.430	5.440	4.160
SAIFI	1.890	3.270	3.100	1.770	1.660	1.230	2.190	1.620	1.410	0.610	1.890	3.270	3.100	1.770	1.660

5 Year Historical Average

SAIDI		6.950		3.046		6.950
SAIFI		2.338		1.412		2.338

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2011	2012	2013	2014	2015
Low Voltage Connections	90.0%	87.5%	97.2%	91.9%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	0.0%	0.0%	100.0%	100.0%	100.0%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	99.1%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	n/a	0.0%	0.0%	0.0%	0.0%
Appointment Scheduling	90.0%	91.4%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	100.0%	95.8%	87.5%	95.8%	96.7%