EXHIBIT 2 – RATE BASE & DSP

2018 Cost of Service

Cooperative Hydro Embrun Inc.
EB-2017-0035

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2.1 OVERVIEW OF RATE BASE

2.1.1 RATE BASE OVERVIEW

CHEI converted to International Financial Reporting Standards ("MIFRS") on January 1, 2015, and had prepared this application under MIFRS. CHEI confirms that there were no other changes that would affect the utility's net book value other than the implementation of new depreciation rates in 2013. In other words, there is no difference between the utility's net book values in NEWCGAAP and MIFRS.

The net fixed assets used to determine the utility's Rate Base include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. CHEI does not have non-distribution assets nor does it conduct non-distribution activities. [1]Controllable expenses include operations and maintenance, billing and collecting and administration expenses which are discussed in detail in Exhibit 4.

CHEI has calculated its 2018 test year rate base to be $4,704,825. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. Table 1 below presents CHEI's Rate Base calculations for the Test Year.

[1] MFR - Non-distribution activities - capital expenditures and reconciliation to total capital budget

Table 1 - Test Year Rate Base

	NEWGAAP	MIFRS
Particulars	**Last Board Approved**	**2018**
Net Capital Assets in Service:		
Opening Balance	2,201,600	4,342,457
Ending Balance	2,543,766	4,327,541
Average Balance	2,372,683	4,334,999
Working Capital Allowance	535,243	369,826
Total Rate Base	2,907,927	4,704,825
Expenses for Working Capital	**Last Board Approved**	**2018**
Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation	20,900	37,769
3550-Distribution Expenses - Maintenance	40,300	56,215
3650-Billing and Collecting	170,174	209,970
3700-Community Relations	4,000	7,875
3800-Administrative and General Expenses	318,905	410,142
LEAP	2,000	
Total Eligible Distribution Expenses	556,279	721,971
3350-Power Supply Expenses	3,560,978	4,209,043
Total Expenses for Working Capital	4,117,257	4,931,014
Working Capital factor	13.0%	7.5%
Total Working Capital	535,243	369,826

2.1.2 RATE BASE TREND

Table 2 below presents CHEI's Rate Base calculations for all required years including the 2018 Test Year. Year over year variance analysis follows.

Table 2 - Rate Base Trend

	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	Last Board Approved	2014	2015	2016	2017	2018
Net Capital Assets in Service:						
Opening Balance	2,201,600	2,206,431	2,363,680	2,458,612	2,781,278	4,342,457
Ending Balance	2,543,766	2,363,680	2,458,612	2,781,278	4,342,457	4,327,541
Average Balance	2,372,683	2,285,056	2,411,146	2,619,945	3,561,867	4,334,999
Working Capital Allowance	535,243	479,700	524,560	577,130	620,421	369,826
Total Rate Base	2,907,927	2,764,755	2,935,706	3,197,075	4,182,288	4,704,825
		-4.92%	6.18%	8.90%	30.82%	12.49%
	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	Last Board Approved	2014	2015	2016	2017	2018
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	20,900	28,851	39,764	34,209	35,830	37,769
3550-Distribution Expenses - Maintenance	40,300	44,655	26,251	46,223	50,645	56,215
3650-Billing and Collecting	170,174	166,891	210,565	177,779	198,023	209,970
3700-Community Relations	4,000	6,982	8,363	7,863	7,500	7,875
3800-Administrative and General Expenses	318,905	319,703	328,131	334,952	359,618	410,142
LEAP	2,000					
Total Eligible Distribution Expenses	556,279	567,081	613,072	601,025	651,616	721,971
3350-Power Supply Expenses	3,560,978	3,122,917	3,422,003	3,838,439	4,120,850	4,209,043
Total Expenses for Working Capital	4,117,257	3,689,998	4,035,075	4,439,464	4,772,466	4,931,014
Working Capital factor	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital	535,243	479,700	524,560	577,130	620,421	369,826

The Rate Base for the 2018 Test Year has increased by $522,537 over the Bridge Year, and $1,796,898 over the last Board Approved Rate Base. The reason for the sizeable increase from the 2014 Cost of Service is mainly attributed to:

Major capital cost drivers 2014

System Access:

- Subdivision Faubourg Ste-Marie: $1 001 927
- 4th Feeder Cloutier Drive: $67 358

Major capital cost drivers 2015

System Access:

- Oligo Project Quatres Saison: $239 868

Major capital cost drivers 2016

System Access:

- Engineering Cost New Substation: $50 013
- Fourth Feeder Notre-Dame: $118 850
- Fourt Feeder Ste-Marie: $128 750

Major capital cost drivers 2017

System Access:

- Versaille III Subdivision: $119 200
- New Substation & Engineering: $1 517 396

System Service:

- Four Way Tie in Switch: $39 650
- 336 MCM Conductors Blais Street: $46 250

Major capital cost drivers 2018

System Renewal:

- Pole replacement: $41,500

-Distribution Transformer replacement: $54,280

Increased Power Supply Expenses

- CHEI has forecasted an increase in the 2018 Power Supply Expenses of over $648,065 over its 2014 Cost of Service.

Increased Distribution Expenses

- The 2018 forecast for OM&A reflects an increase of $165,692 from the 2014 Board Approved. The details of the increases in OM&A are provided in Exhibit 4, but some of the highlights include:
  - increased maintenance costs
  - Increased number of locates due several new subdivisions
  - increased billing expenses due to increase costs from billing supplies
  - increases to regulatory expenses

The Working Capital Allowance has decreased by $165,417 over the 2014 Board Approved. The reason for the decrease from the 2014 Board Approved to the 2018 Test Year is due to the change in Working Capital Allowance rate from 13% to 7.5%.

Year over year variances are presented in the next section.

2.1.3 RATE BASE VARIANCE ANALYSIS

The following paragraphs and Tables 3 to Table 7 provide a narrative on the changes that have driven the increase in rate base since CHEI's 2014 Board Approved Cost of Service Application.

CHEI's materiality threshold is $50,000.

CHEI has provided the following variances on the change in Rate Base:

- ✓ 2018 Test Year (MIFRS) against 2017 Bridge Year (MIFRS)
- ✓ 2017 Bridge Year (MIFRS) against 2016 Actual (MIFRS)
- ✓ 2016 Actual (MIFRS) against 2015 Actual (MIFRS)
- ✓ 2015 Actual (MIFRS) against 2014 Actual (NewCGAAP)
- ✓ 2014 Actual (NewCGAAP) against 2014 Board Approved (NewCGAAP)

2014 Board Approved vs. 2014 Actual:

Table 3 – 2014 BA to 2014 Actual Rate Base Variance

Particulars	**2014 Actual**	**2014 Board Approved**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	2,206,431	2,201,600	4,831	0.22%
Ending Balance	2,363,680	2,543,766	(180,086)	-7.08%
Average Balance	2,285,056	2,372,683	(87,627)	-3.69%
Working Capital Allowance	479,700	535,243	(55,543)	-10.38%
Total Rate Base	2,764,756	2,907,926	(143,170)	-4.92%
Expenses for Working Capital				
Eligible Distribution Expenses:	2014 Actual	2014 Board Approved	Var	%
3500-Distribution Expenses - Operation	28,851	20,900	7,951	38.04%
3550-Distribution Expenses - Maintenance	44,655	40,300	4,355	10.81%
3650-Billing and Collecting	166,891	170,174	(3,283)	-1.93%
3700-Community Relations	6,982	4,000	2,982	74.54%
3800-Administrative and General Expenses	319,703	318,905	798	0.25%
LEAP	-	2,000	(2,000)	-100.00%
	-	-	-	
Total Eligible Distribution Expenses	567,081	556,279	10,802	1.94%
3350-Power Supply Expenses	3,122,917	3,560,978	(438,061)	12.30%
Total Expenses for Working Capital	3,689,998	4,117,257	(427,259)	10.38%
Working Capital factor	13%	13%	15%	0.00%
Total Working Capital	479,700	535,243	- 55,543	10.38%

The total Rate Base in 2014 Actual of $2,764,756 was $143,170 or 4.92% less than the 2014 Board Approved. The main reason for the variance is:

- Increases in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.
- Several subdivisions were running behind schedule at year end and as such, the costs were incurred in the following years.

2015 Actual vs. 2014 Actual:

Table 4 - 2015-2014 Rate Base Variances

Particulars	**2015**	**2014**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	2,363,680	2,206,431	157,248	7.13%
Ending Balance	2,458,612	2,363,680	94,932	4.02%
Average Balance	2,411,146	2,285,056	126,090	5.52%
Working Capital Allowance	524,560	479,700	44,860	9.35%
Total Rate Base	2,935,706	2,764,756	170,950	6.18%
Expenses for Working Capital				
Eligible Distribution Expenses:	2015	2014	Var	%
3500-Distribution Expenses - Operation	39,764	28,851	10,913	38%
3550-Distribution Expenses - Maintenance	26,251	44,655	(18,404)	-41%
3650-Billing and Collecting	210,565	166,891	43,674	26%
3700-Community Relations	8,363	6,982	1,381	20%
3800-Administrative and General Expenses	328,131	319,703	8,427	3%
LEAP	-	-	-	
	-	-	-	
Total Eligible Distribution Expenses	613,072	567,081	45,991	8%
3350-Power Supply Expenses	3,422,003	3,122,917	299,086	10%
Total Expenses for Working Capital	4,035,075	3,689,998	345,077	9%
Working Capital factor	13%	13%		0%
Total Working Capital	524,560	479,700	44,860.00	9%

The total Rate Base in 2015 Actual of $2,935,706 was $170,950 or 6.18% greater than the 2014 Actual. The main reason for the variance is:

- The average net capital assets in service were $126,090 higher than the prior year's average.
- The $213 155 in capital additions during 2015 can be attributed to; Development Promenade Quatre Saison and 4[TH] Feeder Switching Cabinet. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit..
- Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2016 Actual vs. 2015 Actual:

Table 5 - 2016-2015 Rate Base Variances

Particulars	**2016**	**2015**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	2,458,612	2,363,680	94,932	4.02%
Ending Balance	2,781,278	2,458,612	322,666	13.12%
Average Balance	2,619,945	2,411,146	208,799	8.66%
Working Capital Allowance	577,130	524,560	52,570	10.02%
Total Rate Base	3,197,075	2,935,706	261,369	8.90%
Expenses for Working Capital				
Eligible Distribution Expenses:	2016	2015	Var	%
3500-Distribution Expenses - Operation	34,209	39,764	(5,555)	-14%
3550-Distribution Expenses - Maintenance	46,223	26,251	19,972	76%
3650-Billing and Collecting	177,779	210,565	(32,786)	-16%
3700-Community Relations	7,863	8,363	(500)	6%
3800-Administrative and General Expenses	334,952	328,131	6,821	2%
LEAP	-	-	-	
	-	-	-	
Total Eligible Distribution Expenses	601,025	613,072	(12,047)	-2%
3350-Power Supply Expenses	3,838,439	3,422,003	416,436	12%
Total Expenses for Working Capital	4,439,464	4,035,075	404,389	10%
Working Capital factor	13%	13%		0%
Total Working Capital	577,130	524,560	52,570.00	10%

The total Rate Base in 2016 Actual of $3,197,075 is $261,369 or 8.90% greater than 2015 Actual. The main reason for the variance is:

- The average net capital assets in service were $208,799 higher than the prior year's average.
- The $458,645 in capital additions during 2016 can be attributed to; 4th Feeder Ste-Marie, 4th Feeder Notre-Dame, Four Engineer Cost new substation. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.
- The rest of the increase can be attributed to regular maintenance of the distribution system required in order to keep the system running in a safe and reliable manner
  - Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2017 Bridge Year vs. 2016 Actual:

Table 6 - 2017-2016 Rate Base Variances

Particulars	**2017**	**2016**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	2,781,278	2,458,612	322,666	13%
Ending Balance	4,342,457	2,781,278	1,561,179	56%
Average Balance	3,561,867	2,619,945	941,923	36%
Working Capital Allowance	620,421	577,130	43,291	8%
Total Rate Base	4,182,288	3,197,075	985,213	31%
Expenses for Working Capital				
Eligible Distribution Expenses:	2017	2016	Var	%
3500-Distribution Expenses - Operation	35,830	34,209	1,621	5%
3550-Distribution Expenses - Maintenance	50,645	46,223	4,422	10%
3650-Billing and Collecting	198,023	177,779	20,244	11%
3700-Community Relations	7,500	7,863	(363)	-5%
3800-Administrative and General Expenses	359,618	334,952	24,666	7%
LEAP	-	-	-	
	-	-	-	
Total Eligible Distribution Expenses	651,616	601,025	50,591	8%
3350-Power Supply Expenses	4,120,850	3,838,439	282,411	7%
Total Expenses for Working Capital	4,772,466	4,439,464	333,002	8%
Working Capital factor	13%	13%		0%
Total Working Capital	620,421	577,130	43,291.00	8%

The total Rate Base in 2017 Bridge of $4,182,288 is projected to be $985,213 or 31%% more than the 2016 Actual. The main reason for the variance is:

- The average net capital assets in service are projected to be approximately $941,923 higher than the prior year's average.
- The $1,706,996 in capital additions during 2017 can be attributed to; Construction of the new substation, Four Tie Switches, Feeder Section Conductor Upgrade and Development Versaille III. Details can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.
- The rest of the increase can be attributed to regular maintenance of the distribution system required in order to keep the system running in a safe and reliable manner

- Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2018 Test Year vs. 2017 Bridge Year:

Table 7- 2018-2017 Rate Base Variances

Net Capital Assets in Service:	**2018**	**2017**	**Var**	**%**
Opening Balance	4,342,457	2,781,278	1,561,179	56%
Ending Balance	4,327,541	4,342,457	(14,916)	-0%
Average Balance	4,334,999	3,561,867	773,131	22%
Working Capital Allowance	369,826	620,421	(250,595)	-40%
Total Rate Base	**4,704,825**	**4,182,288**	**522,537**	**12%**
Expenses for Working Capital				
Eligible Distribution Expenses:	**2018**	**2017**	**Var**	**%**
3500-Distribution Expenses - Operation	37,769	35,830	1,939	5%
3550-Distribution Expenses - Maintenance	56,215	50,645	5,570	11%
3650-Billing and Collecting	209,970	198,023	11,947	6%
3700-Community Relations	7,875	7,500	375	5%
3800-Administrative and General Expenses	410,142	359,618	50,524	14%
LEAP	-	-	-	
	-	-	-	
Total Eligible Distribution Expenses	721,971	651,616	70,355	11%
3350-Power Supply Expenses	4,209,043	4,120,850	88,193	2%
Total Expenses for Working Capital	4,931,014	4,772,466	158,548	3%
Working Capital factor	8%	13%		42%
Total Working Capital	**369,826**	**620,421**	**- 250,595**	**40%**

The total Rate Base in 2018 Test Year of $4,704,825 is $522,537 or 12% more than the 2017 Bridge Year. The main reason for the variance is:

- The average net capital assets in service are projected to be approximately $773,131 higher than the prior year's average.
- In 2018, increased capital investment in the amount of $150,205 is required in order to keep the system running in a safe and reliable manner.
- Transformers Replacement and Poles Replacement. Details regarding capital planning can be found in the Distribution System Plan in Section 2.5.2 of this Exhibit.

- The rest of the increase can be attributed to regular maintenance of the distribution system required in order to keep the system running in a safe and reliable manner
- Annual changes in the cost of power and increases in OM&A expenses. Details of the OM&A expenditures are presented in Exhibit 4.

2.1.4 FIXED ASSET CONTINUITY SCHEDULE

This Schedule presents a continuity schedule of its investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account for the 2014 to 2016 Actuals and 2017 Bridge Year and 2018 Test Year.

CHEI attests that the OEB Appendices 2-BA continuity statements presented at the next page reconcile with the calculated depreciation expenses, under Exhibit 4 – Operating Costs[2], and resented by asset account. The utility also attests that the net book value balances reported on Appendix 2-BA and balances reconcile with the rate base calculation. [3] [4] [5] The Excel version of the OEB Appendices are field in conjunction with this application. [6] The utility notes that it has not applied for an ACM or ICM in the years between its 2014 Cost of Service and this application. [7]

[2] MFR - Continuity statements must reconcile to calculated depreciation expenses and presented by asset account
[3] MFR - Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actuals, bridge and test year forecast)
[4] MFR - Continuity statements (year end balance, including interest during construction and overheads).
Explanation for any restatement (e.g. due to change in accounting standards)
Year over year variance analysis; explanation where variance greater than materiality threshold
Hist. OEB-Approved vs Hist. Actual
Hist. Act. vs. preceding Hist. Act.
Hist. Act. vs. Bridge
Bridge vs. Test
[5] MFR - Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g.. WIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation
[6] MFR - Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format
[7] Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications

Revised June 14, 2014

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

The only Asset Retirement Obligations occurred in 2016 and related to the retirement of poles from account 1830. $27,052 was removed from the utility's assets, and $15,194 was removed from depreciation expenses. The asset retirements are reflected in the fixed assets continuity statements presented on the next page.[8]

[8] MFR - All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount

Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year 2014 **CGAAP - with changes to policies**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 85,406	$ 40,505	$ -	$ 125,911	$ 72,107	$ 16,715	$ -	$ 88,821	$ 37,090	$ 105,658	$ 80,464
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 284,888	$ -	$ -	$ 284,888	$ 86,470	$ 5,180	$ -	$ 91,649	$ 193,239	$ 284,888	$ 89,059
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 638,783	$ 107,753	$ -	$ 746,536	$ 226,474	$ 17,316	$ -	$ 243,791	$ 502,745	$ 692,660	$ 235,133
47	1835	Overhead Conductors & Devices	$ 605,737	$ 55,662	$ -	$ 661,399	$ 237,379	$ 10,559	$ -	$ 247,938	$ 413,460	$ 633,568	$ 242,659
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 1,016,363	$ 692,811	$ -	$ 1,709,174	$ 436,345	$ 38,936	$ -	$ 475,281	$ 1,233,893	$ 1,362,768	$ 455,813
47	1850	Line Transformers	$ 751,064	$ 288,934	$ -	$ 1,039,999	$ 290,066	$ 22,388	$ -	$ 312,454	$ 727,545	$ 895,532	$ 301,260
47	1855	Services (Overhead & Underground)	$ 193,250	$ 12,464	$ -	$ 205,714	$ 58,936	$ 4,987	$ -	$ 63,923	$ 141,791	$ 199,482	$ 61,430
47	1860	Meters	$ 79,072	$ -	-$ 79,072	$ -	$ 39,311	$ -	-$ 39,311	$ -	$ -	$ 39,536	$ 19,656
47	1860	Meters (Smart Meters)	$ 310,212	$ 25,716	$ -	$ 335,928	$ 23,677	$ 21,538	$ 3,163	$ 48,378	$ 287,550	$ 323,070	$ 36,028
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 50,363	$ 632	$ -	$ 50,995	$ 31,808	$ 4,309	$ -	$ 36,117	$ 14,878	$ 50,679	$ 33,963
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 26,624	$ 430	$ -	$ 27,054	$ 21,556	$ 2,089	$ -	$ 23,645	$ 3,409	$ 26,839	$ 22,600
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,018	$ 151	$ -	$ 4,169	$ 151	$ 4,320	$ 4,093
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 8,486	$ -	$ -	$ 8,486	$ 4,543	$ 579	$ -	$ 5,122	$ 3,364	$ 8,486	$ 4,833
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-$ 555,963	-$ 905,202	$ -	-$ 1,461,165	-$ 190,517	-$ 25,214	$ -	-$ 215,731	-$ 1,245,434	-$ 1,008,564	-$ 203,124
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 3,548,604**	**$ 319,706**	**-$ 79,072**	**$ 3,789,238**	**$ 1,342,173**	**$ 119,533**	**-$ 36,148**	**$ 1,425,558**	**$ 2,363,680**	$ 3,668,921	$ 1,383,866
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -		$ 2,285,056
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -		
		Total PP&E	**$ 3,548,604**	**$ 319,706**	**-$ 79,072**	**$ 3,789,238**	**$ 1,342,173**	**$ 119,533**	**-$ 36,148**	**$ 1,425,558**	**$ 2,363,680**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								-$ 1,641,289	← From RRR year value Account 2105		
		Total						**$ 119,533**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 119,533

Year 2015 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 125,911	$ 1,308	$ -	$ 127,219	$ 88,821	$ 8,628	$ -	$ 97,449	$ 29,770	$ 126,565	$ 93,135
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 284,888	$ 75,410	$ -	$ 360,298	$ 91,649	$ 5,865	$ -	$ 97,515	$ 262,783	$ 322,593	$ 94,582
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 746,536	$ 2,663	$ -	$ 749,199	$ 243,791	$ 18,697	$ -	$ 262,488	$ 486,711	$ 747,867	$ 253,139
47	1835	Overhead Conductors & Devices	$ 661,399	$ 885	$ -	$ 662,283	$ 247,938	$ 11,031	$ -	$ 258,969	$ 403,314	$ 661,841	$ 253,454
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 1,709,174	$ 144,092	$ -	$ 1,853,266	$ 475,281	$ 50,892	$ -	$ 526,173	$ 1,327,093	$ 1,781,220	$ 500,727
47	1850	Line Transformers	$ 1,039,999	$ 110,238	$ -	$ 1,150,236	$ 312,454	$ 27,378	$ -	$ 339,832	$ 810,405	$ 1,095,118	$ 326,143
47	1855	Services (Overhead & Underground)	$ 205,714	$ 15,074	$ -	$ 220,788	$ 63,923	$ 5,331	$ -	$ 69,255	$ 151,533	$ 213,251	$ 66,589
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 335,928	$ 9,244	$ -	$ 345,172	$ 48,378	$ 22,703	$ -	$ 71,081	$ 274,091	$ 340,550	$ 59,730
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 50,995	$ 962	$ -	$ 51,956	$ 36,117	$ 3,813	$ -	$ 39,930	$ 12,027	$ 51,476	$ 38,023
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 27,054	$ 1,385	$ -	$ 28,439	$ 23,645	$ 1,655	$ -	$ 25,299	$ 3,139	$ 27,746	$ 24,472
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,169	$ 151	$ -	$ 4,320	-$ 0	$ 4,320	$ 4,245
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 8,486	$ -	$ -	$ 8,486	$ 5,122	$ 421	$ -	$ 5,543	$ 2,944	$ 8,486	$ 5,332
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-$ 1,461,165	-$ 148,144	$ -	-$ 1,609,309	-$ 215,731	-$ 38,381	$ -	-$ 254,112	-$ 1,355,197	-$ 1,535,237	-$ 234,921
	etc.												
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 3,789,238**	**$ 213,115**	**$ -**	**$ 4,002,353**	**$ 1,425,558**	**$ 118,183**	**$ -**	**$ 1,543,741**	**$ 2,458,612**	$ 3,895,795	$ 1,484,650
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -		$ 2,411,146
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -		$ 2,411,146
		Total PP&E	**$ 3,789,238**	**$ 213,115**	**$ -**	**$ 4,002,353**	**$ 1,425,558**	**$ 118,183**	**$ -**	**$ 1,543,741**	**$ 2,458,612**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								-$ 1,797,853	From RRR year value Account 2105		
		Total						$ 118,183					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 118,183

Year 2016 **IFRS**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 127,219	$ 1,365	$ -	$ 128,584	$ 97,449	$ 8,595	$ -	$ 106,044	$ 22,540	$ 127,901	$ 101,746
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 360,297	$ 50,013	$ -	$ 410,310	$ 97,515	$ 7,006	$ -	$ 104,520	$ 305,790	$ 385,303	$ 101,017
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 749,199	$ 74,099	-$ 27,052	$ 796,246	$ 262,488	$ 18,980	-$ 15,194	$ 266,274	$ 529,972	$ 772,722	$ 264,381
47	1835	Overhead Conductors & Devices	$ 662,283	$ 229,395	$ -	$ 891,678	$ 258,969	$ 12,950	$ -	$ 271,919	$ 619,759	$ 776,981	$ 265,444
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 1,853,266	$ 28,769	$ -	$ 1,882,035	$ 526,173	$ 53,361	$ -	$ 579,535	$ 1,302,501	$ 1,867,651	$ 552,854
47	1850	Line Transformers	$ 1,150,236	$ 39,619	$ -	$ 1,189,855	$ 339,832	$ 29,251	$ -	$ 369,083	$ 820,772	$ 1,170,046	$ 354,457
47	1855	Services (Overhead & Underground)	$ 220,788	$ 22,175	$ -	$ 242,963	$ 69,255	$ 5,797	$ -	$ 75,052	$ 167,911	$ 231,875	$ 72,153
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 345,172	$ 8,523	$ -	$ 353,695	$ 71,081	$ 23,296	$ -	$ 94,377	$ 259,318	$ 349,434	$ 82,729
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 51,956	$ 1,563	$ -	$ 53,520	$ 39,930	$ 2,862	$ -	$ 42,791	$ 10,728	$ 52,738	$ 41,361
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 28,439	$ 2,160	$ -	$ 30,599	$ 25,299	$ 1,545	$ -	$ 26,844	$ 3,754	$ 29,519	$ 26,072
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0	$ 4,320	$ 4,320
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 8,486	$ 7,415	$ -	$ 15,901	$ 5,543	$ 791	$ -	$ 6,334	$ 9,567	$ 12,194	$ 5,938
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-$ 1,609,309	-$ 6,451	$ -	-$ 1,615,760	-$ 254,112	-$ 40,313	$ -	-$ 294,425	-$ 1,321,335	-$ 1,612,534	-$ 274,268
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 4,002,352**	**$ 458,645**	**-$ 27,052**	**$ 4,433,945**	**$ 1,543,741**	**$ 124,120**	**-$ 15,194**	**$ 1,652,667**	**$ 2,781,278**	$ 4,218,148	$ 1,598,204
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -		$ 2,619,944
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -		$ 2,619,945
		Total PP&E	**$ 4,002,352**	**$ 458,645**	**-$ 27,052**	**$ 4,433,945**	**$ 1,543,741**	**$ 124,120**	**-$ 15,194**	**$ 1,652,667**	**$ 2,781,278**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$ 124,120**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 124,120

Year 2017 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 128,584	$ 4,500	$ -	$ 133,084	$ 106,044	$ 9,181	$ -	$ 115,225	$ 17,859	$ 130,834	$ 110,634
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 410,310	$ 1,517,396	$ -	$ 1,927,706	$ 104,520	$ 21,255	$ -	$ 125,775	$ 1,801,931	$ 1,169,008	$ 115,148
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 796,246	$ -	$ -	$ 796,246	$ 266,274	$ 19,906	$ -	$ 286,180	$ 510,066	$ 796,246	$ 276,227
47	1835	Overhead Conductors & Devices	$ 891,678	$ 85,900	$ -	$ 977,578	$ 271,919	$ 15,577	$ -	$ 287,496	$ 690,082	$ 934,628	$ 279,707
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 1,882,035	$ 160,025	$ -	$ 2,042,060	$ 579,535	$ 56,059	$ -	$ 635,593	$ 1,406,467	$ 1,962,048	$ 607,564
47	1850	Line Transformers	$ 1,189,855	$ 40,675	$ -	$ 1,230,530	$ 369,083	$ 30,255	$ -	$ 399,338	$ 831,192	$ 1,210,192	$ 384,210
47	1855	Services (Overhead & Underground)	$ 242,963	$ 20,000	$ -	$ 262,963	$ 75,052	$ 6,324	$ -	$ 81,376	$ 181,587	$ 252,963	$ 78,214
47	1860	Meters	$ -	$ 8,000	$ -	$ 8,000	$ -		$ -	$ -	$ 8,000	$ 4,000	$ -
47	1860	Meters (Smart Meters)	$ 353,695	$ -	$ -	$ 353,695	$ 94,377	$ 23,846	$ -	$ 118,223	$ 235,472	$ 353,695	$ 106,300
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 53,520	$ 1,000	$ -	$ 54,520	$ 42,791	$ 2,506	$ -	$ 45,297	$ 9,222	$ 54,020	$ 44,044
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 30,599	$ 1,500	$ -	$ 32,099	$ 26,844	$ 1,362	$ -	$ 28,206	$ 3,892	$ 31,349	$ 27,525
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0	$ 4,320	$ 4,320
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 15,901	$ -	$ -	$ 15,901	$ 6,334	$ 1,590	$ -	$ 7,924	$ 7,977	$ 15,901	$ 7,129
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-$ 1,615,760	-$ 132,000	$ -	-$ 1,747,760	-$ 294,425	-$ 42,044	$ -	-$ 336,469	-$ 1,411,291	-$ 1,681,760	-$ 315,447
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 4,433,945**	**$ 1,706,996**	**$ -**	**$ 6,140,941**	**$ 1,652,667**	**$ 145,817**	$ -	**$ 1,798,484**	**$ 4,342,457**	$ 5,287,443	$ 1,725,575
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -		$ 3,561,867
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -		$ 3,561,867
		Total PP&E	**$ 4,433,945**	**$ 1,706,996**	**$ -**	**$ 6,140,941**	**$ 1,652,667**	**$ 145,817**	**$ -**	**$ 1,798,484**	**$ 4,342,457**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$ 145,817**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 145,817

Year 2018 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	AVG Gross Bal	AVG AccDep
12	1611	Computer Software (Formally known as Account 1925)	$ 133,084	$ 3,000	$ -	$ 136,084	$ 115,225	$ 9,931	$ -	$ 125,156	$ 10,927	$ 134,584	$ 120,191
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 1,927,706	$ -	$ -	$ 1,927,706	$ 125,775	$ 35,049	$ -	$ 160,824	$ 1,766,882	$ 1,927,706	$ 143,299
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 796,246	$ 48,000	$ -	$ 844,246	$ 286,180	$ 20,506	$ -	$ 306,686	$ 537,560	$ 820,246	$ 296,433
47	1835	Overhead Conductors & Devices	$ 977,578	$ -	$ -	$ 977,578	$ 287,496	$ 16,293	$ -	$ 303,789	$ 673,789	$ 977,578	$ 295,642
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 2,042,060	$ -	$ -	$ 2,042,060	$ 635,593	$ 58,345	$ -	$ 693,938	$ 1,348,123	$ 2,042,060	$ 664,766
47	1850	Line Transformers	$ 1,230,530	$ 74,280	$ -	$ 1,304,810	$ 399,338	$ 31,692	$ -	$ 431,029	$ 873,780	$ 1,267,670	$ 415,184
47	1855	Services (Overhead & Underground)	$ 262,963	$ 20,000	$ -	$ 282,963	$ 81,376	$ 6,824	$ -	$ 88,200	$ 194,763	$ 272,963	$ 84,788
47	1860	Meters	$ 8,000	$ 8,000	$ -	$ 16,000	$ -		$ -	$ -	$ 16,000	$ 12,000	$ -
47	1860	Meters (Smart Meters)	$ 353,695	$ -	$ -	$ 353,695	$ 118,223	$ 24,380	$ -	$ 142,603	$ 211,092	$ 353,695	$ 130,413
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 54,520	$ 1,200	$ -	$ 55,720	$ 45,297	$ 2,616	$ -	$ 47,913	$ 7,807	$ 55,120	$ 46,605
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 32,099	$ 1,500	$ -	$ 33,599	$ 28,206	$ 1,662	$ -	$ 29,868	$ 3,730	$ 32,849	$ 29,037
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0	$ 4,320	$ 4,320
8	1940	Tools, Shop & Garage Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1945	Measurement & Testing Equipment	$ 15,901	$ -	$ -	$ 15,901	$ 7,924	$ 1,590	$ -	$ 9,514	$ 6,387	$ 15,901	$ 8,719
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-$ 1,747,760	-$ 5,775	$ -	-$ 1,753,535	-$ 336,469	-$ 43,766	$ -	-$ 380,235	-$ 1,373,300	-$ 1,750,647	-$ 358,352
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 6,140,941**	**$ 150,205**	**$ -**	**$ 6,291,146**	**$ 1,798,484**	**$ 165,121**	**$ -**	**$ 1,963,605**	**$ 4,327,541**	$ 6,216,043	$ 1,881,045
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -		$ 4,334,999
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -		$ 4,334,999
		Total PP&E	**$ 6,140,941**	**$ 150,205**	**$ -**	**$ 6,291,146**	**$ 1,798,484**	**$ 165,121**	**$ -**	**$ 1,963,605**	**$ 4,327,541**		
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total						**$ 165,121**					

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Tools, Shop	
Meas/Testing	
Communication	
Net Depreciation	$ 165,121

2.2 GROSS ASSETS

2.2.1 GROSS ASSET VARIANCE ANALYSIS

Table 2-AB is presented below as well as in the DSP. The section which follows Table 2-AB presents a breakdown of capital investments by RRFE functions; System Access (Table 8), System Renewal (Table 9), System Services (Table 10) and General Plant (11). That said, in order to comply with the filing requirements, the utility is also presenting a Breakdown of the utility's Gross Assets by function (distribution plant, general plant, etc.) at Table 2.13[9]

Table 8 - OEB Appendix 2-AB Capital Expenditures[10]

Revised June 14, 2014

	Historical (previous actual)						
	Test-5	Test-4	Test-4	Test-4	Test-3	Test-4	Test-2
	2013	2014	2014	2015	2015	2016	2016
CATEGORY	Actual	BA	Actual	Planned	Actual	Planned	Actual
	$		$		$		$
System Access	233,350		1,150,190		337,996		399,233
System Renewal	41,050		33,150		19,609		44,096
System Service	0		0		0		9,264
General Plant	29,500		41,568		3,653		12,503
Total	303,900		1,224,908		361,259		465,096
Contributed Capital	8,000		905,202		148,144		6,451
Net Capital	295,900	$474,595	319,706	$265,000	213,115	$425,000	458,645
System O&M	56,969		73,506		66,015		80,432

	Forecast (planned)					
	Test-1	Test	Test+1	Test+2	Test+3	Test+4
	2017	2018	2019	2020	2021	2022
CATEGORY	Projected Y/E	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$	$
System Access	1,726,096	34,500	135,000	53,000	53,000	78,000
System Renewal	20,000	115,780	20,000	60,000	62,000	40,000
System Service	85,900	0	0	0	0	0
General Plant	7,000	5,700	5,700	5,700	5,700	5,700
Total	1,838,996	155,980	160,700	118,700	120,700	123,700

[9] MFR - Complete Appendix 2-AA along with: explanation for variances, including that of actuals v. OEB-approved amounts for last OEB-approved CoS application; for capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress

[10] MFR - Complete Appendix 2-AB - historical years must be actuals, forecasts for the bridge and test years

Contributed Capital	132,000	5,775	16,700	0	0	0
Net Capital	1,706,996	150,205	144,000	118,700	120,700	123,700
System O&M	86,475	93,984	96,334	98,742	101,201	103,741

Accounting treatment of the cost of funds for construction work-in-progress

All of CHEI's capital work is completed within the same fiscal year including the substation build which was started in the spring of 2017 and will be completed by October of 2017. In the event that a project does span over multiple years, CHEI will follow the OEB's accounting processes and uses account 2055-Work In Progress.

Table 9 at the next page shows year over year capital projects in System Access, System Service, System Renewal and General Plan. CHEI notes that in its 2014 Cost of Service capital projects were not required to be tracked by the RRFE categories. However, CHEI has provided a side by side comparison of the 2014 Board Approved project list vs the 2014 Actual. and explanation

Appendix 2-A
2014 Board Approved Capital Projects Table vs 2014 Actual

Projects	**2014 BA**	**2014 Actual**	**Differenc e**	**Explanation**
St-Jacques And Forget	$20,750	$33,150	$12,400	CHE Replace 2 more pole- on Ste-Marie $ 3 800.00 and Notre Dame $8 600.00 _ Reason Safety Issue
1830-Pole Replacement On Cloutier Street	$39,470	$43,996	$4,526	Minor variance from budget
1835-4Th Feeder On Cloutier Street	$19,375	$23,362	$3,987	Minor variance from budget
1845-New Subdivision				
Patenaude Subdivision/4th feeder	$218,000	$712,993	$494,993	CHE Budget in 2014 for 100 units - Developer Change for 381 units
Oligo Project	$60,000	$11,875	-$48,125	Part of the project has been done /Relocate pole at East and West Entrance of the Subdivision
Domaine Versailles	$60,000	$0	-$60,000	Project has not be done in 2014 -will be done in 2017
New York Central Park	$60,000	$0	-$60,000	Project has not be done in 2014
Subdivision & LCDs Need	$87,500	$288,934	$201,434	CHE Budget in 2014 for 100 units - Developer Change for 381 units
Material & Labour	$4,000	$12,464	$8,464	More customer request during the years for new connections
1860-Smart Meters	$30,500	$25,716	-$4,784	Minor variance from budget

1925-Harris Version 6.4 Upgrade	$20,000	$20,885	$885	Minor variance from budget
1925-Harris Customer Connect	$15,000	$16,549	$1,549	Minor variance from budget
Project not Budget Rebasing 2014				
Pumping Station Ste-Marie	$0	$20,850	$20,850	Project done late in 2014 was not plan-to servicing 381 units for the future
Line Relocated Notre-Dame	$0	$10,000	$10,000	Customer ask to relocate pole(were in the driveway) for a 14 apartments building
Time clock	$0	$633	$633	Not budget in Rebasing 2014
Note Pad Computer	$0	$430	$430	Not budget in Rebasing 2014
Anti Spam Contentment	$0	$1,420	$1,420	Not budget in Rebasing 2014
Software Upgrade	$0	$1,651	$1,651	Not budget in Rebasing 2014
1995 Capital Contribution	-$160,000	-$905,202	-$745,202	Increase due to Patenaude Subdivision 381 units instead of 100
Total	$474,595	**$319,706**	-$154,889	

Most smaller projects were in line with the Board Approved budgets apart from 1845-New Subdivision. The main reason for the divergence from its 2014 Board Approved is that costs related to the four-new subdivisions were only preliminary at the time of the 2014 Board Approval. Actual costs were higher than expected as were the capital contributions.

Table 9 – OEB Appendix 2-AA System Access Project Table

Reporting Basis	**Reporting Basis**		NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	**USoA**	**2014**	**2015**	**2016**	**2017**	**2018**
System Access	**System Access**						
	New O/H and U/G services	1855					
	New O/H and U/G services	1855					
	New O/H and U/G services	1855	$12,464				
	Subdivision Faubourg Ste-Marie	1845	$692,811				
	Subdivision Faubourg Ste-Marie	1850	$288,934				
	Pumping Station Ste-Marie	1830	$10,425				
	Pumping Station Ste-Marie	1835	$10,425				
	Oligo Project East Entrance	1835	$6,577				
	Oligo Project West Entrance	1835	$5,298				
	Subdivision Faubourg Ste-Marie Relocate pole	1835	$20,182				
	Line Relocated 950 Notre-Dame	1835	$10,000				
	4th Feeder Cloutier Drive	1830	$43,996				
	4th Feeder Cloutier Drive	1835	$23,362				
	New Meter	1860	$25,716				
	New O/H and U/G services	1855		$15,074			
	New Meters	1860		$9,244			
	Oligo - Promenade Quatres Saison Project	1850		$110,238			
	Oligo - Promenade Quatres Saison Project (Professional Fees)	1845		$1,864			
	Oligo - Promenade Quatres Saison Project(Engineer)	1845		$5,898			
	Oligo - Promenade Quatres Saison Project(Bollards)	1845		$30,774			
	Oligo - Promenade Quatre Saison Project (Distribution System)	1845		$35,000			
	Oligo - Promenade Quatre Saison Project (Distribution System)	1845		$54,875			
	Oligo - Promenade Quatre Saison Project (Distribution System)	1845		$694			
	Oligo - Promenade Quatre Saison Project (Distribution System)	1845		$525			
	Engineer Cost 4th Switching Cabinet	1820		$73,810			
	New O/H and U/G services	1855			$22,175		
	Facilities to New Bell pole	1835			$2,231		
	Relocate Span Guy , Down Guy and Overhead Triplex	1835			$2,342		
	New Measurement Units	1860			$1,321		
	Oligo - Promenade Grounding all Metal objects	1845			$1,906		
	New Meters	1860			$5,492		
	Engineer Devcor	1845			$1,069		
	Consultation ST-Jacques St. (Relocate Line)	1835			$1,907		
	Relocate 2 U/G service	1845			$12,877		
	New Meter	1860			$508		
	Gateway Communication	1860			$559		
	4th Feeder Ste-Marie	1830			$28,750		
	4th Feeder Ste-Marie	1835			$100,000		
	Installed Composite Cross arm	1835			$3,119		
	Transformer Pharmacies JC	1850			$2,895		
	Engineer Cost New Substation	1820			$50,013		
	Pole Information	1830			$3,900		

	Nameplate Pole Number	1830			$1,125		
	Pole Information	1830			$7,524		
	4th Feeder Notre-Dame	1830			$28,000		
	4th Feeder Notre-Dame	1835			$90,850		
	Load Flow Study	1835			$12,918		
	Load Flow Study	1845			$12,918		
	Overhead Amps Verification	1850			$2,723		
	Transformer Data Collection	1850			$2,112		
	New O/H and U/G services	1855				$20,000	
	Meters	1860				$8,000	
	Versailles III Project	1850				$20,675	
	Versailles III Project	1845				$160,025	
	New Substation - 1820	1820				$1,487,396	
	Engineer Consultant Substation 1820	1820				$30,000	
	New O/H and U/G services	1855					$20,000
	Meters	1860					$8,000
	Replace pole with new 45`	1830					$6,500
	Sub-Total System Access		$1,150,190	$337,996	$399,232	$1,726,096	$34,500
Contributed Capital							
		1995	-$905,202	**-$148,144**	-$6,450	-$132,000	
	Contributed Capital		-$905,202	-$148,144	-$6,450	-$132,000	$0
Total System Access	**Total System Access**		**$244,988**	**$189,852**	**$392,782**	**$1,594,096**	**$34,500**

2014 – 2018 System Access investments are modifications or relocation a distributor is obligated to perform to provide a customer access to electricity services. There is considerable load growth happening as a result of new subdivisions being built. This is causing investment in plant to service the new subdivisions and causing the investment in a larger MS transformer to be able to supply the load. A new feeder was also required to supply the new subdivisions and provide security of supply since Hydro One is no longer able to provide any backup power to CHEI.

<u>Revised June 14, 2014</u>

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 10 - OEB Appendix 2-AA System Renewal Variances

System Renewal	System Renewal	USoA	2014	2015	2016	2017	2018
	Transformers Program (Elbow and Inserts)	1850		$1,879			
	Transformers Program (Elbow and Inserts)	1850		$12,583			
	Installation culverts	1820		**$1,600**			
	REPLACEMENT ROTTEN POLE 20 Bourassa	1830		$2,663			
	REPLACE CONDUCTOR DEVICE 20 Bourassa	1835		$885			
	Future Addition Transformers and Replacement	1850			$10,045		
	Straighten 2 dip poles and installed culvert	1835			$12,207		
	Transformers Program (Elbow and Inserts)	1850			$21,844		
	Transformers Program (Elbow and Inserts)	1850				$20,000	
	Pole Replacement # 11 - 1830	1830					$6,800
	Pole Replacement # 48 - 1830	1830					$4,500
	Pole Replacement # 81 - 1830	1830					$6,500
	Pole Replacement # 108 -1830	1830					$6,200
	Pole Replacement # 139 - 1830	1830					$6,500
	Pole Replacement # 353 -1830	1830					$2,500
	Pole Replacement # 415 -1830	1830					$4,500
	Pole Replacement # 465 -1830	1830					$4,000
	Transformer Replacement # 431 -1850	1850					$4,875
	Transformer Replacement # 456 -1850	1850					$5,575
	Transformer Replacement # 474 -1850	1850					$5,135
	Transformer Replacement # 501 -1850	1850					$5,775
	Transformer Replacement # 504 -1850	1850					$2,725
	Transformer Replacement # 506 -1850	1850					$4,835
	Transformer Replacement # 520 -1850	1850					$5,035
	Transformer Replacement # 522 -1850	1850					$3,825
	Transformer Replacement # 525 -1850	1850					$5,675
	Transformer Replacement # 550 -1850	1850					$2,725
	Transformer Replacement # 35 -1850	1850					$8,100
	Transformers Program (Elbow and Inserts)	1850					$20,000
	Sub-Total System Renewal		$0	$19,610	$44,096	$20,000	$115,780
Contributed Capital							
		1995					
							-$5,775
	Contributed Capital		$0	$0	$0	$0	-$5,775
Total System Renewal	**Total System Renewal**		**$0**	**$19,610**	**$44,096**	**$20,000**	**$110,005**

2014 – 2018 System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. System renewal has been proceeding at a modest pace with the total category spending being below the materiality threshold for 2014 to 2017. In 2018 the utility plans on replacing poles and transformers that are defective as a result of inspections carried out. This accounts for the increased spending.

Revised June 14, 2014

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 11 - OEB Appendix 2-AA System Service Variances

System Service	System Service	USoA	2014	2015	2016	2017	2018
	Pole Replacement	1830					
	Barriers for Transformers	1845					
	Pole replacement	1830					
	Transformers for replacing	1850					
	Pole Replacement 65 Forget Street	1830	$5,400				
	Pole Replacement 1287 St-Jacques Street	1830	$9,850				
	Pole Replacement 1179 Notre-Dame Street	1830	$5,500				
	Pole Replacement 1216 Ste Marie Street	1830	$3,800				
	Pole Replacement 1154 Notre-Dame Street	1830	$8,600				
	Communication Modem	1860			$643		
	Phase Balancing	1835			$1,425		
	Pole Replacement Entrance Elementry School	1830			$4,800		
	In-Line Switches Remove -Blais Notre-Dame and Centenaire	1835			$2,396		
	Four Way Tie In Switch 1835	1835				$39,650	
	336 MCM Conductors 1835	1835				$46,250	
	Sub-Total System Service		$33,150	$0	$9,264	$85,900	$0
Contributed Capital							
		1995					
	Contributed Capital		$0	$0	$0	$0	$0
Total System Service	**Total System Service**		**$33,150**	**$0**	**$9,264**	**$85,900**	**$0**

2014 – 2018 System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. CHEI does minimal System Service capital. The notable exception is the adjustments to the circuits by installing four switches to improve the system configuration flexibility. This allows the new transformer capacity and the fourth feeder to be fully utilized.

Revised June 14, 2014

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

Table 12 - OEB Appendix 2-AA General Plant Variances

General Plant	General Plant	USoA	2014	2015	2016	2017	2018
	Hydro Vac Dip Pole 4th Feeders	1845					
	Future Addition Transformers and Replacement	1850					
	Smart meter deployment	1860					
	Stranded Meter	1860					
	Smart Meter Toll Deployment	1940					
	New Computer	1920					
	Grounding Study Substation	1820					
	Add New Switching Cabinet	1820					
	Ste-Therese Street 4th Feeder	1830					
	Ste-Therese Street 4th Feeder	1835					
	U/G Cable Substation to Ste-Therese	1845					
	Cell phone	1915					
	Computer Equipment Hardware Battery Back-up	1920					
	MOE Standard Bill Print	1611					
	Antivirus Protection	1611					
	Time Clock Employee	1915	$633				
	Note Pad Computer	1920	$430				
	Harris Version 6.4	1611	$20,885				
	Web presentment	1611	$16,549				
	Anti-Spam Contentment	1611	$1,420				
	Software Upgrade Computer Office	1611	$1,651				
	New Cell Phone	1915		$571			
	New Camera	1915		$391			
	New Computer Station	1920		$1,385			
	Antivirus Software	1611		$466			
	ORPC- Membership Module	1611		$840			
	Office Accessories	1915			$1,000		
	Computer Equipment Hardware New Printer	1920			$1,840		
	Computer Screen	1920			$320		
	Drill -Pole Inspection	1945			$7,415		
	Ergotron Standing Desk	1915			$563		
	Upgrade CIS	1611			$840		
	Upgrade CIS	1611			$525		
	Website - 1611	1611				$3,000	
	Antivirus - 1611	1611				$1,500	
	Office Equipment 1915	1915				$1,000	
	Computer & Hardware -1920	1920				$1,500	

	Software - 1611	1611					$3,000
	Office Equipment 1915	1915					$1,200
	Computer & Hardware -1920	1920					$1,500
	Sub-Total General Plant		$41,568	$3,653	$12,503	$7,000	$5,700
Contributed Capital							
		1995					
	Contributed Capital		$0	$0	$0	$0	$0
Total System Service	**Total System Service**		**$41,568**	**$3,653**	**$12,503**	**$7,000**	**$5,700**

2014-2018 General Plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. CHEI has had very modest expenditures in this category with the total annual spending in the category being below the materiality threshold. The larger amounts are typically related to system upgrades for the Billing / CIS system and some web enhancement.

Revised June 14, 2014

Information on year-over-year variance and explanation where variances are greater than the materiality threshold are summarized in the previous section 2.1.3 and explained in detail in Appendix A of the Distribution System Plan.

In compliance with the filing requirements, the capital additions are presented by traditional functions in Table 12 below.

Table 13 – Yearly investments by Traditional Functions[11]

	2014	2015	2016	2017	2018

[11] MFR - Breakdown by function and by major plant account; description of major plant items for test year

Distribution Plant	1611	Computer Software	$40,505	$1,308	$1,365	$4,500	$3,000
Distribution Plant	1820	Distribution Station Equipment <50 kV	$0	$75,410	$50,013	$1,517,396	$0
Distribution Plant	1830	Poles, Towers & Fixtures	$107,753	$2,663	$74,099	$0	$48,000
Distribution Plant	1835	Overhead Conductors & Devices	$55,662	$885	$229,395	$85,900	$0
Distribution Plant	1845	Underground Conductors & Devices	$692,811	$144,092	$28,769	$160,025	$0
Distribution Plant	1850	Line Transformers	$288,934	$110,238	$39,619	$40,675	$74,280
Distribution Plant	1855	Services (Overhead & Underground)	$12,464	$15,074	$22,175	$20,000	$20,000
Distribution Plant	1860	Meters	$0	$0	$0	$8,000	$8,000
Distribution Plant	1860	Meters (Smart Meters)	$25,716	$9,244	$8,523	$0	$0
		Subtotal	**$1,223,846**	**$358,912**	**$453,957**	**$1,836,496**	**$153,280**
General Plant	1915	Office Furniture & Equipment (10 years)	$632	$962	$1,563	$1,000	$1,200
General Plant	1920	Computer Equipment - Hardware	$430	$1,385	$2,160	$1,500	$1,500
General Plant	1945	Measurement & Testing Equipment	$0	$0	$7,415	$0	$0
General Plant	1995	Contributions & Grants	-$905,202	-$148,144	-$6,451	-$132,000	-$5,775
		Subtotal	-$904,140	-$145,798	$4,688	-$129,500	-$3,075
		Total	**$319,706**	**$213,115**	**$458,645**	**$1,706,996**	**$150,205**

2.2.2 ACCUMULATED DEPRECIATION

CHEI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at this link. [add link]. The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below.

CHEI's depreciation expense policy and methodology are provided on the next page. The depreciation expenses continuity schedules are presented at [references].

Table 14 below provides CHEI's depreciable lives by asset class.

Table 14 - Comparison of Depreciation Rates

Account	**Description**	**Pre 2013**	**2013 and beyond**
1611	Computer Software (Formally known as Account 1925)	5	5
1820	Distribution Station Equipment <50 kV	30	55
1830	Poles, Towers & Fixtures	25	40
1835	Overhead Conductors & Devices	25	60
1845	Underground Conductors & Devices	25	35
1850	Line Transformers	25	40
1855	Services (Overhead & Underground)	25	40
1860	Meters	25	25
1860	Meters (Smart Meters)	25	15
1915	Office Furniture & Equipment (10 years)	10	10
1920	Computer Equipment - Hardware	5	5
1935	Stores Equipment	10	10
1940	Tools, Shop & Garage Equipment	10	10
1945	Measurement & Testing Equipment	10	10
1995	Contributions & Grants	25	40

2.2.3 CAPITALIZATION POLICY

CHEI's capitalization policy has not changed since its last Cost of Service in 2014[12] other than it now records capital assets at cost in accordance with MIFRS accounting principles as well as guidelines set out by the Ontario Energy Board, where applicable.

All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. CHEI does not currently capitalize interest on funds used for construction.

CHEI's adherence to the capitalization policy can be described as follows;

- ✓ Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- ✓ General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- ✓ Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity, or the useful life of the capital asset is extended) will be capitalized.
- ✓ With respect to vehicles, please note that CHEI does not own any vehicles.
- ✓ Maintenance services are contracted out.

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not, nor have they ever been capitalized.

[12] MFR - Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.

2.3 ALLOWANCE FOR WORKING CAPITAL

2.3.1 DERVIATION OF WORKING CAPTIAL

CHEI has used the 7.5% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board on June 03, 2015 for a rate of 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). CHEI attests that the Cost of Power is determined by the split between RPP and non-RPP customers based on actual data, using most current RPP price, using current UTR. Table 15 presented below show CHEI's calculations in determining its Allowance for Working Capital.

Table 15 - Allowance for Working Capital

Expenses for Working Capital	**Last Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	20,900	28,851	39,764	34,209	35,830	37,769
3550-Distribution Expenses - Maintenance	40,300	44,655	26,251	46,223	50,645	56,215
3650-Billing and Collecting	170,174	166,891	210,565	177,779	198,023	209,970
3700-Community Relations	4,000	6,982	8,363	7,863	7,500	7,875
3800-Administrative and General Expenses	320,905	319,703	328,131	334,952	359,618	410,142
Total Eligible Distribution Expenses	556,279	567,081	613,072	601,025	651,616	721,971
3350-Power Supply Expenses	3,560,978	3,122,917	3,422,003	3,838,439	4,120,850	4,209,043
Total Expenses for Working Capital	4,117,257	3,689,998	4,035,075	4,439,464	4,772,466	4,931,014
Working Capital factor	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital	535,243	479,700	524,560	577,130	620,421	369,826

2.3.2 LEAD LAG STUDY[13]

CHEI is not proposing to use a lead lag study in order to determine its Working Capital Allowance and has chosen to follow the Board's June 03, 2015 letter which provided two options for the calculation of the allowance for working capital:[14]

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

CHEI notes that it has not previously been directed by the Board to undertake a lead/lag study.

2.3.3 CALCULATION OF COST OF POWER[15]

CHEI calculated the cost of power for the 2017 Bridge Year and the 2018 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Report – November 1, 2016, to October 27, 2017. Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, CHEI will update the electricity prices in the forecast.

The sale of energy is a flow through revenue, and the cost of power is a flow through expense. Energy sales and the cost of power expense are presented in the table below. CHEI records no profit or loss resulting from the flow through energy revenues and expenses. Any temporary variances are included in the RSVA account balances.

The components of CHEI's cost of power are summarized in Table 16 below and detailed in Table 17 to 26;

[13] MFR - Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction
[14] MFR - Lead/Lag Study - leads and lags measured in days, dollar-weighted
[15] MFR - Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP (TOU) price, use current UTR. Should include SME charge.

Table 16 – Summary of Cost of Power

CoP Components	**Total $**
Commodity	$3,481,608
Transmission Network	$242,206
Transmission Connection	$187,049
Wholesale Market Service	$111,041
Rural Rate Protection	$64,774
Smart Meter Entity Charge	$21,625
OESP	$24,803
Low Voltage	$75,938
TOTAL	$4,209,043

Table 17 - Calculation of Commodity

Last Actual kWh's

Customer Class Name	Last Actual kWh's	non-RPP	RPP
Residential	19,268,403	463,023	18,805,380
General Service < 50 kW	4,547,781	326,010	4,221,771
General Service > 50 to 4999 kW	4,242,389	4,242,389	0
Unmetered Scattered Load	93,284	-	93,284
Street Lighting	321,015	321,015	0
other	-	-	0
other	-	-	0
other	-	-	0
other	-	-	0
TOTAL	28,472,872	5,352,437	23,120,435
%	*100.00%*	*18.80%*	*81.20%*
<u>Forecast Price</u>			
HOEP ($/MWh)		$22.59	
Global Adjustment ($/MWh)		$84.50	
Adjustments			
TOTAL ($/MWh)		$107.09	$112.39
$/kWh		*$0.10709*	*$0.11239*
%		18.80%	81.20%
WEIGHTED AVERAGE PRICE	$0.1114	$0.0201	$0.0913

Table 18 - Electricity Projections

Customer	2017			2018		
Class Name	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	22,215,003	0.11000	$2,443,650	22,548,045	$0.11139	$2,511,710
General Service < 50 kW	5,215,832	0.11000	$573,742	5,260,949	$0.11139	$586,037
General Service > 50 to 4999 kW	3,860,951	0.11000	$424,705	2,949,371	$0.11139	$328,541
Unmetered Scattered Load	86,927	0.11000	$9,562	85,667	$0.11139	$9,543
Street Lighting	406,995	0.11000	$44,769	410,950	$0.11139	$45,777
TOTAL	**31,785,708**		**$3,496,428**	**31,254,982**		**$3,481,608**

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in CHEI's previous Cost of Service application as well as other applications. The utility used Table ES-1: Average RPP Supply Cost Summary from the Regulated Price Plan Price Report - November 1, 2016, to October 31, 2017, issued by the Ontario Energy Board on October 19, 2016.

Table 19 - RPP Supply Cost Summary

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2016)

RPP Supply Cost Summary for the period from November 1, 2016 through October 31, 2017		
Forecast Wholesale Electricity Price		$22.59
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.63
Impact of the Global Adjustment ($ / MWh)	+	$84.50
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$2.26
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$112.39**

The utility uses the split between the RPP and Non-RPP to determine the weighted average price. The weighted average price is applied to the projected 2018 Load Forecast to determine the commodity to be included in the Cost of Power. The commodity for 2018 is projected at $3,481,608.

Table 20 - Transmission Network

	2017			2018		
Customer						
Class Name	Volume	Rate	Amount	Volume	Rate	Amount
Residential	22,215,003	0.0073	$162,709	22,548,045	0.0075	$168,597
General Service < 50 kW	5,215,832	0.0068	$35,393	5,260,949	0.0069	$36,445
General Service > 50 to 4999 kW	12,701	2.7157	$34,491	12,736	2.7724	$35,309
Unmetered Scattered Load	86,927	0.0068	$590	85,667	0.0069	$593
Street Lighting	590	2.0482	$1,208	603	2.0910	$1,262
TOTAL	27,531,053		$234,392	27,908,001		$242,206

The Transmission Network charges are calculated in the OEB's RTSR model. The Rates are applied to the 2018 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application. The transmission network charges included in the Cost of Power for 2018 is projected at $242,206.

Table 21 - Transmission Connection

	2017			2018		
Customer						
Class Name	Volume	Rate	Amount	Volume	Rate	Amount
Residential	22,215,003	0.0057	$127,726	22,548,045	0.0059	$132,492
General Service < 50 kW	5,215,832	0.0050	$26,028	5,260,949	0.0051	$26,830
General Service > 50 to 4999 kW	12,701	2.0225	$25,688	12,736	2.0670	$26,326
Unmetered Scattered Load	86,927	0.0050	$434	85,667	0.0051	$437
Street Lighting	590	1.5636	$922	603	1.5979	$964
TOTAL	**27,531,053**		**$180,798**	**27,908,001**		**$187,049**

The Transmission Connection charges are also calculated in the OEB's RTSR model. The Rates are applied to the 2018 Load Forecast to determine the amount to be included in the Cost of Power. The RTSR model is filed in conjunction with this application.

Table 22 - Wholesale Market

	2017			2018		
Customer		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name	Volume		Amount	Volume		Amount
Residential	22,215,003	0.00360	$79,974	22,548,045	0.00360	$81,173
General Service < 50 kW	5,215,832	0.00360	$18,777	5,260,949	0.00360	$18,939
General Service > 50 to 4999 kW	3,860,951	0.00360	$13,899	2,949,371	0.00360	$10,618
Unmetered Scattered Load	86,927	0.00360	$313	85,667	0.00360	$308
Street Lighting	406,995	0.00360	$1,465	410,950	0.00360	$1,479
TOTAL	31,785,708		$114,429	31,254,982		$112,518

On December 15, 2016, the OEB released Decision and Order for the Wholesale Market Service (WMS) effective January 1, 2017. The Board's decision is summarized as follows:

- The WMS rate used by rate-regulated distributors to bill their customers shall be $0.0032 per kilowatt-hour, effective January 1, 2017. For Class B customers, a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0036 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak.

In compliance with this order, CHEI has applied the Board Approved $0.0036/kWh to its 2018 Load Forecast to include $114,642 in its Cost of Power.

Table 23 - Remote Electricity Rate Protection

	2017			2018		
Customer		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name	Volume		Amount	Volume		Amount
Residential	22,215,003	0.00130	$28,880	22,548,045	0.00210	$47,351
General Service < 50 kW	5,215,832	0.00130	$6,781	5,260,949	0.00210	$11,048
General Service > 50 to 4999 kW	3,860,951	0.00130	$5,019	2,949,371	0.00210	$6,194
Unmetered Scattered Load	86,927	0.00130	$113	85,667	0.00210	$180
Street Lighting	406,995	0.00130	$529	410,950	0.00210	$863
TOTAL	31,785,708		$41,321	31,254,982		$65,635

On December 15, 2016, the OEB released Decision and Order for the Rural or Remote Electricity Rate Protection (RRRP) effective January 1, 2017. The Board's decision is summarized as follows:

- The RRRP charge used by rate regulated distributors to bill their customers shall be 0.21 cents per kilowatt-hour, effective January 1, 2017. This unit rate shall apply to a customer’s metered energy consumption adjusted by the distributor’s Board-approved Total Loss Factor.

In compliance with this order, CHEI has applied the Board Approved $0.0021/kWh to its 2018 Load Forecast to include $66.875 in its Cost of Power.

Table 24 - Smart Meter Entity

	2017			2018		
Customer		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name	Volume		Amount	Volume		Amount
Residential	2,040	0.79000	$1,612	2,100	0.79000	$19,908
General Service < 50 kW	168	0.79000	$133	172	0.79000	$1,632
General Service > 50 to 4999 kW	9	0.79000	$7	9	0.79000	$85
TOTAL	**2,217**		**$1,752**	**2,281**		**$21,625**

In compliance with this order, CHEI has applied the Board Approved $0.79/kWh to its 2018 Customer Forecast to include $21,625 in its Cost of Power.

Low Voltage Charges:

The table below presents the derivation of proposed retail rates for Low Voltage (“LV”) service. The 2018 estimates of total LV charges were calculated based on an average of the last 2 years. The projections were allocated to customer classes, according to each class’ share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2018 volumes from the load forecast, as presented in Exhibit 3. Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2018 LV rates appear on a distinct line item on the proposed schedule of rates.

Table 25 - Low Voltage Charges

		2014	2015	2016	2017	2018
4750-Charges - LV		$72,735	$71,341	$82,149	$90,279	$98,400

Customer Class Name		Revenue	% Alloc
Residential	kWh	$132,492	70.83%
General Service < 50 kW	kWh	$26,830	14.34%
General Service > 50 to 4999 kW	kW	$26,326	14.07%
Unmetered Scattered Load	kWh	$437	0.23%
Street Lighting	kW	$964	0.52%
TOTAL		$187,049	100.00%

Customer Class Name	Not Uplifted Volumes	Rate	per
Residential	21,616,344	$0.0025	kWh
General Service < 50 kW	5,043,563	$0.0021	kWh
General Service > 50 to 4999 kW	2,827,501	$0.0038	kW
Unmetered Scattered Load	82,127	$0.0021	kWh
Street Lighting	393,969	$0.6442	kW
TOTAL	29,963,508		

Customer		2017			2018		
Class Name		Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	21,046,900	$0.0018	$37,884	21,616,344	$0.0032	$69,700
General Service < 50 kW	kWh	4,941,575	$0.0016	$7,907	5,043,563	$0.0028	$14,115
General Service > 50 to 4999 kW	kW	12,701	$0.5928	$7,529	2,827,501	$0.0049	$13,849
Unmetered Scattered Load	kWh	82,356	$0.0016	$132	82,127	$0.0028	$230
Street Lighting	kW	590	$0.4583	$270	393,969	$0.0013	$507
TOTAL		26,084,126		$53,722	29,963,508		$98,402

2.4 SMART METER DEPLOYMENT & STRANDED

2.4.1 DISPOSITION OF SMART METERS AND TREATMENT OF STRANDED METERS

CHEI's disposition and treatment of smart meter related costs were address and approved as part of its 2014 Cost of Service Application. Therefore, the utility is not seeking any futher resolution on this matter.[16]

On the topic of Smart Meters, the utility notes that it has not witnessed any cost efficiencies since its last Cost of Service in 2014 related to the utility's use of Smart Meter. [17]

[16] MFR - Stranded Meters - if the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved, a proposal for a Stranded Meter Rate Rider must be made
Explanation for approaches that are not the OEB approach

[17] MFR - Discussion outlining capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies (e.g., AMI communications networks, ODS) in its networks. Qualitative and quantitative description and support should be provided as applicable

2.5 CAPITAL EXPENDITURES

2.5.1 PLANNING

Introduction to Distribution System Plan

CHEI's distribution system strategy is the set of policies, rules, guidelines, etc. that CHEI utilizes to transition its current system into its desired future system. The strategy, as described in this Distribution System Plan provides the rationale for the capital expenditures and supporting activities planned for the 2017-2021 period.

CHEI has pursued the best practices of the electricity distribution industry for many years. This has included adhering to the OEB's Distribution System Code that sets out both good utility practice and minimal performance standards for electricity distribution systems in Ontario, and inspection requirements for distribution equipment. Over the years CHEI has diligently maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. The diligent maintenance of its equipment has permitted CHEI to extract an extended useful working life from its assets; moreover, while the age of the distribution equipment has increased, the reliability of the equipment has also often improved to meet the expectations of CHEI's customers. Historically, this has been achieved with only a moderate increase in the customers' bills over many years.

The future distribution system will be designed to deliver electricity at the quality and reliability levels required by customers and will minimize the lifetime cost by balancing preventive maintenance, life-extending refurbishment, and end-of-life replacement; in short, the system will meet the customers' needs for quality and reliability of power at the minimal cost to the customer.

CHEI places a high priority on balancing its obligations to accommodate growth while addressing the upkeep and replacement of its aging infrastructure. The following are the actions that CHEI plans to take over the next 5-10 years to bring about the desired future.

- Priority will be given to CHEI's legislated/mandatory requirements; for example:
- System access including the obligation to connect customers – mostly Residential, but Commercial as well.
- Accommodate City, Region, Ministry, etc. mandatory project requirements.
- Meet the OEB's – and other regulatory bodies' – quality, reliability, health, safety, environmental, etc. performance standards.
- To safeguard the major investments already made in its critical assets and continue to maintain and upgrade as necessary.
- Continue to invest prudently in modern information technology to provide customers with clear, meaningful bills that can assist them in managing their electricity usage.
- Optimal life extension, for example:
- Intensify condition monitoring to minimize uncertainty regarding decisions relating to equipment maintenance, renewal, and replacement.
- Where economically viable, refurbish cables and equipment in-situ to extend their reliable useful lives.

CHEI notes that the topic of regional issues around CHEIs proposed capital expenditure plan and discussed in the DSP.[18]

CHEI's Distribution System Plan was created with the assistance of AESI and is designed to present a fully integrated approach to capital expenditure planning. This includes a comprehensive documentation of its asset management process that supports its future 5 year capital expenditure plan while detailing the history of its past 5 years' activities. It recognizes its responsibilities to provide its customers with reliable service that is acknowledged as excellent value for money, by ensuring that its asset management activities maintain a focus on customers, operational effectiveness, public policy responsiveness and financial performance.

[18] MFR - As applicable - file evidence that demonstrates that regional issues have been appropriately considered and where applicable addressed in developing the applicant's proposed capital expenditure plan. As part of its planning an applicant should consider municipal planning, including any plans for expansion of boundaries from a regional perspective to demonstrate the most cost effective solutions are being considered

CHEI has relied on the OEB's filing requirements Chapter 5 to guide its presentation of its policies, practices, and decision making processes. OEB appendices related to capital investments are shown at the next page. The Distribution System Plan follows in Section 2.5.2

2.5.2 DISTRIBUTION SYSTEM PLAN

CHEI is pleased to present its Distribution System Plan on the next page.[19]

[19] MFR - DSP filed as a stand-alone document; a discrete element within Exhibit 2

Cooperative Hydro Embrun Inc.

Distribution System Plan

Project #
1601

Date Due
April 28, 2017

Submitted by
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APPENDIX LISTING

Executive Summary

This Consolidated Distribution System Plan (DS Plan or DSP) has been prepared by Acumen Engineered Solutions International Inc. (AESI) for Cooperative Hydro Embrun Inc. (CHEI) in accordance with Chapter 5 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Distribution Applications; Chapter 5 Consolidated Distribution System Plan Filing Requirements dated March 28, 2013.

CHEI's DS Plan is an integrated document that supports the cost-effective planning and operation of its electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for its customers. The DS Plan documents the practices, policies and processes that are in place to ensure that investment decisions support CHEI's desired outcomes in a cost-effective manner and provides value to the customer. CHEI is committed to adhering to its DS Plan in order to provide valued outcomes to its customers. Electricity distributors are capital intensive in nature, and prudent capital investments and maintenance plans are essential to ensure the sustainability and reliability of the distribution network.

CHEI has followed the best practices of the electricity distribution industry for many years including OEB's Distribution System Code (DSC) which sets out good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with best practices, CHEI has diligently maintained its equipment in safe and reliable working order, and only when economically justified, upgraded or replaced its equipment.

Table ES-1 below provides the Historical Investments CHEI has made between 2013 and projected for 2017.

	Historical Investments				
	Test-5	Test-4	Test-3	Test-2	Test-1
	2013	2014	2015	2016	2017
CATEGORY	Actual	Actual	Actual	Actual	Projected Y/E
	$	$	$	$	$
System Access	233,350	1,150,190	337,996	399,233	1,726,096
System Renewal	41,050	33,150	19,609	44,096	20,000
System Service	0	0	0	9,264	85,900
General Plant	29,500	41,568	3,653	12,503	7,000
Total	303,900	1,224,908	361,259	465,096	1,838,996
Contributed Capital	8,000	905,202	148,144	6,451	132,000
Net Capital	295,900	319,706	213,115	458,645	1,706,996

Table ES-1: Historical Capital Investments by Year

As can be seen Capital Investment has been very modest with the exception of System Access investment. This investment is driven by new development and the need to install distribution plant in the subdivisions. Also, because of the new load, a new feeder was required to supply the new subdivisions and a new municipal station was required to supply the existing load and the new subdivision loads. The 2017 System service investment was also related to the new load because addition switches on the distribution lines were required to be able to restore power if a major power failure occurred. Hence all the material investments were driven by new development, either directly to service the development or indirectly to facilitate power restoration with the new developments in place.

Table ES-2 Forecast Investments 2018 to 2022 below shows CHEI's planned investments.

	Forecast Investments				
	Test	Test+1	Test+2	Test+3	Test+4
	2018	2019	2020	2021	2022
CATEGORY	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
System Access	34,500	135,000	53,000	53,000	78,000
System Renewal	115,780	20,000	60,000	62,000	40,000
System Service	0	0	0	0	0
General Plant	5,700	5,700	5,700	5,700	5,700
Total	155,980	160,700	118,700	120,700	123,700
Contributed Capital	5,775	16,700	0	0	0
Net Capital	150,205	144,000	118,700	120,700	123,700

Table ES-2: Forecast Capital Investments by Year

As can be seen from the table System Access investments continue but at a more moderate pace. This is because the utility required capacity changes due to the additional load have been completed and no further investment for this is required in the forecast period.

The System Renewal cost is higher in 2018 because three renewal projects are being completed in this year. Overall the average investment is quite modest.

In developing its long-term DS Plan, CHEI's objective is to make timely investments in infrastructure to ensure its distribution system continues to deliver power at the quality and reliability levels required by its customers. CHEI will continue to advance conservation and demand management.

Distribution System Plan

1. INTRODUCTION

On March 28, 2013, the Ontario Energy Board (OEB or the Board) issued Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 Consolidated Distribution System Plan Filing Requirements (Chapter 5 Requirements). Chapter 5 Requirements provide a standard approach to a distributor's Distribution System Plan (DS Plan or DSP) and filing of asset management and capital expenditure plan information in support of a rate application.

CHEI has compiled its consolidated DS Plan in accordance with the Chapter 5 Requirements.

The DS Plan reflects CHEI's integrated approach to planning, prioritizing, and managing assets, and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations. CHEI has completed this DS Plan with a focus on customer preferences and operational effectiveness while achieving optimal value for capital spending.

CHEI has organized the required information using the section headings in the DS Plan Filing Requirements. Investment projects and activities have been grouped into one of the four OEB defined investment categories: System Access, System Renewals, System Service, and General Plant.

1.1. Utility Overview

CHEI is an electricity distributor licensed by the OEB. In accordance with its Distribution License ED-2002-0405, CHEI provides electricity distribution services in the Town of Embrun, about 45 km south east of Ottawa. CHEI currently services approximately 2150 customers across its service area spanning a distribution service territory of about five square kilometers. CHEI is responsible for maintaining distribution and infrastructure assets deployed within the Embrun service area.

CHEI is an embedded utility in Hydro One Distribution's service territory and as such, is supplied power from Hydro One's Chesterville Transformer Station at 44kV.

CHEI distributes electricity to the Town of Embrun at a primary distribution voltage of 8.32kV through one 8.32kV substation and four feeders. CHEI does not host any utilities. The entire service territory is urban.

CHEI has experienced customer and load growth since about 2006. This is expected to continue until 2023 when the current development plan is expected to be complete since by then virtually all the land suitable for development within the service territory will have been developed. This means that CHEI is looking to ensure that the new plant it installs (e.g. the fourth feeder and the new substation) meet the requirements of all the anticipated development within the service territory and provides for adequate prime capacity and backup in the unlikely event of a major failure such as a power transformer. Once this is achieved only "end of life" replacement of assets is anticipated on an as required basis.

CHEI is incorporated under the Co-operative Corporations Act and is 100% owned by its members. Hydro Embrun is managed by a Board of Directors appointed by the members. CHEI has three employees; a General Manager, an Assistant General Manager and an Administrative Coordinator.

Revenue is earned by CHEI by delivering electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

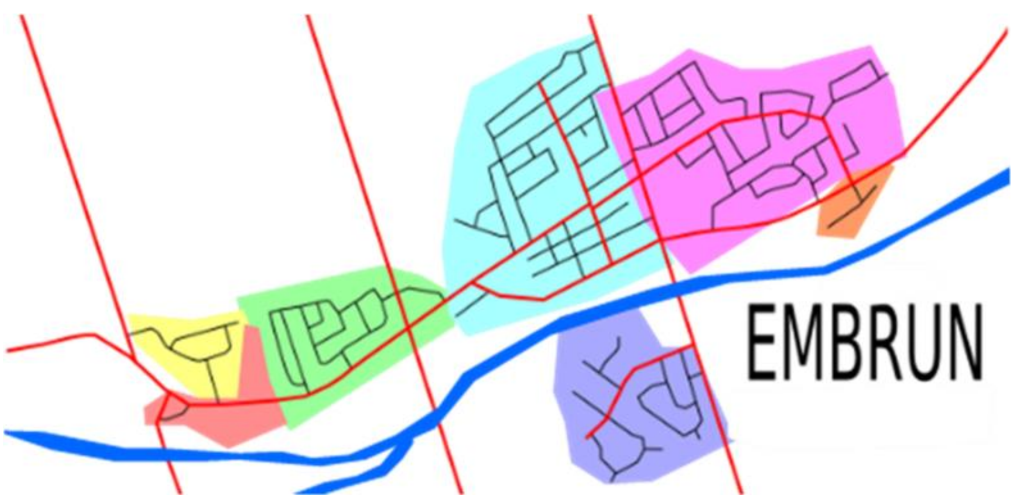
2. [5.2] Distribution System Plan

This Distribution System Plan follows the chapter and section headings set out in Chapter 5 Requirements. The information in this report was provided by Co-operative Hydro Embrun Incorporated (CHEI) and the report was prepared by AESI for CHEI.

2.1. [5.2.1] Distribution System Plan Overview

CHEI has new development taking place within its service territory. These developments are shown in Figure 1 below. This is increasing the load on its Municipal Station (MS). Based on a load study performed in 2016, the existing MS transformer rated at 7.5 MVA/ 10MVA (ONAN/ ONAF) is not able to supply the peak load. In addition Hydro One is dismantling their Embrun Distribution Station (DS) and as a result, the existing emergency load transfer agreement is being terminated and the partial backup for the CHEI load in an emergency will no longer be available. In order to address these critical developments CHEI is upgrading the MS by installing a new substation rated at 10 MVA / 13.3 MVA (ONAN/ ONAF) in 2017 and keeping the old substation to act as a backup in the event of an MS transformer failure and there not being supply capability from Hydro One.

Figure 1 below shows the development areas within the town of Embrun.



By FreshFruitsRule-WMC - Own work, Public Domain, https://commons.wikimedia.org/w/index.php?curid=1086603

Figure 1: Embrun Development Areas

Below is a legend for Figure 1 as to what neighbourhood each colour represents:

Yellow - Industrial Park
Red - Business Park
Green - Chantal Development
Light Blue - Centre ville (town centre)
Purple - Bourdeau Development in the Embrun-Sud (Embrun South) area
Pink - Lapointe Development and Mélanie Construction
Orange - Maplevale

The new developments have also required a new 4th feeder to be installed to provide supply for some of the new developments and provide the ability to route power through the system with flexibility, to restore power in the event of failure of one of the other feeders.

This development has resulted in the following high level historical costs for 2013 to 2017 shown in Table 1 below.

Subdivision Development Costs					
Year/ Development	**2013**	**2014**	**2015**	**2016**	**2017**
Subdivision Faubourg Ste-Marie		$1,022,777			
Oligo Project East Entrance		$11,875			
Oligo - Promenade Quatres Saison Project			$239,868		
Versaille III Project					$180,700
Total		$1,034,652	$239,868	$0	$180,700

Table 1: Historical Subdivision Development Costs by Year

Corresponding to these expenditures for subdivision developments is the utility expenditure to provide supply to the subdivision as well as provide for the capacity to supply increase required for safe, reliable, efficient power to the new as well as the existing customers. These costs are indicated in Table 2 below. These are high level summary costs.

System Alteration and Supply Costs					
Year/ Description	**2013**	**2014**	**2015**	**2016**	**2017**
Old station alterations to accommodate 4th feeder	$62,400		$73,810		
Fourth feeder partial build	$165,950	$67,358		$260,149	
New station Engineering and construction				$80,682	$1,517,396
Total	$228,350	$67,358	$73,810	$340,831	$1,517,396

Table 2: Historical System Alteration and Supply Costs

CHEI expects to achieve cost savings by installing the plant it needs to supply the new load reliably and for the long term. The basic system capacity will be installed by the end of 2017 and after this new subdivisions planned can be accommodated by the system. After the new subdivision development is completed, the major spending will be for the replacement of old “end of life” plant on an as needed basis. There are no reliability issues to address at this time and CHEI intends to keep it this way by doing regular inspections to identify situations before they become issues.

The DSP covers a historical period from 2013 to 2016, the transition year is 2017 and the test year is 2018 with the forecast years being 2019 to 2022.

The information is current as of December 31, 2016.

This is CHEI’s first DSP filing hence there are no changes to be noted.

CHEI has received notification from Hydro One that Hydro One will no longer be able to provide emergency backup power to CHEI after Oct 17, 2018, since Hydro One’s Embrun DS is being decommissioned. This, plus new development in the service territory which increased the forecast peak load on Embrun’s MS beyond its emergency ratings, has caused CHEI to increase the capacity of its MS and provide for redundancy in the event of a failure of its MS transformer. These matters are described in Appendix A and C of this report. The combination of load growth and elimination of external backup alternatives made it imperative for CHEI to act to address the security of its supply for its customers.

While CHEI is a small utility, it is guided by and strives to comply with, the OEB’s four key target objectives referenced in the Renewed Regulatory Framework for Electricity Distributors (RRFE)

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

CHEI has adopted good utility practices of the electricity distribution industry. This has included adhering to the OEB’s DSC that sets out both good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, over the years CHEI has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. CHEI has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an important factor to customers.

CHEI has only replaced equipment when it no longer functioned reliably. Hence it has a range of vintages of equipment. This has not presented any issues and this will continue to be CHEI’s practice. In general, only end of life assets will be replaced.

2.2. [5.2.2] Coordinated Planning with Third Parties

2.2.1. Local Planning Coordination

CHEI has not had a formal planning meeting with the local municipality. Because of size and the low frequency of projects having impact on the utility, the information is passed informally.

As a result of preparing this DSP, CHEI recognized that not having regular meetings with the Municipality and Road Authorities was not good planning. They will remedy this by, setting up meetings at least annually with the town road authority and other authorities that affect their plan locations. Also regular meetings will be scheduled with Hydro One so that project planning and construction information can be shared and coordinated. Communication does take place with Hydro One on the basis of specific issues or questions. An example is the arrangement that was in place for many years for Hydro One to provide limited backup power to CHEI. In October 2016, CHEI was advised that this arrangement would be terminated as of October 17, 2018. This change in backup power availability, as well as the load growth that has occurred and is expected in the future, is part of the reason for the substation upgrade.

2.2.2. Development Planning

CHEI meets with developers when they become aware of projects in order to plan and coordinate the projects. There has been significant recent development in the CHEI service area and beyond. Coordination of services beyond its service territory requires joint planning with Hydro One Networks as well.

2.2.3. Regional Planning

CHEI is part of the St. Lawrence Region Study area. The study was completed April 29, 2016 with a Needs Assessment and a Regional Infrastructure Plan being completed. Neither a Scoping Assessment nor an Integrated Regional Resource plan was required. The result was that there was no work to be done by CHEI and the next review will be in five years as prescribed by the OEB.

CHEI did not participate in the study. They are imbedded in the Hydro One service area. Hydro One Networks was a participant in the study and it is aware of CHEI's load forecast.

The IESO has commented on the REG and planning study for the St. Lawrence Region which is the part of the provincial system that supplies CHEI.

2.3. [5.2.3] Performance Measurement for Continuous Improvement

The purpose of CHEI is to provide a continuous availability of electric power to its customers with sufficient capacity to meet all the customer's needs in a sustainable manner.

As it states on its website:

Our vision is to satisfy our clients by providing the highest quality of service.

We are committed to providing electricity to our clients with efficiency, security and quality.

This means that system reliability and cost of power are significant measures. Power quality has not been an issue, so while an important overall consideration to the usability of the power; it only becomes a driver for spending on the system when power quality problems actually occur.

The cost of power is an important matter for the CHEI customers. In their 2016 Customer Survey (a copy can be found in to Section 1.8.2 of Exhibit 1), the response to the question, “To what extent, if any, is the cost of Electrical service a strain on your household budget?” was that 77.7% of those surveyed responded with either “A great deal” or “Some”. Hence, cost is of importance to CHEI’s customers.

An additional Question was “…how would you rate Cooperative Hydro Embrun's overall performance in serving you?” to which 93.3% of the respondents indicated Excellent or Good.

This indicates that CHEI has been controlling costs to their customer’s satisfaction.

CHEI has a small service territory and as such does not have the workload to sustain a complement of staff to provide all the functions of the utility in-house. It acquires the services it needs on a contract basis. As a result Engineering and Engineering studies are contracted out; as is the system construction, maintenance and emergency trouble calls trouble response and billing. The overall management, purchasing and finance functions, as well as customer service, are maintained in-house.

This approach works well for CHEI from a cost management and timing perspective for the physical work as well as for the timely financial billing or project costing. Project work is contracted on a fixed price basis and maintenance and repair work is based on unit prices negotiated in advance and authorized prior to the work being started except in the case of emergency work after hours.

This approach also means that CHEI does not incur fixed or ongoing costs for engineering work or power system work unless there is work to be done. Then the work is defined and the costs are contained. In this way cost efficiency and work performance is kept high.

Over-all CHEI has worked to keep the bill impacts to its customers as low as it can. The bill impacts over the past four years have been as follows.

Year	2014	2015	2016	2017
	CoS	IRM	IRM	IRM
Monthly Charge	$14.56	$14.77	$18.25	$21.87
Volumetric	$0.0136	$0.0138	$0.0106	$0.0072
Bill Impact	**1.60%**	**3.88%**	**7.88%**	**1.35%**

Figure 2: Bill Impact Summary 2014 to 2017

In addition for the 2015 Yearbook of Electricity Distributors being the latest data available in Tab "Unit QSR", the data shows that Embrun Hydro has an "Average Power and Distribution Revenue less Cost of Power and Related Costs" of $392.74 per customer annually or $0.027 per KWh delivered. This compares to $1081.10 per customer annually or $0.053 per KWh delivered for Hydro One. This comparison to Hydro One is used because that is the utility that totally surrounds the CHEI service territory. In spite of the bill increases, the cost of supporting the CHEI operation is less than half the per customer cost of the Hydro One per customer cost. In addition, compared to other Distribution Utilities, CHEI has among the lowest per customer cost in the province based on the 2015 Yearbook.

With the new developments that have been built and are continuing to be built, the distribution system load has grown beyond its MS and feeder capacity. This is evident from the load and voltage study that was performed in 2016. CHEI has responded by building a 4th feeder to improve system feeder capacity to accommodate the new load and preventing low voltage problems. In addition it is increasing the capacity of its MS by installing a new larger substation which will provide adequate supply capacity for the foreseeable future.

CHEI has a very reliable system. The graphs below show the outage performance of the system based on the standard SAIDI and SAIFI metrics. Figure 3 shows the ratios by year with all the outages included while Figure 4 shows the outages excluding any loss of supply from Hydro One. In this figure, because the scale is so small, it may look like there is a significant spike in outage frequency and an impact in duration, however when viewed in the context of the small scale of the graph this is not the case. The 2016 (a) data point shows the reliability indices if the Scheduled interruptions are removed.

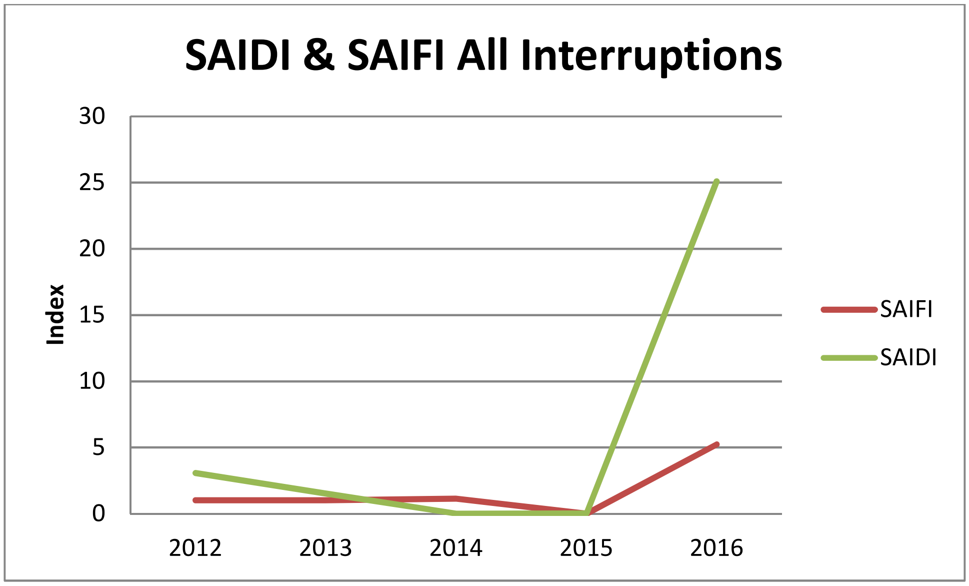


Figure 3: System Reliability 2012 to 2016 for all Interruptions

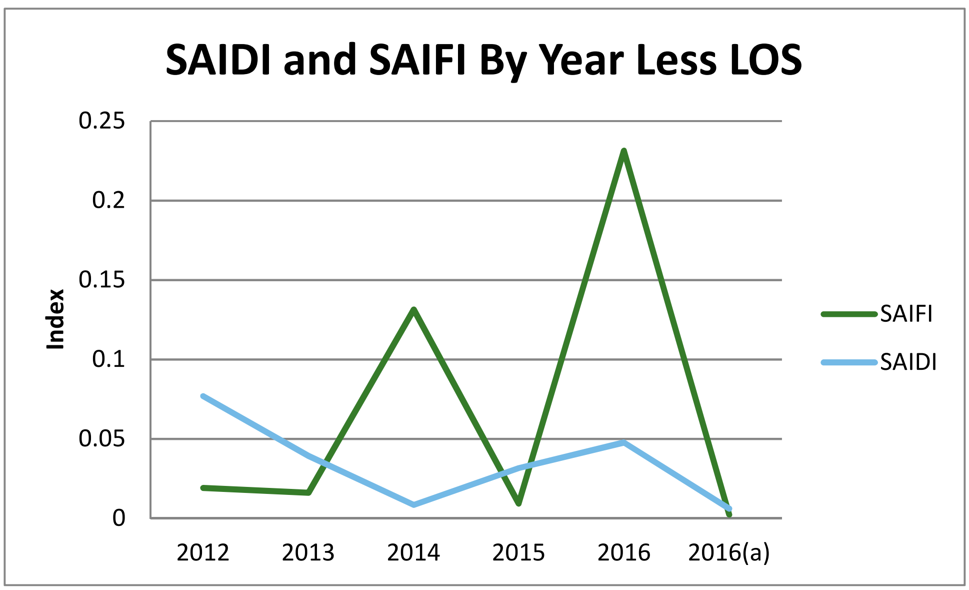


Figure 4: System Reliability 2012 to 2016 excluding Loss of Supply Interruptions

Typically a reliability target is set by taking the average of the past five years for SAIDI and SAIFI. These values are extremely low for Embrun namely 0.081018 for SAIFI and 0.039637 for SAIDI with the loss of supply interruptions removed. This translates into 175 customers interrupted per year and interruption duration of 2.4 minutes per system customer per year.

This information indicates that CHEI does not need to embark on major capital or maintenance programs to address system performance issues at this time. Because of the forecast load growth that is expected to take place CHEI is addressing the MS capacity by installing a new larger Substation in 2017. Mandatory programs included in the future budgets are the Smart Meter replacement (2019) and the removal of all oil filled equipment with PCB concentrations 50 ppm or greater by 2025. In 2019, CHEI is also relocating a rear lot distribution line at a customer's request. The line was built between 1945 and 1950 and no easement was obtained at that time, hence CHEI does not have an easement for the line and needs to fund the cost of the work to provide an alternate supply for the customers involved.

The remaining work forecast is the replacement of end of life poles as identified by testing and the replacement of porcelain fuse cutouts and porcelain air gap arrestors at transformers that present potential safety hazards to the line crews and in the case of air gap arrestors to the public as well. These works will be phased to smooth rate impacts. The switch and lightning arrestor program is an example of CHEI using information based on identified problems in other utilities, it recognizes that the same problems may occur on its system and proactively plans to address them within the constraints of rate impacts. These discretionary investments are modest and are planned to be undertaken to maintain the excellent reliability and safety record of the utility.

3. [5.3] Asset Management Process

3.1. [5.3.1] Asset Management Process Overview

CHEI states the following on its website (English):

> *At Coopérative Hydro Embrun Inc. our vision is to satisfy our clients by providing the highest quality of service.*
>
> *We are committed to providing electricity to our clients with efficiency, security and quality.*

Because the company is a Cooperative, the clients are also the owners / shareholders of the company. This means that if there are issues about the decisions of the company in addition to providing feedback individually as customers, they can be raised at the annual general meeting as company owners or shareholders. This is a rather unique aspect of this LDC when compared to other LDCs and adds awareness and concern for customer / shareholder impacts.

This also translates into increased accountability to deliver on the vision statement which essentially translates to low cost, high reliability electric power.

CHEI delivers this by having a small staff of three and contracting other required functions out such as its Customer Information System (CIS), billing and distribution plant operation, maintenance, and construction.

Over the past five years or so, CHEI has seen new development and the accompanying load growth. This has caused a new feeder from its substation to be required and its station capacity to be increased while its emergency backup from Hydro One is being discontinued. CHEI has addressed these issues by creating a fourth feeder over a four year period of time. This ensures that each feeder can be backed up by another feeder while maintaining voltage to required levels. By doing analysis and making preparations for the needed new station it also saw the possibility to retain the old station for emergency backup in the event of transformer failure solving a redundancy requirement at low cost. CHEI plans to accomplish this by having two transformer stations on the one existing site. CHEI will retain the existing station intact and build a new station adjacent to the existing station. The feeders are designed such that each of the four egress feeders will be able to be supplied from either the new station or the old station. These investments have been staged so that where possible, the investments are phased over time and also constructed just in time to the degree prudently possible.

CHEI also performs maintenance and inspection activities in part to meet the requirements of the Distribution System Code on a three year cycle consistent with the requirements of an urban system but also to ensure its equipment continues to operate in an economical manner and promotes a safe environment for the general public and its workers. Any deficiencies are noted and corrected in a timely manner.

CHEI records comprehensive information about its poles and transformers. Information is entered into a spreadsheet, one sheet for poles and one sheet for transformers. The spreadsheets record the particulars of the asset such as class, height, location and pole number as well as condition information for poles and location number, location, manufacturer, voltage and KVA, date installed and condition information. Condition information is as of the last inspection which is performed every four years. The asset records are used for equipment inspections and the condition is updated after the inspection is carried out. Deficiencies are noted and repairs or replacement is carried out the following year unless the condition will have a high probability of causing an environmental incident or a power outage or be a danger to the public, in which case the work is done as soon as possible. Depending on the capital already required this work may also be deferred where possible. At a minimum it is smoothed and spread in phases so that the impact is mitigated where possible. This is also done within the constraint of maintaining efficiency by creating reasonable quantities of work to be done. Because the system is small often the cost of the work required is less than the materiality threshold.

CHEI historically had sufficient capacity in its substation to supply the entire connected load. It made arrangements for an emergency backup with Hydro One for the service territory in the event of the loss of its one station. With the load growth over the past 10 to 15 years the current station transformer is no longer able to supply the peak load without using its emergency rating. With several years of continued development anticipated the load is expected to grow by over 30% between 2017 and 2023. The load is expected to exceed the emergency rating of the transformer by 2022 for the winter load and 2026 for the summer load. Hence, after several studies and discussions with developers, CHEI is installing a new larger station which is expected to be able to carry the system load for the foreseeable future. In addition, the emergency backup is no longer available from Hydro One and CHEI has been notified that this agreement will be terminated in 2018. In light of this CHEI will be keeping the old station (about 30 years old) as a standby unit to provide power in the event of a failure of the prime (new) transformer. CHEI has investigated various alternatives for supply in the event of a station transformer failure but Hydro One, the only source of power, is unable to provide any assistance to CHEI. In order to provide the feeder capacity and flexibility for emergency situations, CHEI has installed a fourth feeder between 2013 and 2016. This will allow for better voltage performance particularly in emergency or outage situations. This is demonstrated in the study performed by Stantec which is included in Appendix G.

The historical customer reliability data is identified in Figures 3 and 4. As can be seen the reliability performance of the system has been very good. As a result, other than reporting the data to the OEB, there has not been a great need to perform extensive analysis. As a result of this DSP, CHEI will be making changes to its recording of outage information and the analysis it performs so that individual outages can be analyzed by cause code and related to feeder in future.

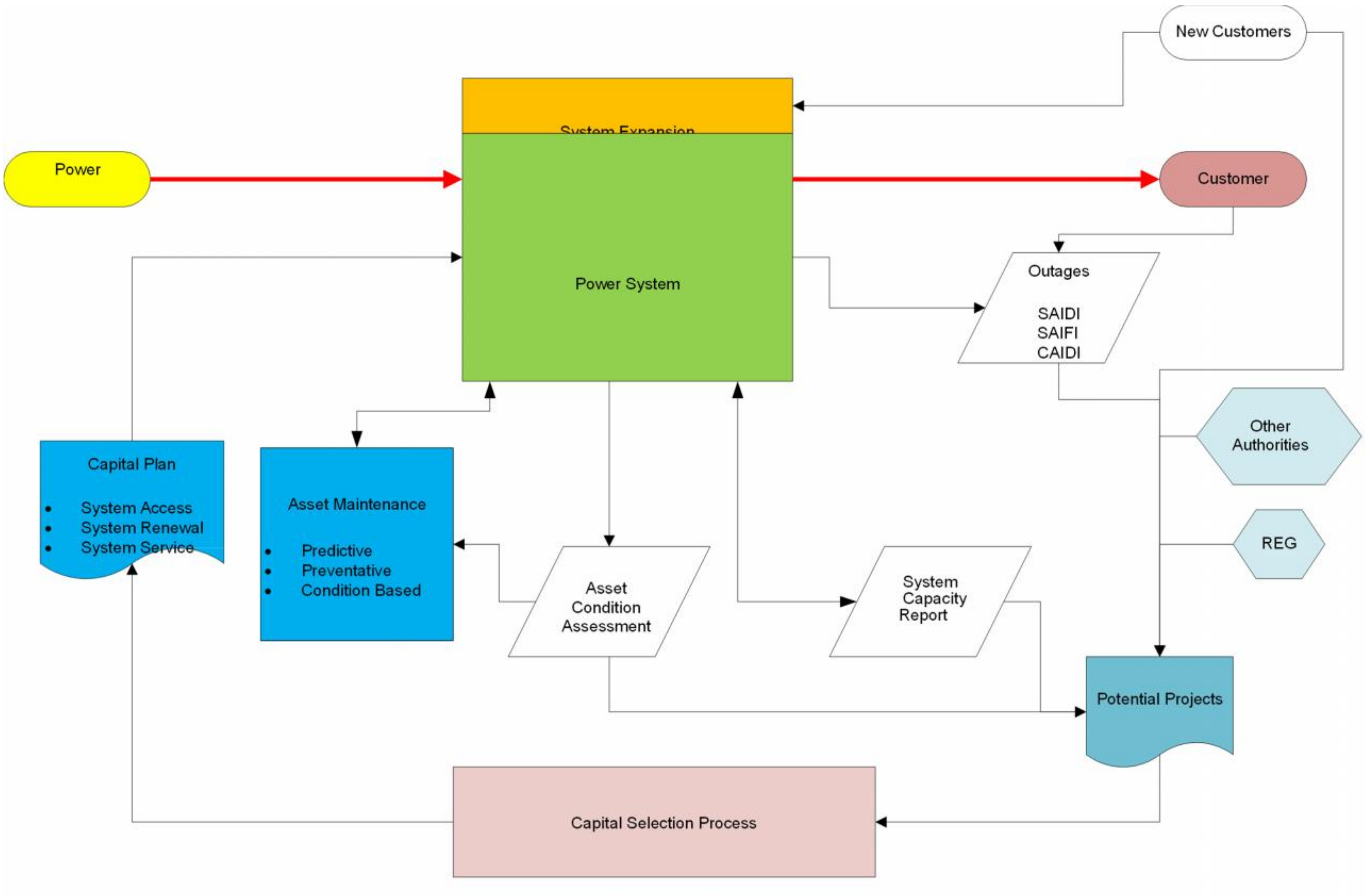
CHEI has used risk and consequence of failure analysis in addressing its substation capacity and station backup issues. The Stantec study in Appendix G requested by CHEI addresses the increasing load on the MS. It also deals with the backup capability that was then available from Hydro One. This was inadequate to supply the entire load in the event of a station transformer failure. Hydro One indicated that it could not provide a Mobile Unit Substation to provide temporary power. Subsequently even the partial backup from Hydro One was no longer available due to the supply station being decommissioned.

CHEI does not have outage data broken down by all outage categories nor by feeder so it is not able to provide the equipment outages nor the worst performing feeder data. It does track Loss of Supply and planned outages. In the future it plans to gather this additional data so it can be reported on. However the outages that remain after the Loss of Supply data is removed and the planned outages are removed in 2016 the remaining outages are inconsequential. From a project justification point of view the past reliability performance is not a driver to undertake capital work.

CHEI has had good reliability performance in part because it has been proactive in addressing issues. While it has not had poor reliability statistics, it has recognized that its underground transformer bushings and inserts would be a problem and it initiated a program to upgrade and replace these components based on the experience of other utilities and recognizing that it was susceptible to the same problems in the future. It then took into account that this work could be spread over several years.

In the same way CHEI is addressing fused cutouts and porcelain air gap lightning arrestors and overhead transformers with broken insulators, oil leaks and excessive rust in the forecast period in order to minimize safety hazards to the public, the environment and to line crews based on the experience of others and doing this on a modest phased multi-year basis. This knowledge is provided by the line contractor who also does work in other utilities and is aware of the experience these utilities have with these line components.

Figure 5 below shows the high level major elements to the development of the asset management plan. The items such as condition assessment, system capacity and reliability are the main system inputs that result in potential projects to address existing problems. Added to these are new customer projects (development), other authorities and REG projects. These potential projects are reviewed and prioritized. In the review, different alternatives are considered and a project scope and details are selected. Where possible, projects are phased over two or more years if the financial impact is larger and there is time available to do this. An example of this is building a fourth feeder in segments over several years. However CHEI also addresses projects that have urgency associated with them such as the transformer replacement program where equipment failure (customer outages) and /or oil leaking into the environment were possible. For the units it became aware of it acted on all the instances in the next budget year.


New Customers
System Expansion
Power
Customer
Power System
Outages
SAIDI
SAIFI
CAIDI
Other Authorities
REG
Capital Plan
• System Access
• System Renewal
• System Service
Asset Maintenance
• Predictive
• Preventative
• Condition Based
Asset Condition Assessment
System Capacity Report
Potential Projects
Capital Selection Process

It is difficult to describe and dissect the decisions that go into the capital program when there are very limited instances of material projects and for the large ones such as the station upgrade or the fourth feeder, the decisions have a very limited set of viable options – you have one MS with one transformer – it has inadequate capacity to carry the load now at normal rating and in future (within the planning horizon) even at emergency rating – therefore an increase is needed to the supply capacity. The decision to build a new station and leave the old station in place allows more analysis.

The old station was about 50% depreciated so it had a remaining financial as well as operating life. While it was not adequate to supply the total load at peak times, its emergency rating would allow more of the load to be carried than the Hydro One backup arrangement that is being discontinued, provided for. So it was helpful from a system security and backup perspective to be available. In addition, removing the existing old station would incur additional cost. Hence the decision was to retain the old station and incorporate it into a complete solution by adding four switching cubicles to allow each egress feeder to be supplied from the old or the new station. This was a good use of existing assets, a cost effective way to solve multiple requirements and a sound system solution for the present and the future supply.

3.2. [5.3.2] Overview of Assets Managed

CHEI supplies the former town of Embrun. It has a service territory of about five square kilometers. The service territory is entirely urban being overhead in the older areas and underground in the new development areas.

The weather is characterized by cold winters with snow and cold temperatures. Embrun has a semi-continental climate, with a warm, humid summer and a very cold winter.

Winters in Embrun are severe. Snow depths of greater than 1 cm are experienced about 120 days each year and freezing rain is not uncommon in the winter. Minimum average temperatures in January are about -15 degrees Celsius and in summer the maximum average temperature is about 26 degrees Celsius.

In the past, since 2001, there has been new development in the Embrun area. It is expected that by 2021 the population will be twice what it was in 2006 per the website http://www.embrun.ca/20th_century_recovery.html.

CHEI has taken this information into account together with the real development taking place to plan and forecast its requirements.

From the Stantec report in Appendix G the load growth from 2017 to 2023 is expected to be over 30%.

CHEI has one municipal station. The existing station is 7.5/10MVA 44kV-8.32kV and has four feeders emanating from the station. The transformer was built in 1988 so is 29 years old. It is supplied at 44kV from a Hydro One feeder.

The CHEI service area is embedded in Hydro One's service territory.

The distribution system consists of about 15 km of overhead lines and about 12 km of underground lines.

In 2017, the station transformer is being increased to 10/13.3MVA 44KV- 8.32KV to accommodate the load growth resulting from new development.

CHEI has 125 single phase pole mounted overhead transformers. The age distribution is shown in Figure 6 below. The age for all the transformers identified below is calculated by grouping the transformers by the decade they were installed and then calculation the age by taking the current year 2017 and subtracting the midyear of the decade installed. For example for the decade of 2000 to 2009 the midyear is 2005. 2017 less 2005 is 12 so the group is graphed as 12 years old.

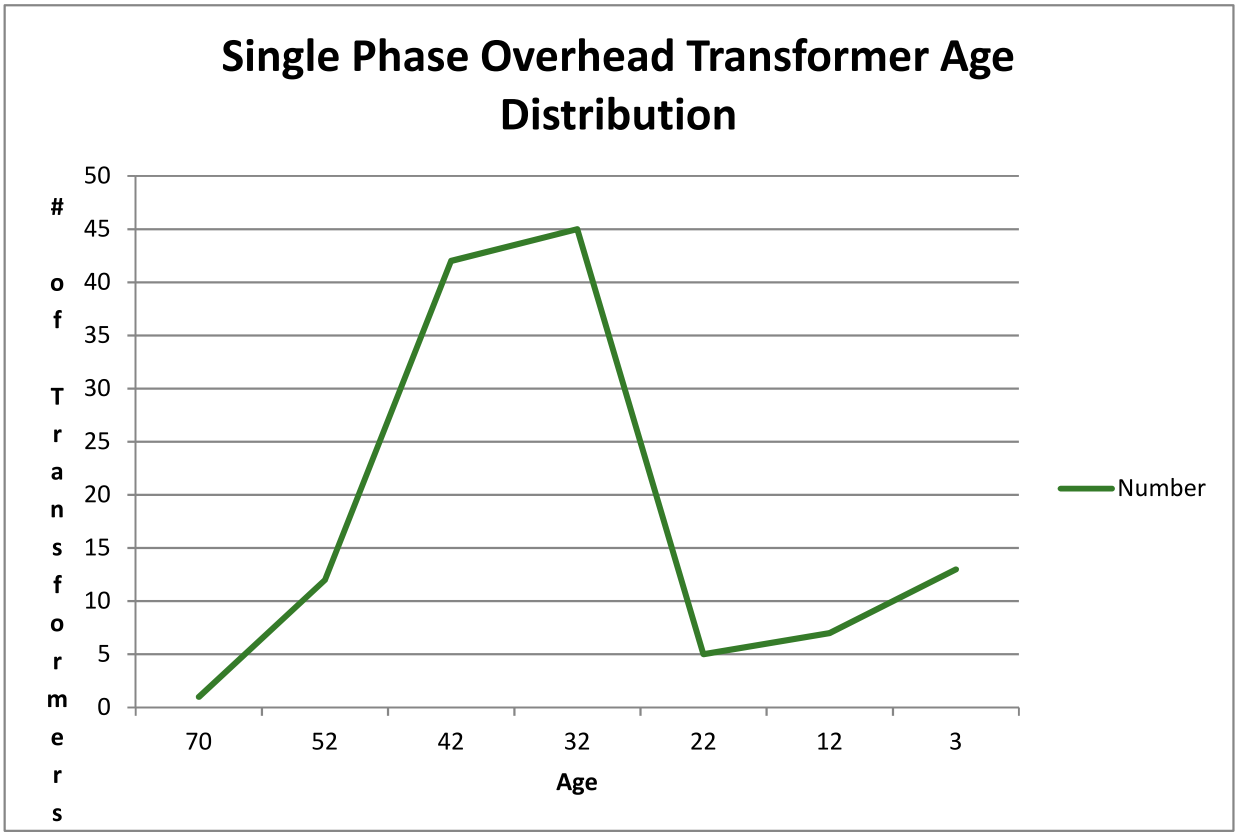


Figure 6: Single Phase Overhead Transformer Age Distribution

CHEI has 17 overhead three phase banks. The age distribution is shown in Figure 7 below.

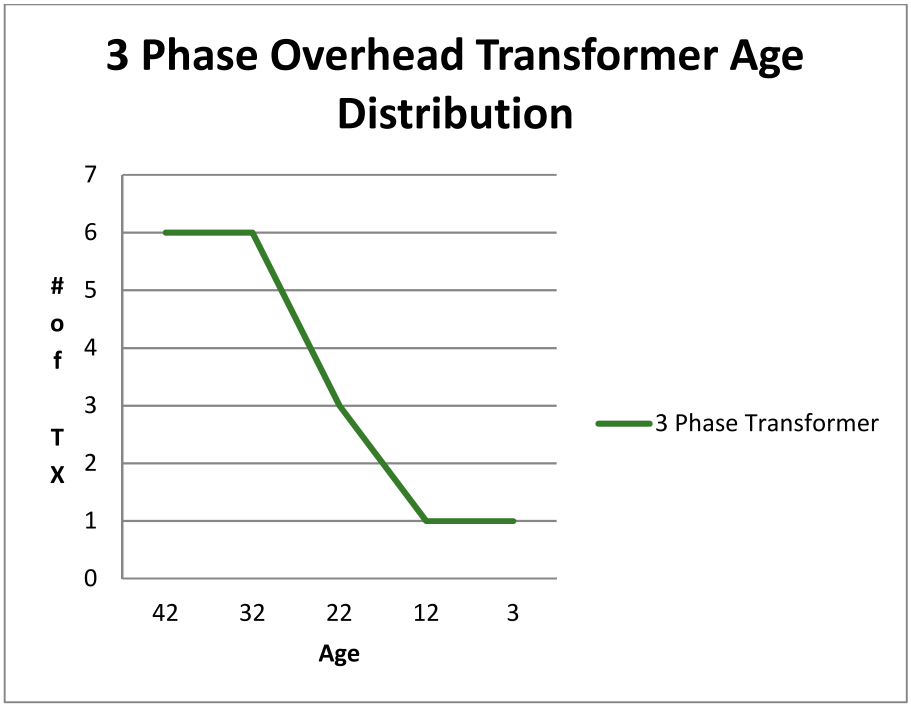


Figure 7: Three Phase Overhead Transformer Age Distribution

CHEI has 133 underground padmounted transformers. The age distribution is shown in Figure 8 below.

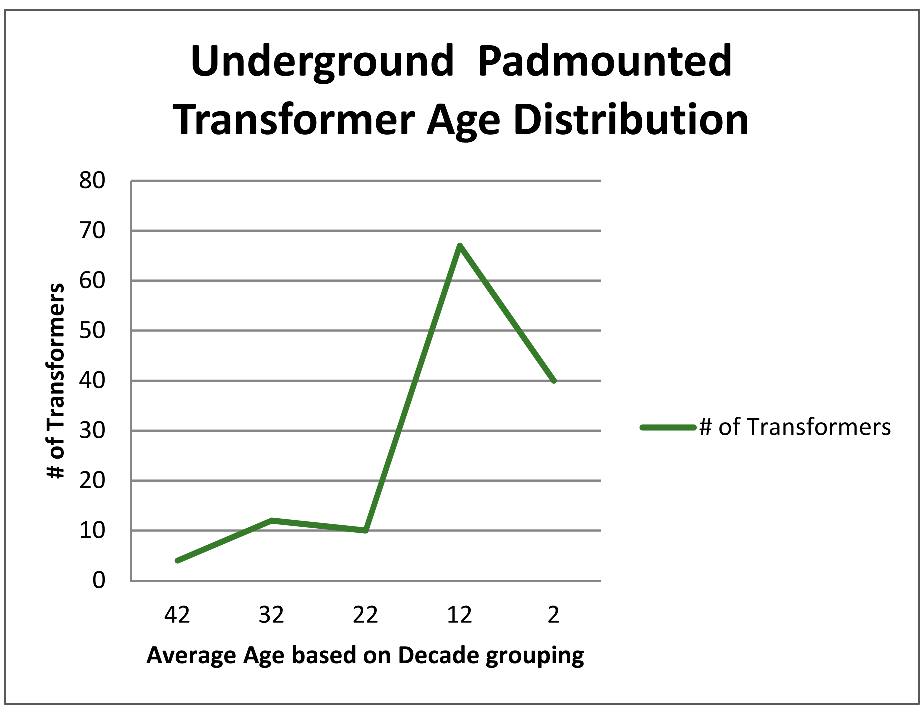


Figure 8: Underground Padmounted Transformer Age Distribution

CHEI has 432 wood poles of various heights and classes. It does not capture the date installed, at this time, so no age distribution can be provided. Pole age for existing poles would be difficult to impossible to determine since no date nails exist in the poles and many of the poles, particularly the older ones, have no readable date information on them. CHEI addresses this by having frequent inspections to ensure the integrity of the pole structures. In addition they have purchased pole testing equipment together with Hawkesbury Hydro to be able to perform more scientific testing.

The current and future pole testing method results in the identification of poles that are at end of life and need to be replaced. These poles are included in the capital plan.

CHEI has taken the development that has taken place and is projected to take place in the area in the near future into account. The existing system was inadequate to provide the load into the future and the voltage at the customer's premises was forecast to inadequate. In response to this CHEI has increased the station transformer capacity in 2017 by installing a new substation with 33% more capacity by installing a 10 MVA unit (ONAN). Both the old station and the new station transformers have fans installed to provide an emergency rating (ONAF). This new station is expected to be adequate to supply the existing and forecast new load into the foreseeable future. An additional 4th feeder was also installed and is now in place, to provide for better voltage regulation and load transfer options particularly in outage situations while suppling new subdivision load.

Because of the lack of backup power from Hydro One and the non-availability of Mobile Unit Substations from Hydro One, CHEI has opted to retain the existing station as a backup should the new station develop a fault and be forced out of service. The old station would allow full load to be supplied on most days with load curtailment happening only on the peak load days when the load exceeds the emergency rating of the old transformer. In this way redundancy is provided, while the failed unit is repaired, at the most reasonable cost available to CHEI.

3.3. [5.3.3] Asset Lifecycle Optimization Policies and Practices

CHEI is a small utility that does not have policies on lifecycle optimization at this time. Its practices meet the statutory requirements of the Distribution System Code. To this end, the three year inspection of plant requirement is met. The inspection, performed by the contractor performing outside plant work, notes any deficiencies and these are addressed by the contractor either at the time of inspection if it is a "five minute job" or it is noted and a quote is provided if it is a larger job. Some aspects like overhead line patrols are carried out by CHEI staff and are performed more frequently than once every three years as required by the DSC because the patrols also identify the tree trimming that is required. Tree trimming is carried out on an annual basis and the need is determined by the line survey.

All system switching, power restoration, after hours trouble calls and responses, pole testing and replacement and line construction as well as utility locates are performed by the contractor.

Pole testing is carried out on a four year cycle. However, CHEI has purchased a sonic pole tester together with Hawkesbury Hydro. This equipment is expected to provide better insight into the condition of the tested pole. Based on the results obtained, the testing cycle may be extended in future. Based on the pole test results the deficient poles are replaced before the next testing cycle but taking into account the other capital work being required and the rate impacts. Note however that this discussion is in the context that the actual System Renewal category expenditures between 2013 and 2016 were all below the materiality threshold which means that the pole replacement is not a large project.

Poles are tested to determine "end of life" and no other procedures are applied.

The major risk that CHEI faced was the ability of its system to supply the new development load for developments built in the past five or more years and expected to continue for several years into the future. CHEI engaged Consultants who identified the new loads and modeled the power system to perform a load flow study. This study identified that a larger MS transformer was required and also that an additional feeder was required to be able to supply the load and maintain voltage within required limits. CHEI built a fourth feeder over three years to minimize customer rate impact and is upgrading the MS in 2017. This addressed the risk of supplying prime load into the foreseeable future. With only a single MS to supply the load, CHEI had entered into an agreement with Hydro One in 2006 for backup power from two Hydro One feeders. However, this backup power will no longer be available after October 2018 as Hydro One is decommissioning the DS that the supply was emanating from. In addition Hydro One does not have any Mobile Unit Substations available in the event of an MS transformer failure. CHEI has decided to retain its old station so that it has the capability of supplying its load and would only curtail the load on the days when the load exceeded the 10 MVA emergency rating of the old MS transformer. This provides a low cost redundancy solution.

CHEI takes its pole and transformer assets and uses a run to failure approach. Poles are tested to see if they are adequate as support structures for wire, switches and transformers. If they are not as determined by testing then they are replaced, immediately if they are deemed to be in danger of failing imminently or on a scheduled basis within a budgetary context. Transformers are checked visually for evidence of abnormal heating at the primary and secondary connections. Typically this is a connection problem that is corrected without removing the transformer. Transformers can have damaged bushings or oil leaks. These conditions would be cause to replace the transformer. Some transformers have evidence of corrosion. If this is just surface rust, the surface is cleaned, repainted, and left in service. Where the rust is severe and has weakened the tank wall the transformer is replaced.

Switches are maintained by cleaning and lubrication on a cyclical basis. Where the switch is damaged it is replaced as required.

The MS transformer is maintained on a cyclical basis and standard oil testing is done annually. Similarly station feeder switches and protection is maintained.

CHEI also uses the experience of its line contractor including considering the experience of other utilities. An example is the replacing the porcelain fused cutouts with polymer fused cutouts and replacing porcelain air gap type lightning arrestors with polymer, solid dielectric arrestors. These projects are being planned proactively because of the problems with this equipment in various utilities even if it has not caused outages or health risks at CHEI. CHEI believes that if they do nothing these devices will cause problems in future. By being proactive the excellent reliability record as well as health and safety record can be maintained.

4. [5.4] Capital Expenditure Plan

4.1. [5.4.1] Summary

CHEI has been able to connect all new load to its system. However, new load connection has been occurring since at least 2006 and the existing system needs to have the supply capacity increased. The bottleneck was the single MS transformer, i.e. in the one MS that CHEI owns and operates. A system load and voltage study conducted in 2016 verified that the existing transformer was insufficient to carry the load into the future even at the emergency rating of the transformer. Therefore CHEI initiated a plan to replace the existing transformer with a larger unit (one size larger) that would be adequate to supply the existing and forecasted load. The forecasted new subdivision load can now be safely connected to the system.

The annual capital expenditure over the forecast period are described in Appendix B. Project descriptions are also included there. A summary of proposed expenditures by category is presented below in Table 3.

	2018	2019	2020	2021	2022
CATEGORY	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
System Access	34,500	135,000	53,000	53,000	78,000
System Renewal	115,780	20,000	60,000	62,000	40,000
System Service	0	0	0	0	0
General Plant	5,700	5,700	5,700	5,700	5,700
Total	155,980	160,700	118,700	120,700	123,700

Table 3: Forecast Expenditure by Category

The System Access projects specifically new subdivisions are customer driven and thus need to be addressed. They are usually deadline oriented and there is flexibility as long as the due date targets are accomplished. The new substation project was driven by the loading requirements. These were also customer driven but the issue was to have the required capacity when it was needed. So part of the timing was determined by the utility.

For the other categories the spending is mostly on System Renewal. System Renewal spending is largely driven by inspection that identifies plant that needs to be replaced.

The System Service and General Plant expenditure or either zero or far below the materiality threshold and are generally for replacements.

The total capital projects including cost and description are included in Appendix B for the forecast period and in Appendix A for the historical period. In each Appendix the projects are sorted by Category.

CHEI did not participate in the Regional Planning Process since it is embedded in the Hydro One system. There are no projects that CHEI needed to undertake as part of the planning process.

CHEI engaged in a Customer Survey in 2016. This is included in Section 1.8.2 of Exhibit 1. Because CHEI is a cooperative it has an annual meeting with all the customers who are members of the cooperative. This also provides for customer engagement and sensitivity to the customers (owners) preferences.

CHEI does not plan to undertake any development on smart grid projects and has no expected REG projects. Load growth and customer growth will continue until at least 2023 based on current information by way of new subdivisions. No other technology or engagement activities are planned at this time.

4.2. [5.4.2] Capital Expenditure Planning Process Overview

Hydro Embrun engages in consultations with relevant third parties.

Hydro Embrun coordinates with the capital programs undertaken by the Village of Embrun.

Hydro Embrun coordinates with the IESO and Hydro One.

For Regional Planning purposes, Hydro Embrun is part of the St. Lawrence Region. A regional study was completed in April 2016. This consisted of a Needs Assessment and a Regional Infrastructure plan. The remaining components were not required. The result was that Hydro Embrun had no work to complete as a result of this study. Hydro Embrun did not participate in the study since they are embedded in the Hydro One system. Hydro One was aware of the Hydro Embrun load forecast and included this information as they participated in the Regional Planning study.

CHEI's objectives are to have or to build the facilities it needs to supply power to its customers economically and reliably. As a result of these objectives, it has in past, built a new feeder and added a new station to its existing MS to accommodate existing customers as well as new customers that were the result of new developments within its service territory. With these investments completed there are three material projects in the forecast period. None of these projects relate to connection of REG. One material project in 2018 with an expected cost of $54,280 is the result of CHEI's inspection program. These transformers had damaged bushings and/or could be leaking oil. Hence they need to be removed from service. Because of the potential for environmental impact and more cost if more damage was caused by a flashover externally or internally. The removal from service will be completed in one year which caused the project to become a material project.

One material project in 2021 is the replacement of porcelain cutouts and porcelain air gap lightning arrestors with polymer insulators and solid valve block lightning arrestors. These devices are known to have defects and fail in service creating safety hazards for line crews working on or in the vicinity of both devices as well as safety hazards for the general public if they are in the vicinity of an air gap lightning arrestors that fails catastrophically. CHEI is replacing these devices over a two year period. The first year, 2020, they are also replacing porcelain line post insulators which have a larger reliability impact if they fail. The switches and lightning arrestors that are replaced in

2020 are in the areas where the general public would have a higher probability of being impacted.

The other material project scheduled to be completed in 2019 is customer driven. A customer who has an overhead line on his property wants the line to be removed because he is developing the lot. This line provides a rear lot supply to several other customers. The line was constructed between 1945 and 1950 and was installed without an easement. Hence CHEI must comply with the request and re-establish supply to the customers affected by the removal of this line. Even with an easement CHEI would have complied with the customer request but it would have had more options on how to achieve this. CHEI engaged in customer consultations and the solution being implemented meets with all the customers' wishes.

CHEI is a very small utility and as such has negligible impact on Regional Processes. CHEI has a few micro-FIT installations and is prepared to connect more if applications are brought forward.

CHEI uses customer survey information data as well as its Corporate Annual Meeting to obtain information from its customers. In addition since its Board is elected at the annual meeting on a rotational basis the Board members are also highly motivated to make sure the membership is well served by the utilities actions. As previously noted, the Customer Survey can be found in Section 1.8.2 of Exhibit 1.

There are currently no REG applications so no investments are required. The few REG connections that exist were single home micro-Fit installations and no system development was required to accommodate them.

4.3. [5.4.3] System Capability Assessment for Renewable Energy Generation

CHEI has some existing REG connected to its system. These are exclusively solar installations and are all micro-fit installations. Table 4 below indicates the number of connections and the capacity installed by year since 2010. There are no applications outstanding at this time and there is one request for an application form that could possibly become a micro-fit installation. If this becomes a project it is expected to be completed in 2017 or 2018.

There is not expected to be any larger REG project at this time which would require the investigation of constraints or that would affect the upstream supply.

Connected REG Loads							
YEAR	**# of CONNECTIONS**	**TYPE**	**SOLAR ARRAY RATING IN kW**	**FEEDER**	**VOLTAGE**	**CONSTRAINTS**	**IMPACT**
2010	1	Solar Photovoltaic (Roof Top)	5	F 3	Secondary 120/240 Primary 4800	No	No
2011	2	Solar Photovoltaic (Roof Top)	18	F 1 (both)	Secondary 120/240 Primary 4800	No	No

Connected REG Loads							
YEAR	# of CONNECTIONS	TYPE	SOLAR ARRAY RATING IN kW	FEEDER	VOLTAGE	CONSTRAINTS	IMPACT
2012	2	Solar Photovoltaic (Roof Top)	20	1 on F 3 1 on F 1	Secondary 120/240 Primary 4800	No	No
2013	3	Solar Photovoltaic (Roof Top)	30	2 on F 3 1 on F 2	Secondary 120/240 Primary 4800	No	No
2014	2	Solar Photovoltaic (Roof Top)	20	F 3(both)	Secondary 120/240 Primary 4800	No	No
2015	0	n/a	n/a	n/a	n/a	n/a	n/a
2016	1	Solar Photovoltaic (Roof Top)	10	F 3	Secondary 120/240 Primary 4800	No	No
Total	11		103				

Table 4: Connected REG Loads

In summary, CHEI has a total of 11 micro-Fit installations for a total of 0.103 MW. There are no outstanding applications at this time but there has been a verbal inquiry about one possible new micro-Fit project. Hence there is no requirement for capital projects related to REG.

4.4. [5.4.4] Capital Expenditure Summary

In general, CHEI has modest capital requirements over the ten year plan window. However, in light of the economic environment, there are two notable exceptions and these are both System Access projects. There is significant development taking place as has been indicated elsewhere and this has caused a significant increase in new plant in subdivisions. Also there has been a need to build new feeder and a new station to supply the load. This subdivision expansion is expected to continue until 2023. The station and feeder expansion are expected to be adequate for the foreseeable future with no additional investment required based on current information.

CHEI has relatively modest System Renewal requirements. In seven out of the ten years covered by the DSP, in the historical and forecast period the total category spending is below the materiality threshold. Similarly for System Service there are only two years out of the ten years covered by the DSP that there is any actual or forecast spending. In one of those years the spending is for line switches to provide switching flexibility as a result of the new station transformer being installed and the fourth feeder being fully operational.

This can be seen from Table 5 below and the project descriptions in Appendix B and C.

The General Plant category is below the materiality threshold for the entire ten year review period. The expenditures are primarily for replacement of office equipment and computers as well as software upgrades and licensing of software for billing systems and the like as well as PC’s.

	Historical (previous actual)					Forecast (planned)				
	Test-5	Test-4	Test-3	Test-2	Test-1	Test	Test+1	Test+2	Test+3	Test+4
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CATEGORY	Actual	Actual	Actual	Actual	Projected Y/E	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$	$	$	$	$	$
System Access	233,350	1,150,190	337,996	399,233	1,726,096	34,500	135,000	53,000	53,000	78,000
System Renewal	41,050	33,150	19,609	44,096	20,000	115,780	20,000	60,000	62,000	40,000
System Service	0	0	0	9,264	85,900	0	0	0	0	0
General Plant	29,500	41,568	3,653	12,503	7,000	5,700	5,700	5,700	5,700	5,700
Total	303,900	1,224,908	361,259	465,096	1,838,996	155,980	160,700	118,700	120,700	123,700
Contributed Capital	8,000	905,202	148,144	6,451	132,000	5,775	16,700	0	0	0
Net Capital	295,900	319,706	213,115	458,645	1,706,996	150,205	144,000	118,700	120,700	123,700
System O&M	56,969	73,506	66,015	80,432	86,475	93,984	96,334	98,742	101,201	103,741

Table 5: Capital Expenditure Summary

4.5. [5.4.5] Justifying Capital Expenditures

4.5.1. [5.4.5.1] Overall Plan

As can be seen from Table 5 above the largest category spending has been for System Access. This is due to the new development taking place in Embrun. This is expected to continue to 2023 based on current information. In 2014 more than one million dollars of electrical plant was installed in one year. As can be seen there has been steady expenditure in this category. In 2017, an additional approximately 1.5 million dollars is required to build a new transformer station. The old station did not have the capacity to supply the existing and the new load. These two investments are obviously related and are the largest investment in the historical and forecast periods.

The new subdivision plant will marginally increase O&M costs for items such as plant locates and inspections. The new station will increase the O&M costs but not significantly. The normal visual inspections will continue as before just on a both units and because they are at the same location there is negligible impact for this on the O&M costs. There will be added costs for annual oil sample gathering and testing but this is a very minor cost. Similarly, the new reclosers will need marginal maintenance and recalibration due to their rugged design. None of these costs are expected to materially increase the O&M costs.

There are no REG projects contemplated as there is no need.

4.5.2. [5.4.5.2] Material Investments

There are three material projects in the forecast period 2018 to 2022. These are:

2018 – Transformer replacement - $54,280
2019 – Line relocation St. Jacques Rd - $90,000
2021 – Cutout and Arrestor replacement - $62,000

For completeness the 2017 new transformer station cost of $1,517,396 will also be addressed.

These projects have individual justifications prepared and are included in Appendices as follows:

Appendix C - MS transformer upgrade - $1,517,396
Appendix D - Transformer replacement - $54,280
Appendix E - Line relocation St. Jacques Rd - $90,000
Appendix F - Cutout and Arrestor replacement - $62,000

APPENDIX A

HISTORICAL CAPITAL PROJECTS 2013 TO 2017

CAPITAL ACTUAL EXPENDITURE 2013

Category	Description	Actual	Project Subtotal	Category Total
	Amounts are in Dollars			
System Access	New Overhead and Underground Services - 1855	$5,000		
	Subtotal		$5,000	
	Station upgrade			
	-Grounding Study Substation- 1820	$10,000		
	-Add New Switching Cabinet - 1820	$52,400		
	Subtotal		$62,400	
	4th Feeder			
	-Ste-Therese Blvd 4th Feeder -1830	$54,800		
	-Ste-Therese Blvd 4th Feeder 1835	$58,750		
	-U/G Cable Substation to Ste-Therese Blvd 1845	$52,400		
	Subtotal		$165,950	
	Category Total			$233,350
System Renewal	Pole Replacement-1830	$29,050		
	Transformers Replacement - 1850	$12,000		
	Category Total			$41,050
System Service	No Project			
	Category Total			$0
General Plant				
	Cell phone -1915	$1,500		
	Computer Equipment Hardware Battery Backup - 1920	$1,500		
	MOE Standard Bill Print 1611	$25,000		
	Antivirus Protection 1611	$1,500		
	Category Total			$29,500
	Total Capital			$303,900
	1995- Contributed Capital			-$8,000
	Net Capital			$295,900

2013 Project Descriptions

System Access

New Overhead and Underground Services $5,000

Cost of customer requested new services

Station Upgrade $62,400

Because of the new development taking place and the loading on the existing substation it became clear that an increase in capacity of the substation would be a requirement in the near future. This project is being executed in three phases.

To prepare for the first phase of the work, a grounding study first had to be performed to assess station grounding and determine whether an upgrade to the grounding was required. It was also determined that an additional feeder from the substation would be required in order to maintain voltage within required limits while ultimately supplying 800 customers in new developments. This work was for the grounding study as well as providing a fourth feeder position at the station.

4th Feeder $165,950

This project provides the underground egress from the station to a terminal pole on Ste-Therese Blvd. In addition, it builds the first part of the fourth feeder required for the new development. Hydro Embrun is completing this new feeder in three phases over a four year period of time in order to smooth the impact on rates and still provide power when needed.

System Renewal

Pole Replacements and Transformer Replacements: $41,050

This project replaced deteriorated poles and transformers that posed environmental threats due to leaks or significant corrosion. This project is below the materiality threshold.

System Service

There are no projects within this category.

General Plant

All projects $29,500

The major project in this category is the cost for implementing the Ministry of Energy standard bill print. The total expenditure for this category is below the materiality threshold.

CAPITAL ACTUAL EXPENDITURE 2014

Category	Description	Actual	Project Subtotal	Category Total
	Amounts are in Dollars			
System Access				
	New O/H and U/G services -1855	$12,464		
	New Meters 1860	$25,716		
	Subtotal		$38,180	
	Subdivision Faubourg Ste-Marie -1845	$692,811		
	Subdivision Faubourg Ste-Marie -1850	$288,934		
	Subdivision Faubourg Ste-Marie Relocate pole 1835	$20,182		
	Subtotal		$1,001,927	
	Pumping Station Ste-Marie -1830	$10,425		
	Pumping Station Ste-Marie -1835	$10,425		
	Subtotal		$20,850	
	Oligo Project East Entrance 1835	$6,577		
	Oligo Project West Entrance -1835	$5,298		
	Subtotal		$11,875	
	Line Relocated 950 Notre-Dame 1835	$10,000		
	Subtotal			
	4th Feeder Cloutier Drive - 1830	$43,996		
	4th Feeder Cloutier Drive - 1835	$23,362		
	Subtotal		$67,358	
	Category Total			$1,150,190
System Service	No Project			
	Category Total			$0
System Renewal				
	Pole Replacement 65 Forget Street -1830	$5,400		
	Pole Replacement 1287 St-Jacques Street -1830	$9,850		
	Pole Replacement 1179 Notre-Dame Street -1830	$5,500		
	Pole Replacement 1216 Ste Marie Street - 1830	$3,800		
	Pole Replacement 1154 Notre-Dame Street -1830	$8,600		
	Category Total			$33,150

Category	Description	Actual	Project Subtotal	Category Total
General Plant				
	Time Clock Employee - 1915	$633		
	Note Pad Computer - 1920	$430		
	Harris Version 6.4 -1611	$20,885		
	Webpresentment - 1611	$16,549		
	Anti-Spam Consentment -1611	$1,420		
	Software Upgrade Computer Office 1611	$1,651		
	Category Total			$41,568
	Total Capital			$1,224,909
	Contributed Capital 1995			-$905,202
	Net capital			$319,706

2014 Project Descriptions

System Access

New Services	$12,464

These expenditures are required to provide overhead and underground services requested by customers. Due to new subdivisions within service territory this number is higher than the historical previous years.

Subdivision Faubourg Ste-Marie	$1,001,927

This project is for to service 381 units within a new subdivision through primary and secondary underground conductor and padmounted transformers.

Pumping Station Ste-Marie	$10,425

This is the service to a new pumping station for the new subdivision.

Subdivision Oligo Project	$11,875

This project provides two terminal poles, one at the east entrance and one at the west entrance to the subdivision, to supply 200 customers within a subdivision. In accordance with Hydro Embrun standards, internal subdivision electrical plant is installed by the utility.

Pole Relocation for new Driveway	$10,000

A pole required relocation to accommodate a proposed driveway for redevelopment of 950 Notre Dame.

4th Feeder Cloutier Drive	$67,358

This is the second of three phases to provide additional feeder capacity for the supply of new developments being built.

System Renewal

Pole Replacement	$33,150

This project is required to replace five poles that failed upon inspection. This project and total category spending are below the materiality threshold.

System Service

There are no projects within this category.

General Plant

Category total	$41,568

The major expenditures within this category are for an upgrade to the Customer Information System and for a website enhancement to promote energy efficiency. These two projects account for $37,434 of the total category spending that is below the materiality threshold.

Capital Actual Expenditure 2015

Category	Description	Actual	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services - 1855	$15,074		
	Subtotal		$15,074	
	New Meters - 1860	$9,244		
	Subtotal		$9,244	
	Oligo - Promenade Quatres Saison Project - 1850	$110,238		
	Oligo - Promenade Quatres Saison Project(Professional Fees) -1845	$1,864		
	Oligo - Promenade Quatres Saison Project(Engineer) -1845	$5,898		
	Oligo - Promenade Quatres Saison Project(Bollards) -1845	$30,774		
	Oligo - Promenade Quatres Saison Project(Distribution System) -1845	$35,000		
	Oligo - Promenade Quatres Saison Project(Distribution System) -1845	$54,875		
	Oligo - Promenade Quatres Saison Project(Distribution System)-1845	$ 694		
	Oligo - Promenade Quatres Saison Project(Distribution System) -1845	$525		
	Subtotal		$239,868	
	4TH Feeder Switching Cabinet at Substation Work in Progress Engineer Cost-1820 Switching Cabinet Actual Substation to Connect Load of Ste-Marie Faubourg Subdivision	$73,810		
	Subtotal		$73,810	
	Category Total			$337,996
System Renewal				
	Transformers Program (Elbow and Inserts) 1850	$1,879		
	Transformers Program (Elbow and Inserts) 1850	$12,583		
	Subtotal		$14,462	
	Installation culverts 1820	$1,600		

Category	Description	Actual	Project Subtotal	Category Total
	Subtotal		$1,600	
	Pole Replacement 20 Bourrassa Street(Rotten Pole)-1830	$2,662		
	Replace Conductor Device 1835	$885		
	Subtotal		$3,547	
	Category Total			$19,609
System Service	none			
	Category Total			$0
General Plant				
	New Cell Phone	$571		
	New Camera	$391		
	New Computer Station	$1,385		
	Antivirus Software	$466		
	ORPC- Membership Module	$840		
	Category Total			$3,653
	Total Capital			$361,259
	1995- Contribute Capital			$(148,144)
	Net Capital			$213,115

2015 Project Descriptions

System Access

New O/H and U/G services $15,074

These projects are to provide overhead and underground services requested by customers. This number is higher than the historical previous years due to new subdivision development.

New Meters $9,244

This is the cost of new meters requested and includes metering for a 31 unit building.

Development Promenade Quatre Saisons $239,868

This project captures the cost of subdivision design, materials and installation for 125 units within a residential development.

4TH Feeder Switching Cabinet at Substation $73,810

This project captures the (Work in progress) Engineering Cost to prepare all drawings for the fourth Feeder at the substation. The project started in 2010 in conjunction with the design of subdivision Faubourg Ste-Marie and was placed in service in 2015.

System Renewal

The total of the projects in this category is $19,609 and is below the materiality threshold. The major cost contributor to this category is the Mini Pad Transformer, Elbow and Insert replacement program, at a cost of $14,462.

Load break elbows and inserts have a limited life expectancy. After repeated normal operations the ablative material on the elbow is worn away and it no longer has rated interrupting capability. Additionally, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to operate. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert through the replacement program.

System Service

There are no projects within this category.

General Plant

Total expenditures for General Plant are $3,653 and below the materiality threshold.

CAPITAL ACTUAL EXPENDITURE 2016

Category	Description	Actual	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services - 1855	$22,175		
	New Meter 1860	$508		
	New Meters - 1860	$5,492		
	New Measurement Units -1860	$1,321		
	Subtotal		$29,496	
	Facilities to New Bell pole - 1835	$2,231		
	Relocate Span Guy , Down Guy and Overhead Triplex - 1835	$2,342		
	Oligo - Promenade Grounding all Metal objects -1845	$1,906		
	Engineer Devcor - 1845	$1,069		
	Consultation ST-Jacques St. (Relocate Line) - 1835	$1,907		
	Relocate 2 U/G service - 1845	$12,877		
	Subtotal		$22,332	
	Engineer Cost New Substation - 1820	$50,013		
	Load Flow Study -1835	$12,917		
	Load Flow Study - 1845	$12,917		
	Overhead Amps Verification - 1850	$2,723		
	Transformer Data Collection - 1850	$2,112		
	Subtotal		$80,682	
	4th Feeder Notre-Dame -1830	$28,000		
	4th Feeder Notre-Dame - 1835	$90,850		
	4th Feeder Ste-Marie 1830	$28,750		
	4th Feeder Ste-Marie -1835	$100,000		
	Pole Information 1830	$3,900		
	Nameplate Pole Number -1830	$1,125		
	Pole Information - 1830	$7,524		
	Subtotal		$260,149	

Category	Description	Actual	Project Subtotal	Category Total
	Installed Composite Crossarm 1835	$3,119		
	Transformer Pharmacie JC -1850	$2,895		
	Gateway Communication - 1860	$559		
	Subtotal		$6,573	
	Category Total			$399,233
System Renewal				
	Straighten 2 dip poles and installed culvert - 1835	$12,207		
	Transformers Program (Elbow and Inserts)- 1850	$21,844		
	Future Addition Transformers and Replacement -1850	$10,045		
	Category Total			$44,096
System Service				
	Communication Modem - 1860	$643		
	Phase Balancing -1835	$1,425		
	Pole Replacement Entrance Elementry School -1830	$4,800		
	In-Line Switches Remove -Blais Notre-Dame and Centenaire 1835	$2,396		
	Category Total			$9,264
General Plant				
	Office Accessories- 1915	$1,000		
	Computert Equipment Hardware New Printer-1920	$1,840		
	Computer Screen -1920	$320		
	Drill -Pole Inspection - 1945 (tools)	$7,415		
	Ergotron Standing Desk 1915	$563		
	Upgrade CIS-1611	$840		
	Upgrade CIS -1611	$525		
	Category Total			$12,503

Category	Description	Actual	Project Subtotal	Category Total
	Total Capital			$465,096
	Contributed Capital			($6,451)
	Net Capital			$458,645

2016 PROJECT DESCRIPTIONS

System Access

New Services and Metering $29,496

This project is for the provision of overhead and underground services and energy meters as requested by customers. Total expenditures within this project were below the materiality threshold.

Relocations and Transfers $22,332

Expenditures in this project are for plant relocations due to municipal development and for transferring plant to new joint-use poles. There is an additional cost reflected in this to investigate the pole-line relocation situated on private property without an easement. Expenditures within this project are below the materiality threshold.

Substation Upgrade – Loading $80,682

This project consists of two main parts. The first is a load study to determine the existing system's capability to carry the load in a variety of scenarios. It was determined that the current station is not capable of carrying the load for the new and prospective developments in place. The second part is the cost of engineering a new station with sufficient capacity to supply the entire load for the planning horizon.

Fourth Feeder Phase 3 $260,149

This is the last phase of the new fourth feeder installation to provide adequate system supply for the new development that has occurred.

Customer Connection $6,573

This project, below the materiality threshold, is for the connection of a commercial customer.

System Renewal $44,096

The total spending in this category is below the materiality threshold. The single major cost contributor to this category is the Mini Pad Transformer, Elbow and Insert replacement program, at a cost of $21,844

Load break elbows and inserts have a limited life expectancy. After repeated normal operations the ablative material on the elbow is worn away and it no longer has rated interrupting capability. Additionally, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to operate. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert through the replacement program.

System Service

The category total spending is $9,264

Expenditures within this category are below the materiality threshold and are for a single pole replacement and the removal of switches.

General Plant

The category total spending is $12,503

The primary expense within this category is for the purchase of a pole testing device. This device is a joint-use device between Hydro Embrun and Hydro Hawkesbury and was purchased by the two utilities; CHEI contributed $7,415 or 50% of the cost towards the purchase price.

Capital Expenditure Forecast to Year End 2017

Category	Description	Plan	Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services (1855)	$20,000		
	Meters (1860)	$8,000		
	Subtotal		$28,000	
	Versaille III Project (1850)	$20,675		
	Versaille III Project (1845)	$160,025		
	Subtotal		$180,700	
	New Substation – (1820)	$1,487,396		
	Engineer Consultant Substation (1820)	$30,000		
	Subtotal		$1,517,396	
	Category Total			$1,726,096
System Renewal				
	Transformers Program (Elbow and Inserts) –(1850)	$20,000		
	Category Total			$20,000
System Service				
	Four Way Tie In Switch (1835)	$39,650		
	336 MCM Conductors (1835)	$46,250		
	Category Total			$85,900
General Plant				
	Website – (1611)	$3,000		
	Antivirus –(1611)	$1,500		
	Office Equipment (1915)	$1,000		
	Computer & Hardware –(1920)	$1,500		
	Category Total			$7,000
	Total Capital			$1,838,996
	Contributed Capital			$(132,000)
	Net Capital			$1,706,996

2017 PROJECT DESCRIPTIONS

System Access

New Services and Metering $28,000

Expenditures within this category are for overhead and underground services and energy meters as requested by customers. This project total was below the materiality threshold.

New Subdivision Versaille $180,675

This project provides the distribution system plant, primary and secondary cable, and transformers required to service 46 units within a residential development.

New Substation Transformer and Related Work $1,517,396

Expenditures within this category are for the engineering and installation of the new station, the interconnection of the old station and commissioning, the connection of ancillary equipment, and rearrangement of feeder connects as required. See Justification in Appendix C.

System Renewal

This category total spending is below the materiality threshold.

Mini Pad Transformer, Elbow and Insert Replacement $20,000

Load break elbows and inserts have a limited life expectancy. After repeated normal operations the ablative material on the elbow is worn away and it no longer has rated interrupting capability. Additionally, if the elbow is not lubricated and operated the elbow, becomes extremely difficult to operate. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert as part of the replacement program.

System Service

Four Tie Switches $39,650

Since Hydro One will no longer provide emergency backup after 2018 and with new loads, CHEI requires four new switches for the flexibility to transfer load to its own feeders in the event of a section of line failing.

Feeder Section Conductor Upgrade $46,250

A portion of an overhead feeder conductor requires upgrade from 1/0 ACSR to 336 MCM ACSR to provide backup to another feeder in the event of a line failure. This is required as Hydro One will no longer provide emergency backup to Hydro Embrun after 2018.

General Plant

Expenditures within this category are $7,000 and below the materiality threshold.

APPENDIX B

FORECAST CAPITAL PROJECTS 2018 TO 2022

CAPITAL FORECAST EXPENDITURE 2018

Category	Description	Plan	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services 1855	$20,000		
	Meters 1860	$8,000		
	Subtotal		$28,000	
	Replace pole with new 45` -1830	$6,500		
	Subtotal		$6,500	
	Category Total			$34,500
System Renewal	Pole Replacement # 11 - 1830	$6,800		
	Pole Replacement # 48 - 1830	$4,500		
	Pole Replacement # 81 - 1830	$6,500		
	Pole Replacement # 108 -1830	$6,200		
	Pole Replacement # 139 - 1830	$6,500		
	Pole Replacement # 353 -1830	$2,500		
	Pole Replacement # 415 -1830	$4,500		
	Pole Replacement # 465 -1830	$4,000		
	Subtotal		$41,500	
	Transformer Replacement # 431 (1850)	$4,875		
	Transformer Replacement # 456 (1850)	$5,575		
	Transformer Replacement # 474 (1850)	$5,135		
	Transformer Replacement # 501 (1850)	$5,775		
	Transformer Replacement # 504 (1850)	$2,725		
	Transformer Replacement # 506 (1850)	$4,835		
	Transformer Replacement # 520 (1850)	$5,035		
	Transformer Replacement # 522 (1850)	$3,825		
	Transformer Replacement # 525 (1850)	$5,675		
	Transformer Replacement # 550	$2,725		

Category	Description	Plan	Project Subtotal	Category Total
	(1850)			
	Transformer Replacement # 35 (1850)	$8,100		
	Subtotal		$54,280	
	Transformers Program (Elbow and Inserts) -1850	$20,000		
	Subtotal		$20,000	
	Category Total			$115,780
System Service	No Project			
	Category Total			$0
General Plant				
	Software - 1611	$3,000		
	Office Equipment 1915	$1,200		
	Computer & Hardware -1920	$1,500		
	Category Total			$5,700
	Total Capital			$155,980
	Contributed Capital			($5,775)
	Net Capital			$150,205

2018 Project Descriptions

System Access

New Overhead and Underground Services $20,000

Cost of customer requested new services.

Meters $8,000

These meters are for the requested new services.

Replace / Relocate Pole $6,500

This is a customer project where the pole will need to be replaced and possibly relocated to meet customer requirements.

System Renewal

Pole Replacement $41,500

Routine pole testing identified eight poles that require replacement. Expenditures within this category are for these pole replacements to mitigate risk to system reliability due to decaying of the wood fibre.

Distribution Transformer Replacement $54,280

Inspections identified 11 transformers that had cracked bushings and leaking oil. These transformers require replacement to prevent future power interruptions and prevent transformer oil from negatively impacting the environment.

Transformers Program (Elbow and Inserts) $20,000

This project is for the Mini Pad Transformer, Elbow and Insert replacement program. Load break elbows and inserts have a limited life expectancy. After repeated normal operations the ablative material on the elbow is worn away and it no longer has rated interrupting capability. Additionally, if the elbow is not lubricated and operated, the elbow becomes extremely difficult to operate. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert as part of the replacement program.

System Service

There are no projects within this category.

General Plant

There are no material projects and the category total of $5,700 is also well below the materiality threshold.

CAPITAL FORECAST EXPENDITURE 2019

Category	Description	Plan	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services 1855	$20,000		
	Meters 1860	$8,000		
	Meters 1860 (Meter replacement)	$17,000		
	Subtotal		$45,000	
	Relocate Line on St-Jacques Road	$90,000		
	Subtotal		$90,000	
	Category Total			$135,000
System Renewal	Transformers Program (Elbow and Inserts) -1850	$20,000		
	Category Total			$20,000
System Service	No Projects			
General Plant				
	Software - 1611	$3,000		
	Office Equipment 1915	$1,200		
	Computer & Hardware -1920	$1,500		
	Category Total			$5,700
	Total Capital			$160,700
	Contributed Capital			-$16,700
	Net Capital			$144,000

2019 PROJECT DESCRIPTIONS

System Access

New Services and Meters	$45,000

Expenditures within this category are for customer-requested new services and meters required for new developments. This category also includes expenditures of $17,000 for the Smart Meter replacement program. CHEI anticipates that this program will be complete within a four year period.

Relocate Line on St-Jacques Road	$90,000

The location of this project is on St-Jacques Blvd north of Sainte-Therese Blvd. Currently the homes on the west side of St-Jacques Blvd are supplied from a pole line located in the rear lots of these properties. However, the utility does not have an easement on which this pole line is located. There is a vacant lot at the Sainte-Therese Blvd side of the line which is the source of supply. This lot is will be developed and the owner has requested that the rear-lot pole line be removed. Various options have been discussed with this and other owners affected, but without an easement the utility must remove the line as requested. Expenditures within this project are for the conversion required to relocate the services from rear-lot feed to street feed and provide the required secondary on the street.

System Renewal

Total expenditures within this category are $20,000 and are below the materiality threshold.

The sole project for this category is the Mini Pad Transformer, Elbow and Insert replacement program. Load break elbows and inserts have a limited life expectancy. After repeated normal operations the ablative material on the elbow is worn away and it no longer has rated interrupting capability. In addition if the elbow is not lubricated and operated the elbow becomes extremely difficult to operate. Both these conditions present a safety hazard to the operator. This is being addressed by replacing the elbow and the transformer insert. This has been a multi-year project and with this work the project is completed.

System Service

There are no projects within this category.

General Plant

The total for this category is $5,700 and is below the materiality threshold.

CAPITAL FORECAST EXPENDITURE 2020

Category	Description	Plan	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services 1855	$20,000		
	Meters 1860	$5,000		
	Meters 1860 (Smart Meter replace)	$10,000		
	Subtotal		$35,000	
	New Transformers (inventory)	$18,000		
	Subtotal		$18,000	
	Category Total			$53,000
System Renewal				
	Replace of Porcelain Post Insulators St.-Jacques Rd (Double Circuit)	$20,000		
	Subtotal		$20,000	
	Replacement of Switch, Arrester And Mounting Bracket at individual pole mount transformer locations	$40,000		
	Subtotal		$40,000	
	Category Total			$60,000
System Service	No Projects			$0
General Plant				
	Software - 1611	$3,000		
	Office Equipment 1915	$1,200		
	Computer & Hardware -1920	$1,500		
	Category Total			$5,700
	Total Capital			$118,700
	Contributed Capital			$0
	Net Capital			$118,700

2020 Project Descriptions

System Access

New Services and Meters $35,000

Expenditures within this category are for customer requested new services and associated meters related to new development and to accommodate other customer requests. Smart Meter replacements of $10,000 are also included within these expenditures. This program is planned to be completed over a four year period of time.

Transformers (Inventory) $18,000

These transformers are required to supply of new customers and will be capitalized when received.

System Renewal

Replace of Porcelain Post Insulators on
St.-Jacques St (Double Circuit) $20,000

This project is to replace porcelain post-type insulators on St-Jacques St. These insulators are of the same vintage and construction as those that have failed in other utilities. While they have not yet failed for CHEI, the utility recognizes they have been problematic and proactively plans to address this by replacement of these units that are in a critical section of line affecting potentially two of its four feeders.

Replacement of Transformer Cut Out and Arrester $40,000

Porcelain-fused cutouts and porcelain air gap type arrestors are known to fail in service, creating safety hazards. Typically fused cut outs will break and fail while being operated by a line crew. This may cause either cause a short circuit or leave crew hanging on to a live wire without a place to safely park the lead. Similarly, air gap lightning arrestors may fail explosively and create a hazard for crew and/or general public in the immediate vicinity. Both of these failure types and mechanisms have been documented. CHEI plans to address this equipment problem over a two year period.

System Service

There are no projects within this category.

General Plant

The total for this category is $5,700 and is below the materiality threshold.

CAPITAL FORECAST EXPENDITURE 2021

Category	Description	Plan	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services 1855	$20,000		
	Meters 1860	$5,000		
	Meters 1860	$10,000		
	Subtotal		$35,000	
	New Transformers (Inventory)	$18,000		
	Subtotal		$18,000	
	Category Total			$53,000
System Renewal				
	Replacement of Switch, Arrester And Mounting bracket at individual pole mount transformer locations	$62,000		
	Category Total			$62,000
System Service	No Project			$0
General Plant				
	Software - 1611	$3,000		
	Office Equipment 1915	$1,200		
	Computer & Hardware -1920	$1,500		
	Category Total			$5,700
	Total Capital			$120,700
	Contributed Capital			$0
	Net Capital			$120,700

2021 Project Descriptions

System Access

New Services and Meters	$35,000

Expenditures within this category are for customer requested new services and associated meters related to new development and to address other customer requests. Smart Meter replacements of $10,000 are also included within these expenditures. This program is planned to be completed over a four year period of time.

Transformers (Inventory)	$18,000

These transformers are required to supply of new customers and will be capitalized when received.

System Renewal

Replacement of Transformer Cut Out and Arrester	$62,000

Porcelain-fused cutouts and porcelain air gap type arrestors are known to fail in service, creating safety hazards. Typically fused cut outs will break and fail while being operated by a line crew. This may cause either cause a short circuit or leave crew hanging on to a live wire without a place to safely park the lead. Similarly, air gap lightning arrestors may fail explosively and create a hazard for crew and/or general public in the immediate vicinity. Both of these failure types and mechanisms have been documented. CHEI plans to address this equipment problem over a two year period. This is the second and final year of the project to address this equipment problem.

System Service

There are no projects within this category.

General Plant

The total for this category is $5,700 and is below the materiality threshold.

CAPITAL FORECAST EXPENDITURE 2022

Category	Description	Plan	Project Subtotal	Category Total
	Amounts are in dollars			
System Access				
	New O/H and U/G services 1855	$20,000		
	Meters 1860	$5,000		
	Meters 1860 (Smart Meter Replace)	$10,000		
	Subtotal		$35,000	
	New Transformers (Inventory)	$18,000		
	Subtotal		$18,000	
	PCB Transformers Dated Prior to 1985	$25,000		
	Subtotal		$25,000	
	Category Total			$78,000
System Renewal				
	Replacement of Existing Overhead in Line Cut outs and distribution switches	$40,000		
	Subtotal		$40,000	
	Category Total			$40,000
System Service	No Project			$0
General Plant				
	Software - 1611	$3,000		
	Office Equipment 1915	$1,200		
	Computer & Hardware -1920	$1,500		
	Category Total			$5,700
	Total Capital			$123,700
	Contributed Capital			$0
	Net Capital			$123,700

2022 PROJECT DESCRIPTIONS

System Access

New Services and Meters	$35,000

Expenditures within this category are for customer requested new services and associated meters related to new development and to address other customer requests. Smart Meter replacements of $10,000 are also included within these expenditures. This program is planned to be completed over a four year period of time.

Transformers (Inventory)	$18,000

These transformers are required to supply of new customers and will be capitalized when received.

System Renewal

Replacement of Inline Cut Outs	$40,000

Porcelain-fused cutouts are known to fail in service, creating safety hazards. Typically fused cut outs will break and fail while being operated by a line crew. This may cause either cause a short circuit or leave crew hanging on to a live wire without a place to safely park the lead. This failure type has been documented. CHEI plans to address this equipment problem over a two year period. This project replaces the cut outs and switches of this style that are used at laterals and other switching points on the feeder.

System Service

There are no projects within this category.

General Plant

The total for this category is $5,700 and is below the materiality threshold.

APPENDIX C

NEW STATION JUSTIFICATION

NEW STATION JUSTIFICATION

This Appendix details the justification for CHEI's new substation. Reference is made to a study completed by Stantec. This study "Utility load Flow and Evaluation Study" can be found in full in Appendix G. Drawings of the station are referenced in this appendix.

This is a System Access project with a total cost of $1,517,396 occurs in 2017.

CHEI considered its existing load, the new load that would result from the new development and the capacity of its existing MS. It also considered its ability to supply its customers in the event of a station transformer failure. That is, CHEI considered the ability to supply prime load as well as the ability to provide single contingency power within its system.

CHEI also presented this project to the Cooperative's Annual Meeting on April 18, 2017 as noted in the following excerpt from this filing Exhibit 1(1.8.1 Overview of Customer Engagement) :

> ***Annual General Assembly Meeting:*** *The utility held a Town Hall meeting on April 18, 2017, where the General Manager presented the utility's 2017 and 2018 Capital Budget. The utility presented its budgets by RRFE grouping (system access, renewal, services and general plant) and USoA account. The General Manager discussed in details the specifics around the need and costs related to the new 44KV substation. Fifty customers attended the meeting. None of the attendees provided feedback on the utility's proposed capital budget other than to thank the utility for its presentation and praise the utility for their good work.*

LOADING

In 2016 the existing summer and winter load were as indicated in Figure 1 and Figure 2 below.

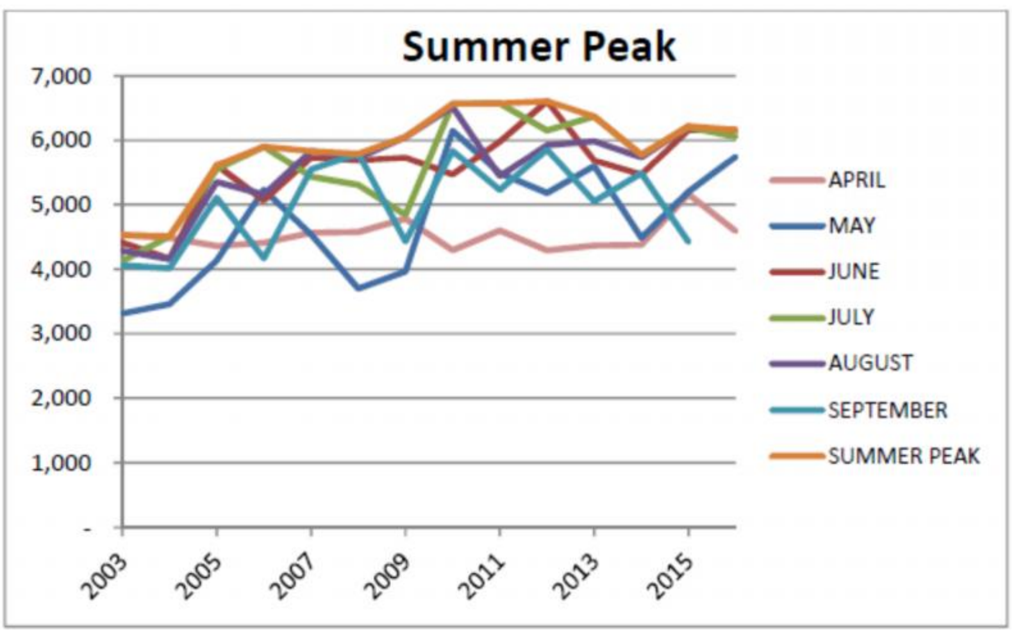


Figure 1 Summer Loading

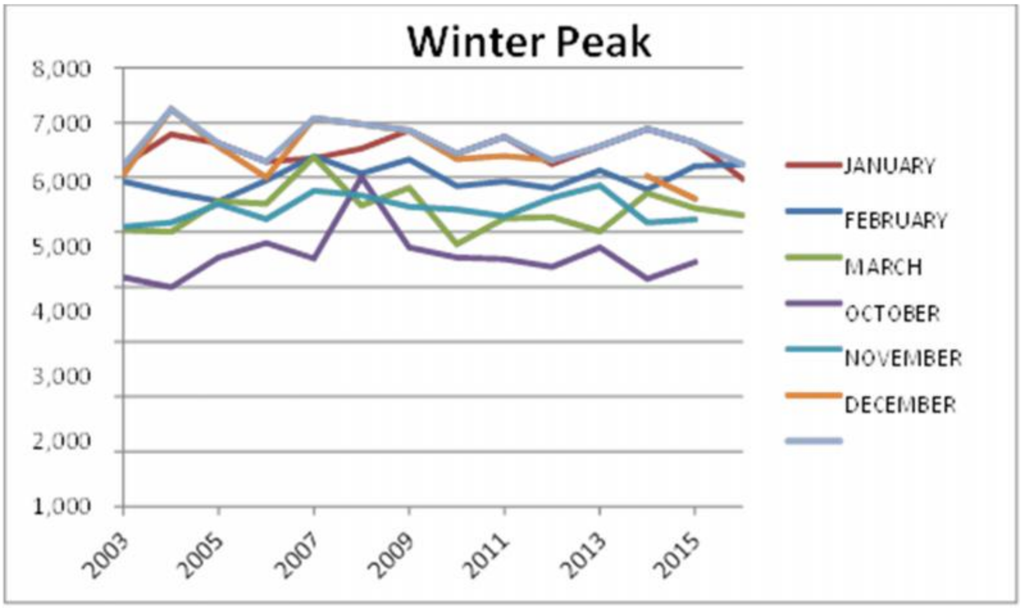


Figure 2 Winter Loading

The existing load in 2016 is estimated to be for the summer and winter peak values 7,341 kVA (or 6,607 kW) and 7,871 kVA (or 7,084 kW), respectively, assuming a 0.9 power factor.

The existing load is expected to grow at about 1% to take into account new loads such as appliances, pools, A/C, etc.

The following areas are proposed for future in-fill development during the following time periods, with an estimated units/development and the preferred feeder for connection (based on location and existing feeder capacity). As the subdivisions are not fully developed in the first year of construction it was assumed that the development will take 5 years with 50% of the buildings constructed in the first year and 12.5% each subsequent year:

South-East of Ste Marie and Castor	2016, 306 units under development, F03
South-West of Ste Marie and Notre-Dame	2016, 61 units under development, F03
North-East of Notre-Dame and Rue Manoir	2017, 41 units, F02
North of Rue Blais at Notre-Dame	2019, 40 units, F03
South-East of St Jacques and the Castor	2019, 50 units, F02
South-East of Ste Marie and Notre-Dame	2019, 150 units, F03
South-West of Ste Marie and the Castor	2019, 370 units, F04

With this proposed development schedule, and each additional residential house at an average peak Demand of 1.67kW (or 1.86kVA as was derived above), the future additional kVA Demand loading forecast for the complete system is shown below:

Peak Annual Loading												
Period (Demand kVA)	Current	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Summer	7341	7719	7894.5	8633.6	8963.6	9296.9	9535.0	9775.4	9873.1	9971.9	10071.6	10172.3
Winter	7871	8249	8429.8	9174.3	9509.7	9848.4	10092.0	10338.0	10441.4	10545.8	10651.3	10757.8
Normal Growth			1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Future Development F2		37	11	52	24	24	13	13				
Future Development F3		340	87	264	132	132	45	45				
Future Development F4				344	87	87	87	87				

Table 6 – Future Peak Demand Loading

Based on Table 6 above, the load increase from 2017 to 2023 is 31.4%.

CAPACITY

The existing capacity of CHEI's MS is 7.5/10 MVA ONAN/ONAF.

From this loading (Table 6) it can be seen that in 2017 the forecast summer load exceeds the existing MS transformer ONAN rating of 7.5 MVA. For station transformers, this ONAN rating is considered the normal capacity, with the ONAF rating being reserved for emergency situations. This definition is usually applied to systems that have multiple municipal stations. It is recognized that the transformer is working "harder" at ONAF ratings and it is not considered good engineering practice to continuously operate in this range.

It can also be seen that, per the projection, by 2026 the summer load will exceed the ONAF rating.

Hence, as a risk mitigation action, the capacity of the MS transformer should be increased. The next logical standard size is 10/13.33 MVA ONAN/ONAF.

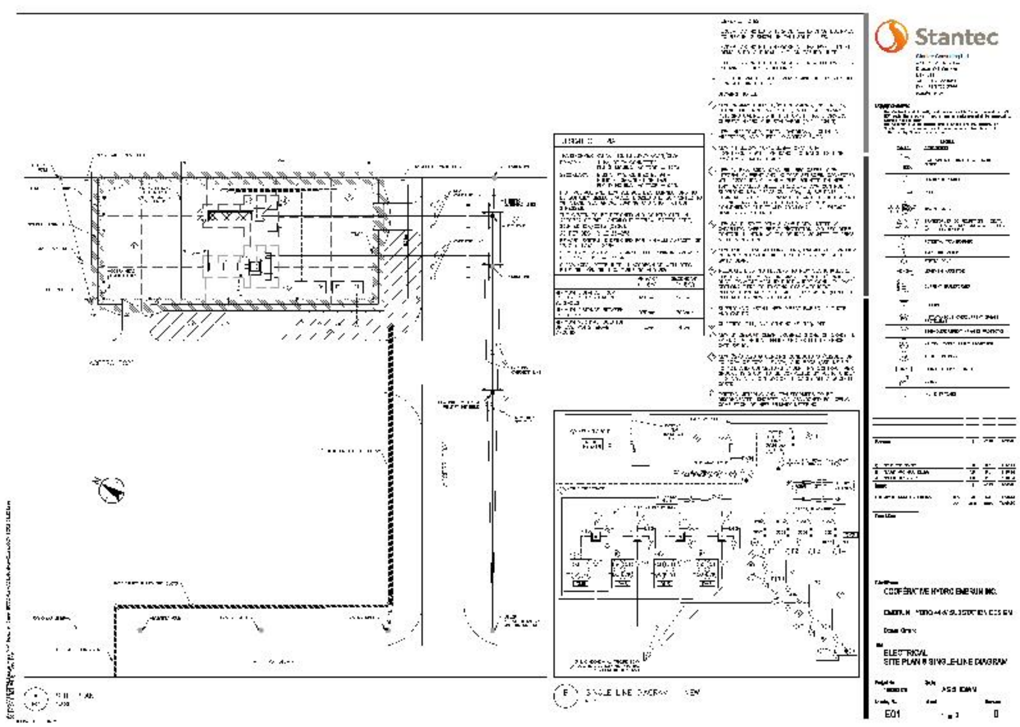
By installing a new 10/13.33 MVA transformer the station will be able to supply the forecast load until 2025 without exceeding the ONAN rating at peak load in the summer and until 2021 without exceeding the ONAN rating in the winter. Typically the load in the winter corresponds to the coldest ambient temperatures because of electric heating. This is also when the transformer has additional capacity; the transformer capacity is calculated for a 40 degrees Celsius ambient temperature. If the ambient temperature is lower than this, then the transformer has a greater loading capacity. Also annual winter peak loads tend to be of relatively short duration as a result of heating and cooking loads being coincident to a significant degree. Once the cooking load reduces the peak is over. These two factors indicate that the winter load up to 2027 is not a significant loading concern.

The summer rating situation differs significantly. The transformer ambient temperature is much closer to the ambient rating temperature of 40 degrees Celsius and hence there is a less additional capacity. For summer loading, the nominal rating of the transformer is usually used without adjustment. The peak loads often result when air conditioning load is coincident with cooking. However, in summer there is a greater diversity in cooking that does not involve electrical load, for example outside BBQ. This means that the shape of the peak load curve in summer is typically fairly flat reflecting the cooling loads which typically drop somewhat after the sun sets. On particularly humid days the load stays higher even then. This means that the transformer sees a relatively high load for most of the day. This preloading means that the oil and windings are quite hot already and they do not have any additional “reserve” loading capacity. In 2026 and 2027 the forecast peak loads marginally exceed the ONAN rating of the transformer in summer. The amount they are over is marginal (less than 2% in 2027) but a review of the loads should be carried out by or before this timeframe to ensure the system has adequate capacity in both summer and winter.

When CHEI recognised that additional capacity was required to supply prime load, it undertook studies to see if a new station could be built on the same property as the existing station with the added capability of being able to transfer the feeder load from one station to the other. This way the station single contingency issues could be addressed and in emergencies one transformer could be a full or partial backup for the other transformer.

The new construction involves a new 44kV supply and protection, a station transformer rated 10/13.3 MVA, a secondary bus, four feeder positions with vacuum reclosers and associated control equipment, four padmounted switches to allow each feeder to be connected to either the new station or the old station, as well as station metering with associated communications equipment. This solution allows for the supply of prime load and also provides a solution for the single contingency supply. The solution is not perfect in that there are some peak days when the old transformer cannot supply the entire load at the emergency rating and voluntary load curtailment would be necessary or some form of rotating outages. However this is an economical solution that provides a substantial improvement to the previous backup arrangements with Hydro One where in the order of half the load could be restored.

The drawings for the station are included below to show the details of the installation. (Double click on the page below to open the drawing PDF.)



CHEI tendered the project out on a design and install basis. The contract was awarded to the low cost acceptable bidder and this work is scheduled to be completed in October 2017.

The “Design-Build Performance Specifications Issued For Tender” are included below. (Double click on the page below to open the drawing PDF.)

Cooperative Embrun Hydro
44kV Substation Capacity and Redundancy Upgrade
Embrun, Ontario

DESIGN-BUILD PERFORMANCE SPECIFICATIONS

ISSUED FOR TENDER

October 19, 2016

Prepared For:

Cooperative Embrun Hydro
821 Notre Dame Suite 200
Embrun, Ontario K0A 1W1

Prepared By:

Stantec Consulting Ltd.
1331 Clyde Avenue
Ottawa Ontario K2C 3G4

Project: 163302179

Stantec

1.1 INVITATION

.1 Bid Call

.1 Offers signed under seal, executed, and dated will be received by Cooperative Hydro Embrun, 821 Notre Dame St#200, Embrun, ON, before **2PM local time on Thursday, November 17, 2016.**

.2 Offers submitted after above time may be returned to bidder unopened.

.3 Offers will be opened privately after the time for receipt of Bids.

.4 Amendments to submitted offer will be permitted if received in writing prior to bid closing and if endorsed by same party or parties who signed and sealed offer.

1.2 INTENT

.1 Intent of this Bid call is to obtain an offer to perform work to complete defined work for a Design-Build Stipulated Price Contract, in accordance with the Contract Documents.

1.3 CONTRACT DOCUMENTS IDENTIFICATION

.1 Contract Documents are identified as:

.1 General Design-Build Requirements (section that follows)

.2 Drawings:

.1 E01 – Electrical Site Plan & Single-Line Diagram

.2 E02 – Electrical Details

.3 E03 – Substation Communications – Optional Price

1.4 CONTRACT/BID DOCUMENTS

.1 Definitions

.1 Contract Documents: Defined in CCDC14-2013, Design-Build Stipulated Price Contract 'Definitions'.

.2 Bid Documents: Contract Documents supplemented with Instructions to Bidders and Bid Form.

.3 Bid, Offer, or Bidding: Act of submitting an offer under seal.

.4 Bid Price: Monetary sum identified in Bid Form as an offer to perform work.

.2 Availability

.1 Bid Documents are made available only for purpose of obtaining offers for this project. Their use does not confer license or grant for other purposes.

.3 Examination

.1 Immediately notify Consultant upon finding discrepancies or omissions in Bid Documents.

.4 Queries/Addenda

.1 Direct questions to **Benoit Lamarche at benoit@hydroembrun.com**.

.2 Addenda may be issued during bidding period. All addenda become part of Contract Documents. Include costs in Bid Price.

.3 Verbal answers are only binding when confirmed by written addenda.

.4 Clarifications requested by bidders must be submitted by **11:59PM Friday, November 4, 2016**. Reply will be in form of an addendum, a copy of which will be forwarded to bidders by **11:59AM, Tuesday November 8, 2016**.

1.5 SITE ASSESSMENT

.1 Site Examination and Bidders Briefing

.1 An optional visit to project site has been arranged for Bidders as follows: **Thursday October 27, 2016, at 1:00PM**. Contractors interested in attending shall report to the **Embrun Hydro Substation, located at 1342 St. Jacques Rd, Embrun, ON**. Note that the site visit is not mandatory.

.2 Those who wish to attend must notify Embrun Hydro a minimum of 24 hours in advance.

.3 Representatives of Owner will be in attendance.

.4 Information relevant to Bid Documents will be recorded in Addendum and issued to Bidders.

1.6 BID SUBMISSION

.1 Bid Ineligibility

.1 Bids that are unsigned, improperly signed or sealed, conditional, illegible, obscure, contain arithmetical errors, erasures, alterations, or irregularities of any kind, may, at the discretion of Owner, be declared informal.

.2 Bids with Bid Forms and enclosures which are improperly prepared may, at discretion of Owner, be declared informal.

.3 Bids are by invitation, only from selected bidders. Bids from unsolicited bidders may be returned.

.2 Submissions

.1 Bidders shall be solely responsible for delivery of their Bids in manner and time prescribed.

.2 Submit one copy of executed offer on Bid Forms provided, signed and with corporate seal in a sealed opaque envelope, clearly identified with Bidder's name, project name and Owner's name on outside.

1.7 BID ENCLOSURES/REQUIREMENTS

.1 Insurance

.1 Provide proof of insurance. Insurance requirements outlined in CCDC14 shall be applicable.

.2 Bid Form Requirements.

.1 Bidder, in submitting an offer, accepts specified shutdown window for work stated in Contract documents for performing work.

.2 Refer to Supplementary Conditions for inclusion of taxes.

.3 Bid Signing

.1 Bid form shall be signed under seal by Bidder.

.2 Sole Proprietorship : Signature of sole proprietor in presence of witness who will also sign. Insert words "Sole Proprietor" under signature. Affix seal.

.3 Partnership: Signature of all partners in presence of witness who will also sign. Insert word ‘Partner' under each signature. Affix seal to each signature.

.4 Limited Company: Signature of duly authorized signing officer(s) in normal signatures. Insert officer's capacity in which signing officer acts, under each signature. Affix corporate seal. If Bid is signed by officials other than President and Secretary of company, or President-Secretary-Treasurer of company, copy of by-law resolution of Board of Directors authorizing them to do so must also be submitted with Bid in Bid envelope.

.5 Joint Venture: Each party of joint venture must execute Bid under respective seals in manner appropriate to such party as described above, similar to requirements of Partnership.

1.8 OFFER ACCEPTANCE/ REJECTION

.1 Duration of Offer

.1 Bids shall remain open to acceptance, and irrevocable for a period of fifteen (15) days after the Bid closing date.

.2 Acceptance of Offer

.1 The Owner may accept any bid, whether it is the lowest or not, and reserves the right to reject any or all bids.

.2 After acceptance by Owner, Owner will issue to successful Bidder written Bid acceptance.

1.9 PERFORMANCE BOND

.1 Within 15 calendar days of receipt of written acceptance of offer, successful bidder shall be required to provide a performance bond for 50% of the bid amount.

.2 By signing and sealing Bid Form, Bidder agrees to submit the required performance bond within the specified deadline.

END OF SECTION

Part 1 General

1.1 DESIGN BUILD PROJECT FORMAT

.1 Contractor to provide design-build services for the expansion of the Embrun 44kV substation for capacity and redundancy issues as noted within these documents. Governing contract to be used is the CCDC 14 – 2013, Design-Build Stipulated Price Contract.

.2 Design to meet minimum requirements listed within these documents.

.3 Contractor to be responsible for required submissions to respective authorities. Where required, contractor will provide documents sealed by a professional engineer licensed in the Province of Ontario. Typically, sealed documents are required for:

- .1 Drawings for authority approval
- .2 Tower foundation design
- .3 Tower structure design
- .4 Recloser structure and bus arrangement
- .5 Recloser structure foundation design
- .6 Ground Grid and Power Systems Studies
- .7 Final Construction documents

1.2 GENERAL SCOPE OF WORK

.1 Intercept existing 44kV overhead line supplying substation, supply and install new in-line switches, and new pole c/w crossarm(s), insulators, guys, supports, lightning arresters, instrument transformers, metering cabinet, wiring and supports to implement primary metering.

.2 Supply and install 44kV line extension and required poles, crossarms, conductors, insulators, guys, and all required wiring and hardware.

.3 Supply and install 44kV tower with fused loadbreak and lightning arresters, 44/8.32kV 10/13.33MVA transformer, four new 15kV 3-phase reclosers complete with integral current and voltage sensors; reclosers to be connected to transformer 8.32kV secondary using insulator mounted 1200A IPS aluminum bus and appropriately rated substation connectors; supply and install lightning arresters and solid-state relays for protection of the four existing town feeders, complete with 240/120VAC control PT, panel and wiring.

.4 Supply and install new 15kV underground cabling to new padmounted sectionalizers tied to four existing town feeders.

.5 Supply and install underground direct buried ducts, cabling, foundations, and slabs as required.

.6 Supply and install an additional 6” depth of ¾” clean crushed stone around the complete substation fence to a distance of 2 meters (or to the property line) from the fence.

.7 At a minimum, supply and install an additional 10 x 10 foot copper clad ground rods, up to 200m of #2/0 copper grounding conductor, and required exothermic connectors (all typically within clean conducting soil 300mm below grade – reinstate soil and stone above it after installation). If required, additional grounding work to be included as prescribed by the substation grounding study to be completed under this mandate.

.8 Optional Price (for Additional Communications Work): Replace existing analog meters within 8.32kV switchgear with new digital metering systems; provide new remote terminal unit (RTU) and industrial Ethernet switch for remote monitoring of digital metering systems, new protection relays and annunciation of warnings and alarms from existing and new 44kV-8.32kV transformer control panels. Metering and relay data shall be accessible via RTU embedded web-server, and transformer and substation warnings and alarms shall initiate SMS text messages following a customizable and programmed sequence. Contractor shall be responsible for the design, implementation, programming, configuration, testing and commissioning of the new communications system.

1.3 STAGING AND SCHEDULING OF WORK

.1 The contractor is responsible for the arrangement and organization of the required work and staging to implement this project.

.2 The contractor must maintain operational access to the switchgear and substation during non-shutdown periods of this project.

.3 The contractor must stage work and perform switching operations and use emergency feeders such that power interruptions to customers supported by Embrun Hydro feeders are avoided to the extent possible; should service interruptions be required, they shall be scheduled in advance at the discretion of Embrun Hydro during periods of light loading in the evenings or overnight, and downtime shall be minimized. Power interruptions will only be permitted in instances where there is no other safe means to execute the work.

.4 All construction and commissioning work to be completed by November 30, 2017.

1.4 CODES AND STANDARDS

.1 Perform work in accordance with the following codes, standards, and regulations:

- .1 CSA C22.1-2015 Canadian Electrical Code Part I (23rd Edition) and Ontario Amendments
- .2 NETA, Acceptance Testing Specification for Electrical Power Distribution Equipment and Systems.
- .3 Comply with CSA and Ontario Hydro Electrical Bulletins in force at time of tender submission.

1.5 CIRCUIT PHASING

.1 For any systems that may be paralleled, physical confirmation that phases are being configured appropriately is required.

.2 After completion of the system modification, perform phasing across the poles of the open device within the looped or parallel systems with both lines energized. Confirm a-a', b-b', and c-c' voltage is zero, and a-b', a-c', b-c' voltage is rated line to line voltage

.3 For all measurements, use appropriate personnel, work methods, and PPE per CSA Z462 'Electrical Workplace Safety'

1.6 PERMITS, FEES AND INSPECTION

.1 Submit to Electrical Inspection Department and Supply Authority necessary number of drawings and specifications for examination and approval prior to commencement of work. Pay associated fees.

.2 Notify Engineer of changes required by Electrical Inspection Department prior to making changes.

.3 Furnish Certificates of Acceptance from Electrical Inspection Department authorities having jurisdiction on completion of work to Engineer.

1.7 MATERIALS AND EQUIPMENT

.1 All materials to be new and unused.

.2 Equipment and material to be CSA certified. Where there is no alternative to supplying equipment which is not CSA certified, obtain special approval from Electrical Inspection Department.

1.8 WARRANTY AND TRIAL USAGE

.1 All equipment to carry a minimum of a one year unlimited warranty on all parts, labour, and expenses for the replacement of the defective or non-functional part from the date of energization.

.2 Extended warranty to be provided for new 44-8.32kV transformer as well as all relays and reclosers provided under this project. For these components, two year unlimited warranty on all parts, labour, and expenses for the replacement of the defective or non-functional part from the date of energization shall be provided.

.3 Warranty of the electrical systems or equipment that is energized and used on temporary or partial basis shall not commence until the entire project has reached Substantial Completion.

1.9 EXTRA WORK

.1 Extra work may be requested by the issuance of a Contemplated Change Notice (CCN) and/or a Change Directive (CD). In addition to the net additional cost of the work, the Contractor shall be entitled to a maximum of 15% to cover overheads and profit on his work and 10% to cover overheads and profit on sub-trades.

.2 Provide detailed breakdowns of material and labour with unit prices and extensions required for review of CCN's and CD's, and breakdowns for any substantial work being performed by a sub-contractor.

.3 Cost quotations shall be based on industry accepted costing methods.

1.10 FINISHES

.1 Shop finish metal enclosure surfaces by application of rust resistant primer inside and outside, and at least two coats of finish enamel. All equipment, except for the tower structure, to be 'equipment green' finish to EEMAC Y1-1-1955.

.2 Clean and touch up surfaces of shop-painted equipment scratched or marred during shipment or installation, to match original paint.

.3 Identify electrical equipment with mechanically attached lamacoid nameplates.

1.11 SINGLE LINE ELECTRICAL DIAGRAMS

.1 Client will provide the contractor with a copy of the existing electrical single line in AutoCAD. Contractor will update the existing copy of electrical single line to as-built configuration. Provide copy of updated single line drawings in electronic AutoCAD format to client via CD.

.2 Provide 6 full size, colour, paper copies to client.

.3 Drawings: 600 x 600 mm minimum size.

1.12 FIELD QUALITY CONTROL

.1 All electrical work to be carried out by qualified, licensed electricians or apprentices as per the conditions of the Provincial Act respecting manpower vocational training and qualification. Employees registered in a provincial apprentices program shall be permitted, under the direct supervision of a qualified licensed electrician, to perform specific tasks - the activities permitted shall be determined based on the level of training attained and the demonstration of ability to perform specific duties.

.2 The work of this division to be carried out by a contractor who holds a valid Master Electrical contractor license as issued by the Province that the work is being constructed.

1.13 SUBMITTALS

.1 Submit to Engineer and Owner submittals listed for review. Submit with reasonable promptness and in orderly sequence so as to not cause delay in Work. Failure to submit in ample time is not considered sufficient reason for an extension of Contract Time and no claim for extension by reason of such default will be allowed.

.2 Work affected by submittal shall not proceed until review is complete.

.3 Contractor's responsibility for errors and omissions in submission is not relieved by Engineer's review of submittals.

.4 Indicate materials, methods of construction and attachment or anchorage, erection diagrams, connections, explanatory notes and other information necessary for completion of Work.

.5 Submit 1 electronic copy in Adobe Acrobat .pdf format of the following items requested in specification sections or as requested by the Engineer:

- .1 Shop drawings of all products required within the project, including but not limited to:
  - .1 Reclosers
  - .2 Protection Relays
  - .3 Switchgear, Sectionalizers
  - .4 Power Transformers
  - .5 Instrument transformers and metering equipment
  - .6 Towers and Supports
  - .7 Poles and Framing Hardware
  - .8 Cabinets and Enclosures
  - .9 Switches
  - .10 Fuses
  - .11 Panelboards
  - .12 Lightning Arresters
  - .13 Wiring and Bus
  - .14 Insulators and Substation Connectors
  - .15 Remote Terminal Unit
  - .16 Ethernet Switch
  - .17 Digital Metering Systems
- .2 Product data sheets or brochures where shop drawings will not be prepared due to standardized manufacture of product.

.1 If standardized product data sheets are being provided due to the standard nature or manufacture of a specific product, ensure that either information on other models or ratings not applicable to project is removed, or circle and/or highlight applicable model or rating information. If not all model or rating information is present on data sheet, supplement standard information to provide details applicable to project.

.3 Test reports

.1 Report signed by authorized official of testing laboratory that material, product or system identical to material, product or system to be provided has been tested in accord with specified requirements.

.2 Testing must have been within 3 years of date of contract award for project.

.4 Certificates

.1 Statements printed on manufacturer's letterhead and signed by responsible officials of manufacturer of product, system or material attesting that product, system or material meets specification requirements.

.2 Certificates must be dated after award of project contract complete with project name.

.5 Manufacturers instructions

.1 This may consist of pre-printed material describing installation of product, system or material, including special notices and Material Safety Data Sheets concerning impedances, hazards and safety precautions.

.6 Manufacturer's Field Reports

.1 This may include documentation of the testing and verification actions taken by manufacturer's representative to confirm compliance with manufacturer's standards or instructions.

.7 Operation and Maintenance Data

.8 Programming, settings, and annotation for any electronic or digital control devices

.9 Additional Submittals:

.1 Site Specific Health & Safety Plan

.2 Demonstration and Training Materials

.3 Power Systems Studies

.4 Ground Grid Study

.5 Tower erection drawings

.6 Concrete pad design drawings

.7 Geotechnical surveys and reports

.8 Recloser structure and arrangement drawings

.9 44kV metering arrangement drawings

.10 Communication system schematics (part of optional price)

.6 Allow six (6) business days for Engineer’s review of each submission.

.7 Adjustments made on shop drawings by Engineer are not intended to change Contract Price. If adjustments affect value of Work, state such in writing to Engineer prior to proceeding with Work.

.8 Make changes in shop drawings as Engineer may require, consistent with Contract Documents. When resubmitting, notify Engineer in writing of any revisions other than those requested.

.9 Accompany submissions with transmittal letter, containing:

- .1 Date.
- .2 Project title and number.
- .3 Contractor's name and address.
- .4 Identification and quantity of each shop drawing, product data and sample.
- .5 Other pertinent data.

.10 Submissions shall include:

- .1 Date and revision dates.
- .2 Project title and number.
- .3 Specification Section Number
- .4 Name and address of:
  - .1 Subcontractor.
  - .2 Supplier.
  - .3 Manufacturer.
- .5 Contractor's stamp, signed by Contractor's authorized representative certifying approval of submissions, verification of field measurements and compliance with Contract Documents.
- .6 Details of appropriate portions of Work as applicable:
  - .1 Fabrication.
  - .2 Layout, showing dimensions, including identified field dimensions, and clearances.
  - .3 Setting or erection details.
  - .4 Capacities.
  - .5 Performance characteristics.
  - .6 Standards.
  - .7 Operating weight.
  - .8 Wiring diagrams.
  - .9 Single line and schematic diagrams.
  - .10 Relationship to adjacent work.

1.14 CLOSEOUT SUBMITTALS

.1 Provide a complete O&M manual for all products and supplied items

.2 Manual will be supplied in PDF format for review by client and engineer, when completed and accepted, will be provided in both electronic (PDF) and 4 hard copies within binders.

.3 Manual to include approved shop drawings, instruction manuals, maintenance guides, commissioning reports, warranties, and other related items for all supplied parts.

.4 Manual to include subcontractor, supplier, and manufacturer, with name, address, and telephone number of responsible principal.

.5 Drawings: provide with reinforced punched binder tab. Bind in with text; fold larger drawings to size of text pages.

.6 Provide 1:1 scaled AutoCAD files in .dwg format on CD.

.7 Provide any electronic or digital programming, settings, control, or annotation in both readable paper form in the binder and as original software files on the CD in the required and compatible file format necessary for working with the devices.

.8 Provide spare parts, maintenance materials, and special tools to client.

Part 2 Products

2.1 POLE LINE

.1 Wood utility poles: to CAN/CSA-O15, preservative treated. Length and class: per design build.

2.2 INSULATORS

.1 Primary insulators: to ANSI C29.17, nominal rating 46 kV

.2 Suspension insulators: Dead-end type: nominal rating 46kV

.3 Guy strain insulators: Strain type: to EEMAC1B-1, nominal rating 1 kV

2.3 GUYS AND ANCHORS

.1 Guy wire: to CAN/CSA-G12.

.2 Guy guard: plastic, colored yellow

2.4 PRIMARY CONDUCTORS

.1 Minimum size # 2/0 AWG

2.1 PRIMARY METERING

.1 POTENTIAL TRANSFORMERS

- .1 44000:115V Potential transformers: to CSA C60044-2, metallized with silicon insulator for outdoor use.
- .2 Use appropriate metering accuracy for IESO application.
- .3 Provide fusing where required.
- .4 IESO metering in separate pole-mounted, lockable, cabinet.

.2 CURRENT TRANSFORMERS

- .1 52kV Current transformers: to CSA C60044-1, for outdoor use.
- .2 Use appropriate metering accuracy for IESO application.
- .3 Wiring on current transformer secondaries to be #10 AWG minimum.
- .4 Provide positive action automatic short-circuiting device in secondary terminals.

2.2 OVERHEAD, HOT-STICK OPERATED, 46kV ISOLATION POINT

.1 Provide isolation point midpoint of span from pole to tower.

2.3 STATION TOWER

.1 Steel structural members: to CAN/CSA-G40.21.

.2 High tensile, hot dipped galvanized, bolts, nuts, washers: to CAN/CSA-S16.1.

2.4 FUSED LOAD AIR BREAK SWITCHES

.1 Group-operated load-interrupter switches: fused, three-pole, single-throw units, manually operated by handle through insulated mechanical linkage.

.2 High pressure contact type complying with ANSI C37.32.

.3 Factory assembled to suit specific configuration and mounting conditions of project.

.4 Interrupter unit to permit opening and closing under rated full load current.

.5 Operating handle: padlockable, 42 inches above finished grade.

2.5 PRIMARY FUSES

.1 Voltage rating: 46 kV

.2 Continuous current rating: per design build.

.3 Three phase symmetrical short circuit ratings: per design build

.4 Provide 3 spare refill units. Size and speed to be determined by contractor provided coordination study.

2.6 GRAVEL

.1 Provide and install 150mm layer of clear, washed, 19mm stone within areas requiring rectification within Substation area, and within 2 m outside of fence perimeters and gate swing radius (level grade and adjust swales as required).

2.7 WARNING SIGNS

.1 Provide danger signs around substation fence and on pole.

2.8 LIGHTNING ARRESTERS

.1 Arrester component parts: to CAN/CSA-C233.1.

.2 On main 44kV and 8.32kV towers, Arrester characteristics:

- .1 Station class arrester.
- .2 MCOV: per manufacturer’s recommendation.
- .3 Outdoor Type

2.9 GROUND RODS, GROUND CONDUCTORS AND GRADIENT MAT

.1 Continuous grounding system including, electrodes, conductors, connectors and accessories in accordance with CSA C22.2 No.0.4 and requirements of local authority having jurisdiction.

.2 Install gradient control mats. Connect mats to station ground electrode and switch mechanism operating rods.

.3 Install at least one Ground Electrode Box inside the high voltage substation to allow easy access to the actual grid.

.4 The station ground grid resistance will be measured after completion of construction and changes if required shall be made to ensure that the design resistance was achieved.

2.10 UNDERGROUND DIRECT BURIED DUCTS

.1 CSA C22.2 No. 211.1-06(R2011): Rigid PVC Type DB2/ES2 for direct burial, minimum size 100 mm.

  .1 In each spare duct install pull rope continuous throughout each duct run with 3 m spare rope at each end.

  .2 Provide concrete encasement for ducts when travelling under vehicular areas

2.11 44kV – 8.32kV TRANSFORMER

.1 Liquid cooled, outdoor, power transformer type ONAN/ONAF, capacity: 10/13.33 MVA to CAN/CSA-C88-M90(2014) – Power Transformers and Reactors.

.2 Primary voltage: 44,000V, 60Hz, delta connected, 3phase, 3 wire.

.3 Secondary voltage: 8,320, wye connected, 3phase, 4wire, neutral brought out through bushing for solid grounding.

.4 Basic impulse level: 250kV primary, 95kV secondary.

.5 Angular displacement and turns ratio to match existing – contractor to verify existing transformer characteristics and ensure matching of new transformer to allow parallel operation of transformers during make-before-break operations without circulating currents.

.6 Impedance: percent (per unit) impedance to match existing transformer to allow parallel operation during make-before-break operations

.7 Losses as per CSA C802.3-15.

.8 Temperature rise 65˚C

.9 Transformers suitable for pad mounting with lifting hooks

.10 Transformer to have a sealed tank liquid preservation system.

.11 Provide required amount of 120VAC or 240VAC single phase fans to provide ONAF requirements

.12 Provide permanent welded type rads

.13 Four-2.5% taps, 2-FCAN, 2-FCBN and nominal. Internally operated off-load tap changer, with provision for padlocking.

.14 Insulating liquid: standard mineral oil

.15 Top mounted external primary bushings, side mounted throat bushings

.16 ACCESSORIES SUPPLIED WITH TRANSFORMER

  .1 Liquid temperature measuring device, maximum indicating type, with alarm contacts.

  .2 Liquid level gauge with alarm contacts.

  .3 Pressure relief device

  .4 Sudden Pressure relay with alarm contacts and shut-off valve.

  .5 Winding Celsius temperature detector relay and sensing elements with fan and alarm contacts.

.6 Top non-flammable insulating liquid sampling device.
.7 Vacuum pressure gauge with bleeder.
.8 50 mm drain valve with plug.
.9 Needle sample valve
.10 Top filter press connection.
.11 Nema 4X control box, with all alarms wired to terminal blocks

.17 Acceptable Manufacturers:

.1 ABB Inc.
.2 General Electric
.3 Northern Transformer
.4 Pauwels
.5 Pioneer
.6 Siemens
.7 VA-Tech

.18 Factory Acceptance Testing:

.1 The contractor will pay for travel, accommodation, and meal expenses for one Owner and one engineering representative to witness all factory acceptance tests of the transformer. Assume travel from Ottawa for the Engineer and Embrun for the Owner Representative to the location of the factory where transformer is being tested. Assume local travel expenses, accommodations, and meals for one full day before tests begin until, and including, one full day after tests complete.
.2 Contractor to liaise with factory and be responsible for notifying Owner and engineer at least 15 business days before transformer is ready for final testing, providing locations, manufacturer contact information, test times, and other related information.
.3 Supplier or manufacturer to have conducted all required tests prior to the witness test by the Owner and engineer and determined that the system(s) are operating and functioning properly. Test documents shall be provided to the engineer at least 2 business days before FAT testing is scheduled.
.4 Subsequent site visits by the Owner and engineer as a result of the supplier or manufacturer’s failure to provide acceptable performance of the equipment shall be at the expense of the contractor, including the engineer’s time chargeable at the rate applicable and all travel expenses.
.5 Any costs associated with delays or cancellations of the FAT testing causing extra or subsequent visits to the factory by the Owner and engineer to be borne by the contractor. All costs will be substantiated by receipts and/or invoices.

2.12 8320V SWITCHES AND RECLOSERS

.1 CUTOUTS

.1 Open-type solid or fused cutout as indicated to ANSI C37.42.
.2 14.4kV nominal 15kV maximum, 95kV BIL, 200A, interrupting ratings as required by Power Systems Studies.
.3 Fuse current rating: 150% of transformer full-load current (typical)
.4 Include switch link instead of fuse for solid cutouts.

.2 RECLOSERS

.1 3-phase vacuum interrupter reclosers conforming to ANSI/IEEE C37.60-2003 American National Standards Requirements for Overhead, pad-mounted, dry vault, and submersible automatic circuit reclosers and fault interrupters for alternating current systems up to 38kV.

.2 Ratings:

.1 Maximum voltage: 15kV

.2 BIL (minimum): 95kV

.3 Continuous Current (minimum): 600A

.4 Interrupting Ratings: as determined by Power Systems Studies

.5 Mechanical Operations (minimum): 10,000

.3 Integral current and voltage sensors:

.1 Three Class 1 current transformers for protection, instrumentation and metering.

.2 Three voltage sensors for voltage measurement accurate to 1% and loss of voltage indication.

.4 Control:

.1 Control cabinet including solid-state protection relay, 120VAC input and integral battery backup.

.2 Programmable electronic control allowing operating characteristics to be modified without de-energizing recloser.

.3 Manufacturer supplied control cables as required for interconnection of reclosers and protection relays. Contractor to ensure cables are of sufficient length to suit mounting arrangement.

.5 Manual trip handle:

.1 Mechanically linked to trip and lockout all three phases simultaneously.

.2 Suitable for hot-stick operation.

.3 Shall not require external power for operation.

.6 Corrosion resistant galvanized mounting frame for pole/structure mounting c/w lifting lugs and provision for lightning arresters.

.3 Acceptable Manufacturers:

.1 ABB

.2 Eaton (Cooper)

.3 G&W

.4 General Electric

.5 S&C

.6 Schneider

.7 Thomas & Betts (Elastimold)

.4 SOLID-STATE PROTECTION RELAYS

.1 Automatic recloser control, compatible with and provided by the same supplier as the reclosers

.2 Internal battery and charger

.3 Phase, Neutral, and Ground overcurrent protection, both timed and instantaneous

.4 Customizable recloser logic

.5 DNP3, IEC 61850 and Modbus RTU Protocols over independent RS-232, and Ethernet ports.

.6 Embedded Web Server capable of displaying settings, metering data, and status reports.

.7 Minimum 3 digital inputs and 2 digital outputs standard.

.8 Integral metering capability, including the following:

.1 Power, Energy, and Demand

.2 Logging and Recording

.5 Acceptable Manufacturers:

.1 ABB

.2 Eaton

.3 General Electric (Multilin)

.4 Schneider (MiCom)

.5 SEL (Schweitzer)

2.13 PAD MOUNTED SECTIONALIZERS

.1 Switchgear to contain two load-interrupter switches capable of make-before-break switching between two incoming sources.

.2 Switchgear shall be of solid dielectric construction and vacuum interrupters or consist of a gas-tight tank containing SF6 gas

.3 The ratings for the integrated switchgear shall be as designated below:

.1 Frequency: 60Hz

.2 Short-Circuit Current, Amperes, RMS, Symmetrical: 25kA

.3 Voltage Class, kV: 15.5kV

.1 Maximum Voltage, 15.5 kV

.2 BIL Voltage, 95 kV

.4 Main Bus Continuous Current, Amperes: 600A

.5 Three-phase switching

.4 Enclosure construction shall be 'Tamper Proof' and designed to C57.12.28-2005 - IEEE Standard for Pad-Mounted Equipment - Enclosure Integrity

.5 Doors shall have a minimum of two hinges.

.6 Acceptable Manufacturers:

.1 ABB

.2 Eaton (Cooper)

.3 G&W

.4 S&C (Vista)

.5 Schneider

.6 Thomas & Betts (Elastimold)

.7 THREE-POLE LOAD INTERRUPTER SWITCHES

.1 Switches designed to C37.72 – IEEE Standard for Manually-Operated Dead-Front Padmounted Switchgear with Load/Interrupting Switches and Separable Connectors for Alternating-Current Systems.

.2 The switch shall be provided with an integral ground position that is readily visible through a viewing window to eliminate the need for cable handling and exposure to high voltage to ground the equipment.

.3 The switch shall be provided with an open position that is readily visible through a viewing window to eliminate the need for cable handling and exposure to high voltage to establish a visible gap.

.4 Continuous Current, Amperes: 600A

.5 Withstand rating in accordance with Power Systems Studies

2.14 UNDERGROUND DISTRIBUTION CABLE

.1 Single conductor, 500MCM, AL, class B stranded, 33% concentric neutral.

.2 Manufactured to CSA C68.3 for Tree Retardant Crosslinked Polyetheylene (TRXLPE)

.3 Insulation: 100% TRXLPE rated for 90ºC, for 15,000V, as defined in ANSI/ICEA S-94-649.

.4 Semi-conducting thermosetting polymeric stress control layer.

.5 LLDPE jacket rated minus 40ºC, coloured black with red stripes.

.6 Cable to implement water penetration protection to withstand 5psi water penetration tests per ICEA T-34-664

2.15 CONTROL TRANSFORMER

.1 Oil-filled outdoor transformer: to CAN/CSA C2.

.2 Transformers suitable for pole mounting substation.

.3 Primary voltage: 8320V, 60 Hz, single-phase.

.4 Secondary voltage: 240V-120V, single-phase mid-tap, 3 wire.

.5 Capacity, as required.

2.16 PANELBOARDS

.1 Panelboards: to CSA C22.2 No.29 and product of one manufacturer.

.1 Install circuit breakers in panelboards before shipment.

.2 In addition to CSA requirements manufacturer's nameplate must show fault current that panel including breakers has been built to withstand.

.2 250V panelboards: bus and breakers with symmetrical interrupting capacity as required by Power Systems Studies.

.3 Sequence phase bussing with odd numbered breakers on left and even on right, with each breaker identified by permanent number identification as to circuit number and phase.

.4 Panelboards: mains, number of circuits, and number and size of branch circuit breakers as required to supply loads, adhering to the requirements of the Ontario Electrical Safety Code.

.5 Copper bus with neutral of same ampere rating of mains.

.6 Mains: suitable for bolt-on breakers.

.7 Include grounding busbar with 3 of terminals for bonding conductor equal to breaker capacity of the panel board.

.8 NEMA-4X hinged enclosure, sealed, gasketted and suitable for pole/structure mounting.

.9 BREAKERS

.1 Breakers with thermal and magnetic tripping in panelboards, ground fault protection where required by the Ontario Electrical Safety Code.

.2 Main breaker: separately mounted on top or bottom of panel to suit cable entry. When mounted vertically, down position should open breaker.

2.17 BUS PIPE (IPS)

.1 Aluminum alloy seamless hollow tubular pipe manufactured by hollow ingot process in accordance with ASTM B241.

.2 Minimum ampacity: 1200A

2.18 CABLE CONNECTORS AND TERMINATIONS

.1 Provide stress cones for 15,000V concentric neutral XLPE cable.

.2 Provide copper long barrel compression connectors to CSA C22.2 No.65.

2.19 REMOTE TERMINAL UNIT (PART OF OPTIONAL PRICE)

.1 Internet-ready RTU for remote monitoring shall include the following:

.1 Embedded backup battery charger

.2 Integrated wireless cellular communications

.3 Embedded HTML5 web server with editor

.4 Security suite with authentication, encryption and firewall

.5 IP Pass-through, file transfer, email, and text messaging

.6 Modbus and DNP3 protocols

.7 Ethernet, USB, RS232, and RS485 ports

.8 Micro SD card for local archives, program back-up and remote start-up

.9 Mixed I/O configurations, 26 points (minimum)

.10 Expandable I/O

.11 Appropriate environmental controls must be provided to maintain temperature and humidity within operating limits of RTU.

2.20 INDUSTRIAL ETHERNET SWITCH (PART OF OPTIONAL PRICE)

.1 10/100Mbps unmanaged fast Ethernet switch, minimum 10 ports, for rugged use.

.2 Appropriate environmental controls must be provided to maintain temperature and humidity within operating limits of Ethernet Switch.

2.21 DIGITAL METERING SYSTEMS (PART OF OPTIONAL PRICE)

.1 Polyphase, digital electrical meter, capable of performing the following measurements:

.1 Power, Energy, and Demand

.1 Voltage and Current per phase, average, unbalance

.2 Power: real, reactive, apparent, power factor, frequency

.3 Energy: bi-directional, total, import, export, net

.4 Demand: block, rolling block, thermal, predicted

.2 Communications and I/O

.1 RS-232 ports, 1, for local programming

.2 Ethernet ports, 1, with Modbus TCP slave protocol

.3 Relay outputs (standard), 2, configurable for various alarms

.4 Analog output, 2, configurable for various parameters

.3 Revenue Metering & Standards

.1 ANSI C12.16 accuracy compliant

.2 ANSI C12.20 0.2 compliant, Class 10 & 20

.3 Instrument Transformer Correction

Part 3 Execution

3.1 HEALTH AND SAFETY

.1 Implement all appropriate health and safety regulations per Canada Occupational Safety and Health Regulations, Province of Ontario Occupational Health and Safety Act and Regulations for Construction Projects, CSA Z462, and other industry and applicable standards

3.2 DEMONSTRATION AND TRAINING

.1 Provide training on start-up, operation, shut-down of equipment, components and systems. Instructions to include features of controls, adjustment of set-points, information on servicing, etc.

.1 Provide 2 hours for new switches and sectionalizers.

.2 Provide 2 hours for new relays and reclosers.

.3 Provide 2 hours for cellular communications system and web interface (part of optional price).

.2 Demonstrate scheduled operation and maintenance of equipment and systems to Owner's personnel and their representatives two weeks prior to date of substantial performance.

.3 Owner will provide list of personnel to receive instructions, and will coordinate their attendance at agreed-upon times.

.4 Note that not all facility personnel will be available to be trained at the same time, and thus there will be at least two sets of training sessions to accommodate all personnel, potentially on separate days. Exact number and timing of sessions shall be confirmed by the Owner.

.5 Submit a detailed training plan for review and approval by Engineer at least 20 business days before any training. The plan shall include a listing of components, systems, and integrated systems and other topics that will be covered in the training period. The plans shall also include tentative dates and times for each training session. Provide list of persons and their qualifications as instructors.

.6 Provide a copy of the full O&M manual, or a dedicated training binder for review, which shall include all Operation and Maintenance information for each component and main subcomponents of all devices listed as requiring training for.

.7 Submit a training summary report within one week after completion of demonstration, that demonstration and instructions have been satisfactorily completed.

3.3 POWER SYSTEMS STUDIES

.1 Provide short circuit, device evaluation, coordination, and arc flash study from main 44kV fusing through the new 44kV-8.32kV transformer, down through the new relays and sectionalizers to the largest fuses on downstream feeders. Power systems studies to encompass the following scope:

- .1 Complete on site data gathering to obtain equipment ratings and conductor lengths.
- .2 Create system model of the electrical distribution system with ETAP or SKM's Power Tools for Windows power systems software.
- .3 Liaison with electrical utility to confirm actual source impedances, as required.
- .4 Complete a short circuit study and arc flash study for all potential system configurations including maximum and minimum utility fault levels.
- .5 Summarize the findings of the short circuit study and device evaluation study in table format including only relevant information.
- .6 Provide detailed time current curves showing the coordination between over current devices.
- .7 Provide a table summarizing the worst case arc flash levels at each piece of electrical equipment.
- .8 Compile all findings into a report sealed by a Professional Engineer.
- .9 Supply and install arc flash labels for all substation equipment. Labels shall be suitable for outdoor equipment.

3.4 GROUND GRID STUDY

.1 Provide ground grid study for the purposes of designing substation ground grid, and interconnecting to existing system, to achieve overall maximum impedance of 2 ohms. Ground grid study to encompass the following scope:

- .1 Perform 4 pole Wenner soil testing in a minimum of two separate locations to determine actual site soil resistivity conditions. Wenner testing will be completed with probe spacing up to a maximum of 30 meters and completed at 2 meter intervals.
- .2 The soil model shall be input into a ground grid computer simulation software program, as well as the existing ground grid, and various options shall be evaluated to determine ground grid design modifications required to achieve the 2 ohm resistance requirement. Hand calculations are not acceptable.
- .3 Specifications shall be updated to reflect the proposed ground grid design.
- .4 The resistance of the ground grid shall be evaluated for summer, spring and winter conditions.
- .5 Once the proposed ground grid modifications are implemented, fall of potential testing shall be completed to determine the actual ground grid resistance. The fall of potential test results shall be compared to computer simulations to determine if the original ground grid computer model's impedance reflects the actual ground grid impedance. If differences are noted, the ground grid simulations shall be modified to reflect actual conditions and the report will be revised at no additional cost. Recommendations shall be provided to modify if the required resistance is not achieved.

3.5 TOWER ERECTION DRAWINGS

.1 Provide tower erection drawings stamped by Professional Engineer for all new substation structures prior to manufacture and any foundation work. Drawings must indicate exact location of new structures, taking into account all existing and proposed new equipment structures in close proximity to ensure that required clearances can be met, adhering to all applicable codes & standards, and that new construction will not pose any safety hazard.

3.6 TESTING AND COMMISSIONING

.1 Provide or engage qualified services to perform new switchgear commissioning.
  - .1 Each person that will hold a station guarantee has to provide confirmation from their supervisor or manager that they are a 'Qualified' person, typically per OHSA or CSA Z462 requirements
  - .2 The said person(s) must then take the EUSA Work Protection Code course.

.2 Safety practices shall include, but are not limited to, OHSA, CSA Z462, WHMIS, OSHA 29 CFR 1910.146.

.3 Provide a final typed test report, which shall include a detailed deficiency list, comments, results, analysis, and recommendations, both in hardcopy and electronically.

.4 Provide the following minimum testing (after visual and mechanical inspection and cleaning) for all new switchgear supplied:
  - .1 SWITCHGEAR ASSEMBLIES, GREATER THAN 750V
    - .1 Perform tests on all instrument and control power transformers in accordance with relevant Section.
    - .2 Perform insulation resistance tests on each bus section.
    - .3 Perform an overpotential (hi-pot) test on each bus section.
    - .4 Perform a system function test.
    - .5 Verify the operation of switchgear cell heaters.
    - .6 Provide phasing across open points
  - .2 LOAD BREAK SWITCHES, GREATER THAN 750V
    - .1 Visual and Mechanical Inspection, provide all typical inspections and cleaning
    - .2 Perform insulation resistance tests on each pole, phase to phase and phase to ground with switch closed and across each open pole for one minute.
    - .3 Perform resistance measurements through all switch contacts with a low resistance ohmmeter.
  - .3 FUSES, GREATER THAN 750V
    - .1 Disassemble fuse units to inspect link conditions and record link nameplate data.
    - .2 Measure fuse resistance with a Low Resistance Test Set.
  - .4 CURRENT TRANSFORMERS
    - .1 Perform insulation resistance test of the current transformer.
    - .2 Perform a polarity test of each current transformer using the DC injection bumping method, or any automated method within an approved test set.
    - .3 Perform a ratio verification test by injecting a large enough amount of current through the primary circuit of the CT to be able get a measurable

amount of current from the secondary circuit of the CT, note the amount and calculate the measured ratio.

.4 Perform an excitation test on transformers used for relaying applications in accordance with ANSI/IEEE C57.13.1.

.5 VOLTAGE TRANSFORMERS

.1 Perform insulation resistance tests primary winding to ground with the secondary winding grounded.

.2 Perform a polarity test on each transformer to verify the polarity marks or H1 X1 relationship.

.3 Perform a turns ratio test on all tap positions.

.6 LIGHTNING ARRESTERS, GREATER THAN 750V

.1 Perform resistance measurements of ground connection with a low resistance ohmmeter.

.2 Perform an insulation resistance test.

.7 CABLES, GREATER THAN 750V

.1 Perform a shield continuity test on each power cable.

.2 Perform an insulation resistance test utilizing a megohmmeter with a voltage output of at least 5000 volts DC for cables rated greater than 750 volts AC. Individually test each conductor with all other conductors and shields grounded. Test duration shall be one minute.

.3 Provide VLF testing for all shielded power cables containing extruded dielectric insulation to IEEE 400.2 "Guide for Field Testing of Shielded Power Cable Systems Using Very Low Frequency (VLF)".

.8 SWITCHES, CUTOUTS

.1 Perform resistance measurements through bolted connections using low-resistance ohmmeter.

.2 Perform insulation resistance tests on each pole, phase-to-phase and phase-to-ground with recloser closed, and across each open pole for one minute, applying voltage in accordance with manufacturer’s recommendation.

.3 Measure contact resistance across each cutout.

.4 Perform dielectric withstand voltage test on each pole, phase-to-ground with cutout closed. Ground adjacent cutouts, if applicable. Test voltage shall be in accordance with manufacturer’s published data.

.9 PROTECTIVE RELAYS

.1 Verify tightness of mounting hardware and connections.

.2 Inspect targets and indicators.

.3 Ensure correct magnitude and polarity of power supply to relay including the verification of any external power supply voltage drop resistors inherent to the relay.

.4 Verify operation of all light emitting diode indicators.

.5 Set contrast for liquid crystal display readouts.

.6 Verify that all settings are in accordance with coordination study or setting sheet supplied by owner.

.7 Perform functional testing to verify all protective functions.

.8 Verify correct operation of metering functions.

.10 RECLOSERS

.1 Perform all mechanical operation and contact alignment tests on both the recloser and its operating mechanism in accordance with manufacturer's published data.

.2 Perform resistance measurements through bolted connections using low-resistance ohmmeter.

.3 Perform insulation resistance tests on each pole, phase-to-phase and phase-to-ground with recloser closed, and across each open pole for one minute, applying voltage in accordance with manufacturer's recommendation.

.4 Perform a contact/pole resistance test.

.5 Perform insulation resistance tests on all control wiring with respect to ground.

.6 Verify correct operation of integral voltage and current sensors, and position indicator.

.11 TRANSFORMERS, MEDIUM VOLTAGE, LIQUID FILLED

.1 Perform insulation resistance tests (two winding transformers). With all primary side (High) electrical connections shorted together and all secondary side (Low) electrical connections shorted together test High to Low with Low Grounded, Low to High with High Grounded, High and Low connected together to Ground. Calculate both DA and PI

.2 Perform turns ratio tests on all tap positions for all phases to ensure proper exercising of the off load tap changer.

.3 Perform insulation power factor/dissipation factor test (two winding transformers).

.4 Perform power factor/dissipation factor tests for all bushings rated above 2601 volt AC

.5 Perform excitation current tests in accordance with test equipment manufacturer's published data.

.6 Measure the resistance of each winding with an approved winding resistance tester, on all primary windings in each tap changer positions and on each secondary winding.

.7 Remove a sample of insulating liquid in accordance with ASTM D923. Sample shall be tested per ASTM D877, D974, D971, D1500, D1524, D1533, and D924.

.8 Remove a sample of insulating liquid in accordance with ASTM D3613 and perform dissolved gas analysis (DGA) in accordance with ANSI/IEEE C57.104 or ASTM D3612.

3.7 COMMUNICATIONS SYSTEM WORK (PART OF OPTIONAL PRICE)

.1 Configure new remote terminal unit to perform the following:

.1 Monitor digital inputs from transformer control panels (estimated total of 20).

.2 Monitor the following devices via ModBus/TCP:

.1 All new and existing digital metering systems (4)

.2 All new protective relays (4)

.3 Send SMS text messages in the event of warning(s) and/or alarm(s) from monitored devices. Contractor is responsible for customizing SMS text message content effectively communicate warning/alarm condition. Message contents to be reviewed and approved by owner and engineer prior to programming.

.4 Receive acknowledgement of warning/alarm SMS text messages; re-send message in the event that acknowledgement is not received within specified period of time, and/or send message to an alternate cellular number or numbers in a customized sequence until message is acknowledged.

.5 Program web page to display all monitored devices, metering data, status, and parameters. Contractor to submit page layout and information in advance for review by owner and engineer.

END OF SECTION

CONTRACT PRICE: The CONTRACTOR offers to perform the CONTRACT for the following amounts.

Base Contract:	Lump Sum Price	$
	HST	$
	Contract Price (including HST)	$
Additional Work (Drawing E03):	Optional Price	$
	HST	$
	Optional Price (including HST)	$

ADDENDA: The CONTRACTOR states that he has received the following ADDENDA which have been considered and taken into account in determining the Prices tendered in the Schedule of Prices.

Addendum Number	Date Issued	Number of Pages

Name of CONTRACTOR

Legal Status (Corporation, Partnership or Sole Ownership):

Mailing Address:

CONTRACTOR:	Witness:	Corporate Seal:
Signature	Signature	
Printed Name	Printed Name	
Address	Address	

Contractor to Complete and Detail the Following Price Breakdown (taxes excluded):

1. Power Transformer: ______________________________
2. Switchgear/Sectionalizers: ______________________________
3. 44kV Poles, Switches, Primary Metering: ______________________________
4. 44kV & 8.32kV Structures and Foundations: ______________________________
5. Reclosers and Relays: ______________________________
6. Low-Voltage and Control: ______________________________
7. Grounding & Ground Grid Study: ______________________________
8. Power Systems Studies: ______________________________
9. Testing & Commissioning: ______________________________
10. Miscellaneous (Other): ______________________________
11. Project Management, Overhead, and Profit: ______________________________

Total (to match Lump Sum price): ______________________________

Contractor to Provide List of Manufacturers, Providers, for the Following:

1. Power Transformer: ______________________________
2. Switchgear/Sectionalizers: ______________________________
3. Reclosers: ______________________________
4. Protection Relays: ______________________________
5. Communications (PLC): ______________________________
6. Ground Grid Study: ______________________________
7. Power Systems Studies: ______________________________

END OF SECTION

*CHEI provides the following information to satisfy the requirements listed in "**B. Evaluation criteria and information requirements for each project/activity**".*

Efficiency, Customer Value, Reliability

a. The main driver for the project is the increase of system load as a result of development and forecast future development. The load exceeds the normal capacity of its MS. In the near future the forecast load will exceed the emergency rating of the MS. This load forecast from the Stantec study (included in Appendix G) based on planned developments is the main driver for this project.

b. This project is high priority because the load on the existing MS exceeds the normal (ONAN) rating. Further, after October 2018 outside backups from Hydro One will not be available in the event of the loss of the station transformer through failure. At this time only a partial backup is available from Hydro One. The installation of a station is a "lumpy" investment for a small utility. Where multiple station transformers are replaced then the projects and costs may be staggered. However, with one replacement smoothing options may not exist.

c. CHEI considered the possibility of operating with the current equipment and then, in the event of a failure, responding by making an emergency purchase of a transformer and work required to install it and put it into service. This would put all the customers out of service for as long as it takes to purchase, transport, install and commission the equipment. There is no assurance that the appropriate capacity and voltage ratios transformer will be available, nor assurance of the age, condition and delivery time of the unit. Further, costs for the unit, transportation and the installation will likely be at a premium. This solution was not considered further. This was also the only alternative since Hydro One had already indicated that it could no longer provide a backup feeder supply nor could it provide a mobile unit substation.

The current approach is to maintain system reliability by installing a new unit substation which at a feeder level is interconnected with the old station, on a planned basis with a new unit sized to meet the system need with a minimum of premium expenses.

This approach:

- Prevents a long duration unexpected outage for the customers
- Minimizes the cost of the transformer replacement in the event of a transformer failure.
- Allows customers to be notified about outages in advance
- Allows for planned outages to have planned work completed
- Allows for better planning and efficient use of resources during construction
- Retains the old station and facilities so that at least partial redundancy is achieved should there be a failure with the new unit

With the new unit substation, the reliability is expected to be retained at the same high level.

Safety

By doing the work on a planned basis where there are no customers out of power except where planned means that worker safety is significantly enhanced. In addition the safety for the customers is enhanced since the unexpected loss of power as a result of a failure means the loss of basic necessities, especially those with young children and the elderly.

Cyber-security, Privacy

Not applicable.

Co-ordination, Interoperability

The approach ensures that equipment built to the appropriate standards is installed, preventing future potential problems.

Economic Development

Not applicable.

Environmental Benefits:

By reducing the transformer loading relative to its nameplate rating, the transformer efficiency would be slightly improved meaning that the losses would be lower with the new transformer.

The **category-specific requirements** for the project are addressed below.

This is a System Access project. It is needed as a result of load growth caused by new development which will continue until 2023 per the currently available information. CHEI has one MS and after 2018 will have no backup for any of its load from Hydro One, nor any reasonable expectation of any emergency equipment should the MS transformer fail in service. CHEI is adding a unit substation with a larger transformer and is retaining the old substation so that it has the ability to restore all or most of the power if the new transformer in the new unit station were to fail. So the project also as a by-product assists in partially addressing redundancy or reserve capacity.

System Access Historical expenditures have been as indicated below:

	2013	2014	2015	2016	2017
CATEGORY	Actual	Actual	Actual	Actual	Projected Y/E
	$	$	$	$	$
System Access	233,350	1,150,190	264,186	392,714	1,726,071

Table 7: Historical System Access Expenditure

The major contributors to these costs are identified below.

	2013	2014	2015	2016	2017
Partial Details	Actual	Actual	Actual	Actual	Projected Y/E
	$,000	$,000	$,000	$,000	$,000
New Subdivision	0	1,002	240	29	181
4th Feeder	166	67	0	260	0
Station	62	0	0	81	1.517

Table 8: Major Components of the Annual Costs in Table 7

These projects are all listed in Appendix A, the Historical Expenditures 2013 to 2017.

The timing of the project was determined by the load increase resulting from the development that was proceeding and forecast to continue until 2023. Also, changes to the current arrangement with Hydro One to supply limited backup power by October 2018, was a consideration.

Customer and third party input, except for Hydro One as noted above, played no role in the project. CHEI has an obligation to supply the power required by its customers. This was the prime driver.

The final cost of the project did not determine the timing of the project in a material way. CHEI, as a norm, tries to plan its utility plant to support customer driven subdivision work on a just in time basis but meeting the customers' requirements. This project was no different in this respect.

The final cost of the project is the result of the whole design to be implemented. The transformer was a significant cost and is largely determined by the size of transformer purchased. It was decided to purchase and install a unit that was adequate for the planning horizon. The remaining components of the new station indicated above and the interconnections with the old station also contributed to the cost. This is not a minimal upgrade to the station but improves the supply capability of the feeders and improved the feeder capacity and protection. It also solves the backup supply problem so the investment is very efficient in solving multiple issues. Costs are minimized by tendering the work and receiving competitive bids.

CHEI plan to recover all the costs through rates as well as through the increased energy sales provided by the new customers.

APPENDIX D

JUSTIFICATION DISTRIBUTION TRANSFORMER RENEWAL

Distribution Transformer Renewal

As part of the inspections carried out in 2017, 11 distribution transformers were identified that had cracked or damaged bushings and were leaking oil. These transformers are being replaced to prevent future power interruptions and prevent transformer oil from affecting the environment. The total cost of this project is $54,200 which is just beyond the materiality threshold of $50,000.

While the transformers were not in danger of failing with the current oil leakage, CHEI decided to replace the transformers in one project in the year following the inspection so that the work could be done on a planned basis fiscally as well as physically and to exercise stewardship over the environment.

By doing the work in 2018 care is taken to prevent leakage of oil into the environment within its service territory. The Castor River runs through the town of Embrun so CHEI is sensitive to environmental concerns.

This replacement of transformers is not related to any load increases. The work is planned to be started and completed in 2018. The transformers supply customers and no changes to the secondary circuits are contemplated as part of this project. This project will not impact O&M costs.

CHEI provides the following information to satisfy the requirements listed in “**Evaluation criteria and information requirements for each project/activity**”

Evaluation Criteria and Information Requirements for the Project

Efficiency, Customer Value, Reliability

As part of the plant inspection process these transformers were identified as being deficient because at least one of the bushings was cracked or damaged and leaking oil.

This is a project that must be addressed. Because of the environmental impact i.e. potential oil spill into the environment, it was decided to replace all the units in one year. This project is the only material project in 2018.

The project involves the replacement of 11 distribution transformers. It has no impact of system operation efficiency. It is a very cost-effective project. The customer benefit is that by performing this work now any potential oil spill clean-up is avoided. This project does not prevent any outages in the near term. If nothing is done an outage could result involving these transformers due to damaged insulators flashing over or water ingress into the oil derating the insulating strength of the oil.

Safety

None

Cyber Security, Privacy

None

Co-ordination, Interoperability

None

Economic Development

None

Environmental Benefits

As noted the project prevents oil from entering the environment.

Category-Specific Requirements for the Project

This is a System Renewal Project.

The forecast expenditures for System Renewal are listed below.

2018	2019	2020	2021	2022
Forecast	Forecast	Forecast	Forecast	Forecast
$	$	$	$	$
115,780	20,000	60,000	62,000	40,000

Table 9: System Renewal Expenditure Forecast 2018 to 2022

The projects that contribute to the total as listed below.

	2018	2019	2020	2021	2022
	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
Pole Replacement	41,500				
Transformer Replacement	54,280				
Elbow and Insert Replacement		20,000			
Porcelain Insulator replacement			20,000		
L/A & cutout replacement			40,000	62,000	40,000

Table 10: Projects that make the Major Contributions to the Category Total Expenditures

The transformers being replaced have been identified as deficient as a result of the regular inspection process. The project timing is determined by the relative priority of the defect. The poles and the transformers represent a top priority for renewal because they potentially impact reliability and in the case of the transformers also have a potential environmental impact if nothing is done.

No outages have occurred so there has not been customer impact yet.

CHEI replaces assets when they are at end of life. In the case of transformers when they have failed in service or if they are damaged in a way that the risk of failure in service is increased substantially or there are environmental consequences like oil leaks. These transformers meet these criteria and are planned to be replaced.

Should the units fail while in service there would be a trouble call per failure and possible overtime costs to replace the transformer and depending on the severity of the failure require spill containment and oil clean up. All this would cost more than the planned replacement proposed.

The replacement is like-for-like with no enhancements.

APPENDIX E

JUSTIFICATION LINE RELOCATION – ST. JACQUES RD

LINE RELOCATION ST-JACQUES RD

General Information on the Project

There is a rear lot power line that supplies the houses on St. Jacques Road north of Sainte Therese Blvd. This can be viewed at https://www.google.ca/maps/@45.2702519,-75.2741512,130m/data=!3m1!1e3 on Google maps.

This line is not on a registered easement and no rear lot easement exists. Even if an easement had existed CHEI would have done its best to accommodate the customers' requirement however it would have had more options in addressing the situation. The residents have not agreed to provide an easement. Also the currently vacant lot one lot in from the corner of St. Jacques and Sainte Therese Blvd on the north side of Sainte Therese Blvd has asked that the line be removed from the lot because the owner plans to build on the lot. This removes the supply to the homes north of Sainte Therese Blvd on the west side of St. Jacques Rd.

This project will remove the rear lot power line and transformers and secondary and convert the supply for the homes so that:

- Two services are supplied from an overhead transformer and pole on an easement supplied by primary from Sainte Therese Blvd
- Four secondary services are supplied from St. Jacques Rd. directly
- Three services are supplied from a laneway from a new overhead transformer on a new easement, supplied by primary from St. Jacques Rd

This project is planned to be constructed in 2019 with the start and finish dates within 2019 at a cost of $90,000. This project does not increase any load to the system as it is a replacement of existing rear lot facilities with front lot facilities to accommodate a customer request to remove power lines that have no legal right to be where they are currently located. CHEI has not completed comparable projects over the historical period. The work is being scheduled for 2019 so that proper customer engagement can take place and the project can proceed smoothly to completion within the budget set.

The project is consistent with the Board's investment evaluation criteria as shown below:

EVALUATION CRITERIA AND INFORMATION REQUIREMENTS FOR THE PROJECT

Efficiency, Customer Value, Reliability

The trigger for this project is the request by a customer to CHEI to remove a power line from his property. The power line was not on any registered easement or like instrument and thus CHEI has no choice but to comply with the property owner's request. Also no easements were available for the remainder of the line nor was anyone willing to grant any easement which would have made it possible for the line to remain and be supplied from the north end of the line rather than the south. Thus CHEI had no choice but to provide a supply from the street (St. Jacques Rd.) and make adjustments to the connections at the individual homes affected as required.

Since this is a customer request and CHEI has no legal right to occupy the land where the line is built it is a top priority for CHEI to meet the reasonable timing of the land owner's request to remove the line and provide new service to affected homeowners. CHEI, in the course of discussion with the parties involved, determined that 2019 was a timeframe that would meet the line removal requirement and would give CHEI the time to develop a detailed design of the adjustments to the affected services with customer consultations.

The project changes the supply from a rear lot to a front lot design. This does not impact system operation efficiency or cost effectiveness. There are benefits that accrue to the customer requesting the line to be removed from the property to accommodate development. Other affected customers do not benefit. The project has no measurable effect on reliability or outages.

The alternative that was pursued was to achieve the right to occupy the land where the line was built. This could not be achieved. Without this there was no alternative where the rear lot line remained possible.

Safety

Not applicable

Cyber-security, Privacy

Not applicable.

Co-ordination, Interoperability

Not applicable.

Economic Development

Not applicable.

Environmental Benefits:

Not applicable.

Category-Specific Requirements for the Project

The project is a System Access project. It is classified this way because the work is required due to a customer request that when complied with will leave other customers without a source of power. So this project meets the requirements of what the customer requested namely the removal of certain CHEI owned facilities from his property that CHEI has no legal right to refuse since it has no easements. The remaining work involves re-establishing the supply of power to the customers affected by this equipment removal.

A further complicating factor is that the entire rear lot line was not covered by an easement. CHEI was not able to achieve an agreement with the parties involved to grant and easement for the remainder of the existing line so a feed could be established from another point so the entire line needs to be removed. The new supply will be established from the street side of the homes on St Jacques Rd.

The timing of the project is customer driven based on his request. Completing the project in 2019 meets the customers' requirements.

The project costs were minimized by achieving an overhead design where this was possible. Only four services require underground installation and a secondary road crossing. Many options were considered to have an overhead solution but rear lot supply could not be achieved because of easements. Given that fact a partial overhead / partial underground solution was the best that could be achieved.

APPENDIX F

JUSTIFICATION FOR THE RENEWAL OF TRANSFORMER CUTOUTS AND LIGHTNING ARRESTORS

Justification for Cut-Out and Lightning Arrestor Renewal

Porcelain fused cut outs and porcelain air gap type arrestors are known to fail in service. Both devices create safety hazards when they fail in service. Typically the fused cut out will fail by breaking while being operated by a line crew and either cause a short circuit or leave the crew doing the switching hanging on to a live wire at the end of the insulated switch stick with no place to safely park the lead. Air gap lightning arrestors may fail explosively either in service or when a nearby device is operated and create a hazard for anyone in the immediate vicinity either general public or a worker. Both of these failure types and mechanisms have been documented. CHEI plans to address this equipment problem over 2 years. In an associated project in 2022 the remaining porcelain line cut outs are planned to be replaced.

General Information on the Project/Activity

Total capital spending this project is:

2020	$40K
2021	$62K
Total	$102K

Table 11 Project Total Spending

The spending on a similar project for the replacement of porcelain cut out only replacement in the remainder of the power system is expected to be $40k and will be done in 2022.

This project does not alter customer attachments or loads.

The project starts in 2020 and completes in 2021. As indicated the remaining system cutouts only will be replace in 2022.

The project is straight forward and is expected to be completed in accordance with the plan.

No comparative projects were carried out in the historical period.

No “Leave to Construct” approval under Section 92 of the OEB Act is required.

Evaluation Criteria and Information Requirements for each Project/Activity

Efficiency, Customer Value, Reliability

The main trigger for this project is public and worker safety. While no events have occurred the failure of these devices is well known in the industry. While CHEI has an enviable reliability record and has not had safety events take place historically, it is also a known fact that the failure mechanisms of lightning arrestors in particular have the potential for major safety events. Being aware of what could happen to the public as well as their workers CHEI is addressing this potential risk by removing it. Being a small entity it has a relatively small number of these devices and is able to address it over a two year period of time at a moderate cost.

The priority of this project is relatively low. The pole and transformer replacement and the load break elbow and insert replacement all have more urgent needs because the impact is more immediate and probable.

The project replaces existing devices with new devices that have a better design that has better safety characteristics. Hence system operation efficiency is not affected. Also the replacement is prior to any history of failures so reliability is not improved but because the failures of the old equipment is deemed to be inevitable failures are prevented and reliability is maintained at the high level CHEI has attained to date. The customers will not be exposed to the hazards associated with Lightning arrestor failures and the crew environment will also be safer with the new equipment in service.

Safety

Public and worker safety have been key considerations for this project. As described above the failure mechanisms provide real hazards to the public and the worker. By removing the old failure prone equipment with current standard equipment these hazards are removed and the risk is mitigated.

Cyber-security, Privacy

Not applicable.

Co-ordination, Interoperability

Not applicable

Economic Development

Not applicable.

Environmental Benefits:

Not applicable.

Category-Specific Requirements for the Project

This is a System Renewal Project.

The forecast expenditures for System Renewal are listed below.

2018	2019	2020	2021	2022
Forecast	Forecast	Forecast	Forecast	Forecast
$	$	$	$	$
115,780	20,000	60,000	62,000	40,000

Table 12: System Renewal Expenditure Forecast 2018 to 2022.

The projects that contribute to the total as listed below.

	2018	2019	2020	2021	2022
	Forecast	Forecast	Forecast	Forecast	Forecast
	$	$	$	$	$
Pole Replacement	41,500				
Transformer Replacement	54,280				
Elbow and Insert Replacement		20,000			
Porcelain Insulator replacement			20,000		
L/A & cutout replacement			40,000	62,000	40,000

Table 13: Projects that make the Major Contributions to the Category Total Expenditures

CHEI has taken the approach that the items most at risk need to be replaced first. This means the poles that failed inspection and transformers with oil leaks and cracked insulators. Next is the completion of Load break elbow and insert replacement program. These devices are used whenever switching takes place on the underground system. CHEI then addresses devices on its system that although it has not experienced problem yet it is well known in the industry that the devices have known problems and defects that affect reliability and crew safety. These programs are carried out on a modest pace demonstrating due diligence and financial stewardship.

APPENDIX G

STANTEC LOAD AND VOLTAGE STUDY

Note: Double click on next page to open the report.

Coopérative Hydro Embrun Inc.

Utility Load Flow and Evaluation Study

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December 20, 2016

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Issued for Final

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1 INTRODUCTION

Stantec Consulting Ltd. is pleased to submit this Utility Load Flow Study of the electrical distribution system of the Cooperative Hydro D'Embrun Inc. This study has been prepared in accordance with relevant standards, including the Ontario Electrical Safety Authority (ESA), National Electrical Manufacturer's Association (NEMA), Institute of Electrical and Electronic Engineers (IEEE), Municipal Electrical Association (MEA), Canadian Standards Authority (CSA), and the American National Standards Institute (ANSI).

1.1 Objectives and Scope of Studies

There were a number of objectives for this study, including:

- Determining the acceptability of the system with current and future load growth, including loading that has been recently defined for the next 10 year period from 2016 to 2026
- Finding whether the system would operate acceptably during emergency situations.
- Optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.

1.2 Scope of Studies

The Load Flow Study includes all feeders from and including the 44kV Utility Substation down to each major tap at the 8.32(4.8)kV level, no secondary lines were included. All loads were represented as spot loads in the middle of the distribution segments, and are shown on the system model layout under Appendix A.

1.3 Assumptions

A number of assumptions and generalizations are made when modelling a complex system. Some of the ones made in this study are as follows:

- Loads are modelled as spot loads placed in the center of the section with loads sized using measurements made at strategic points within the system during the day of September 2016.
- Each feeder's loads were modelled at a Power Factor of 0.9.
- The drawing 'Utility Single Line Diagram' completed on March 11th, 2016 was used as the basis of the system model, with site data gathering completed in September 2016 to determine loading.
- The new subdivision that is planned to be constructed in 2018 on the west side of St. Marie Road was modeled using 370 houses based on the developer's proposed predesign layout.

Listed below are discrepancies between field loading data and transformer's phase information as supplied by Hydro Embrun single line. If actual transformer phasing differs from this report, Stantec should be notified as soon as possible so the report and single line can be updated.

1. Transformer #33-150 does not appear to be on Feeder 1 as the transformer is a three phase transformer and the spot measurement taken upstream of the transformer showed no current measurement on red or white phases. Therefore, it was assumed that transformer #33-150 was fed from Feeder 2 strictly for the purpose of determining the demand load of the transformer. However, when performing the voltage drop and equipment overload the transformers were modelled as if they were on feeder 1.

2. Transformer #552-25 does not appear to be on red phase as indicated. The spot measurement taken upstream of the transformer showed no current measurement on red but there was current on blue phase. Therefore, it was assumed that transformer #552-25 is on blue phase.

3. It is believed that the open point between feeder 1 & 2 is at switch S#846. This is due to no current measured at this location and where the open point should have been S#845 there was measured current on all three phases. Therefore, for determining the load of the transformers between these points the demand load was modelled as if switch S#845 is closed and S#846 is open. However, when performing the voltage drop and equipment overload the transformers were modelled as if they were on feeder 1.

4. Transformers #472-75 and #473-50 do not appear to be on red phase as indicated. The spot measurement taken upstream of the transformers showed no current measurement on red but there was current on white phase. Therefore, it was assumed that the transformers are on white phase.

5. Transformers #426-25 and #427-75 do not appear to be on white phase as indicated. The spot measurement taken upstream of the transformers showed no current measurement on white but there was current on red phase. Therefore, it was assumed that the transformers are on red phase.

6. Transformers #433-167, #435-75, #436-50 and #437-100 do not appear to be on red phase as indicated. The spot measurement taken upstream of the transformers showed no current measurement on red phase but there was current on white and blue phase. Due to white phase having a much higher current measurement than blue phase it was assumed that the transformers are on white phase.

7. Transformers #513-50 and #514-50 do not appear to be on white phase as indicated. The spot measurements that were taken upstream of the transformers showed no current on white phase but there was current on blue phase. Therefore, it was assumed that the transformers were on blue phase.

8. Transformers #528-100, #529-75, #530-50, #531-75 and #532-75 do not appear to be on white phase as indicated. The spot measurement taken upstream of the transformers showed no current measurement on white but there was current on blue phase. Therefore, it was assumed that the transformers are on blue phase.

2 STUDY FINDINGS

2.1 Distribution System Equipment Ratings

The main equipment within the Embrun Hydro substation is listed below, along with the ratings that are used to evaluate these components for various loading scenarios.

Table 1 – System Components Ampacity

Transformer Substation		
System Components	***Rating***	***Ampacity @ (8.32kV (44kV)***
44kV Switch	Contiuous Amps	3173A (600A)
44kV Fuses	Contiuous Amps	1015A (192A)
S&C Electric SMD-1A, 175E	Daily 8 hour peak	1037A (196A)
Standard Speed TCC 153-1	Emergency 8 hour peak	1185A (131A)
44,000/8320V Transformer	Continuous Amps ONAN rating	520A (98A)
Delta/Wye (Grnd), Z=6.4%	Continuous Amps ONAF rating	693A (131A)
7.5MVA/10MVA, ONAN/ONAF		
8.32kV Secondary Switchgear	Continuous Amps	1200A
Rated Voltage 15kV, 1200A, 95kV BIL		
Feeders 1, 2, 3		
8.32kV Feeder Switches, S&C Alduti	Contiuous Amps	600A
8.32kV Feeder Fuses	Contiuous Amps	300A
S&C SM-5, 300E	Daily 8 hour peak	306A
Standard Speed TCC 153-4	Emergency 8 hour peak	320A
Feeders 4		
8.32kV Feeder Switches, S&C Mini	Contiuous Amps	600A
8.32kV Feeder Fuses	Contiuous Amps	400A
S&C SM-5, 300E	Daily 8 hour peak	404A
Standard Speed TCC 153-4	Emergency 8 hour peak	419A

Note that the factor limiting capacity within the substation is the transformer, with an 8.32kV rating of 520A without fans, and 693A with the fans operating. Feeders 1, 2 and 3 are each rated for a continuous loading of 300A, while feeder 4 is rated for 400A or a total of 1300A for all four feeders combined. In October 2017, upgrades to the 44kV – 8.32kV substation are expected to be complete which will provide additional capacity as well as full redundancy. The new transformer will be capable of supporting the entire system load in the event that the existing transformer is out of service for maintenance or repair. The new transformer will be 10/13.33MVA, 33% larger than the existing transformer to provide full redundancy, while allowing for anticipated load growth over the next 15-20 years.

The various conductors within the distribution system are also rated below. Please note that the rating of feeder #3's 350MCM CU, and feeder #4's 500MCM AL cables are based on Table D17C of the Ontario Electrical Safety Code. Also, while insulated cables have a fairly limited set of current ratings (typically free air, raceway, or direct buried ratings), ACSR cables have a wide range of ratings, based on ambient temperatures, peak conductor temperatures, cross winds, emissivity of the conductor, and sun heating. The following conductor ratings are standard ratings, based on maximum absolute conductor temperatures of 105˚C, ambient temperatures of 30˚C (Summer) and 10˚C (Winter), 0.6 m/sec (2 feet/sec) of cross wind, 0.7 coefficient of emissivity, and full sun.

Table 2 – Conductor Ampacity

Cable Type	*Rating*	*Ampacity @ 30˚C Ambient*	*Ampacity @ 10˚C Ambient*
Cable - 500 MCM 1/C AL XLPE 100%	Continuous Amps	372	372
Cable - 350 MCM 1/C CU XLP 100%	Continuous Amps	375	375
Cable - 2/0 AWG 1/C Alum TR-XLP 100%	Continuous Amps	188	188
ACSR - 336 kcmil 26/7	Continuous Amps	647	733
ACSR - 3/0 AWG	Continuous Amps	370	419
ACSR - 1/0 AWG	Continuous Amps	288	326
ACSR - #2 AWG	Continuous Amps	228	285
ACSR - #4 AWG	Continuous Amps	172	215

Feeders 1, 2 and 3 use 350MCM 1/C CU XLP cables in direct-buried 4-inch ducts for the runs between the 8.32kV switchgear and the overhead distribution lines, while feeder 4 uses 500MCM 1/C AL XLPE cables for those runs. The largest feeder switches are at least 300 Amps, and are currently evaluated as 300 amps, to ensure that all normal and emergency situations which may be above that level are flagged properly. Most main line (F1/F2/F3 trunk) feeder switches are either 400 or 600 Amps, with solid blades, whereas the majority of the feeder switches within this system are rated for either 100 or 200 Amps, with various fusing used, typically in the range of 70 to 100 Amps. Typically winter ratings of these switches are at least 25% higher than summer ratings due to the lower ambient temperature, and are rated that way within this study. It would be beneficial to add all confirmed switch and fuse ampacities to the system utility diagram at some point in the future. The switches S#818, S#819, and S#822 are modelled as 200 Amp units, S#809 as a 300 Amps, S#846 as a 100 Amps and the F1, F2, and F3 feeder dip pole and ties have been modelled as 400 Amp switches.

2.2 Distribution System Loading

The study is based on current measurements taken within all the main feeders of the system on September 2016 during normal business hours, and the total measured was 2,843 kVA. Typically, system peaks with heavy residential loads occur early morning and later afternoon/evening, and thus these readings are extrapolated for summer and winter peak monthly loading to evaluate worst case conditions. Using billing data from Embrun Hydro we can see the peak monthly demand loading in the following graph:

Table 3 – Monthly Peak Demand

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Max
JANUARY	6,624.00	6,286.00	6,346.00	6,531.00	6,862.00	6,436.00	6,744.00	6,239.00	6,570.00	6,887.63	6,633.65	5,971.95	6,887.63
FEBRUARY	5,564.80	5,942.00	6,385.00	6,068.00	6,326.00	5,838.00	5,925.00	5,798.00	6,126.00	5,778.12	6,204.54	6,235.96	6,385.00
MARCH	5,561.60	5,519.00	6,372.00	5,485.00	5,808.00	4,779.00	5,250.00	5,273.00	5,013.00	5,711.29	5,437.25	5,310.26	6,372.00
APRIL	4,358.40	4,407.00	4,562.00	4,576.00	4,779.00	4,294.00	4,598.00	4,291.00	4,366.00	4,375.30	5,159.88	4,588.41	5,159.88
MAY	4,132.00	5,231.00	4,536.00	3,699.00	3,963.00	6,149.00	5,487.00	5,180.00	5,598.00	4,484.81	5,199.98	5,744.71	6,149.00
JUNE	5,611.00	5,065.00	5,730.00	5,687.00	5,731.00	5,467.00	5,979.00	6,607.00	5,685.00	5,464.00	6,162.44	6,162.00	6,607.00
JULY	5,548.00	5,902.00	5,433.00	5,304.00	4,839.00	6,567.00	6,573.00	6,152.00	6,369.64	5,774.78	6,205.89	6,056.00	6,573.00
AUGUST	5,350.00	5,155.00	5,833.00	5,730.00	6,052.00	6,520.00	5,441.00	5,925.00	5,985.00	5,734.68	6,219.25		6,520.00
SEPTEMBER	5,108.00	4,169.00	5,545.00	5,793.00	4,428.00	5,835.00	5,227.00	5,858.00	5,049.59	5,484.04	4,421.32		5,858.00
OCTOBER	4,539.00	4,801.00	4,519.00	6,005.00	4,719.00	4,535.00	4,508.00	4,365.00	4,722.09	4,147.28	4,451.32		6,005.00
NOVEMBER	5,509.00	5,237.00	5,754.00	5,671.00	5,464.00	5,414.00	5,290.00	5,624.00	5,851.65	5,173.24	5,230.05		5,851.65
DECEMBER	6,558.00	5,998.00	7,084.00	6,974.00	6,854.00	6,330.00	6,393.00	6,309.00		6,022.08	5,607.89		7,084.00
ANNUAL PEAK	6,624.00	6,286.00	7,084.00	6,974.00	6,862.00	6,567.00	6,744.00	6,607.00	6,570.00	6,887.63	6,633.65	6,235.96	7,084.00

Using the maximums from this table gives a baseline value of 6,607kW for Summer Peak Demand and 7,341kW for Winter Peak Demand for 2016. The peaks are also graphed below to see the individual monthly loading trends over the years:

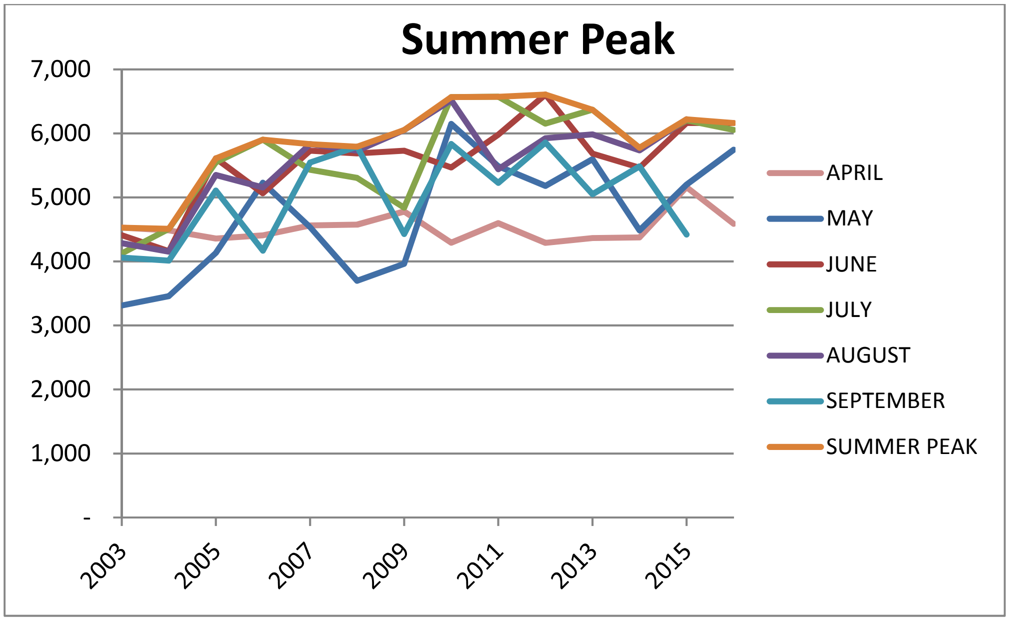


Figure 1: Summer Peak Demand

As can be seen, summer peaks have steadily climbed over the years because of system growth and other items such as air conditioning and pool installations. However, the most recent summer loadings appear to be plateauing when compared to previous years.

The following graph shows winter peaks, which are typically a function both of load growth and winter temperature, since improved energy efficiency and transitioning from baseboard heating to forced air helps offset system growth. Most new houses usually have natural gas heating, and thus do not represent a significant additional winter load, unlike older electrically heated houses.

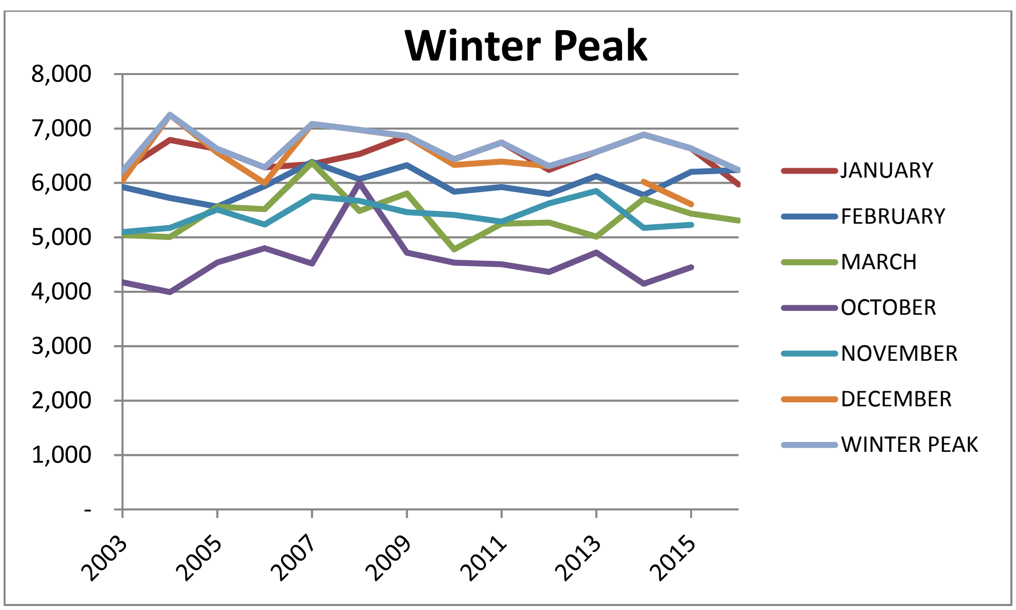


Figure 2: Winter Peak Demand

The distribution of loads within the system will not have changed substantially. Thus we scale the base loading measurements of 2016 to the summer and winter peak values of 7,341 kVA (or 6,607 kW) and 7,871 kVA (or 7,084 kW) respectively. Please note, all four feeders were scaled equally, however, Feeder F1 with more of its load as commercial vs. the majority residential elsewhere, may have some natural balancing since commercial will typically peak during the day, while residential will peak in mornings and late afternoons. However, this effect was not evaluated since we did not have any daily feeder trending values to review.

Table 4 – Current 2016 Peak Demand Loading

Current 2016 Peak Demand Loading							
Feeder	**Phase**	**Amps-Measured**	**kVA - Measured**	**Adj. Amps Summer**	**Adj. KVA - Summer**	**Adj. Amps Winter**	**Adj. kVA - Winter**
Feeder 1	R	57.1	274.1	147.5	707.8	158.1	758.9
	W	60.5	290.4	156.2	750.0	167.5	804.1
	B	60.1	288.5	155.2	745.0	166.4	798.8
Feeder 2	R	77.6	372.5	200.4	962.0	214.9	1031.4
	W	80.2	385.0	207.1	994.2	222.1	1066.0
	B	86.7	416.2	223.9	1074.8	240.1	1152.4
Feeder 3	R	38	183.8	98.9	474.8	106.1	509.1
	W	58	279.8	150.6	722.7	161.4	774.9
	B	57	272.2	146.4	702.9	157.0	753.6
Feeder 4	R	10	48.0	25.8	124.0	27.7	132.9
	W	5	23.5	12.7	60.7	13.6	65.1
	B	2	8.6	4.6	22.3	5.0	23.9
		kVA Total:	2842.6		7341.1		7871.1

As can be seen, the kVA peaks are higher in winter, indicative of substantial electrical baseboard heating in older residential neighbourhoods. As winter load remain relatively stagnant over the last 10 years the summer loads have been steadily rising.

2.3 Future Load Growth

The distribution system and its components must be evaluated both under existing and future loading to properly plan and sequence future capital upgrades. Most municipal utility's loads will grow over time due to a variety of reasons, with the main contributors listed below:

- Existing customers add load (pool pumps, new air conditioners, etc.)
- New developments or single in-fill customers are added within the Utility boundary.
- The Utility boundaries are enlarged.

We are estimating that natural load usage growth of existing customers will be no more than 1% per year. The additional energy usage typical of more air conditioners, computers, TV's, and other electronic goods will be offset by the additional transitioning to energy efficient lighting, baseboard to forced air replacements, replacement of old appliances with new reduced consumption units, and other energy efficient changes.

The client base within Embrun contains 1,954 residential units, 181 commercial units less than 50kW, and 11 commercial units greater than 50kW. As most commercial units are already natural gas heated, we assume the small commercial units are all an average of about 15kW, while the large units are on average 100kW, gives the following kW Demand per unit (based on peak 2006 winter conditions):

- Residential units = 3,269kW total, or 1.67kW/unit (equivalent to 1.86kVA at 0.9PF)
- Smaller Commercial = 15kW/unit, or 2,715kW total
- Large Commercial = 100kW/unit, or 1,100kW total

We assume most developed areas have currently been in-filled close to capacity. However, the following areas are proposed for future in-fill development during the following time periods, with an estimated units/development and the preferred feeder for connection (based on location and existing feeder capacity). As the subdivisions are not fully developed in the first year of construction it was assumed that the development will take 5 years with 50% of the buildings constructed in the first year and 12.5% every following year:

- South-East of Ste Marie and Castor 2016, 306 units under development, F03
- South-West of Ste Marie and Notre-Dame 2016, 61 units under development, F03
- North-East of Notre-Dame and Rue Manoir 2017, 41 units, F02
- North of Rue Blais at Notre-Dame 2019, 40 units, F03
- South-East of St Jacques and the Castor 2019, 50 units, F02
- South-East of Ste Marie and Notre-Dame 2019, 150 units, F03
- South-West of Ste Marie and the Castor 2019, 370 units, F04

With this proposed development schedule, and each additional residential house at an average peak Demand of 1.67kW or 1.86kVA as was derived above, the future additional kVA Demand loading forecast for the complete system is shown below:

Table 5 – Future Peak Demand Loading

	Peak Annual Loading												
Period (Demand kVA)	***Current***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***	***2027***
Summer	7341	7719	7894.5	8633.6	8963.6	9296.9	9535.0	9775.4	9873.1	9971.9	10071.6	10172.3
Winter	7871	8249	8429.8	9174.3	9509.7	9848.4	10092.0	10338.0	10441.4	10545.8	10651.3	10757.8
Normal Growth			1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Future Development F2		37	11	52	24	24	13	13				
Future Development F3		340	87	264	132	132	45	45				
Future Development F4				344	87	87	87	87				

Assuming all new future development is added to the local feeder in a method that tends to balance the phases or each feeder, future summer and winter peak loading for each feeder would be as follows:

Table 6 – Future Peak Summer Loading

Peak Summer Loading												
Period (Demand kVA)		***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***
Feeder 1	R	147.5	148.9	150.4	151.9	153.5	155.0	156.5	158.1	159.7	161.3	162.9
	W	156.2	157.8	159.4	161.0	162.6	164.2	165.9	167.5	169.2	170.9	172.6
	B	155.2	156.8	158.3	159.9	161.5	163.1	164.8	166.4	168.1	169.8	171.5
Feeder 2	R	200.4	202.4	216.4	218.6	220.8	223.0	225.2	227.4	229.7	232.0	234.3
	W	207.1	209.2	223.3	225.5	227.7	230.0	232.3	234.6	237.0	239.4	241.8
	B	223.9	226.1	240.4	242.8	245.2	247.7	250.1	252.6	255.2	257.7	260.3
Feeder 3	R	98.9	99.9	107.4	108.4	133.8	135.1	136.5	137.9	139.2	140.6	142.0
	W	150.6	152.1	160.1	161.7	187.6	189.4	191.3	193.2	195.2	197.1	199.1
	B	146.4	147.9	155.8	157.4	183.3	185.1	186.9	188.8	190.7	192.6	194.5
Feeder 4	R	25.8	26.1	26.3	50.5	57.1	63.7	70.4	76.5	77.3	78.1	78.9
	W	12.7	12.8	12.9	36.9	43.4	49.9	56.4	62.4	63.1	63.7	64.3
	B	4.6	4.7	4.7	28.7	35.0	41.4	47.9	53.8	54.4	54.9	55.5

Table 7 – Future Peak Winter Loading

Peak Winter Loading												
Feeder	***Phase***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***
Feeder 1	R	158.1	159.7	161.3	162.9	164.5	166.2	167.8	169.5	171.2	172.9	174.7
	W	167.5	169.2	170.9	172.6	174.3	176.1	177.8	179.6	181.4	183.2	185.1
	B	166.4	168.1	169.8	171.5	173.2	174.9	176.7	178.4	180.2	182.0	183.8
Feeder 2	R	214.9	217.0	231.2	233.5	235.8	238.2	240.6	243.0	245.4	247.8	250.3
	W	222.1	224.3	238.5	240.9	243.3	245.7	248.2	250.7	253.2	255.7	258.3
	B	240.1	242.5	256.9	259.4	262.0	264.7	267.3	270.0	272.7	275.4	278.2
Feeder 3	R	106.1	107.1	114.7	115.8	141.2	142.6	144.1	145.5	147.0	148.4	149.9
	W	161.4	163.0	171.2	172.9	198.9	200.9	202.9	204.9	206.9	209.0	211.1
	B	157.0	158.6	166.6	168.3	194.3	196.2	198.2	200.1	202.1	204.2	206.2
Feeder 4	R	27.7	28.0	28.2	52.4	59.0	65.7	72.4	78.5	79.3	80.1	80.9
	W	13.6	13.7	13.8	37.9	44.3	50.8	57.4	63.4	64.0	64.7	65.3
	B	5.0	5.0	5.1	29.0	35.4	41.8	48.3	54.2	54.7	55.3	55.8

3 NORMAL CONDITIONS EVALUATION

3.1 Loading Assessment

The loading assessment for the distribution with a normal switching configuration and loads from 2016 to 2026 is shown below:

Table 8 – Future Peak Annual Loading

Peak Annual Loading (Winter)															
Feeder	Phase	Rating	Current 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1015	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		520	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		693	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV Switchgear		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Continuous)		300	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Daily 8 hour)		306	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Emergency 8 hour)		320	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
Feeder 1	R	375	158.1	159.7	161.3	162.9	164.5	166.2	167.8	169.5	171.2	172.9	174.7	176.4
	W	375	167.5	169.2	170.9	172.6	174.3	176.1	177.8	179.6	181.4	183.2	185.1	186.9
	B	375	166.4	168.1	169.8	171.5	173.2	174.9	176.7	178.4	180.2	182.0	183.8	185.7
Feeder 2	R	375	214.9	219.6	222.6	228.4	232.4	236.4	239.6	242.9	245.4	247.8	250.3	252.8
	W	375	222.1	226.9	229.9	235.8	239.9	243.9	247.3	250.7	253.2	255.7	258.3	260.8
	B	375	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
Feeder 3	R	375	106.1	130.7	138.1	157.8	168.6	179.4	184.3	189.2	191.1	193.0	195.0	196.9
	W	375	161.4	186.7	194.6	214.9	226.2	237.6	243.1	248.6	251.1	253.6	256.1	258.7
	B	375	157.0	182.2	190.1	210.3	221.6	233.0	238.4	243.9	246.3	248.8	251.3	253.8
Feeder 4														
8.32kV Feeder Switches		400	27.7	28.0	28.2	28.5	28.8	29.1	29.4	29.7	30.0	30.3	30.6	30.9
8.32kV Fuses (Continuous)		400	27.7	28.0	28.2	28.5	28.8	29.1	29.4	29.7	30.0	30.3	30.6	30.9
8.32kV Fuses (Daily 8 hour)		404	27.7	28.0	28.2	28.5	28.8	29.1	29.4	29.7	30.0	30.3	30.6	30.9
8.32kV Fuses (Emergency 8 hour)		419	27.7	28.0	28.2	28.5	28.8	29.1	29.4	29.7	30.0	30.3	30.6	30.9
Feeder 4	R	372	27.7	28.0	28.2	52.4	59.0	65.7	72.4	78.5	79.3	80.1	80.9	81.7
	W	372	13.6	13.7	13.8	37.9	44.3	50.8	57.4	63.4	64.0	64.7	65.3	66.0
	B	372	5.0	5.0	5.1	29.0	35.4	41.8	48.3	54.2	54.7	55.3	55.8	56.4

As can be seen, current peak loading of 7,871.1kVA (winter) is above the capacity of the transformer if fans were not present, but within the capacity of the transformer with existing fans operating. Note, the maximum peak is during the winter which is a time of fairly low ambient temperature and would provide the transformer more capacity than normal. The municipal transformer is now 28 years old, with typical life expectancies ranging from 30-40 years for well maintained oil-filled power transformers. In 2022, the completion of the new subdivision and infill will cause the system loading to surpass the ONAF (fan rated) capacity of the single transformer. Within municipal distribution systems some peak overloading is occasionally acceptable, since the peaks are typically short lived (< 4 hours) and not continuous. However, it should be noted that as the age of the transformer increases, the possibility of failure also increases. Redundancy when supplying the Embrun system is already an issue, as the emergency infeeds from Hydro-One may not be sufficient during peak times of the day to support the complete system in the event of the failure of the main transformer. The addition of a new transformer to the substation in 2017 will address these capacity and redundancy issues.

To evaluate the present and future loading on the feeders, the graph shows the proposed load growth added to the feeders that they are near, plus attempting reasonable phase balancing with the additional loads. Since the main conductors for feeders 1, 2, and 3 networks are 336 kcmil, the limiting factor in each circuit becomes the underground 350MCM CU cable from the substation. As such, the ratings in the table represent the ampacity of feeders 1, 2, and 3 underground cables rather than the main overhead circuit conductors. It can be seen that the loading within the feeder conductors are acceptable, but are reaching the capacity of the feeder fuses, during peak operation.

All other components within the distribution networks, including switches and conductors, seem to be adequate to support the normal load growth expected through the year 2026.

3.2 System Losses

With the existing nominal system loading is 2,838.45 kVA (losses inclusive), distribution losses (including substation losses) total 10.38 kW, approximately 0.40% of system loading. At peak summer loading of 7,344.5 kVA, losses total 69.74 kW, approximately 1.06% of system loading. At peak winter loading of 7874.56 kVA (losses inclusive), losses total 80.22 kW, approximately 1.13% of system loading.

There were some unbalanced currents as shown in the table that follows. Keeping the currents in the phases balanced reduces energy losses, as return currents travel through undersized neutrals and the overall inductance of the line is higher.

Table 9 – System Losses

Feeder	Phase	Amps - Measured	Avg.	(%)	Preferred Rephasing	Final	(%)
Feeder 1	R	158.41			6.46	164.87	
	W	167.79	164.3	3.58	-2.35	165.44	1.05
	B	166.71			-4.15	162.56	
Feeder 2	R	215.41			8.63	224.04	
	W	222.7	226.28	6.39	6.85	229.55	1.46
	B	240.74			0	225.13	
Feeder 3	R	106.19			35.96	142.15	
	W	162.17	141.93	25.18	-20.99	141.18	0.47
	B	157.43			-16.31	141.12	
Feeder 4	R	27.72			-11.6	16.12	
	W	13.6	15.44	79.53	0.4	14	9.28
	B	5			11.17	16.17	

Possible options to rebalance are as follows:

1. F1: 542-50-R to B, 453-75-B to R, 544-75-W to R, 545-75-B to R and 546-100-W to R,
2. F2: 82-50-R to B, 83-50-B to R, 84-R to B, 85-50-B to R and 86-50-B to R
3. F3: 406-75-W to R, 407-50-W to R, 409-50-W to R, 411-50-W to R, 430-50-B to W, 431-100-W to B, 432-100-B to W 527-50-B to W and 536-75-B to W
4. F4: 1000-167-B to R, 1001-167-R to B, 1003-B to R and 1006-25-R to B

Note that the future loading additions from 2016 to 2020 would also be good opportunities to rebalance the loading, and may preclude the requirements to change existing distribution arrangements at additional costs.

3.3 Feeder voltages under normal operation

As per CAN3-C235-83 'Preferred Voltage Levels for AC Systems, 0 to 50,000V' all service entrance voltages should be no less than 91.7% of nominal (110V) and no higher than 104.2% of nominal (125V) during normal operating conditions. During extreme operating conditions the voltages may fall to 88.3% (106V) or rise to 105.8% (127V) of nominal.

Using the existing distribution system configuration, at peak 2016 loading (winter) of 7, 871 kVA the worst case feeder voltage is 96.37%. The voltage profile maps can be seen on the relevant graphs under Appendix B, which show that all voltages are within the acceptable range.

The case of system loading in 2026 winter peaks of 10,536.1 kVA with the existing substation and four feeders was simulated. The minimum voltage on F3 was 93.75%, of nominal, fairly low, but within the acceptable operating range. The minimum voltage of F1, F2, and F4 was 97.49%, 96.86%, and 98.81% well within the acceptable operating range. The voltage profile maps can be seen within Appendix B.

3.4 System upgrades to minimize losses and support voltage

Other suggested changes to the system involve utilizing the switches that interconnect the feeder networks to redistribute the loading between the feeders. Transferring a small amount of load from F2 to F1 by opening S#845 and closing S#846 decreases the minimum feeder voltage in the circuit under peak winter loading conditions to 96.74%. Losses are reduced from 91.16 kW to 85.45 kW. This translates into annual savings of $5,002 at $0.10 kW/Hr.

4 EMERGENCY CONDITIONS EVALUATION

4.1 Feeder configurations during emergency conditions

The following scenarios are provided to show the loading and voltage results across the system as a result of the loss of each feeder in turn. Simple switching results are shown first, followed by more complex switching if required.

Scenario 1 – Loss of F1, use F2 and F4 to feed F1 circuit

Open S#833

Open S#814

Open S#815

Open S#822

Close S#821

Close S#829

Close S#845

Close F1_TIE

Close F4_TIE

Close F1/2-F3/4_TIE

As can be seen, this scenario is marginally acceptable during an emergency at peak demand until 2018; after that the feed will need to be transferred over to the proposed new 44kV-8.32kV transformer which is expected to be commissioned by October 2017. Also by 2026, S#846 will be placed in overload as the switch's ampacity is listed as 100A and will see 127A during peak demand, however the rated ampacity of the switch should be confirmed.

Table 10 – Scenario 1 Peak Annual Loading

Peak Annual Loading (Winter)														
Feeder	***Phase***	***Rating***	***Current 2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***	***2027***
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1454	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		694	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		925	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV IPS Bus		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Continuous)		300	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Daily 8 hour)		306	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Emergency 8 hour)		320	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
Feeder 1	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 2	R	375	238.8	243.8	247.0	253.1	257.3	261.6	265.1	268.6	271.3	274.0	276.8	279.5
	W	375	253.3	258.4	261.8	268.0	272.3	276.7	280.4	284.1	287.0	289.8	292.7	295.7
	B	375	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
Feeder 3	R	375	106.1	130.7	138.1	157.8	168.6	179.4	184.3	189.2	191.1	193.0	195.0	196.9
	W	375	161.4	186.7	194.6	214.9	226.2	237.6	243.1	248.6	251.1	253.6	256.1	258.7
	B	375	157.0	182.2	190.1	210.3	221.6	233.0	238.4	243.9	246.3	248.8	251.3	253.8
Feeder 4														
8.32kV Feeder Switches		400	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Continuous)		400	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Daily 8 hour)		404	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Emergency 8 hour)		419	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
Feeder 4	R	372	161.8	163.5	165.1	190.6	198.6	206.6	214.8	222.4	224.6	226.8	229.1	231.4
	W	372	149.9	151.4	152.9	178.3	186.2	194.1	202.1	209.6	211.7	213.8	215.9	218.1
	B	372	106.9	107.9	109.0	134.0	141.4	148.9	156.4	163.4	165.1	166.7	168.4	170.1

In Summer 2016 using the complex switching, the worst case voltage level within F1 is 93.20%, F3 is 96.50%, and F4 is 92.33% all within acceptable ranges. By 2026, the worst case voltage level within F2 is 92.32%, F3 is 94.67%, and F4 is 93.03%, within extreme and normal operating ranges respectively.

<u>Scenario 2</u> – Loss of F2, use F1 and F4 to feed F1 circuit

Open S#834

Open S#814

Open S#815

Open S#822

Close S#821

Close S#829

Close S#845

Close F1_TIE

Close F4_TIE

Close F1/2-F3/4_TIE

This scenario is identical to Scenario 1 except Feeder F2 and Feeder 1 are swapped. Refer to the table above. This scenario is marginally acceptable during an emergency at peak demand until 2018; after that the feed will need to be transferred over to the proposed new 44kV-8.32kV transformer which is expected to be commissioned by October 2017. Also by 2026, S#846 will be placed in overload as the switch's ampacity is listed as 100A and will see 127A during peak demand, however the rated ampacity of the switch should be confirmed.

Table 11 – Scenario 2 Peak Annual Loading

Peak Annual Loading (Winter)														
Feeder	***Phase***	***Rating***	***Current 2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***	***2027***
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1454	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		694	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		925	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV IPS Bus		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Continuous)		300	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Daily 8 hour)		306	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
8.32kV Fuses (Emergency 8 hour)		320	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
Feeder 1	R	375	238.8	243.8	247.0	253.1	257.3	261.6	265.1	268.6	271.3	274.0	276.8	279.5
	W	375	253.3	258.4	261.8	268.0	272.3	276.7	280.4	284.1	287.0	289.8	292.7	295.7
	B	375	304.6	310.3	314.1	320.9	325.8	330.7	334.9	339.2	342.6	346.0	349.4	352.9
Feeder 2	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 3	R	375	106.1	130.7	138.1	157.8	168.6	179.4	184.3	189.2	191.1	193.0	195.0	196.9
	W	375	161.4	186.7	194.6	214.9	226.2	237.6	243.1	248.6	251.1	253.6	256.1	258.7
	B	375	157.0	182.2	190.1	210.3	221.6	233.0	238.4	243.9	246.3	248.8	251.3	253.8
Feeder 4														
8.32kV Feeder Switches		400	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Continuous)		400	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Daily 8 hour)		404	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
8.32kV Fuses (Emergency 8 hour)		419	161.8	163.5	165.1	166.7	168.4	170.1	171.8	173.5	175.3	177.0	178.8	180.6
Feeder 4	R	372	161.8	163.5	165.1	190.6	198.6	206.6	214.8	222.4	224.6	226.8	229.1	231.4
	W	372	149.9	151.4	152.9	178.3	186.2	194.1	202.1	209.6	211.7	213.8	215.9	218.1
	B	372	106.9	107.9	109.0	134.0	141.4	148.9	156.4	163.4	165.1	166.7	168.4	170.1

Scenario 3 – Loss of F3, use F4 to feed F3 circuit

Open S#835

Close F1_TIE

Close F4_TIE

Close F1/2-F3/4_TIE

Table 12 – Scenario 3 Peak Annual Loading

Peak Annual Loading (Winter)														
Feeder	***Phase***	***Rating***	***Current 2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***	***2026***	***2027***
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1015	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		520	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		693	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV Switchgear		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Continuous)		300	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Daily 8 hour)		306	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
8.32kV Fuses (Emergency 8 hour)		320	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
Feeder 1	R	375	158.1	159.7	161.3	162.9	164.5	166.2	167.8	169.5	171.2	172.9	174.7	176.4
	W	375	167.5	169.2	170.9	172.6	174.3	176.1	177.8	179.6	181.4	183.2	185.1	186.9
	B	375	166.4	168.1	169.8	171.5	173.2	174.9	176.7	178.4	180.2	182.0	183.8	185.7
Feeder 2	R	375	214.9	219.6	222.6	228.4	232.4	236.4	239.6	242.9	245.4	247.8	250.3	252.8
	W	375	222.1	226.9	229.9	235.8	239.9	243.9	247.3	250.7	253.2	255.7	258.3	260.8
	B	375	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
Feeder 3	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 4														
8.32kV Feeder Switches		400	175.0	176.8	178.5	180.3	182.1	183.9	185.8	187.6	189.5	191.4	193.3	195.2
8.32kV Fuses (Continuous)		400	175.0	176.8	178.5	180.3	182.1	183.9	185.8	187.6	189.5	191.4	193.3	195.2
8.32kV Fuses (Daily 8 hour)		404	175.0	176.8	178.5	180.3	182.1	183.9	185.8	187.6	189.5	191.4	193.3	195.2
8.32kV Fuses (Emergency 8 hour)		419	175.0	176.8	178.5	180.3	182.1	183.9	185.8	187.6	189.5	191.4	193.3	195.2
Feeder 4	R	372	133.7	158.7	166.4	210.2	227.6	245.1	256.7	267.8	270.5	273.2	275.9	278.7
	W	372	175.0	200.4	208.4	252.7	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
	B	372	162.0	187.2	195.2	239.3	256.9	274.7	286.7	298.1	301.1	304.1	307.1	310.2

As can be seen, this scenario is acceptable for the foreseeable future.

In Summer 2016, the worst case voltage level within F1 is 98.19%, F2 is 96.41%, and F4 is 95.11%, all within acceptable ranges. By 2026, the worst case voltage level within F1 is 97.67%, and F2 is 97.07%, are within normal operating ranges. However, F4 is 93.66% which is just within normal operating range and well within extreme operating range.

Scenario 4 - Loss of F3, use F4 to feed F3 circuit

Open S#835

Close F1_TIE

Close F4_TIE

Close F1/2-F3/4_TIE

Table 13 – Scenario 4 Peak Annual Loading

Peak Annual Loading (Winter)														
Feeder	**Phase**	**Rating**	**Current 2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1015	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		520	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		693	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV Switchgear		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	240.1	245.1	248.3	254.4	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
8.32kV Fuses (Continuous)		300	240.1	245.1	248.3	254.4	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
8.32kV Fuses (Daily 8 hour)		306	240.1	245.1	248.3	254.4	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
8.32kV Fuses (Emergency 8 hour)		320	240.1	245.1	248.3	254.4	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
Feeder 1	R	375	158.1	159.7	161.3	162.9	164.5	166.2	167.8	169.5	171.2	172.9	174.7	176.4
	W	375	167.5	169.2	170.9	172.6	174.3	176.1	177.8	179.6	181.4	183.2	185.1	186.9
	B	375	166.4	168.1	169.8	171.5	173.2	174.9	176.7	178.4	180.2	182.0	183.8	185.7
Feeder 2	R	375	214.9	219.6	222.6	228.4	232.4	236.4	239.6	242.9	245.4	247.8	250.3	252.8
	W	375	222.1	226.9	229.9	235.8	239.9	243.9	247.3	250.7	253.2	255.7	258.3	260.8
	B	375	240.1	245.1	248.3	254.4	258.6	262.9	266.4	270.0	272.7	275.4	278.1	280.9
Feeder 3	R	375	133.7	158.7	166.4	210.2	227.6	245.1	256.7	267.8	270.5	273.2	275.9	278.7
	W	375	175.0	200.4	208.4	252.7	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
	B	375	162.0	187.2	195.2	239.3	256.9	274.7	286.7	298.1	301.1	304.1	307.1	310.2
Feeder 4														
8.32kV Feeder Switches		400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Continuous)		400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Daily 8 hour)		404	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Emergency 8 hour)		419	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 4	R	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As can be seen, this scenario is acceptable till 2022.

In Summer 2016, the worst case voltage level within F1 is 98.19%, within F2 is 96.41%, and F3 is 96.51%, all within acceptable ranges. By 2026, the worst case voltage level within F1 is 97.67%, F2 is 97.07%, and F4 is 94.23% are within normal operating ranges.

Therefore, reviewing the previous scenarios, we can determine that the main weakness within the system is the rating of the main fuses on Feeders 1, 2, and 3, which will no longer be an issue following the substation upgrades, as the feeder will then be transferable to the new transformer. The 8.32kV distribution supplied by the new transformer will consist of relay-operated reclosers. The relays will allow the protection settings to be increased to match the ampacity of the cables, thereby providing additional feeder capacity than can be achieved with the fusing currently in place.

<u>Scenario 5</u> – Loss of 44kV main transformer, use Hydro-One east and west emergency supply.

If we use the Hydro-One east and west end emergency supply to supply Embrun by opening switches S#833, S#834, and S#835, dip pole #2A and closing switches S#800, S#845, S#843 and Dip Pole #3A, we see that the overall the loading cannot exceed the 250A allowable for this emergency supply. The scenario is outlined in the graph below:

Table 14 – Scenario 5 Peak Annual Loading

Peak Annual Loading (Winter)														
Feeder	Phase	Rating	Current 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
44kV Switch		3173	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Fuses		1015	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAN		520	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
44kV Trans. ONAF		693	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
8.32kV Switchgear		1200	546.2	577.8	590.5	642.1	665.5	689.0	706.0	722.5	729.7	737.0	744.4	751.8
Feeders 1, 2 ,3														
8.32kV Feeder Switches		600	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Continuous)		300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Daily 8 hour)		306	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Emergency 8 hour)		320	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 1	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 2	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 3	R	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	375	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 4														
8.32kV Feeder Switches		400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Continuous)		400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Daily 8 hour)		404	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.32kV Fuses (Emergency 8 hour)		419	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 4	R	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	372	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro One East Emergency Feed														
8.32kV Max Feed		250	406.5	413.1	418.0	425.8	431.8	437.8	443.0	448.4	452.9	457.4	462.0	466.6
	R	370	373.0	379.3	383.9	391.3	396.9	402.6	407.5	412.5	416.6	420.7	425.0	429.2
	W	370	389.6	396.1	400.8	408.4	414.2	420.0	425.1	430.3	434.6	438.9	443.3	447.7
	B	370	406.5	413.1	418.0	425.8	431.8	437.8	443.0	448.4	452.9	457.4	462.0	466.6
Hydro One West Emergency Feed														
8.32kV Max Feed		250	175.0	200.4	208.4	252.7	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
	R	370	133.7	158.7	166.4	210.2	227.6	245.1	256.7	267.8	270.5	273.2	275.9	278.7
	W	370	175.0	200.4	208.4	252.7	270.5	288.4	300.5	312.0	315.1	318.3	321.5	324.7
	B	370	162.0	187.2	195.2	239.3	256.9	274.7	286.7	298.1	301.1	304.1	307.1	310.2

As can be seen, we cannot off-load Feeder 1, 2 onto Hydro One east feeder and after 100% occupancy of new subdivision has been completed, Feeder 3, 4 will no longer be able to be off-loaded on to the Hydro One west feed. The east and west emergency connections would only be able to supply 91% of Embrun distribution during an event where the 44kV transformer is lost and rolling blackouts may be required while the transformers is being repaired or replaced. That number could climb to 78% in 3 years as many of the new subdivisions are not yet at full occupancy. Also, switches S#822, S#842, S#843, and S#846 would be placed into overload. Therefore, under the recommendations section we list possible methods to add redundancy to the distribution system.

5 RECOMMENDATIONS

5.1 Substation Redundancy & Capacity

From the findings, it is possible that the capacity of the main transformer for ONAF (fan-rated) capacity will be surpassed upon completion of the subdivision in South-West of Ste Marie and the Castor in 2022, for both the summer and winter peak. With the completion of the Patenaude East subdivision the ONAN (non-fan rated) will be surpassed in both summer and winter peaks. As part of the substation upgrade project in 2017, digital meters will be installed on each feeder to provide much more accurate metering of the loading during various peak periods. This will allow further detailed evaluation of the effects of the loading upon the existing and new transformers.

The issue of redundancy is also problematic. However, the issue of absolute transformer capacity will be addressed with the proposed substation upgrades expected to be completed in October 2017. The new substation will resolve the redundancy issues as the new transformer will be a 10/13.3MVA transformer which is capable of supporting 100% of the peak load for the next 15–20 years. Currently, if the transformer fails, the only short term solutions would be as follows:

- Use the Emergency Hydro-One infeeds from East and West (discussed further under Option 1)
- Borrow or purchase a used transformer from another Utility or Surplus Equipment Dealer
- Borrow a Hydro-One Mobile Unit Substation (MUS)

Borrowing or purchasing a used transformer would be a difficult option if it had not been arranged beforehand. The costs to have an option on a spare transformer could be substantial, plus the costs and time to transport and install a transformer would be significant. This is not an optimal solution and would not be recommended.

The previous solution of using one of Hydro-One's Mobile Unit Substation (MUS) to temporarily supply the distribution is no longer available as Hydro One has very few MUS units and they cannot supply units to other utilities. Also, the MUS require very specific connection points and the substation is not properly configured for these connections making it an operational and personal safety hazard.

5.1.1 Option 1: Continue Using Hydro-One Infeeds from east and west

The current method of providing the required redundancy is by using a feeder from each of the Hydro-One substations located to the east and west of Embrun. Each of the two feeders could provide support for 3.6 MVA of loading on an 'as required' basis. Using this method as a temporary way to provide the required redundancy means that the purchase of a second transformer or construction of another substation could be deferred until required for capacity reasons. It is our belief that Embrun Hydro is still covered by this Hydro-One program and Hydro-One is contractually obligated to provide 2 years notice to Embrun Hydro before the removal of the emergency supplies. While formal notice has not been provided, Hydro One has indicated that they may be decommissioning the station to the east of Embrun in the near future.

2016 winter peak loading conditions were simulated with the existing substation out of service. The entire load was serviced by a feeder on the west side, connected to the system at switch S#800, and a feeder on the east side, connected at switch S#843. The main switch configuration was as follows:

- Open F1, F2, F3, and F4 feeder switches (Isolate Embrun sub from distribution system)
- Close S#845 (connect F2 to F1)
- Close Interconnection Switches Tie, F3 and F4
- Close S#800 and S#844 (tie both F3/F4 and F1/F2 to Hydro-One)

Voltage and load profile maps are included in Appendix B and Appendix C, respectively. The worst case feeder voltage in the system was found to be 92.73% of nominal, which is above the minimum acceptable for emergency conditions, but switches S#842, S#843, and S#846 would be overloaded. However, the power that can be supplied from each of the feeders is limited to the 250 Amps of firm capacity allowed by the 280A reclosers on each circuit, meaning each feeder can supply 3.6 MVA of continuous loading for a total of 7.2 MVA. Peak winter loading is 8,057 kVA (although non-continuous loading), which makes the peak loading just beyond the combined capacity of the two Hydro-One emergency feeders. The loading on the East supply with the above switching configuration is 373.0A/389.6A/406.5A on R/W/B respectively, and on the West supply is 133.7A/175.0A/162.0A on R/W/B respectively during peak winter conditions. Therefore, roughly 10% of loads would have to be shed during the few peaks in winter that reach 8MVA. By 2026 the loading will be approximately 33% higher, and load shedding requirement would be even more significant in the future.

The costs of this support is a monthly shared DS charge based on peak kW demand per month, and regular kWhr pass-through charges, also determined on a monthly basis. The annual costs from 2016 to 2026 were estimated based on the following assumptions but the values are old and may no longer be valid:

- Shared DS charges will be fixed at $1.60/kW for the duration of the agreement
- Typical peak demand during an outage will be 70% of peak winter load
- Typical outage frequency – 1 every other year

While the two extra feeders will provide acceptable redundancy for the system, this is not a permanent solution, as load shedding already has to be done. Within 5 years, peak system loading will be 9,995 kVA, which means only 72% of the system loading will be supported by the Hydro-One emergency in-feeds. Therefore, the continued reliance solely on the Hydro-One emergency in-feeds is not acceptable with the substantial system load additions due to further development in the next five years.

5.1.2 Option 2: Addition of new transformer to existing substation

Redundancy and capacity issues will be addressed by adding a second transformer to the existing substation. Some modifications will be required to the existing substation in order to accommodate a second transformer, as listed in the detailed budget pricing under Appendix E. The main modifications that will be required are as follows:

- Modifications to the tower structure to accommodate second transformer
- New primary fuses and IPS structures
- Ground Grid may have to be revised
- Second transformer pad and pad for new switchgear
- New secondary switchgear for Transformer 2.
- New Primary metering
- Tower-mounted reclosers to supply 8.32kV feeders from new transformer
- Sectionalizer switchgear to allow make-before-break switching of each 8.32kV feeder between transformers

The construction for the new substation has been awarded as a design-build project to K-Line Maintenance & Construction Ltd. for approximately $1.5M plus taxes. Maintenance costs for the transformer and new switchgear are estimated at $25,000 on a five year cycle.

5.2 Feeder protective devices

There are some drawbacks with the usage of fused load breaks as the main switching devices for the Embrun feeders.

- Low level intermittent or continuous arcing may not provide enough fault current to clear fuses.
- High fault levels required to clear fuses, possibly resulting in significant damage downstream at the point of faulting.
- Operation of the fuses require operators to replace fuse links, resulting in at least 2 hours of feeder downtime, plus costs of fuse links (typically $800 per set of 3 links).
- Typically, it was reported that at least one fuse link has to be replaced every few years.

It was recommended in the previous (2014) report to replace the feeder devices with reclosers or medium voltage circuit breakers with recloser relays.

Reclosers were used in the design of the new substation as they have several advantages over fused loadbreaks. The main advantages of relay-operated reclosers are their flexibility as they provide sensitive ground/ phase protection, sequence of events and wave form capture, as well as the capability of reclosing quickly a few times after an initial fault. If the fault is still not cleared the recloser will begin a final timing sequence to allow for a downstream fuse to clear the fault. If the fault has not cleared by this time, the re-closure will open to isolate the downstream power system. For feeders that have a significant amount of underground distribution such as Embrun's Feeder F4, the reclosers can be programed to operate more like a breaker and open quickly on a fault.

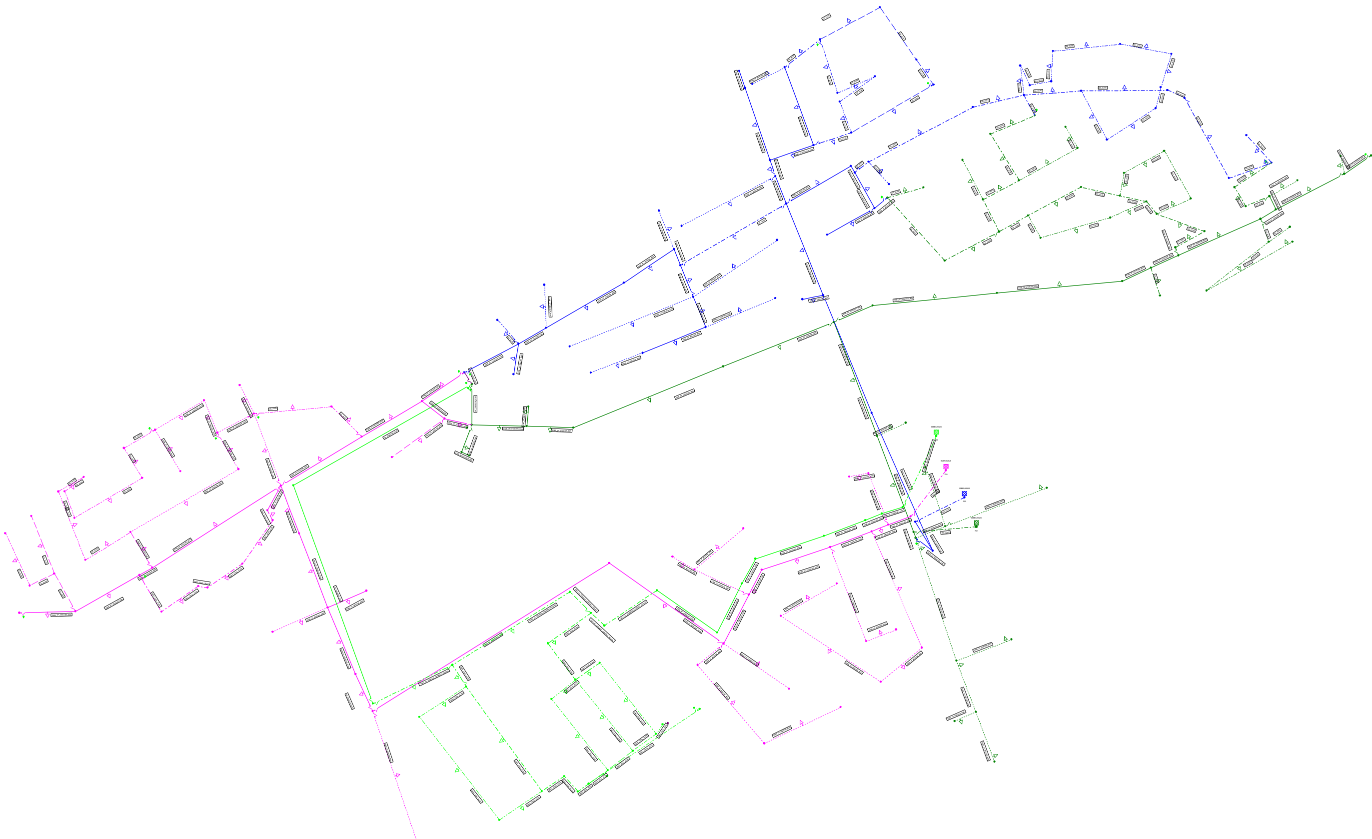
5.3 Itemized Recommendations

- New modern digital metering for feeders F1, F2, and F3 within the substation are being installed under the substation upgrade project expected to be finished October 2017. This metering will provide all basic electrical parameters (voltage, current, PF, power, energy, and demand), plus power quality parameters (sags and swells, harmonics, transients, flicker), data and waveform logs (triggering, min/max, trending, timestamps), communications, set points, and alarming. This upgrade will allow trending to be done to confirm the pattern of daily loading, and to trend future load growth.
- Update system single line to add further system information, including the source of transformers #477-75 and #476-75 on Centenaire Street, conductor sizes for all major feeders, and ampacities of all switches. (Budget $15,000)
- The system main feeders should be measured before rebalancing to verify the imbalance and then the re-phasing should be done. (Budget $5,000)
- Confirm Switch S#846 rated ampacity. If the ampacity is found to be less than 150A the switch will need to be replaced with a switch rated for a minimum 150A to accommodate future emergency condition.
- Either rebalance feeders as new loads added in 2016-2022, or rebalance current loading within feeders 1, 2, 3 and 4 to minimize losses, possible options to rebalance include the following:
  - F1: 542-50-R to B, 453-75-B to R, 544-75-W to R, 545-75-B to R and 546-100-W to R,
  - F2: 82-50-R to B, 83-50-B to R, 84-R to B, 85-50-B to R and 86-50-B to R
  - F3: 406-75-W to R, 407-50-W to R, 409-50-W to R, 411-50-W to R, 430-50-B to W, 431-100-W to B, 432-100-B to W 527-50-B to W and 536-75-B to W
  - F4: 1000-167-B to R, 1001-167-R to B, 1003-B to R and 1006-25-R to B

APPENDIX A
SYSTEM BASE MODELS

Base 2016 Model Feeder 1/2/3/4
Base 2016 Model by Conductor and Phase
Based 2026 Model by Feeder 1/2/3/4

Stantec Consulting Ltd.
2016 Base Case: Model by Feeder 1/2/3/4



Legend

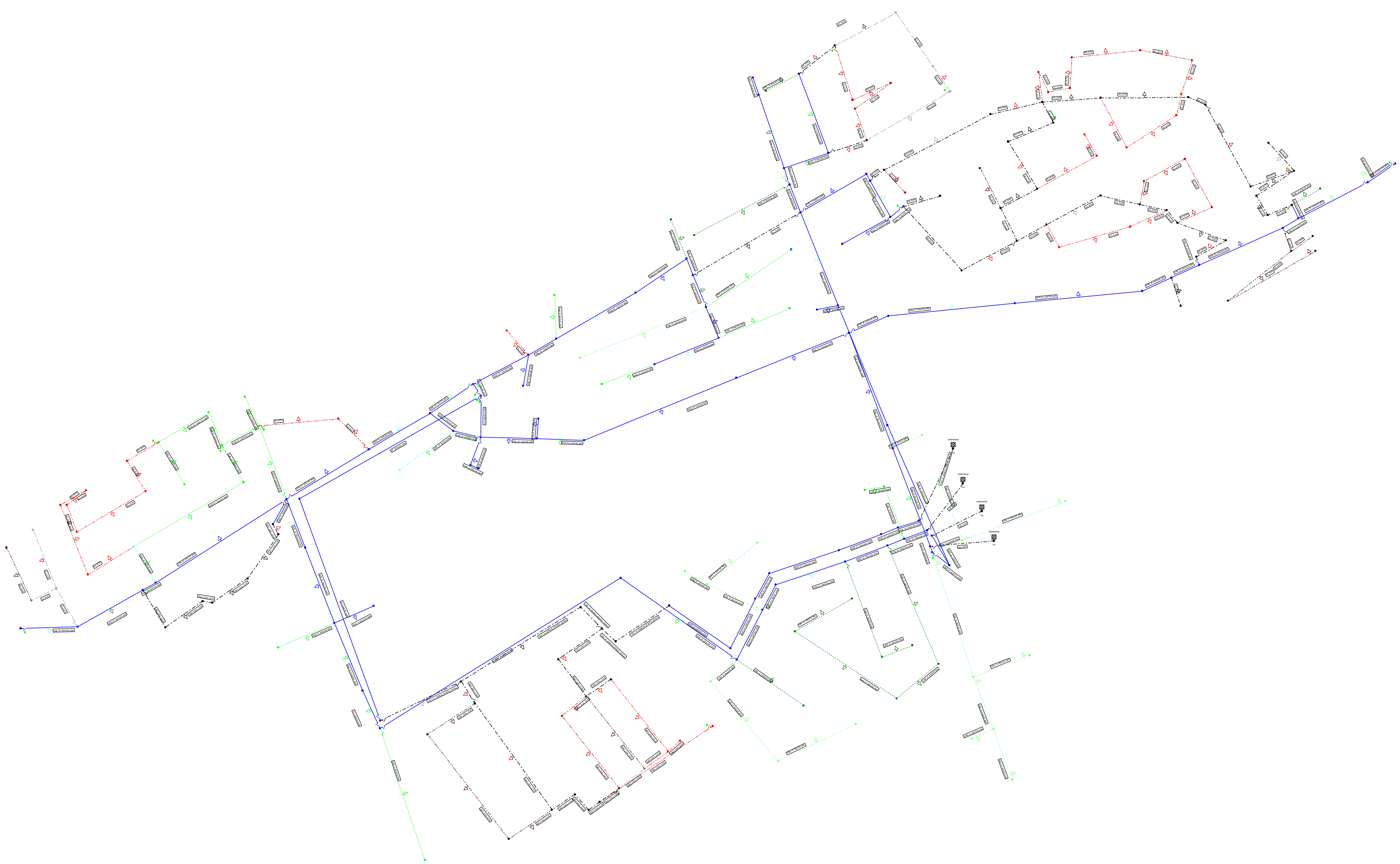
Layer :
Network color

Colors :
F01
F02
F03
F04

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Base Case: Model by Conductor and Phase



Legend

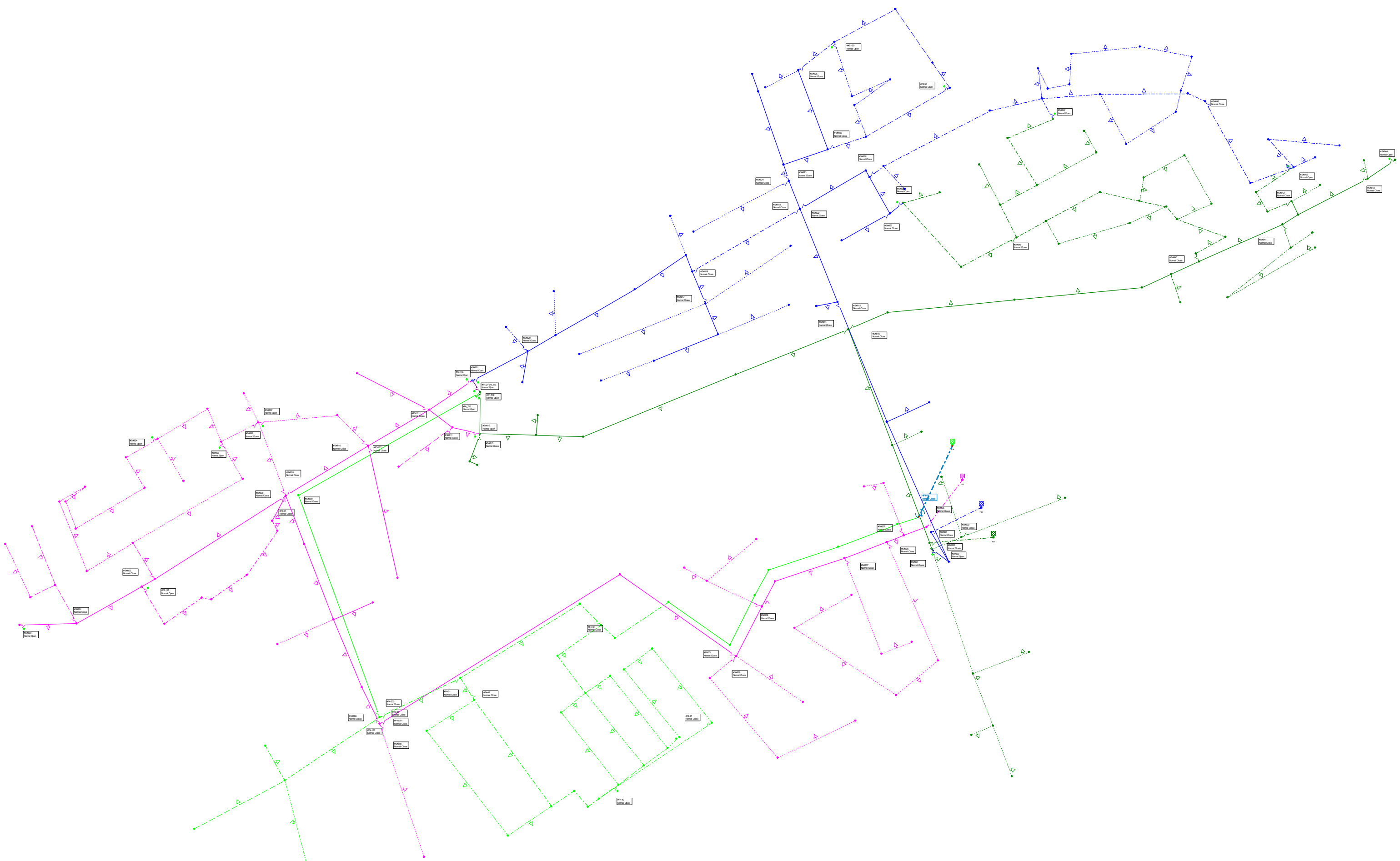
Layer :
Phase color

Colors :
- Overhead phase - A
- Overhead phase - B
- Overhead phase - C
- Overhead phase - AB
- Overhead phase - AC
- Overhead phase - BC
- Overhead three--phase
- Cable phase A
- Cable phase B
- Cable phase C
- Cable phase AB
- Cable phase AC
- Cable phase BC
- Cable three-pha-se

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2026 Base Case: Model by Feeder 1/2/3/4



Legend

Layer :
Network color

Colors :
F01
F02
F03
F04

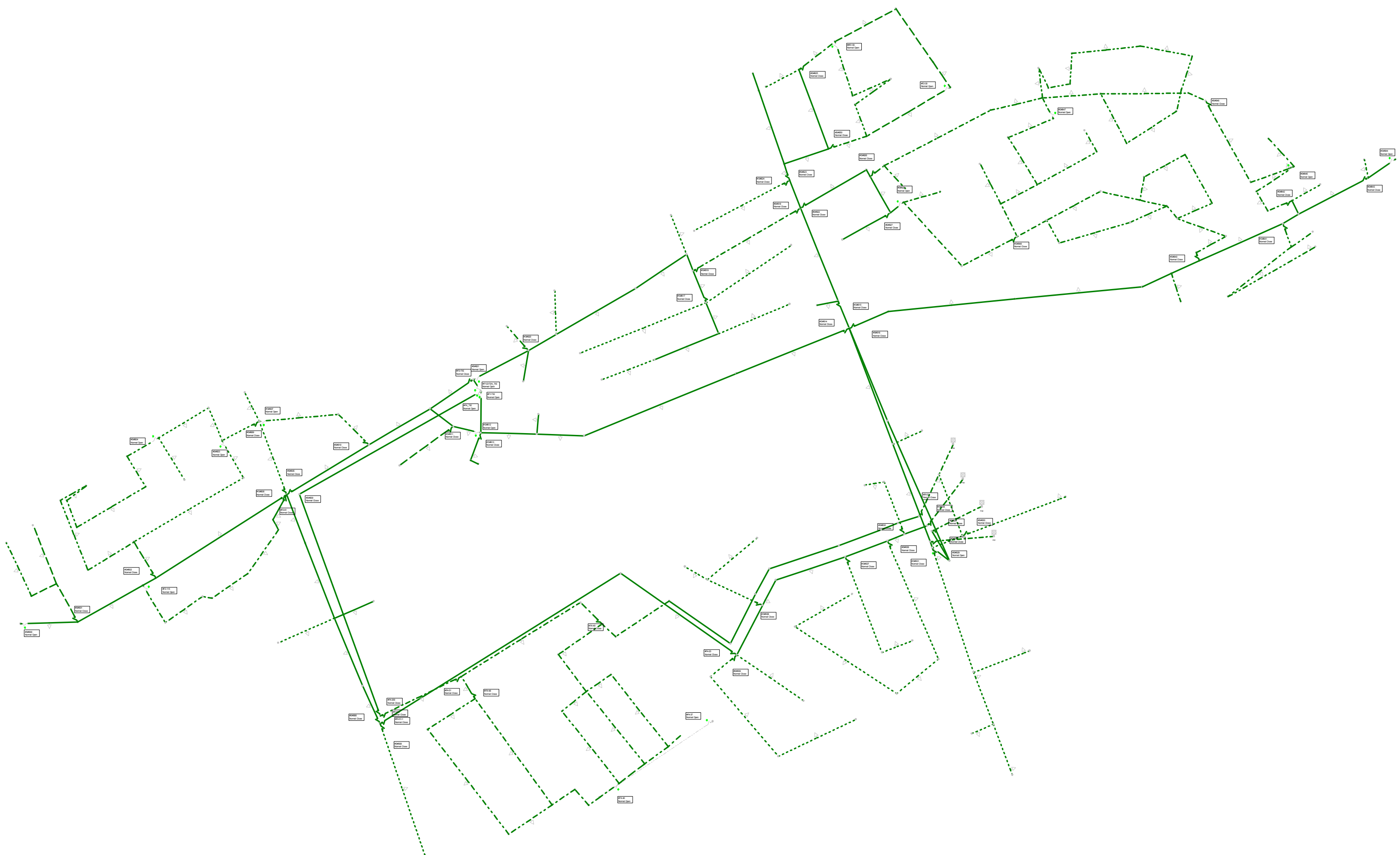
Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

APPENDIX B
VOLTAGE SUPPORT RESULTS

2016 Base Case – Winter Loading
2026 Base Case – Winter Loading
2016 Summer Peak Loading, F1 failed, support by F2 and F4, Complex Switching
2016 Summer Peak Loading, F2 failed, support by F1 and F4, Complex Switching
2016 Summer Peak Loading, F3 failed, support by F4, Simple Switching
2016 Summer Peak Loading, F4 failed, support by F3, Simple Switching
2026 Summer Peak Loading, F1 failed, support by F2 and F4, Complex Switching
2026 Summer Peak Loading, F2 failed, support by F1 and F4, Complex Switching
2026 Summer Peak Loading, F3 failed, support by F4, Simple Switching
2026 Summer Peak Loading, F4 failed, support by F3, Simple Switching
2016 Winter Peak Loading, F1/F2/F3 failed, support by Hydro-One, Complex Switching

Stantec Consulting Ltd.
2016 Base Case: Winter Loading



Legend

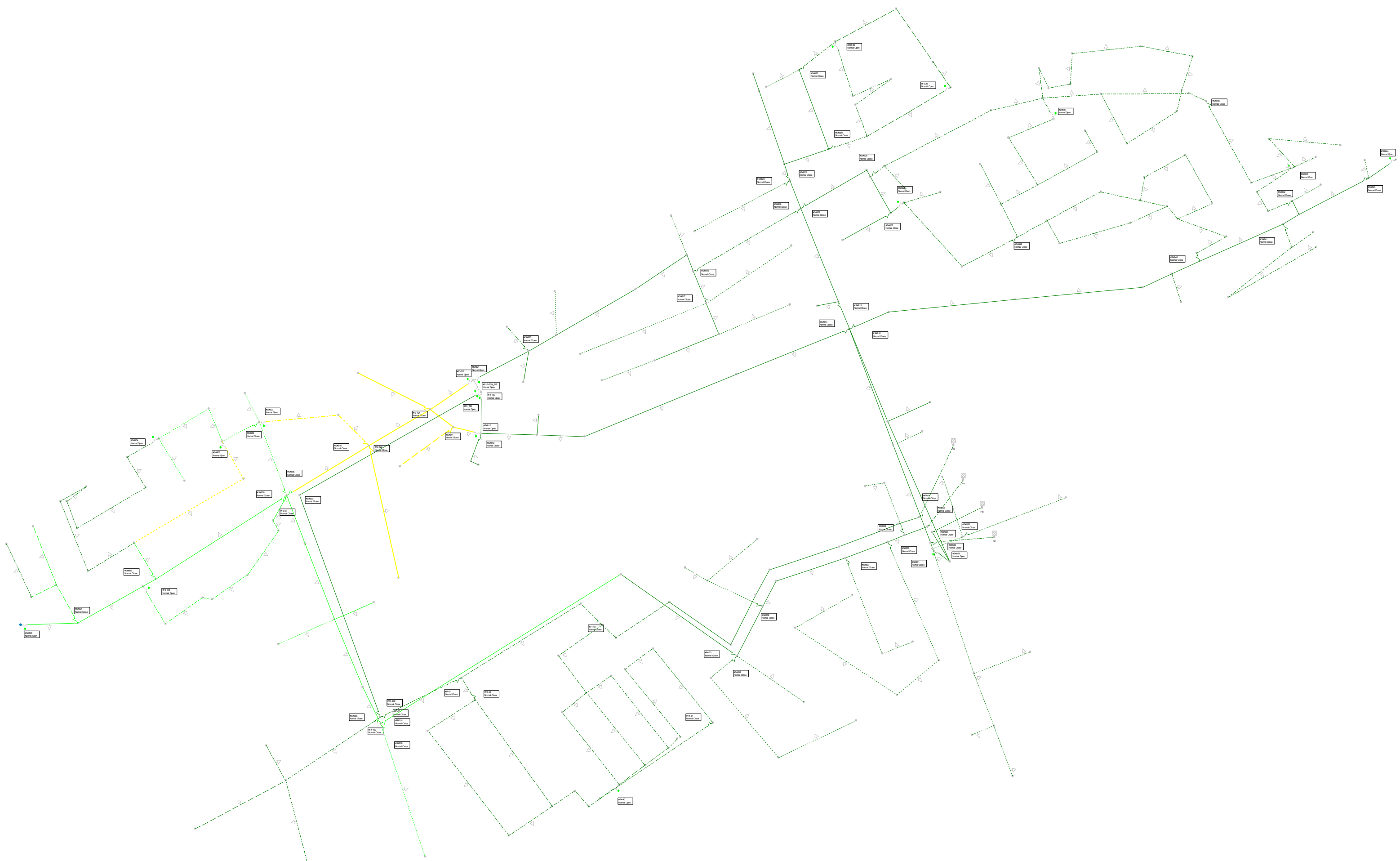
Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 100.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2026 Base Case: Winter Loading



Legend

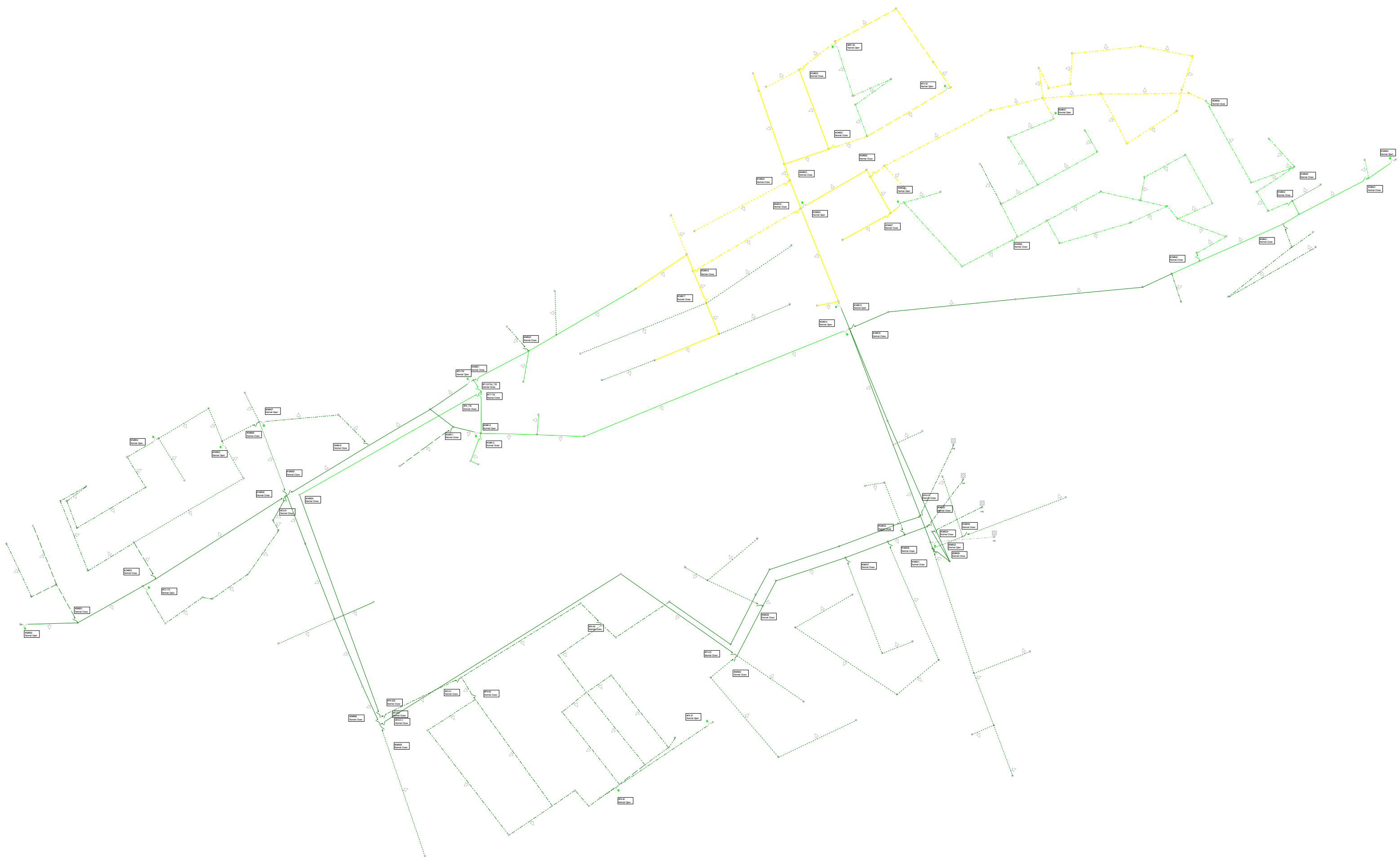
Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 105.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F1 Fail, Support by F4 Complex Switching



Legend

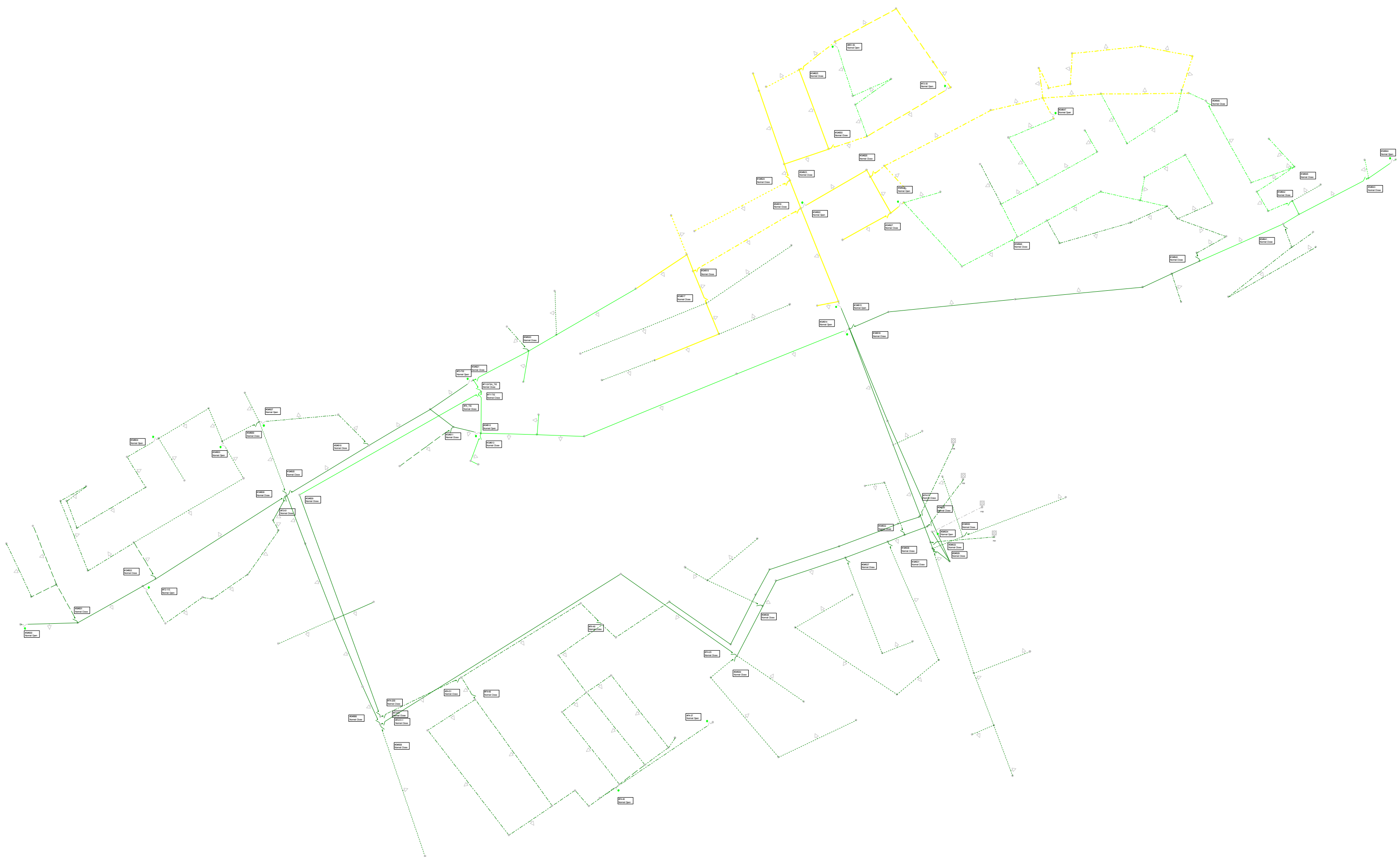
Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 105.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F2 Fail, Support by F4 Complex Switching



Legend

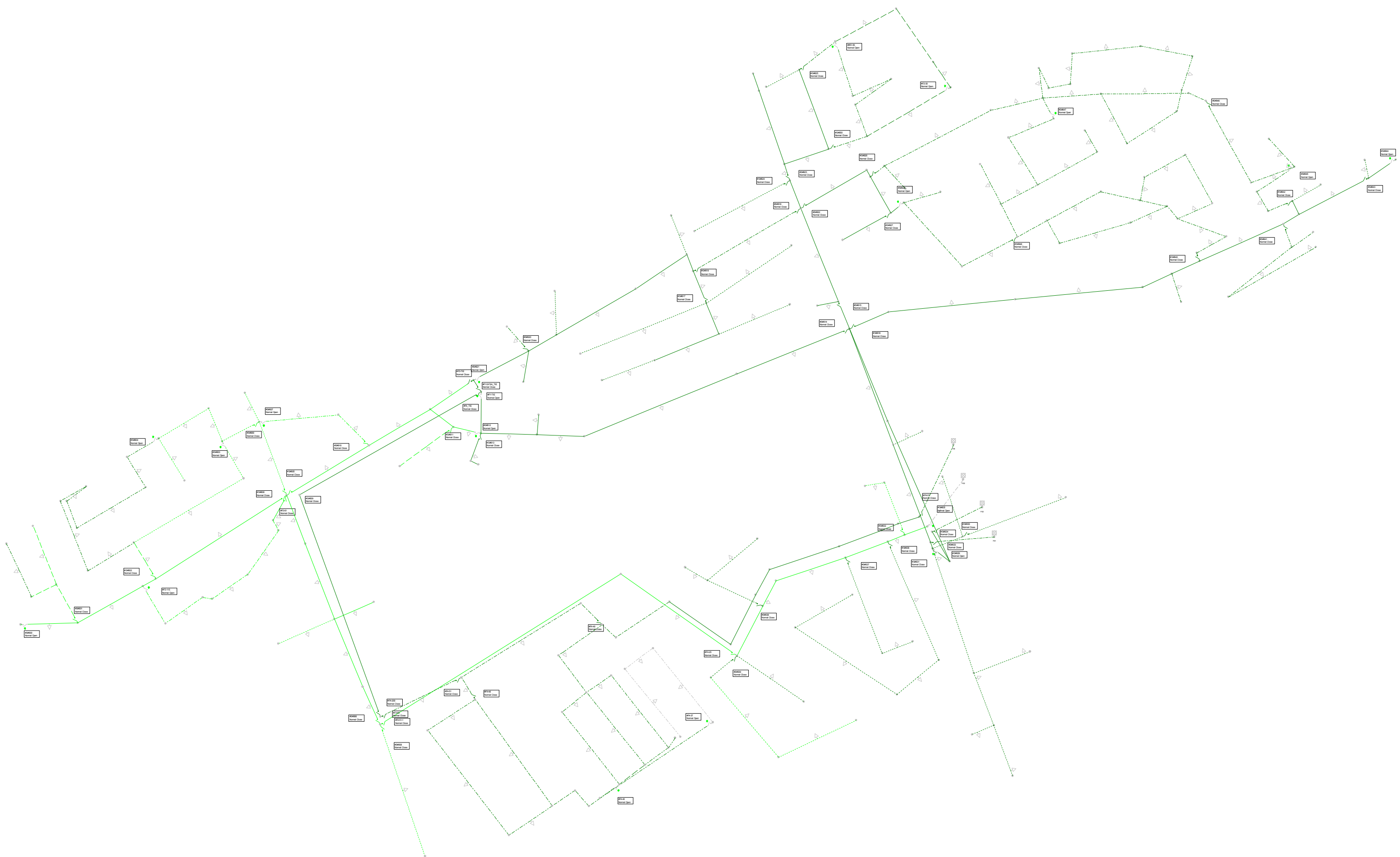
Layer :
Voltage level color(%)

Colors :
0.00 88.30
88.30 91.70
91.70 94.00
94.00 96.00
96.00 105.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F3 Fail, Support by F4 Simple Switching



Legend

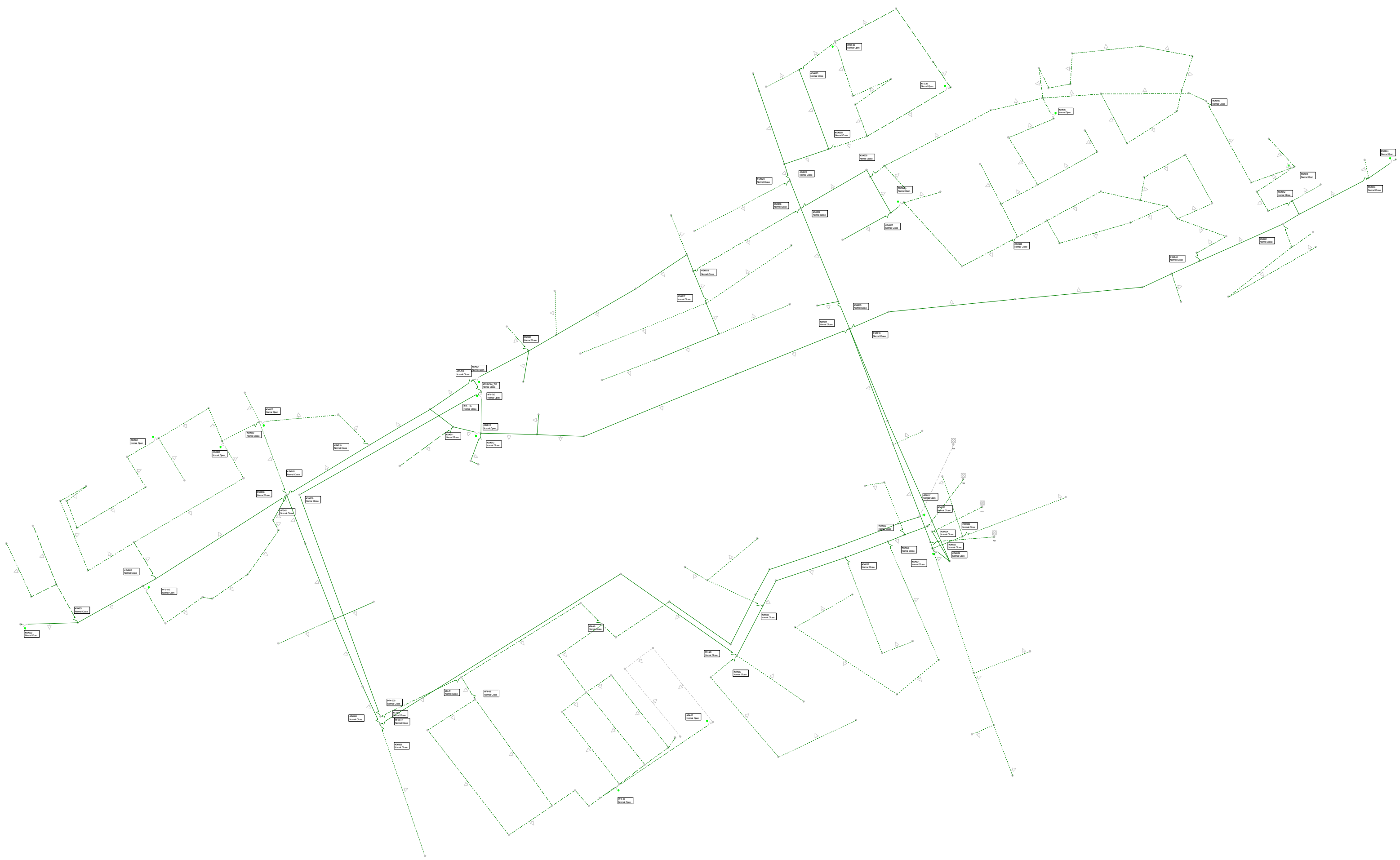
Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 105.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F4 Fail, Support by F3 Simple Switching



Legend

Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 105.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

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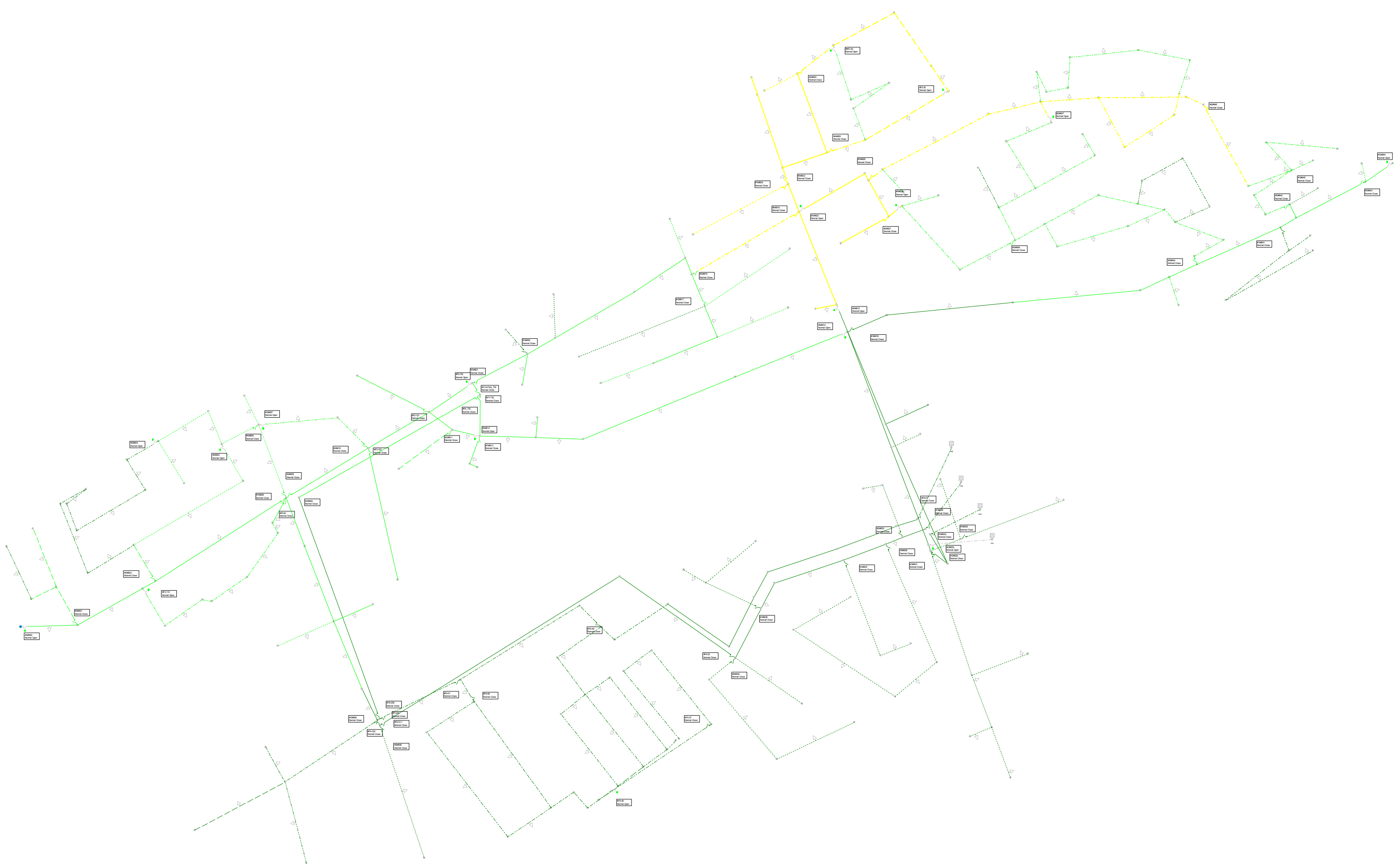
Stantec Consulting Ltd.
2026 Loading Summer F1 Fail Very Complex Switching



Legend

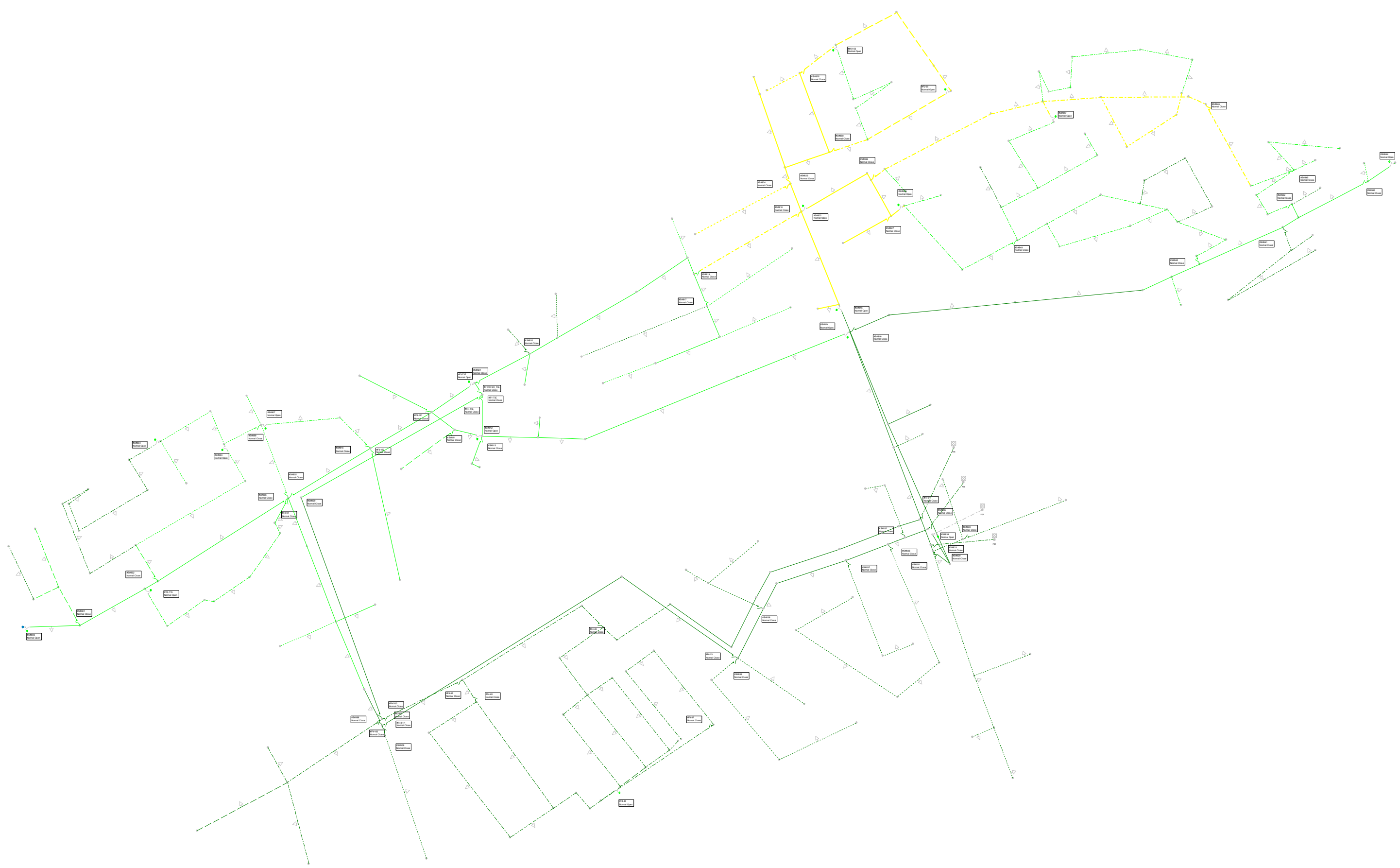
Layer :
Voltage level color(%)

Colors :
- 0.00 88.30
- 88.30 91.70
- 91.70 94.00
- 94.00 96.00
- 96.00 105.00

Line Types:
- A-OH
- B-OH
- C-OH
- AB-OH
- AC-OH
- BC-OH
- 3-OH
- A-UG
- B-UG
- C-UG
- AB-UG
- AC-UG
- BC-UG
- 3-UG

Symbols :
- Switch, (O)
- Load
- Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F2 Fail Very Complex Switching



Legend

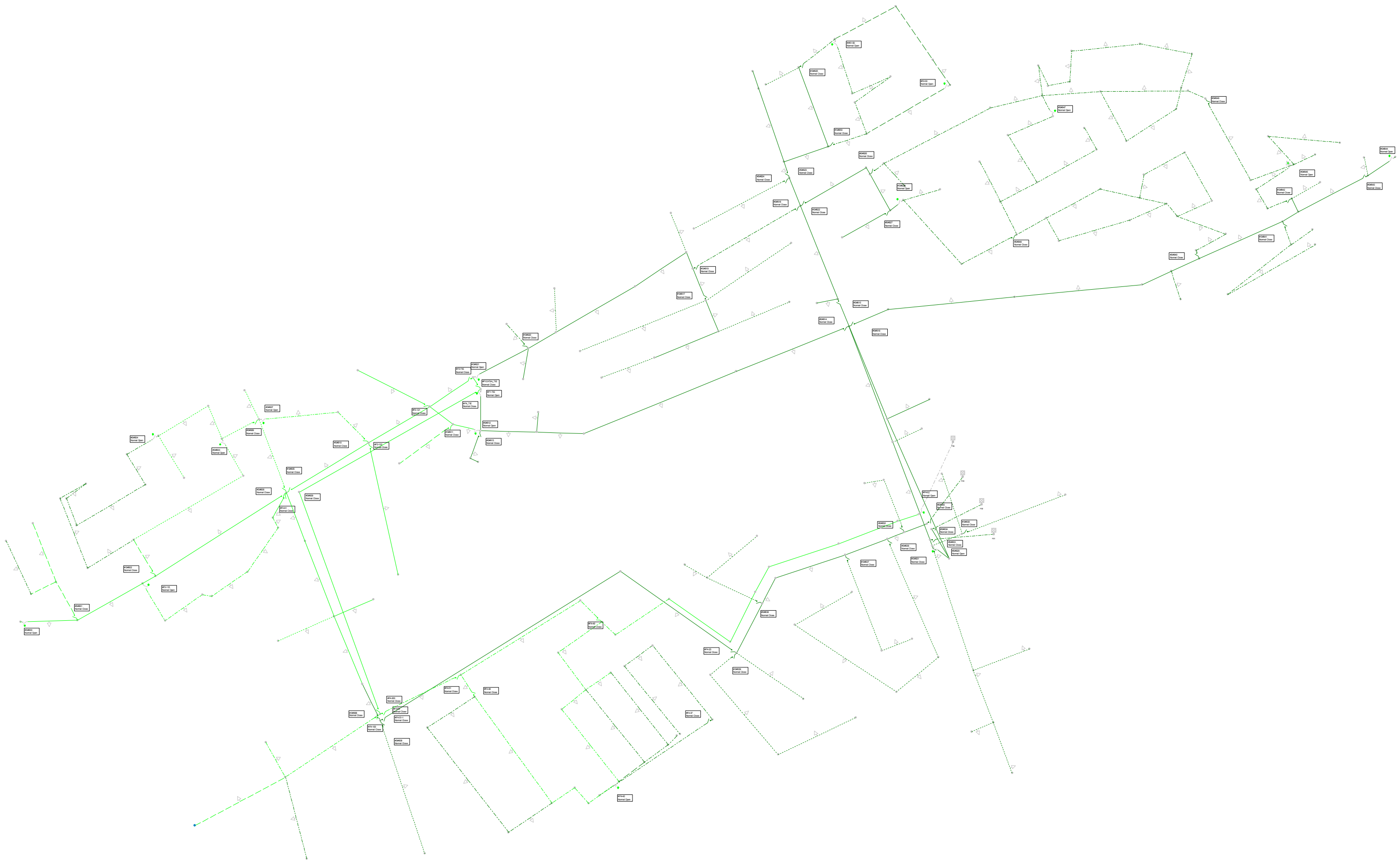
Layer :
Voltage level color(%)

Colors :
0.00 88.30
88.30 91.70
91.70 94.00
94.00 96.00
96.00 105.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F3 Fail Simple Switching



Legend

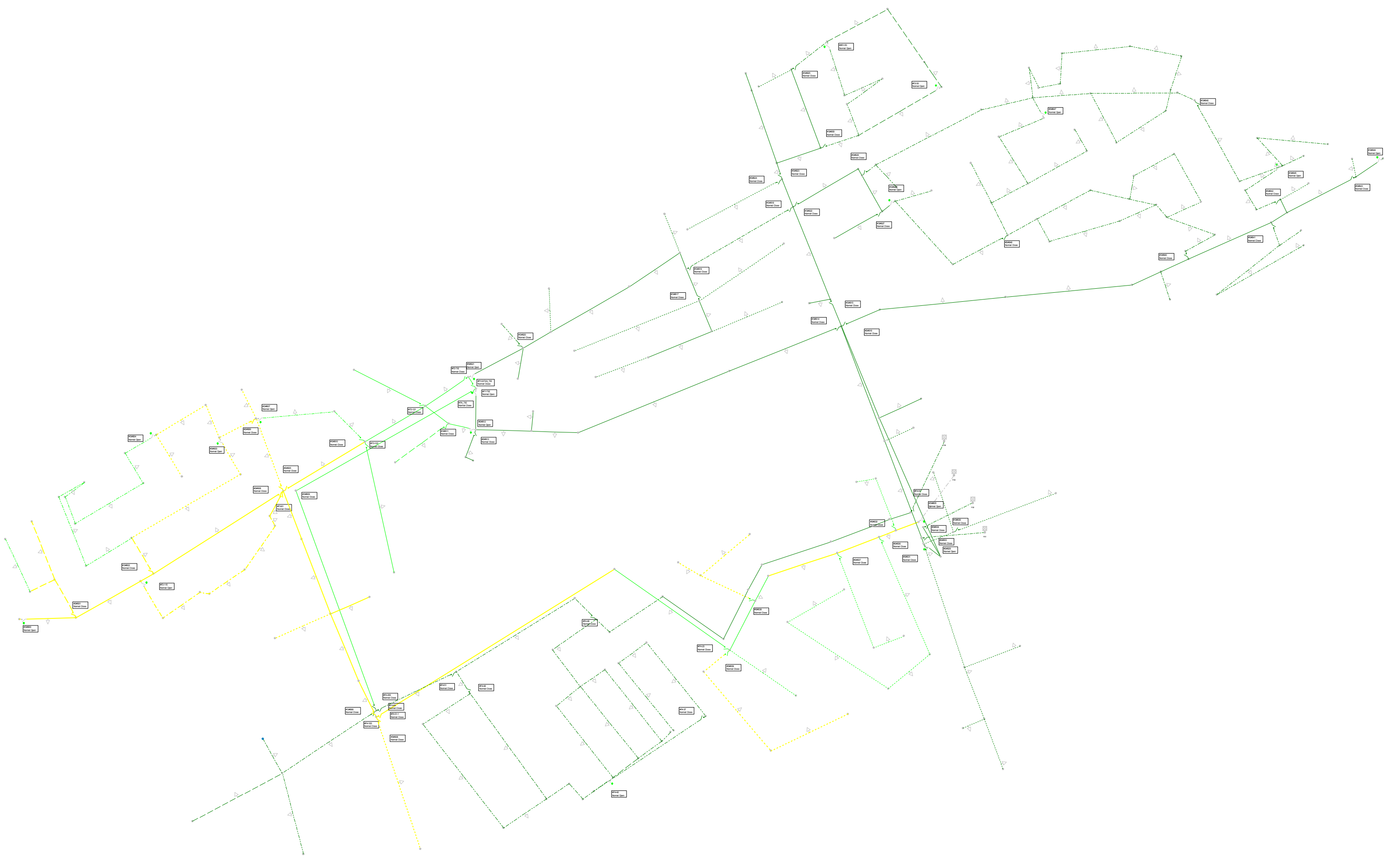
Layer :
Voltage level color(%)

Colors :
0.00 88.30
88.30 91.70
91.70 94.00
94.00 96.00
96.00 105.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F4 Fail Simple Switching



Legend

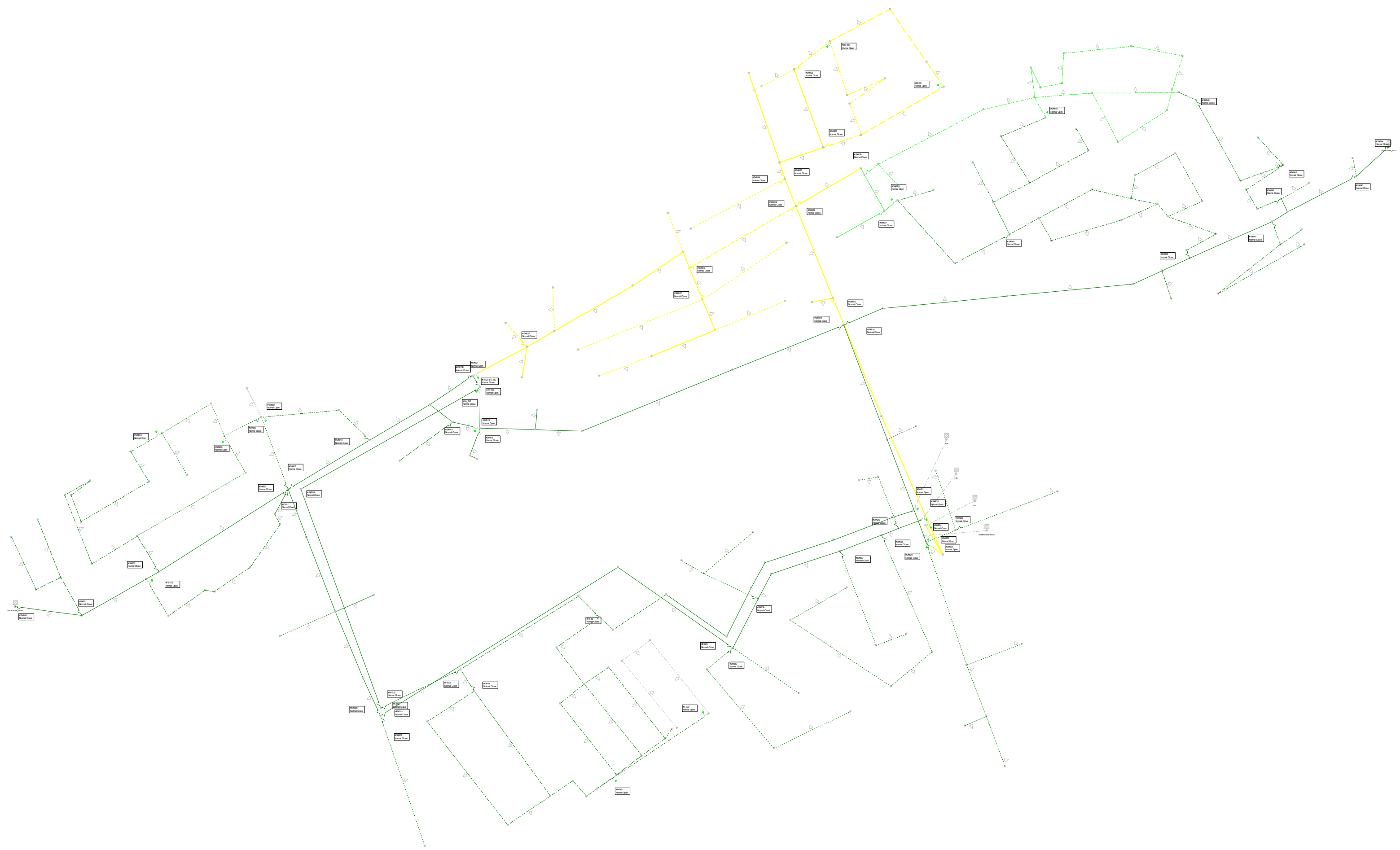
Layer :
Voltage level color(%)

Colors :
0.00 88.30
88.30 91.70
91.70 94.00
94.00 96.00
96.00 105.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Winter Peak Loading, F1/F2/F3/F4 failed, support by Hydro-One, Complex Switching



Legend

Layer :
Voltage level color(%)

Colors :
0.00 88.30
88.30 91.70
91.70 94.00
94.00 96.00
96.00 105.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

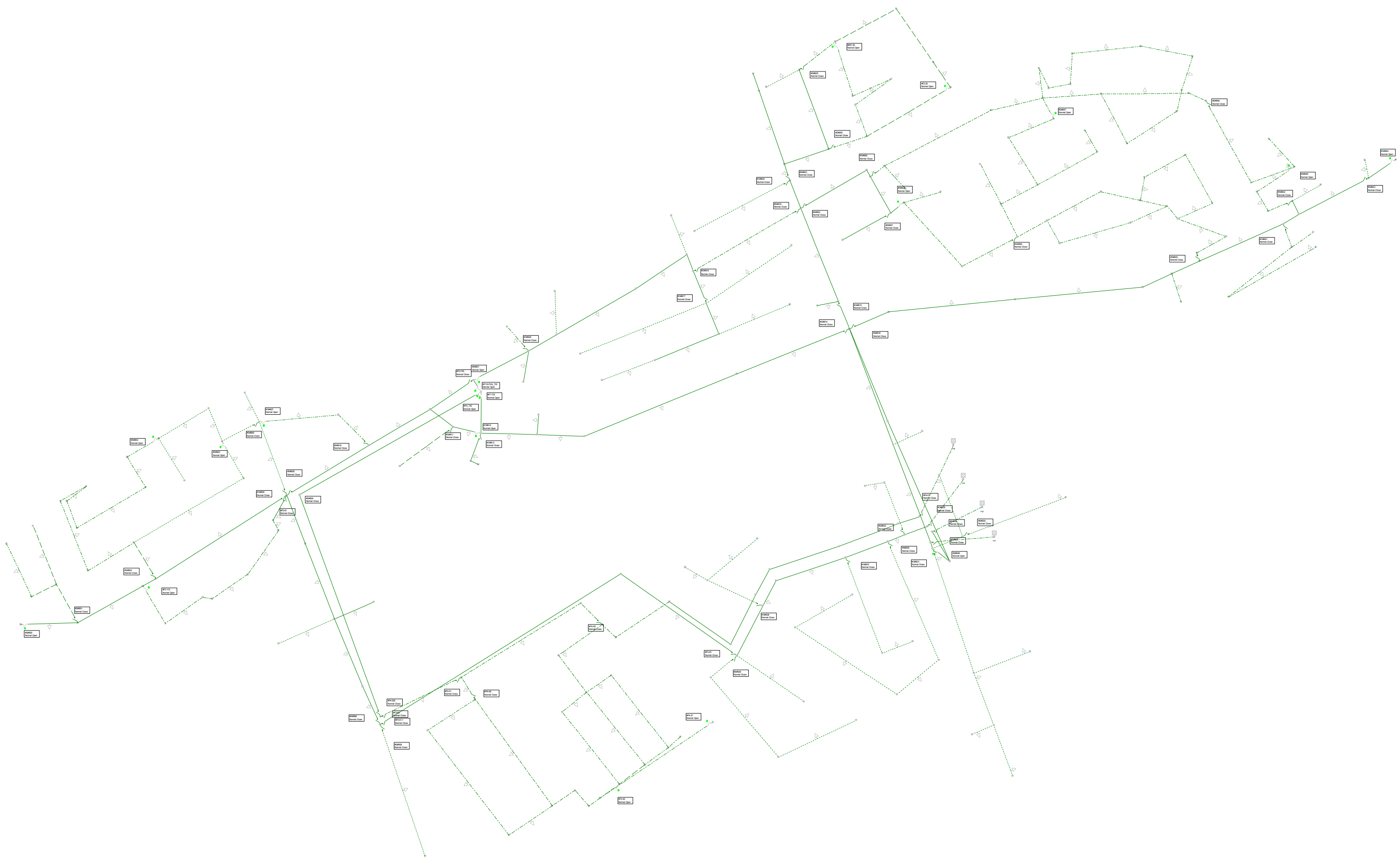
Symbols :
Switch, (O)
Load
Switch, (C)

APPENDIX C

LOADING RESULTS

2016 Base Case – Winter Loading
2026 Base Case – Winter Loading
2016 Summer Peak Loading, F1 failed, support by F2 and F4, Complex Switching
2016 Summer Peak Loading, F2 failed, support by F1 and F4, Complex Switching
2016 Summer Peak Loading, F3 failed, support by F4, Simple Switching
2016 Summer Peak Loading, F4 failed, support by F3, Simple Switching
2026 Summer Peak Loading, F1 failed, support by F2 and F4, Complex Switching
2026 Summer Peak Loading, F2 failed, support by F1 and F4, Complex Switching
2026 Summer Peak Loading, F3 failed, support by F4, Simple Switching
2026 Summer Peak Loading, F4 failed, support by F3, Simple Switching
2016 Winter Peak Loading, F1/F2/F3 failed, support by Hydro-One, Complex Switching

Stantec Consulting Ltd.
2016 Base Case: Winter Loading



Legend

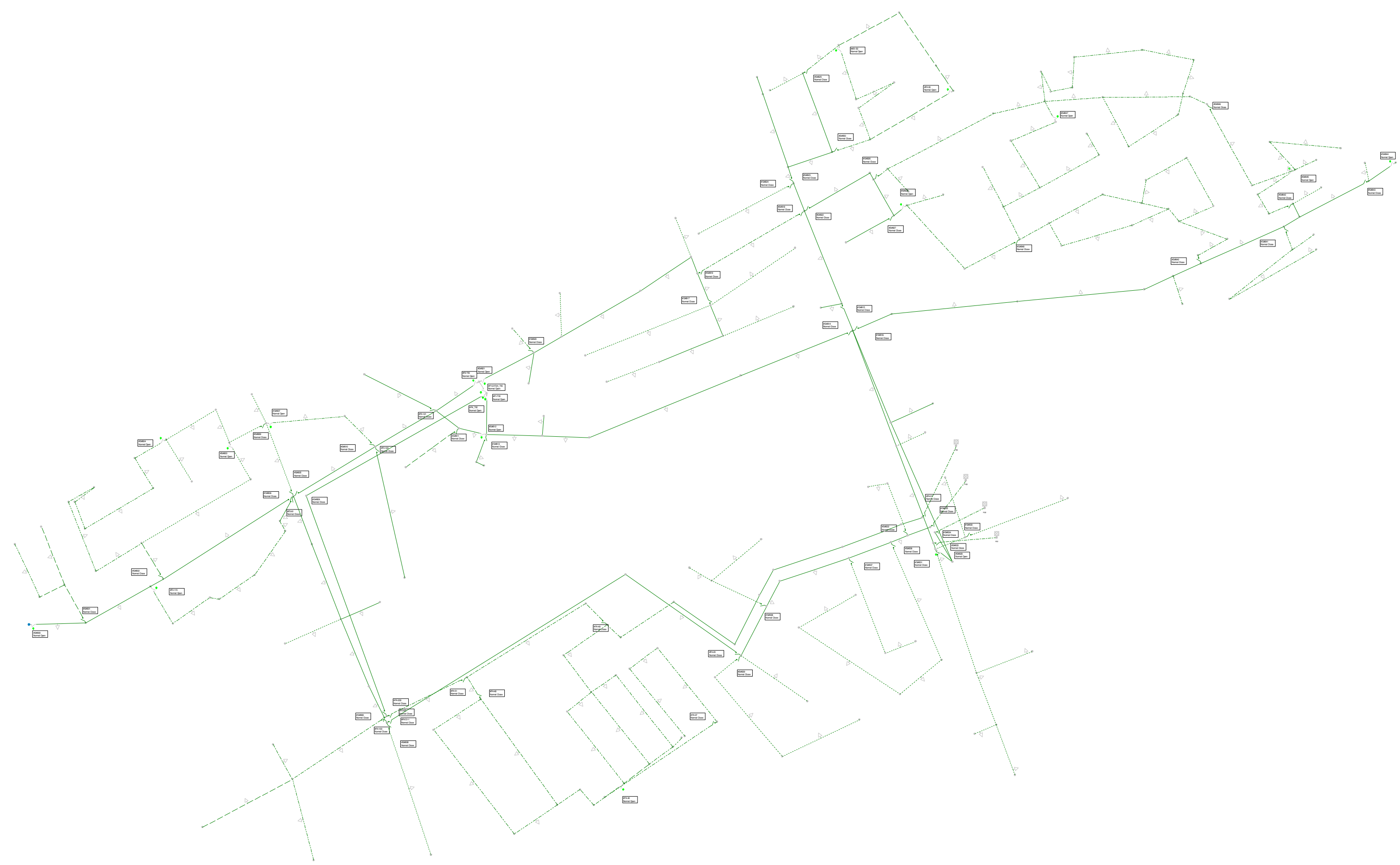
Layer :
Loading level color(%)

Colors :
0.00 95.00
95.00 100.00
100.00 500.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Base Case: Winter Loading



Legend

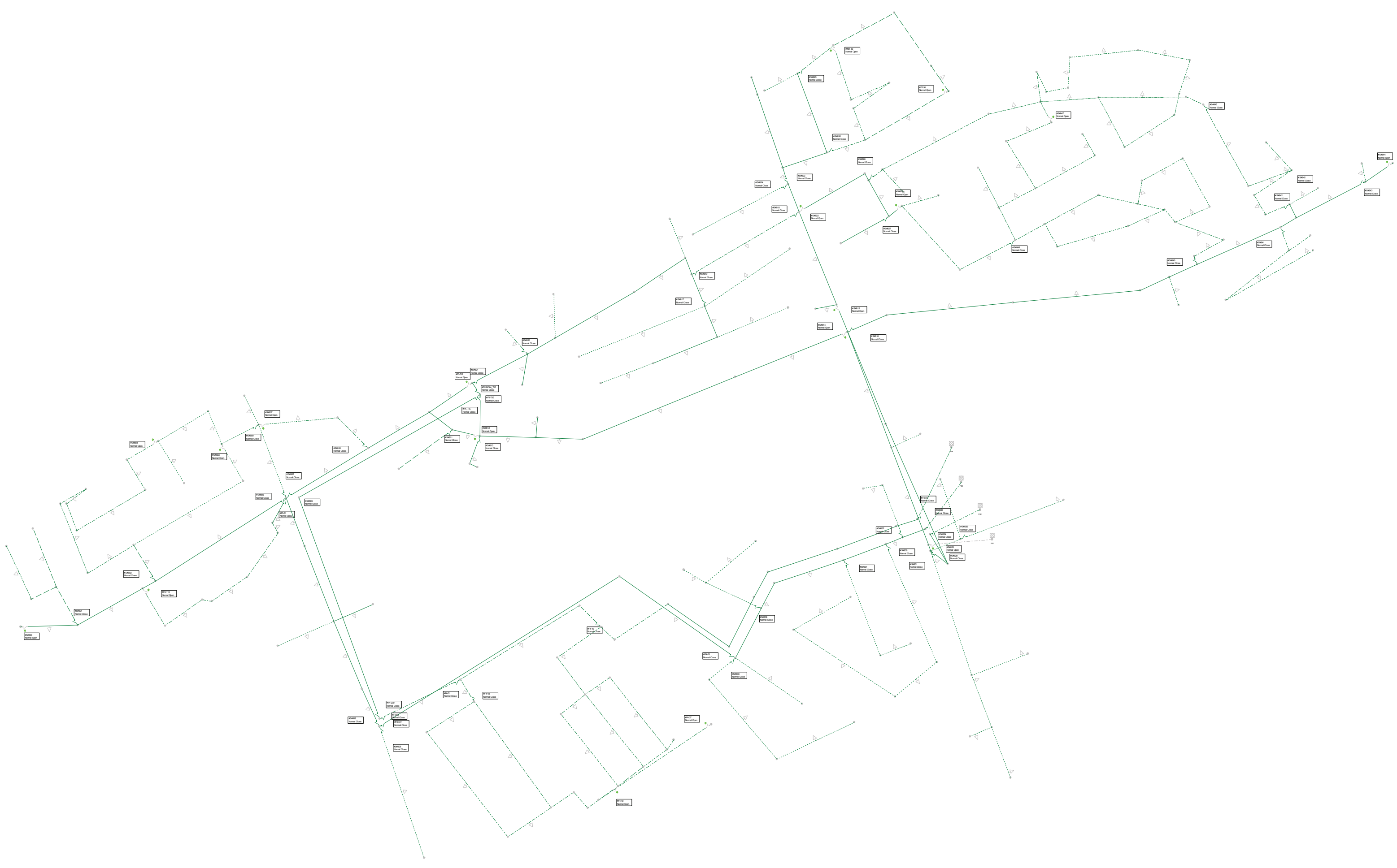
Layer :
Loading level color(%)

Colors :
0.00 95.00
95.00 100.00
100.00 500.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F1 Fail, Support by F4 Complex Switching



Legend

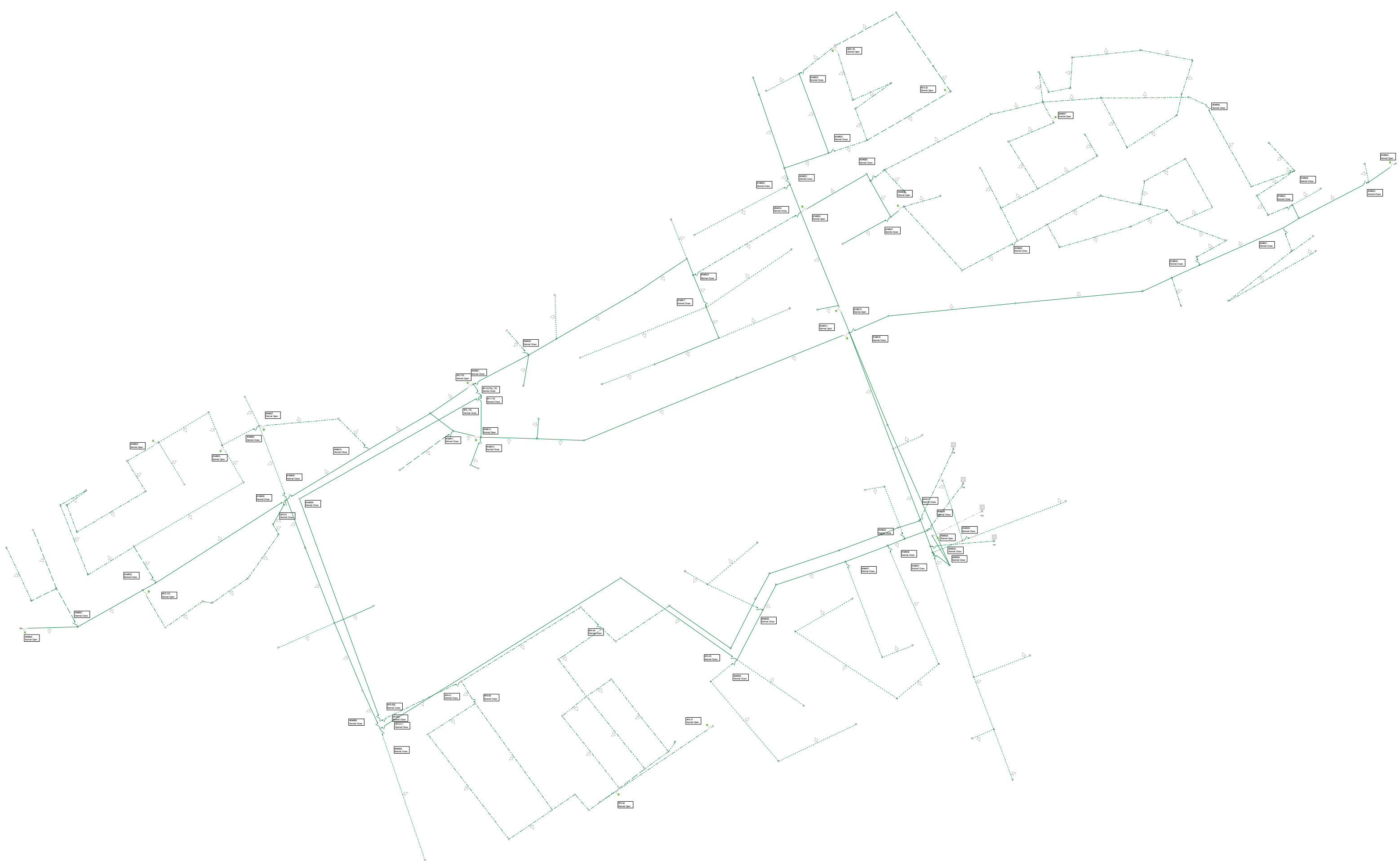
Layer :
Loading level color(%)

Colors :
0.00 95.00
95.00 100.00
100.00 500.00

Line Types:
A-OH
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F2 Fail, Support by F4 Complex Switching



Legend

Layer :
Loading level color(%)

Colors :
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95.00 100.00
100.00 500.00

Line Types:
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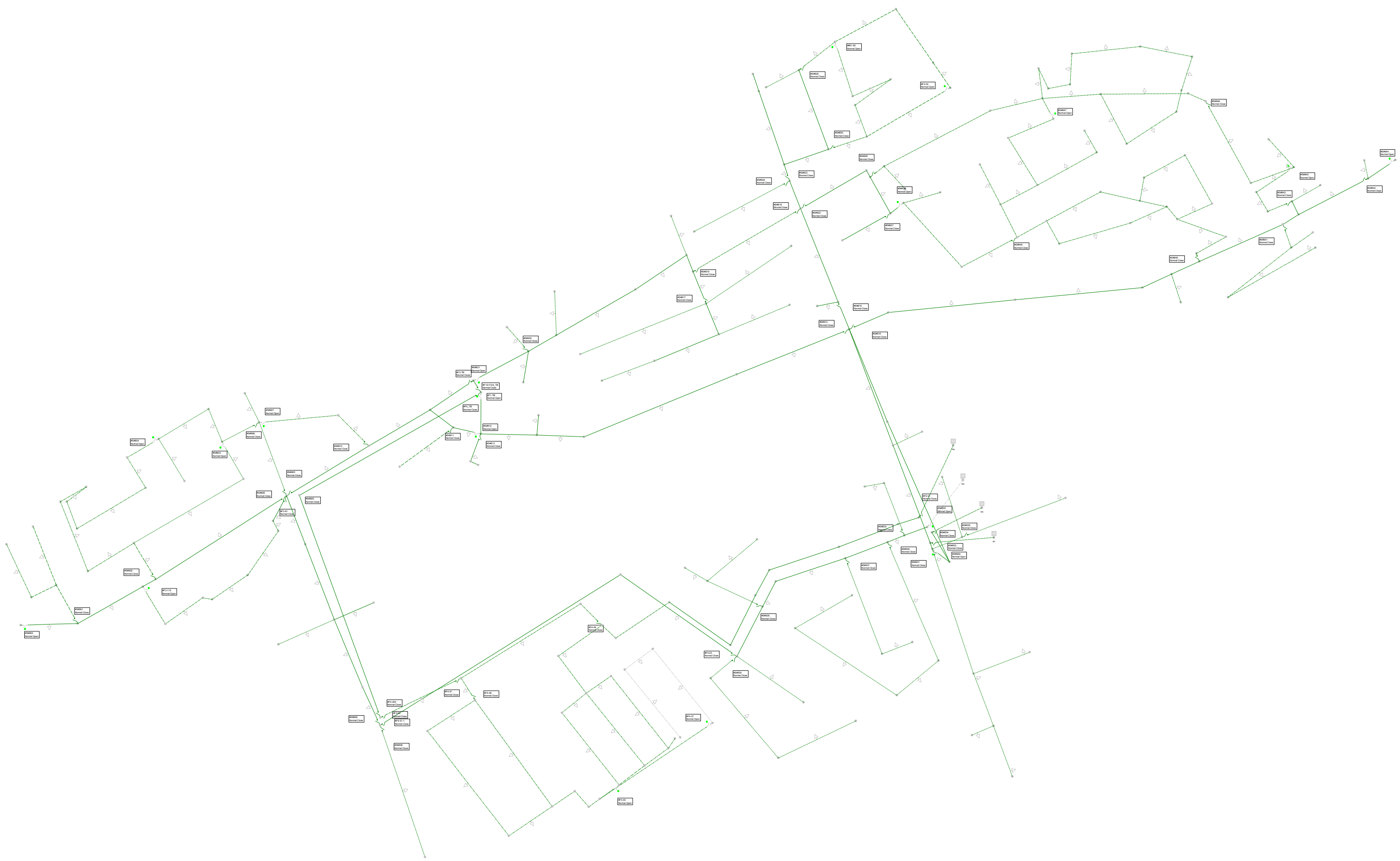
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F3 Fail, Support by F4 Simple Switching



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Line Types:
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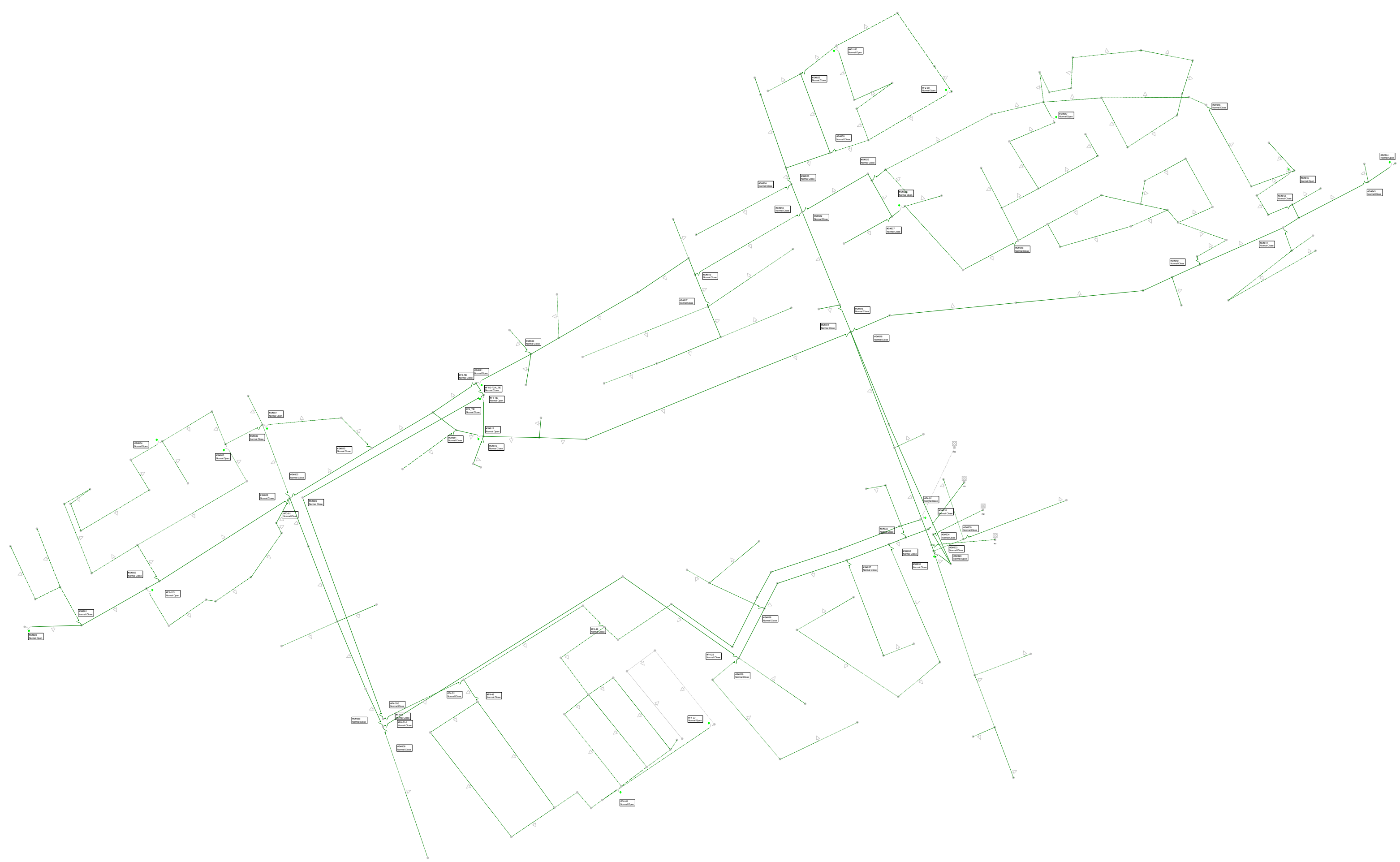
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Summer Loading, F4 Fail, Support by F3 Simple Switching



Legend

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A-UG
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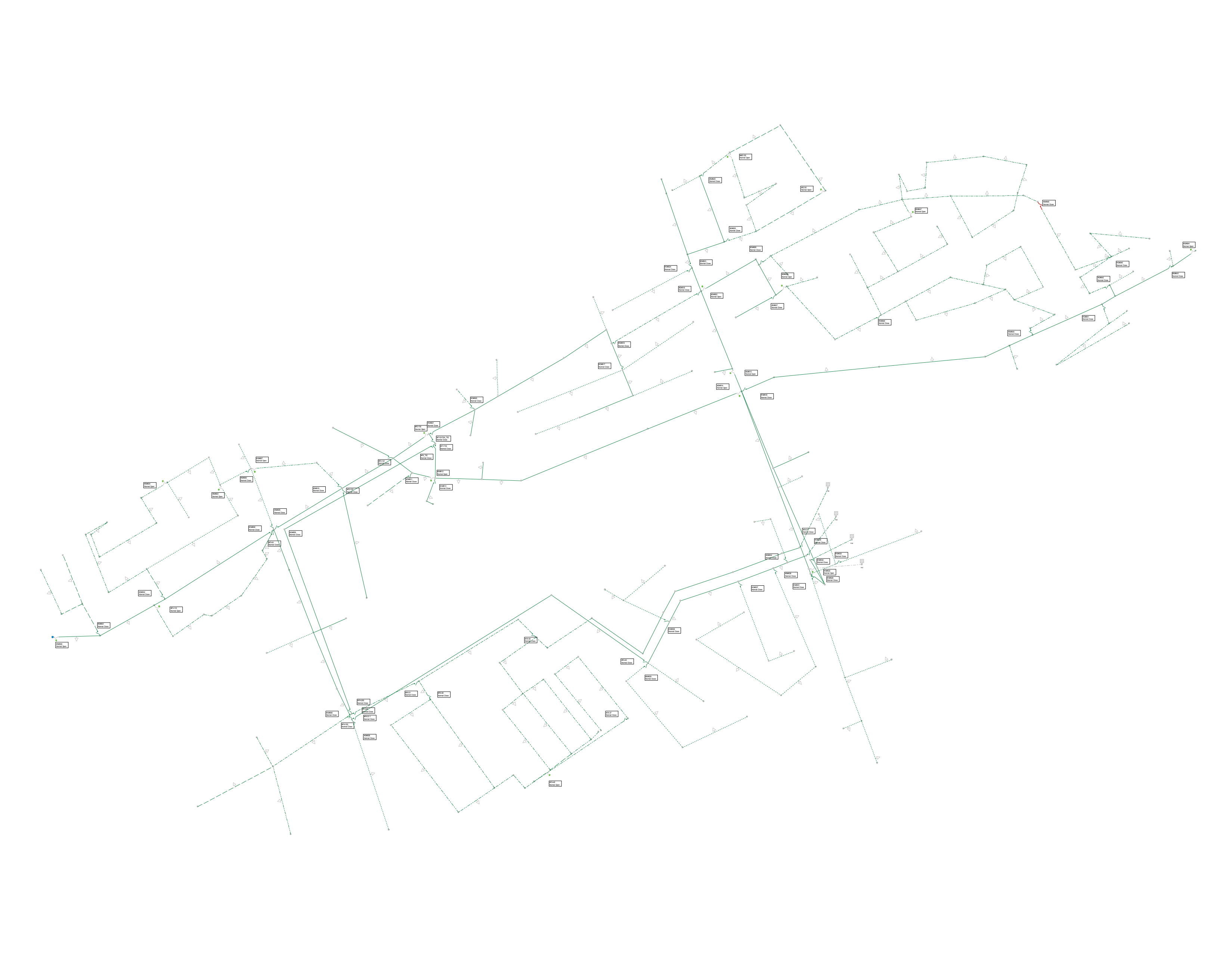
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F1 Fail Very Complex Switching



Legend

Layer :
Loading level color(%)

Colors :
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95.00 100.00
100.00 500.00

Line Types:
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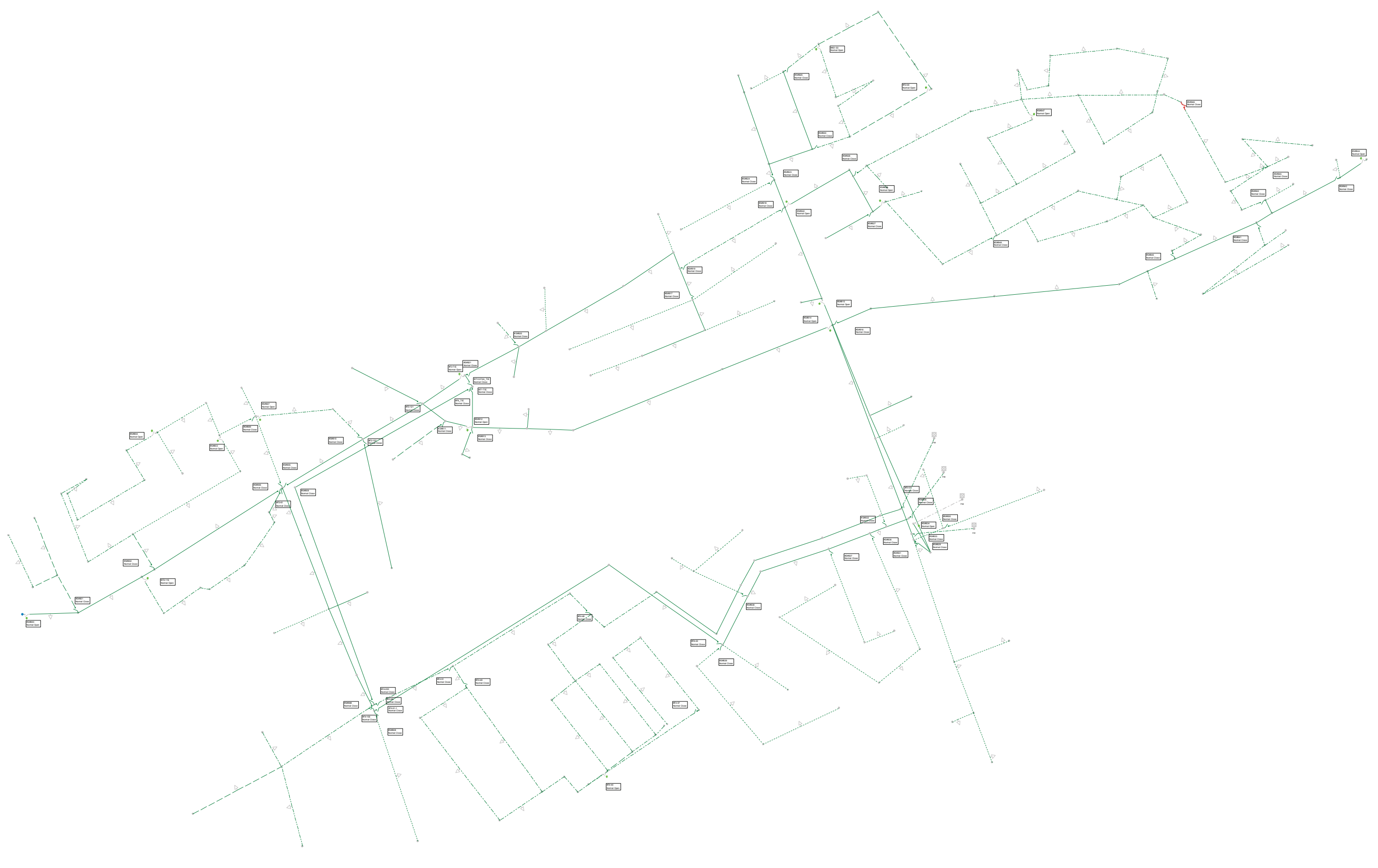
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F2 Fail Very Complex Switching



Legend

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Line Types:
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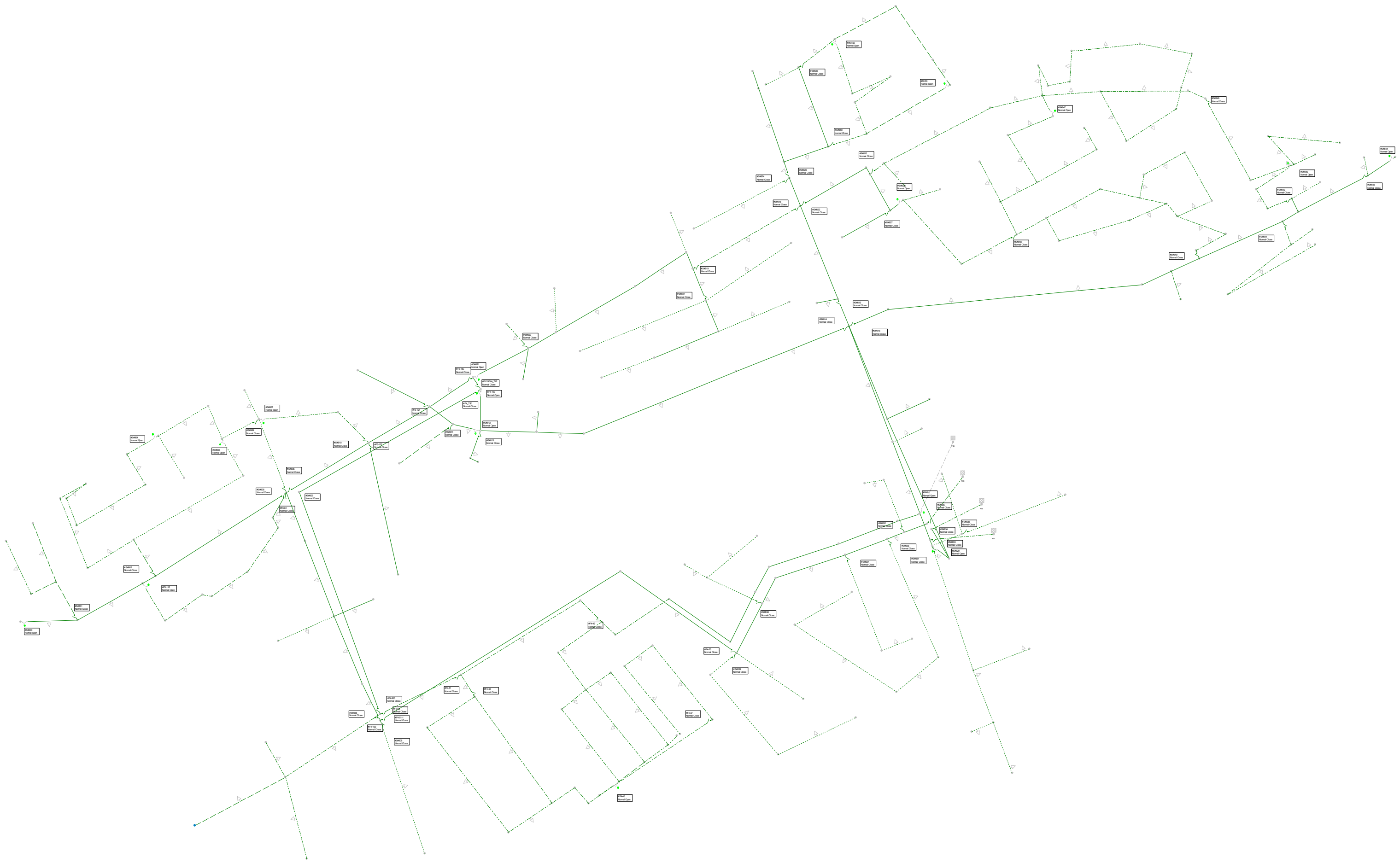
B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F3 Fail Simple Switching



Legend

Layer :
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B-OH
C-OH
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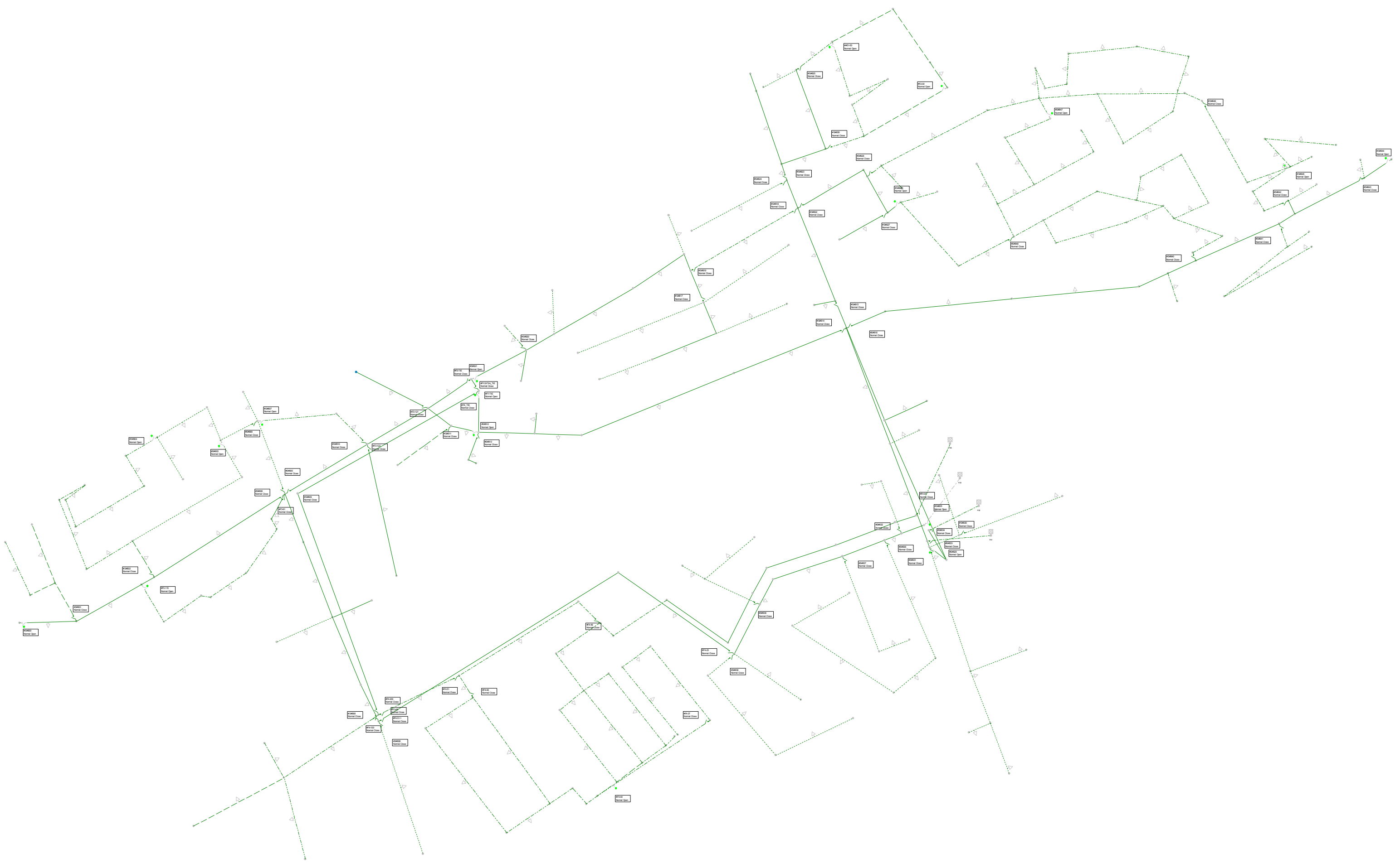
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2026 Loading Summer F4 Fail Simple Switching



Legend

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Loading level color(%)

Colors :
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Line Types:
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B-OH
C-OH
AB-OH
AC-OH
BC-OH
3-OH
A-UG
B-UG
C-UG
AB-UG
AC-UG
BC-UG
3-UG

Symbols :
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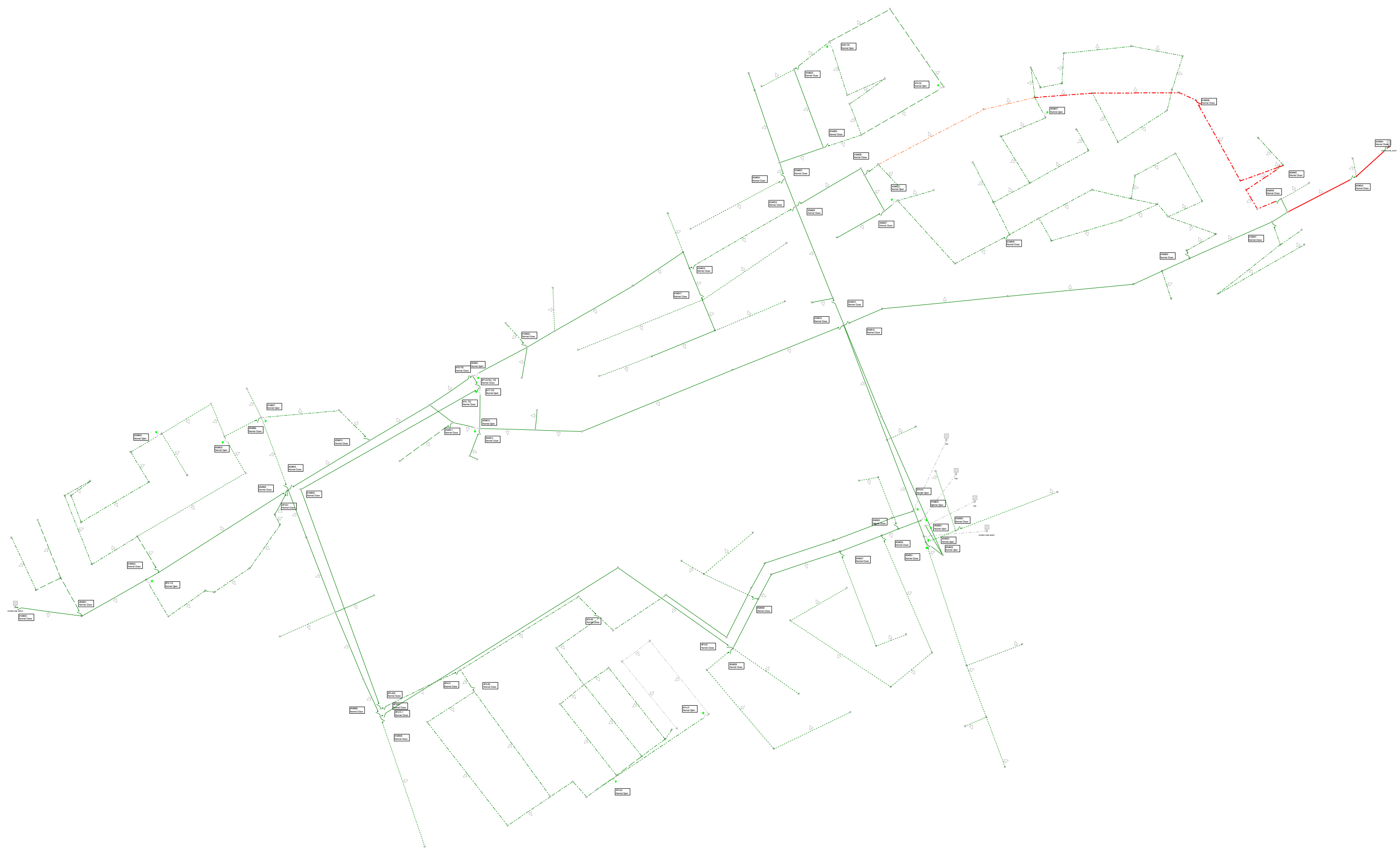
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Winter Peak Loading, F1/F2/F3/F4 failed, support by Hydro-One, Complex Switching



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C-OH
AB-OH
AC-OH
BC-OH
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B-UG
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AB-UG
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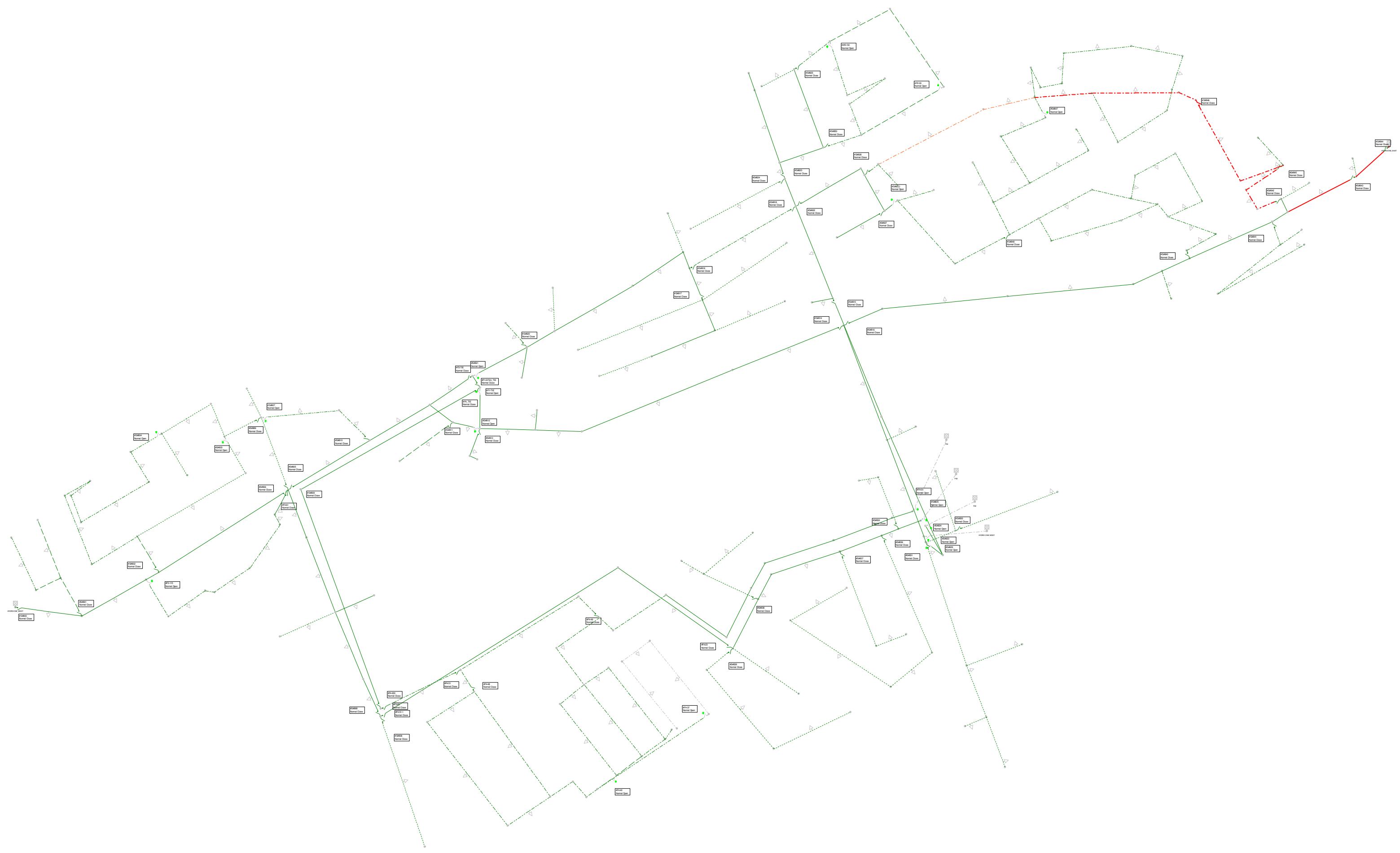
Symbols :
Switch, (O)
Load
Switch, (C)

Stantec Consulting Ltd.
2016 Winter Peak Loading, F1/F2/F3/F4 failed, support by Hydro-One, Complex Switching



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Layer :
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AB-UG
AC-UG
BC-UG
3-UG

Symbols :
Switch, (O)
Load
Switch, (C)

APPENDIX D
DISTRIBUTION DRAWING

Existing Embrun Distribution System Drawing

DENOTES	PADMOUNT TRANSFORMER
DENOTES	OVERHEAD TRANSFORMER
DENOTES	3ø PADMOUNT TRANSFORMER
DENOTES	3ø OVERHEAD TRANSFORMERS
DENOTES	OVERHEAD SWITCH
DENOTES	HYDRO POLE
DENOTES	SWITCHING CABINET
DENOTES	OPEN POINT
DENOTES	SECONDARY LINE
DENOTES	UNDERGROUND WIRE
DENOTES	F1 FEEDER – 3ø LINE
DENOTES	F1 FEEDER – 2ø LINE
DENOTES	F1 FEEDER – 1ø LINE
DENOTES	F2 FEEDER – 3ø LINE
DENOTES	F2 FEEDER – 2ø LINE
DENOTES	F2 FEEDER – 1ø LINE
DENOTES	F3 FEEDER – 3ø LINE
DENOTES	F3 FEEDER – 2ø LINE
DENOTES	F3 FEEDER – 1ø LINE
DENOTES	F4 FEEDER – 3ø LINE
DENOTES	F4 FEEDER – 2ø LINE
DENOTES	F4 FEEDER – 1ø LINE

COOPERATIVE
HYDRO
D'EMBRUN
INC.

821 NOTRE–DAME STREET, SUITE 200
EMBRUN, ONTARIO, K0A 1W1
Tel. (613)443–5110

REVISIONS

No.	DESCRIPTION	DATE	BY
6	Update – Feeder 3 & 4	Dec 05/14	RM
7	Update	Oct 23/15	RM
8	Update – New Subdivision Added	Feb 08/16	BY
9	Update	Mar 11/16	RM

CLIENT

DESIGNED MV
DRAWN CP
CHECKED MV

PROJECT
Utility Plan – Overall (1)

TITLE
UTILITY SINGLE LINE DIAGRAM

DATE	SCALE	JOB No.	DWG. No.
MAR 17/05	1:2000 metric	P05–016	1

APPENDIX H

IESO LETTER OF COMMENT

Note: Double click on next page to open the report.

IESO Letter of Comment

Cooperative Hydro Embrun Renewable Energy Generation Plan

March 6, 2017

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.

Cooperative Hydro Embrun Inc. – Distribution System Plan

On February 27, 2017, the IESO received REG information ("Plan") from Cooperative Hydro Embrun Inc. ("Hydro Embrun") as part of its Distribution System Plan. The IESO has reviewed the REG information and provides the following comments.

OPA FIT/microFIT Applications Received

Hydro Embrun's REG Plan notes that 11 microFIT projects representing 103 kW of capacity are connected to Hydro Embrun's distribution system.

According to the IESO's information, as of January 31, 2017, the IESO has offered contracts to 12 microFIT projects totalling 91 kW of capacity that are connected to Hydro Embrun's distribution system. The renewable energy generation connections information in Hydro Embrun's Plan is therefore reasonably consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The Plan indicates that Hydro Embrun's distribution system is fully embedded in the Hydro One Networks Inc. ("Hydro One") distribution system through Chesterville TS, which is part of the St. Lawrence Region for regional planning purposes. The IESO notes that while the information from Hydro Embrun was included in the St. Lawrence regional planning study,[2] Hydro Embrun did not participate directly in the study as an embedded LDC in the area. Under the new regional planning process endorsed by the OEB in August 2013, while the host distributor is required to gather information from their respective embedded LDCs, it is not required that embedded LDCs be directly involved.

The IESO confirms Hydro Embrun's involvement in regional planning for the St. Lawrence Region (Group 3), which was completed with the publishing of the Needs Assessment by Hydro One on April 29, 2016. The Needs Assessment determines that no further regional coordination is required for the St. Lawrence Region at this time. Therefore, the regional planning process for this region is complete and will be undertaken again when the next 5-year review cycle commences, unless there is sufficient load growth or an event that triggers the requirement to initiate the regional planning process before then.

The IESO looks forward to working with Hydro Embrun on regional planning, and will include Hydro Embrun in its relevant communications for the St. Lawrence Region. The IESO appreciates the opportunity to comment on the Renewable Energy Generation information provided as part of Hydro Embrun's Distribution System Plan.

[2] Hydro One Needs Assessment published April 29, 2016.

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 I

LETTER FROM HYDRO ONE THAT THE TEMPORARY DISTRIBUTION FACILITY ALLOCATION AGREEMENT IS BEING TERMINATED

Note: Double click on next page to open the report.

Hydro One Networks Inc.
25 Morrow Road,
Barrie, ON L4N 3V7
www.HydroOne.com

Tel: 416-953-4738
Email: stacey.pasztor@hydroone.com

Stacey Pasztor
Account Executive
Key Account Management

October 17, 2016

Cooperative Hydro Embrun Inc.
821 Notre Dame Street, Suite 200
Embrun, Ontario K0A 1W1

Attention: Mr. Benoit Lamarche
General Manager

RE: Notice of Termination - Temporary Distribution Facility Allocation Agreement

Dear Benoit,

As you are aware, Hydro Embrun's feeders are connected to Hydro One's St. Onge Distribution Feeder and Embrun DS Feeder in accordance with the terms of the Temporary Distribution Facility Allocation Agreement made between Cooperative Hydro Embrun Inc. ("**Hydro Embrun**") and Hydro One Networks Inc. ("**Hydro One**") dated August 2, 2006 (the "**Agreement**").

The Embrun DS Feeder is connected to Hydro One's Embrun DS. Embrun DS has reached the end of its expected service life and is no longer required by Hydro One, thus, it does not make economic sense for Hydro One to refurbish the station.

In light of the decommissioning of Embrun DS, Hydro One has decided to exercise its right to terminate the Agreement. By way of this letter, Hydro One is providing Hydro Embrun with 2 years prior written notice of termination in accordance with Section 6 of the Agreement. As such, the Agreement will expire on October 17, 2018 (the "**Termination Date**"). In accordance with Section 9 of the Agreement, Hydro Embrun is required to disconnect from Hydro One's St. Onge Distribution Feeder and Embrun DS Feeder at Hydro Embrun's sole expense on the Termination Date.

Presently, distribution feeders from St. Onge DS and Embrun DS extend to Embrun Hydro's service territory to provide backfeed capabilities. Upon termination of the Agreement, the provision of backfeed capabilities to Embrun Hydro will also cease indefinitely.

Yours truly,

2.5.4 CAPITALIZATION OF OVERHEAD

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not, nor have they ever been capitalized. (as such Appendix 2-D is not applicable in this case)[20]

2.5.5 COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

CHEI attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs or in its Distribution System Plan.

As such, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement are not applicable in this case.[21]

CHEI is not considering incremental conservation initiatives in order to defer or avoid future infrastructure projects as part of distribution system planning processes [22] nor is it planning on applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs etc. [23] Lastly, CHEI is not considering a generation facility. [24]

2.5.6 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

CHEI is not proposing any special or different approach to funding its capital expenditure[25]

---

[20] MFR - Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any

[21] MFR - If applicable, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include, initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments

[22] MFR - Description of how incremental conservation initiatives have been considered in order to defer or avoid future infrastructure projects as part of distribution system planning processes

[23] MFR - If applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs etc. the application must include a consideration of the projected affects to the distribution system on a long term basis and the projected expenditures. Distributors should explain the proposed program in the context of the distributors five year Distribution System Plan or explain any changes to its system plans that are pertinent to the program

[24] MFR - Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09:
- Appendices 2-FA through 2-FC identifying all eligible investments for recovery

[25] MFR - Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification

2.5.7 ADDITION OF ICM ASSETS TO RATE BASE

CHEI has never applied for a rate adder to recover an investment through the OEB's Incremental Capital Module.[26] And as such, CHEI does not need to balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue.[27]

[26] MFR - Distributor with previously approved ICM(s) - schedule of ICM amounts, variances and explanation
[27] Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue

2.5.8 SERVICE QUALITY AND RELIABILITY PERFORMANCE[28]

CHEI records and reports annually the following Service Reliability Indices:

- SAIDI = Total Customer-Hours of Interruptions/Total Customers Served
- SAIFI = Total Customer Interruptions/Total Customers Served
- CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

These indices provide CHEI with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g. to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation). They are reported in accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook.

CHEI's ESQR have been improving year over year since 2012. This partly due to new tracking processes that were put in place following an OEB audit. With respect to SQIs, the results have been steady until 2016 when the utility had a higher than normal numbers of scheduled interruptions and outages from its supplier HONI. The utility doesn't expect this trend of higher than normal SAIFI and SAIDI results to continue in future years. Based on its experience, this should be minimal once the new TS is in service at the end of 2017.[29]

CHEI is not proposing any benchmarking that is currently in place.[30]

[28] MFR - 5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken
[29] MFR - 5 historical years of SAIDI and SAIFI - for all interruptions, all interruptions excluding loss of supply, and all interruptions excluding major events; explanation for any under-performance vs 5 year average and actions taken
[30] MFR - Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale

1 **Table 26 – OEB App 2-G ESQR Results[31]**

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	90.5%	100.0%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	65.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	80.0%	96.0%	97.0%	97.6%	92.8%	95.2%
Rescheduling a Missed Appointment	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	4.0%	3.0%	2.4%	7.2%	4.8%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	91.4%	100.0%
Emergency Urban Response	90.0%	100.0%	100.0%	100.0%	88.9%	100.0%
Emergency Rural Response	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	93.0%	0.0%	0.0%	100.0%	100.0%
Micro-embedded generation facilities	90.0%	n/a	100.0%	100.0%	100.0%	100.0%

2

3 **Table 27 – OEB App 2-G SAIFI SAIDI Results**

Index	**Includes outages caused by loss of supply**					**Excludes outages caused by loss of supply**				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	3.080	1.540	0.010	0.030	125.590	0.080	0.040	0.010	0.030	0.370
SAIFI	1.020	1.020	1.140	0.010	26.240	0.020	0.020	0.130	0.010	2.070
5 Year Historical Average										
SAIDI					1.165					0.040
SAIFI					0.798					0.045

4

[31] MFR - Completed Appendix 2-G

APPENDIX

LIST OF APPENDICES

N/A	
N/A	