EXHIBIT 2 – RATE BASE & DSP

2018 Cost of Service

Hydro Hawkesbury Inc.
EB-2017-0048

TABLE OF CONTENTS

Table of Figures

2.1 OVERVIEW OF RATE BASE

2.1.1 RATE BASE OVERVIEW

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. HHI does not have non-distribution assets nor does it conduct non-distribution activities. [1] Controllable expenses include operations and maintenance, billing, collecting and administration expenses which are discussed in detail in Exhibit 4.

HHI converted to International Financial Reporting Standards ("MIFRS") on January 1, 2015, and has prepared this application under MIFRS. HHI 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.

HHI has calculated its 2018 test year rate base to be $8,615,028. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6. Table 1 below presents HHI'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***	***VAR***
Particulars	**Last Board Approved**	**2018**	
Net Capital Assets in Service:			
Opening Balance	3,320,570	7,112,824	3,792,254
Ending Balance	4,867,995	7,007,776	2,139,781
Average Balance	4,094,282	7,060,300	2,966,017
Working Capital Allowance	2,291,918	1,554,729	-737,190
Total Rate Base	6,386,201	8,615,028	2,228,828
Expenses for Working Capital	Last Board Approved	2018	VAR
Eligible Distribution Expenses:			
3500-Distribution Expenses - Operation	96,550	95,593	-957
3550-Distribution Expenses - Maintenance	205,700	204,514	-1,186
3650-Billing and Collecting	426,315	476,632	50,317
3700-Community Relations	200	-	-200
3800-Administrative and General Expenses	395,900	433,375	37,475
LEAP	2,000	-	-
Total Eligible Distribution Expenses	1,126,665	1,210,114	83,449
3350-Power Supply Expenses	16,503,476	19,519,602	3,016,126
Total Expenses for Working Capital	17,630,141	20,729,716	3,099,576
Working Capital factor	13.0%	7.5%	-0
Total Working Capital	2,291,918	1,554,729	-737,190

The main contributor to the increase in Rate Base between 2014 Board Approved and the 2018 Test Year is the addition of 3.525M related to the project management, electrical and civil/structural engineering design and construction supervision services for the upgrades to their 110kV existing substation. In 2012 Hawkesbury Hydro initially engaged a 3rd party engineering firm to upgrade their 110kV existing substation. Several critical issues arose during the construction which led to years of delays in putting in service the substation which eventually went into service in May of 2017. A chronicle of events and summary of costs and issues is presented in the next Section 2.1.2.

2.1.2 TIMELINES AND REASONS FOR THE DELAY WITH THE 110KV PROJECT (2012-2017)

In 2012, HHI applied to the Ontario Energy Board, to recover from its customers, the revenue requirement associated with the incremental capital costs associated with the replacement of failing transformers.

HHI's Incentive Regulation Mechanism ("IRM") application (EB-2011-0273) included an ICM for two projects: replacement of a 44-kV distribution transformer at a capital cost of $712,919 (the "44 kV project") and replacement of two transformers at the 110-kV substation at a capital cost of $1,517,813 (the "110 kV project"). In its decision, the Board approved the two projects and allowed HHI to recover the associated annual revenue requirement through a rate rider to start on May 1, 2012. In a decision issued on April 19, 2012, The Ontario Energy Board found that the need, prudence, and materiality for each for the two applied-for projects had been established and accepted HHI's request for incremental capital totaling $2,230,722.

As part of its 2014 Cost of Service application, HHI added $790,136 for the 44-kV project and $1,517,813 for the 110-kV project to its Rate Base. During the interrogatories, HHI was asked to explain the reasons why the 110KV was not yet in service.

After explaining the delays, HHI indicated that the in-service date was expected to be March 2014 with a total forecast cost $1,547,900. ($30,087 higher than initially anticipated).

Reasons for delays

In 2012, HHI hired the services of BPR to provide for the management, electrical and civil /structural engineering design and construction supervision services for the upgrade of HHI's 110 KV station. BPR estimated the project cost at $1.5 million.

HHI applied to the OEB for an Incremental Capital Module (ICM) and subsequently applied to Infrastructure Ontario for a loan based on the report from BPR and approval from the OEB. On September 1, 2012, HHI secured a loan with Infrastructure Ontario in the amount of $2,300,000.00 to fund both transformers.

Following the approval of both the OEB and Infrastructure Ontario, HHI ordered the work and equipment as designed by BPR (transformer, circuit switcher and the installation of a control building).

In 2014, HHI hired General Electric to assist with the commissioning of the new transformer. While reviewing the engineering reports and requirements, General Electric noted that major equipment (and costs) for the 110KV project needed to be added to the original estimate provided by BPR.

Majors considerations which needed to be addressed included:

1. Costs related to a control building and panels. Costs related to excavation, concrete, labor and electricity to the building, Bell Canada for reading by the IESO, meter, etc.
2. Costs related to the demolition of the old building by qualified linemen and contractors.
3. Cost related to the need to replace the original basin with a new design.
4. Costs related to the provision of telecommunications with Hydro One.
5. Costs relate to the creation of a "commissioning / authorization" plan.
6. the estimate for labour, material and engineering costs, originally provided as a "rough order of magnitude" estimate, needed to be comprehensively updated In addition to the considerations advanced by General Electric, HHI determined that significant design updates were required to meet the requirements from Hydro One, the IESO and the Ministry of Energy, requirements that had not been fully addressed in the original estimate.

Revised design and specifications were submitted to Hydro One. Hydro One required changes to the design of the proposed circuit switcher in order to meet the requirements of the Transmission System Code. The proposed changes were made and a revised proposal was sent to Hydro One.

In the Fall of 2013 HHI was told by Albarrie GeoComposite that the installation of the SorbWeb system (oil containment) was being suspended due to an investigation of an oil spill unrelated to Hawkesbury's station.

In early 2014, Albarrie GeoComposite confirmed that the investigation was still pending and advised HHI that they would no longer be able to install the SorbWeb as planned. As a result, BPR was required to design a new containment system which was required.

In the Summer of 2014, The Town of Hawkesbury put all work related to the 110KV on hold pending a detailed implementation plan and an emergency plan for the oil containment system. Accordingly, while the transformer was received it could not be installed. Instead, the transformer was mounted on a temporary base pending the completion of the implementation plan.

Both plans were re-designed and submitted to South Nation and the Ministry of Energy. BPR required 5 months to draft the 90-page emergency document, as well as all other plans for the Town of Hawkesbury and all other authorities involved.

By December of 2014, HHI had incurred a significant amount of capital costs and turned to Infrastructure Ontario to draw down on its loan. In view of the unexpected delays and issues with the timelines of the project, Infrastructure Ontario required that the following steps be taken prior to allowing a draw down on the financing:

- ✓ Provide a complete budget update including 'Original Cost Estimates,' 'Percentage Complete' and any 'Holdbacks.'
- ✓ Provide specifics around the expense of the initial containment structure and the cost of the new one.
- ✓ Provide a detailed schedule for completing the project.
- ✓ Provide an Independent Engineer's report on the project (Stantec Ottawa)

Since detailed engineering were required prior to draw down on the Infrastructure Ontario loan, HHI was required to use its working cash allowance to pay costs associated with the transformer, fully expecting to drawdown on its loan with Infrastructure Ontario during the last quarter of 2014.

By the end of 2014, HHI had disbursed more than $700,000 out of its own cash flow without the ability to draw down on the Infrastructure Ontario loan.

In January of 2015, per Infrastructure Ontario's request, HHI hired Stantec Ottawa to review progress on the project design and construction.

In April 2015, Tetra Tech (formally BPR) submitted a progress report to Stantec Ottawa for review. In, November 2015 Stantec Ottawa finalized its report and submitted it to Infrastructure Ontario for approval. Infrastructure Ontario approved the engineering report and released funds to HHI. The funds were received by HHI in July of 2016.

In June of 2015, Tetra Tech designed the new oil containment plans. The designs along with various documents were submitted to the Ministry of Energy for their approval, which was provided in February of 2016.

The application included the following:

- ✓ An Environment Response Plan
- ✓ An Acceptance letter from South Nation Conservation
- ✓ An Acceptance letter from the Town of Hawkesbury
- ✓ A Design Brief from Tetra Tech

The application also noted that a secondary oil containment system was to be installed for the substation oil-filled transformers consisting of a Geocomposite clay liner based basins and Imbiber beads type drain shut-off system to block drainage in the event of a spill.

By the fall of 2015, Hydro One was waiting for the final stamped drawings and specification for review, and HHI was waiting for the final approval from the Ministry of Energy to either complete and/or change the actual design (lay-out of the substation).

Hydro One had partially reviewed the drawing and specification of the proposed load breaker switch designed by BPR only to find that it did not meet the requirements of the Transmission System Code.

Revised designs were sent to several manufacturers, and Mindcore was ultimately chosen to supply the required Load Break Switch to meet requirements from Hydro One, IESO, and the Transmission System Code. The revised Load Break Switch was purchased in June of 2016.

With all approvals in hand, an official RFP was sent out by Stantec Montreal in September of 2016 for the installation of the transformer. The contract was awarded to Eptcon Ltd. who began the work shortly thereafter.

The scheduled outage to remove the 110kv feed from Hydro One was originally planned for late October. However, the outage was postponed due to missing equipment.

The outage was then rescheduled to early December 2016; however, as such an installation is complicated and can easily jeopardize the reliability of the system if anything goes wrong, HHI and its Board of Directors opted to wait until the Spring of 2017 when peak demand on its system is lower – a decision that was made in the best interest of its customers. *(The process of Hydro One removing the loops to the old 55T1 transformer is irreversible. If anything goes wrong with the connecting or energizing of the new 55T3 transformer, HHI would find itself in a critical situation where most of the service area would be left without power. Winter months are HHI's highest peak months, and therefore Board of Directors and HHI's management made the decision to wait until the spring to energize the new transformer.)*

During this time, Tetra Tech, Stantec Montreal, and Ottawa performed the required work approval with Hydro One and IESO (meter and equipment registration). Tetra Tech also submitted an updated budget to Infrastructure Ontario as costs were deemed final. A final report from Stantec Ottawa was required for Infrastructure Ontario to approve financing. The report from Stantec Ottawa to Infrastructure Ontario is presented in Appendix A of this Exhibit. The new transformer is in service as of May 2017.

Summary of Cost Escalation

HHI proposes to refund the remaining over-collected from the period of January 1, 2014 to December 31, 2018 for the project approved in 2014 and has included in its Rate Base, revised costs in the amount of 3.525M.

The escalation of the budget over time is detailed in the table below. The addition of 1.3 is immediately related to the revised TetraTech's initial budget, which is driven by the updating of the estimate to a class 2 level, along with the addition of certain specific items not contemplated in the original budget. The remaining .5M is made up of costs such as project/construction management related costs such as Stantec costs, and the material difference in actual labour costs relative to what was in the original budget. The main drivers behind the cost escalation are;

- ✓ Unforeseen failure events involving the new 43T2 transformer.
- ✓ Substantial changes required and costs incurred to meet requirements of authorities having jurisdiction (IESO, Hydro-One, and the MOE).
- ✓ Higher than originally anticipated engineering costs compared to the initial budget. (inadequate equipment for connection to the grid and higher rated equipment needed to be procured.)
- ✓ Increase in engineering service based on new reliability design criteria.

Those items highlighted represent areas where the costs have gone up significantly. The first two columns show the amount TetraTech estimated for each item in their first two budgets (ROM and Class 2).

The columns in the middle show what each item is actually going to cost, within and outside of Eptcon's contract.

The last two columns show how much the cost has increased for each item since TetraTech's Class 2 and ROM estimates.

Major items which have gone up by over $200K are highlighted in red of which the biggest item is the civil work (excavation, bases, concrete, etc.). Although there was civil work done prior to tender, Eptcon’s cost for this item alone was significantly in excess of the budget. Items for which the cost escalated by more than $100K since the ROM are highlighted in orange and items for which the cost escalated by more than $50K since the ROM are highlighted in yellow.

	Description	Original Budgets from Tetra Tech		Actual Costs			Cost Escalation	
		Original Budget (ROM)	Class 2	Others	Eptcon	Total	Since Class 2	Since ROM
	Hydro One (other reviews/approvals)							
	Hydro One Review	$25,000.00	$60,000.00	$60,000.00		$60,000.00	$0.00	$35,000.00
	Hydro One Capital Work	$100,000.00				$0.00	$0.00	($100,000.00)
	IESO			$1,450.00		$1,450.00	$1,450.00	$1,450.00
	ESA		$1,450.00	$2,150.00		$2,150.00	$700.00	$2,150.00
	Major Equipment							
	New Transformer 110kV-12.4kV 15/20/25MVA	$780,697.50	$654,290.00	$612,509.00	$128,319.00	$740,828.00	$86,538.00	($39,869.50)
	New Circuit Switchers c/w Steel Structure, P&C	$131,000.00	$148,850.00	$136,765.00	$207,637.33	$344,402.33	$195,552.33	$213,402.33
	Other Equipment (Switches)	$10,000.00	$7,488.00		$47,719.00	$47,719.00	$40,231.00	$37,719.00
	Control Building, incl. civil (and Demolition of Existing Shed)		$226,735.00	$77,843.99		$77,843.99	($148,891.01)	$77,843.99
	Load break Switches (Mindcore)		$75,590.00	$69,476.52		$69,476.52	($6,113.48)	$69,476.52
	New 110kV and 12.47kV Structures							
	New steel structures c/w assembly, insulators, cables, trays, conduits, controls, insulators, CT's, arresters	$48,190.00	$184,737.00		$316,886.98	$316,886.98	$132,149.98	$268,696.98
	Metering							
	Move Metering	$20,000.00	$29,450.00	$22,496.07		$22,496.07	($6,953.93)	$2,496.07
	Construction					$0.00	$0.00	$0.00
	Civil (Excavation, Equipment bases, concrete, etc.), demo	$52,008.00	$557,767.00	$172,713.43	$609,451.28	$782,164.71	$224,397.71	$730,156.71
	Oil Containment	$85,000.00			$48,457.38	$48,457.38	$48,457.38	($36,542.62)
	Fence Modification, new gate entrance	$6,824.00	$7,344.00	$1,645.00	$8,386.00	$10,031.00	$2,687.00	$3,207.00
	Program P&C Tests	$7,500.00	$94,445.00		$79,885.50	$79,885.50	($14,559.50)	$72,385.50
	Grounding (New Ground Grid)	$8,302.00	$84,793.00	$27,662.50	$94,056.73	$121,719.23	$36,926.23	$113,417.23
	Contractor Markup (10% excluding transformers)	$15,781.15					$0.00	($15,781.15)
	Relocate existing transformers		$14,408.00				($14,408.00)	$0.00
	Risk Contingency for Contaminated Soil		$99,470.00				($99,470.00)	$0.00
	Engineering							
	Tetra Tech (Engineering & Services)	$100,000.00	$373,442.00	$313,593.00		$313,593.00	($59,849.00)	$213,593.00
	Independent Engineer Reporting (Stantec Ottawa)			$70,222.00		$70,222.00	$70,222.00	$70,222.00
	Construction Management (Stantec Montreal)			$75,600.00		$75,600.00	$75,600.00	$75,600.00
	Engineering/Project Management Support (General Electric)			$167,849.75		$167,849.75	$167,849.75	$167,849.75
	Contingency (15%)	$208,545.40	$210,000.00					
	TOTAL	$1,598,848.05	$2,830,259.00	$1,811,976.26	$1,540,799.20	$3,352,775.46	$522,516.46	$1,753,927.41

Refund of over collection (2012-2014)

In its 2014 Cost of Service proceeding EB-2013-0139, it was the consensus from all intervening parties was that HHI had over collected the amount required by the current ICM rate rider as the 110-kV project was not in service in 2012 as planned. Therefore, the Board directed HHI to determine the actual ICM rate rider amount collected from May 1, 2012, to February 28, 2014, associated with the 110-kV project (the "110 kV rate rider refund amount") and refund it back to its customers.

As requested by the Board, HHI calculated the actual ICM rate rider amount collected from May 1, 2012, to February 28, 2014, associated with the 110KV project and refunded it back to its customers via a rate rider.

A breakdown of the over collection for both 44KV and 110KV projects is presented below.

Revenues from ICM Rate Rider (Acct 1508.005)

2012		(119,260.14)
2013		(227,788.12)
2014	Jan Act	(24,936.71)
	Feb Proj.	(22,523.48)
Revenues at February 28, 2014		**(394,508.45)**
Rate Rider Ratios	**Split**	**Incremental CAPEX**
SUB 44KV	32%	712,909.00
SUB 110KV	68%	1,517,813.00
		2,230,722.00
Rate Rider Split per Project		
	SUB 44KV	**SUB 110KV**
2012	(38,113.95)	(81,146.19)
2013	(72,798.05)	(154,990.07)
2014	(15,167.64)	(32,292.55)
	(126,079.64)	**(268,428.81)**

Rate Class		**Total Incremental Capital $ by Rate Class**		**Billed kWh (over 10 months)**	**Billed kW (over 10 months)**	**Distribution Volumetric Rate kWh Rate Rider**	**Distribution Volumetric Rate kW Rate Rider**
Residential	kWh	-$141,719.42	52.80%	44,632,599.17	-	-0.0032	
General Service Less Than 50 kW	kWh	-$38,141.19	14.21%	17,135,541.67	-	-0.0022	
General Service 50 to 4,999 kW	kW	-$82,708.05	30.81%	71,822,305.00	191,511.67		-0.4319
Sentinel Lighting	kW	-$268.18	0.10%	90,391.67	270.83		-0.9902
Street Lighting	kW	-$5,448.31	2.03%	1,006,969.17	2,580.00		-2.1117
Unmetered Scattered Load	kWh	-$143.65	0.05%	183,889.17	-	-0.0008	
		-$268,428.81					

Proposed Refund of overcollection (March 1, 2014- December 31, 2017)

Since the 110-kV project was not in service until May of 2017, HHI is proposing to refund the ICM rate rider amount collected from March 1, 2014, to December 31, 2017, essentially refunding the entire amount associated with the 110-kV project (the "110 kV rate rider refund amount") back to its customers.

HHI has calculated the refund to be in the amount of -$304,488.77. Details are presented in the table below. HHI proposes to dispose of this repayment in a 1 year disposition period. Further details on the disposition are explained in Exhibit 8.

A breakdown of the refund and associate rate rider for the 110KV projects is presented below.

	Test Year Rev Req incl. 110kV	**Test Year Rev Req excl. 110kV**	**Diff. to be refunded back to the customer**
OM&A Expenses	$1,126,665	$1,126,665	$0
Amortization Expense	$206,119	$178,643	-$27,476
			$0
Total Distribution Expenses	$1,332,784	$1,305,308	-$27,476
			$0
Regulated Return On Capital	$385,394	$338,306	-$47,089
IFRS Adjustment			$0
Grossed up PILs	$12,526	$7,167	-$5,359
Service Revenue Requirement	**$1,718,178**	**$1,643,614**	**-$74,565**
			$0
Less: Revenue Offsets	$140,139	$140,139	$0
			$0
Base Revenue Requirement	**$1,578,039**	**$1,503,474**	**-$74,565**

Total credit for over-collection of revenues associated with the 110kV substation.

	2014	**2015**	**2016**	**2017**	**Total**
Diff in Revenue Requirement	-$74,565	-$74,565	-$75,832	-$77,046	
Price Cap Approved in IRM	100.00%	1.70%	1.60%	0.00%	
	-$74,565	-$75,832	-$77,046	-$77,046	-$304,489

Rate Rider

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Balance (excluding 1589)**	**Rate Rider for Deferral/Variance Accounts**	
RESIDENTIAL	kWh	48,228,553	-$103,553.54	**-$0.0021**	***$/kWh***
GENERAL SERVICE < 50 KW	kWh	18,143,532	-$34,373.59	**-$0.0019**	***$/kWh***
GENERAL SERVICE > 50 TO 4999 KW	**kW**	211,046	-$164,345.45	**-$0.7787**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	429,307	-$813.34	**-$0.0019**	***$/kWh***
SENTINEL LIGHTING	**kW**	238	-$292.92	**-$1.2292**	**$/kW**
STREET LIGHTING	**kW**	1,844	-$1,109.93	**-$0.6020**	**$/kW**
Total			**-$304,488.77**		

2.1.2 RATE BASE TREND

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

Table 2 - Rate Base Trend

	CGAAP	***NEWGAAP***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***
Particulars	**Last Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Net Capital Assets in Service:						
Opening Balance	3,320,570	3,288,222	4,799,922	5,116,512	6,412,494	7,112,824
Ending Balance	4,867,995	4,799,922	5,116,512	6,412,494	7,112,824	7,007,776
Average Balance	4,094,282	4,044,072	4,958,217	5,764,503	6,762,659	7,060,300
Working Capital Allowance	2,291,918	1,610,643	1,519,271	1,534,703	2,908,677	1,554,729
Total Rate Base	**6,386,201**	**5,654,714**	**6,477,488**	7,299,206	9,671,336	8,615,028
						-

	CGAAP	**NEWGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Expenses for Working Capital	**Last Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	96,550	51,300	55,990	68,472	113,406	95,593
3550-Distribution Expenses - Maintenance	205,700	181,555	179,949	168,399	194,970	204,514
3650-Billing and Collecting	426,315	395,636	409,354	418,864	462,696	476,632
3700-Community Relations	200	-	-	-	-	-
3800-Administrative and General Expenses	395,900	340,177	299,046	341,082	422,354	433,375
6105-Taxes other than Income Taxes	-	15,264	15,126	14,843	-	-
	2,000					
Total Eligible Distribution Expenses	1,126,665	983,932	959,466	1,011,660	1,193,426	1,210,114
3350-Power Supply Expenses	16,503,476	11,405,626	10,727,236	10,793,747	21,181,013	19,519,602
Total Expenses for Working Capital	17,630,141	12,389,558	11,686,701	11,805,407	22,374,439	20,729,716
Working Capital factor	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital	**2,291,918**	**1,610,643**	**1,519,271**	**1,534,703**	**2,908,677**	**1,554,729**

The Rate Base for the 2018 Test Year has decreased by -1,056,308 over the Bridge Year, and increased by $2,228,828 over the last Board Approved Rate Base. The reason for the sizeable increase from the 2014 Board Approved Rate Base is mainly attributed to:

Major capital cost drivers 2014 (relative to the 2014 BA Rate Base)

System Access:

- 44KV Substation: $42,750

Major capital cost drivers 2015

System Renewal:

- 44KV Substation: $320,188
- Replace poles, fixtures as per AMP: $88,560
- Capital Contribution: -$93,493

Major capital cost drivers 2016

System Renewal:

- Sub 115 KV: $59,244
- Sub 44 KV: $54,101
- Replace poles, fixtures as per asset management plan: $65,573
- Replace 3/0 primary with new 336 mcm: $69,003

Major capital cost drivers 2017

System Renewal:

- Sub 115kv for station betterment: $3,352,775
- Hydro One mandatory telemetry costs $149,000
- Upgrade to backup TS 55T1 $23,224

Major capital cost drivers 2018

System Renewal:

- Pole replacement: $81,500

Increased Power Supply Expenses

- HHI has forecasted an increase in the 2018 Power Supply Expenses of over $3,136,687 in excess of its 2014 Cost of Service. This is mainly due to commodity costs.

Distribution Operational Expenses

- The 2018 forecast for Operation and Maintenance remained at the same level as the 2014 Board Approved while the Working Capital Allowance has decreased by $728,148 over the 2014 Board Approved. The reason for the drop 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 is 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 HHI's 2014 Board Approved Cost of Service Application.

As justified in Exhibit 1, HHI's materiality threshold is $50,000.

HHI 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

	NEWGAAP	NEWGAAP		
Particulars	**2014 Board Approved**	**2014**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	3,320,570	4,201,028	880,458	26.52%
Ending Balance	4,867,995	4,799,922	(68,073)	1.40%
Average Balance	4,094,282	4,500,475	406,192	9.92%
Working Capital Allowance	2,291,918	1,610,643	(681,275)	29.73%
Total Rate Base	**6,386,200**	**4,515,907**	**(1,870,294)**	**29.29%**
Expenses for Working Capital	**NEWGAAP**	**NEWGAAP**		
Eligible Distribution Expenses:	**2014 Board Approved**	**2014**	**Var**	**%**
3500-Distribution Expenses - Operation	96,550	51,300	(45,250)	46.87%
3550-Distribution Expenses - Maintenance	205,700	181,555	(24,145)	11.74%
3650-Billing and Collecting	426,315	395,636	(30,679)	7.20%
3700-Community Relations	200	-	(200)	100.00%
3800-Administrative and General Expenses	395,900	340,177	(55,723)	14.07%
6105-Taxes other than Income Taxes	-	15,264	15,264	
6205-Sub-account LEAP Funding	2,000	-	(2,000)	100.00%
Total Eligible Distribution Expenses	1,126,665	983,932	(142,733)	12.67%
3350-Power Supply Expenses	16,503,476	11,405,626	(5,097,850)	30.89%
Total Expenses for Working Capital	17,630,141	12,389,558	(5,240,583)	29.73%
Working Capital factor	13.0%	13.0%	15%	0.00%
Total Working Capital	**2,291,918**	**1,610,643**	**-681,275**	**29.73%**

The total Rate Base in 2014 Actual of $4,515,907 was $1,870,294 or -29.29% less than the 2014 Board Approved. The main reasons for the variance are:

- **Failure of the 110KV going in service as planned (Avg. net fixed assets) -$50,211**

  The biggest contributor to the decrease in Rate Base from 2014BA to 2014 Actual was the failure of the 110KV substation to come in service as explained in Section 0.0 of this Exhibit. The capital expenditure included in the 2014 Cost of Service project was in the amount of-$1,588,052

- **Repairs and inspection of the 43T1 transformer $42,750**

This was the cost to remove the old transformer which was producing high levels of dissolved combustible gas in the transformer oil on the 43T1 transformer (44kV to 12.4kV). This work is described further in Appendix C.

- **Pole replacement** **$24,310**

  As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

- **Replace 3/0 primary wire** **$ 31,221**

  The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

The rest of the increase can be attributed to the regular maintenance of the distribution system required in order to keep the system running in a safe and reliable manner.Details of these projects in excess of the materiality threshold are explained in the DSP.

2015 Actual vs. 2014 Actual:

Table 4 - 2015-2014 Rate Base Variances

	NEWGAAP	MIFRS		
Particulars	**2014**	**2015**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	4,201,028	4,799,922	598,893	14.26%
Ending Balance	4,799,922	5,116,512	316,590	6.60%
Average Balance	4,500,475	4,958,217	457,742	10.17%
Working Capital Allowance	15,432	1,519,271	1,503,839	9744.94%
Total Rate Base	**4,515,907**	**6,477,488**	**1,961,581**	**43.44%**
Expenses for Working Capital	**NEWGAAP**	**MIFRS**		
Eligible Distribution Expenses:	**2014**	**2015**	**Var**	**%**
3500-Distribution Expenses - Operation	51,300	55,990	4,691	9.14%
3550-Distribution Expenses - Maintenance	181,555	179,949	(1,606)	0.88%
3650-Billing and Collecting	395,636	409,354	13,718	3.47%
3700-Community Relations	-	-	-	

3800-Administrative and General Expenses	340,177	299,046	(41,131)	12.09%
6105-Taxes other than Income Taxes	15,264	15,126	(138)	0.91%
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	983,932	959,466	(24,466)	2.49%
3350-Power Supply Expenses	11,405,626	10,727,236	(678,390)	5.95%
Total Expenses for Working Capital	12,389,558	11,686,702	(702,856)	5.67%
Working Capital factor	13.0%	13.0%		0.00%
Total Working Capital	**1,610,643**	**1,519,271**	**(91,372)**	**5.67%**

The total Rate Base in 2015 Actual of $6,477,488 was $1,961,581 or 43.44% greater than the 2014 Actual. The main reason for the variance are:

- **44kV MS transformer repair.** **$320,188**

  Refurbish old Ferranti transformer after failure of the new Pioneer transformer. See Appendix C for details.

- **Pole replacement** **$88,560**

  As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

- 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
- Decrease in the cost of power and 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

	MIFRS	MIFRS		
Particulars	**2015**	**2016**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	4,799,922	5,116,512	316,590	6.60%
Ending Balance	5,116,512	6,412,494	1,295,982	25.33%
Average Balance	4,958,217	5,764,503	806,286	16.26%
Working Capital Allowance	1,519,271	1,534,703	15,432	1.02%

Total Rate Base	**6,477,488**	**7,299,206**	**821,718**	**12.69%**
Expenses for Working Capital	**MIFRS**	**MIFRS**		
Eligible Distribution Expenses:	**2015**	**2016**	**Var**	**%**
3500-Distribution Expenses - Operation	55,990	68,472	12,482	22.29%
3550-Distribution Expenses - Maintenance	179,949	168,399	(11,551)	6.42%
3650-Billing and Collecting	409,354	418,864	9,510	2.32%
3700-Community Relations	-	-	-	
3800-Administrative and General Expenses	299,046	341,082	42,036	14.06%
6105-Taxes other than Income Taxes	15,126	14,843	(282)	1.87%
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	959,466	1,011,660	52,194	5.44%
3350-Power Supply Expenses	10,727,236	10,793,747	66,511	0.62%
Total Expenses for Working Capital	11,686,702	11,805,407	118,705	1.02%
Working Capital factor	13.0%	13.0%		0.00%
Total Working Capital	**1,519,271**	**1,534,703**	**15,432**	**1.02%**

The total Rate Base in 2016 Actual of $7,299,206 is $821,718 or 12.69% greater than 2015 Actual. The main reason for the variances are:

- **115 kV MTS new protection installation** **$59,244**

  The replacement of the transformer and the refurbishment of the station required an upgrade to the station protection. This project accomplishes this protection upgrade.

- **44kV MS commissioning of rebuilt transformer** **$54,101**

  This project covered the cost of installing and commissioning the rebuilt transformer making it ready for service. This work was completed in 2015, but the invoicing was not received until 2016. See Appendix C for station details.

- **Pole replacement program** **$69,572**

  As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

- **Line Conductor replacement** **$69,003**

  The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

- **Building** **$52,500**

  As part of normal due diligence, HHI had the condition of the roof of the office / service center assessed. The assessment recommended that the roof be replaced. This project carries out the refurbishment of the roof at 850 Tupper St office and service center. This is a flat roof.

- 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

2017 Bridge Year vs. 2016 Actual:

Table 6 - 2017-2016 Rate Base Variances

Particulars	**MIFRS 2016**	**MIFRS 2017**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	5,116,512	6,412,494	1,295,982	25.33%
Ending Balance	6,412,494	7,112,824	700,330	10.92%
Average Balance	5,764,503	6,762,659	998,156	17.32%
Working Capital Allowance	1,534,703	2,908,677	1,373,974	89.53%
Total Rate Base	**7,299,206**	**9,671,336**	**2,372,130**	**32.50%**
Expenses for Working Capital	**MIFRS**	**MIFRS**		
Eligible Distribution Expenses:	**2016**	**2017**	**Var**	**%**
3500-Distribution Expenses - Operation	68,472	113,406	44,934	65.62%
3550-Distribution Expenses - Maintenance	168,399	194,970	26,571	15.78%
3650-Billing and Collecting	418,864	462,696	43,832	10.46%
3700-Community Relations	-	-	-	
3800-Administrative and General Expenses	341,082	422,354	81,272	23.83%
6105-Taxes other than Income Taxes	14,843	-	(14,843)	100.00%
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	1,011,660	1,193,426	181,766	17.97%
3350-Power Supply Expenses	10,793,747	21,181,013	10,387,267	96.23%
Total Expenses for Working Capital	11,805,407	22,374,439	10,569,032	89.53%
Working Capital factor	13.0%	13.0%		0.00%
Total Working Capital	**1,534,703**	**2,908,677**	**1,373,974.00**	**89.53%**

The total Rate Base in 2017 Actual of $9,671,336 is $2,372,130 or 32.50% greater than 2016 Actual. The main reason for the variance is:

- **115kV MTS upgrade** **$3,525,000**

  This project represents the cost of upgrading the existing 115kV MTS. This project installs a 15/20/25 MVA transformer as well as transformer pads and electrical connections. This work is the work that was identified in EB-2011-0173. Additional information can be found in Appendix A.

  Accounting Note: Since the beginning of the construction of the new sub-station, HHI accumulates the expenses in "Construction in progress". As of December 31, 2016, an amount of $2,807,257 had been capitalized. By the end of 2017, another $717,743 will be capitalized for a total of $3,525,000.

  The reduction of -$2,807,257 in "Construction in progress" consists of the 2017 amounts capitalized ($717,743) less the transfer of $3,525,000.

- **44kV MS -44kV insulator replacement** **$5,000**

  Replacement of the old 44 kV insulators in the station.

- **Pole replacement** **$60,000**

  As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

- **Porcelain Insulator replacement** **$21,720**

  Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way, future outages that will be inevitable if no action is taken will be prevented.

- **Software: North Star system upgrade** **$31,000**

- The rest of the increase can be attributed to the 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

	MIFRS	MIFRS		
Particulars	**2017**	**2018**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	6,412,494	7,112,824	700,330	10.92%
Ending Balance	7,112,824	7,007,776	(105,048)	-1.48%
Average Balance	6,762,659	7,060,300	297,641	4.40%
Working Capital Allowance	2,908,677	1,554,729	(1,353,948)	-46.55%
Total Rate Base	**9,671,336**	**8,615,028**	**-1,056,308**	**-10.92%**
Expenses for Working Capital	**MIFRS**	**MIFRS**		
Eligible Distribution Expenses:	**2017**	**2018**	**Var**	**%**
3500-Distribution Expenses - Operation	113,406	95,593	(17,813)	15.71%
3550-Distribution Expenses - Maintenance	194,970	204,514	9,544	4.90%
3650-Billing and Collecting	462,696	476,632	13,936	3.01%
3700-Community Relations	-	-	-	
3800-Administrative and General Expenses	422,354	433,375	11,021	2.61%
6105-Taxes other than Income Taxes	-	-	-	
6205-Sub-account LEAP Funding	-	-	-	
Total Eligible Distribution Expenses	1,193,426	1,210,114	16,688	1.40%
3350-Power Supply Expenses	21,181,013	19,519,602	(1,661,411)	7.84%
Total Expenses for Working Capital	22,374,439	20,729,716	(1,644,723)	7.35%
Working Capital factor	13.0%	7.5%		42.31%
Total Working Capital	**2,908,677**	**1,554,729**	**-1,353,948**	**46.55%**

The total Rate Base in 2018 Actual of $8,615,028 is $-1,056,308 or -10.92% lesser than 2017 Actual. The main reason for the variance is:

- **Pole replacement** **$81,500**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

- **3/0 Conductor upgrade** **$10,000**

  The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

- **Porcelain insulator replacement** **$17,930**

  Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way, future outages that will be inevitable if no action is taken will be prevented.

- **Close Loops on u/g radial feeds** **$10,000**

  HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the original cable fails. The modern design is to install a looped feed with a open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually, so this is a proactive project that will mitigate future adverse reliability impacts.

- 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

2.1.4 FIXED ASSET CONTINUITY SCHEDULE

This Schedule shows 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.

HHI 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 is being filed 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]

Asset Retirement Obligations occurred in 2014, 2015 and 2016 and related for the most part to the disposal of meters with the exception of 2016 where 2839 was related to the retirement of poles from account 1830. Since assets were fully depreciated, depreciation expenses were not affected. The asset retirements are reflected in the fixed assets continuity statements presented on the next page.[8]

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[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
[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

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Year 2014 CGAAP - with changes to policies

			Cost						Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**CGAAP to IFRS Adjustments**	**Additions**	**Disposals**	**Closing Balance**	**RRR**	**Opening Balance**	**CGAAP to IFRS Adjustments**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 205,278	-$ 152,303	$ 13,784	$ -	$ 66,759	$ 219,062	$ 152,303	-$ 152,303	$ 19,751	$ -	$ 19,751	$ 47,008
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 8,588	-$ 2,608	$ -	$ -	$ 5,980	$ 8,588	$ 2,608	-$ 2,608	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 482,802	-$ 108,057	$ -	$ -	$ 374,745	$ 482,802	$ 108,057	-$ 108,057	$ 9,831	$ -	$ 9,831	$ 364,914
47	1820	Distribution Station Equipment <50 kV	$ 1,098,160	-$ 165,860	$ 42,750	$ -	$ 975,050	$ 1,140,910	$ 165,860	-$ 165,860	$ 27,936	$ -	$ 27,936	$ 947,114
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 544,688	-$ 145,340	$ 24,310	$ -	$ 423,658	$ 568,998	$ 241,986	-$ 241,986	$ 19,143	$ -	$ 19,143	$ 404,514
47	1835	Overhead Conductors & Devices	$ 481,750	-$ 275,813	$ 31,221	$ -	$ 237,159	$ 512,972	$ 275,813	-$ 275,813	$ 10,363	$ -	$ 10,363	$ 226,796
47	1840	Underground Conduit	$ 113,855	-$ 74,586	$ -	$ -	$ 39,269	$ 113,855	$ 74,586	-$ 74,586	$ 2,748	$ -	$ 2,748	$ 36,521
47	1845	Underground Conductors & Devices	$ 265,913	-$ 130,846	$ -	$ -	$ 135,067	$ 265,913	$ 130,846	-$ 130,846	$ 9,978	$ -	$ 9,978	$ 125,089
47	1850	Line Transformers	$ 428,840	-$ 227,035	$ -	$ -	$ 201,804	$ 428,840	$ 227,035	-$ 227,035	$ 9,934	$ -	$ 9,934	$ 191,870
47	1855	Services (Overhead & Underground)	$ 33,380	-$ 9,610	$ 1,095	$ -	$ 24,864	$ 34,475	$ 9,610	-$ 9,610	$ 1,130	$ -	$ 1,130	$ 23,734
47	1860	Meters	$ 254,843	-$ 193,343	$ -	-$ 54,357	$ 7,143	$ 640,595	$ 193,343	-$ 193,343	-$ 6,826	$ 7,143	$ 317	$ 6,826
47	1860	Meters (Smart Meters)	$ 622,999	-$ 135,346	$ 9,666	$ -	$ 497,319	$ -	$ 146,730	-$ 146,730	$ 42,488	$ -	$ 42,488	$ 454,830
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 862,329	-$ 252,894	$ 13,386	$ -	$ 622,821	$ 875,715	$ 252,894	-$ 252,894	$ 33,825	$ -	$ 33,825	$ 588,996
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 39,383	-$ 23,356	$ 457	$ -	$ 16,484	$ 39,840	$ 23,356	-$ 23,356	$ 2,966	$ -	$ 2,966	$ 13,518
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 57,839	-$ 50,774	$ 1,404	$ -	$ 8,468	$ 59,243	$ 50,774	-$ 50,774	$ 2,803	$ -	$ 2,803	$ 5,665
10	1930	Transportation Equipment	$ 204,794	-$ 198,402	$ -	$ -	$ 6,392	$ 189,046	$ 198,402	-$ 198,402	$ 2,556	$ -	$ 2,556	$ 3,836
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 29,580	-$ 16,019	$ -	$ -	$ 13,562	$ 29,580	$ 16,019	-$ 16,019	$ 2,279	$ -	$ 2,279	$ 11,283
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 6,018	-$ 4,466	$ -	$ -	$ 1,552	$ 6,018	$ 4,466	-$ 4,466	$ 207	$ -	$ 207	$ 1,345
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	-$ 254,514	$ 254,514	$ -	$ -	$ -	-$ 220,028	-$ 28,084	$ 28,084	$ -	$ -	$ -	$ -
N/A	etc.	Construction in progress	$ -	$ 804,777	$ 707,031	$ -	$ 1,511,809		$ -	$ -	$ -	$ -	$ -	$ 1,511,809
	etc.	Contributions & Grants	$ -	-$ 226,430	$ -	$ -	-$ 226,430		$ -	$ -	-$ 6,402	$ -	-$ 6,402	-$ 220,028
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
							$ -		$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 5,534,825**	**-$ 1,333,797**	**$ 845,104**	**-$ 54,357**	**$ 4,991,775**	**$ 5,444,724**	**$ 2,246,603**	**-$ 2,246,603**	**$ 184,710**	**$ 7,143**	**$ 191,854**	**$ 4,799,922**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -						$ -	$ -
		Total PP&E	**$ 5,534,825**		**$ 845,104**	**-$ 54,357**	**$ 4,991,775**		**$ 2,246,603**		**$ 184,710**	**$ 7,143**	**$ 191,854**	**$ 4,799,922**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)												
		Total									**$ 184,710**			

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	$ 184,710

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Year **2014 IFRS**

			Cost						Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**CGAAP to IFRS Adjustments**	**Additions**	**Disposals**	**Closing Balance**	**RRR**	**Opening Balance**	**CGAAP to IFRS Adjustments**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 205,278	-$ 152,303	$ 13,784	$ -	$ 66,759	$ 219,062	$ 152,303	-$ 152,303	$ 19,751	$ -	$ 19,751	$ 47,008
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 8,588	-$ 2,608	$ -	$ -	$ 5,980	$ 8,588	$ 2,608	-$ 2,608	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 482,802	-$ 108,057	$ -	$ -	$ 374,745	$ 482,802	$ 108,057	-$ 108,057	$ 9,831	$ -	$ 9,831	$ 364,914
47	1820	Distribution Station Equipment <50 kV	$ 1,098,160	-$ 165,860	$ 42,750	$ -	$ 975,050	$ 1,140,910	$ 165,860	-$ 165,860	$ 27,936	$ -	$ 27,936	$ 947,114
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 544,688	-$ 145,340	$ 24,310	$ -	$ 423,658	$ 568,998	$ 241,986	-$ 241,986	$ 19,143	$ -	$ 19,143	$ 404,514
47	1835	Overhead Conductors & Devices	$ 481,750	-$ 275,813	$ 31,221	$ -	$ 237,159	$ 512,972	$ 275,813	-$ 275,813	$ 10,363	$ -	$ 10,363	$ 226,796
47	1840	Underground Conduit	$ 113,855	-$ 74,586	$ -	$ -	$ 39,269	$ 113,855	$ 74,586	-$ 74,586	$ 2,748	$ -	$ 2,748	$ 36,521
47	1845	Underground Conductors & Devices	$ 265,913	-$ 130,846	$ -	$ -	$ 135,067	$ 265,913	$ 130,846	-$ 130,846	$ 9,978	$ -	$ 9,978	$ 125,089
47	1850	Line Transformers	$ 428,840	-$ 227,035	$ -	$ -	$ 201,804	$ 428,840	$ 227,035	-$ 227,035	$ 9,934	$ -	$ 9,934	$ 191,870
47	1855	Services (Overhead & Underground)	$ 33,380	-$ 9,610	$ 1,095	$ -	$ 24,864	$ 34,475	$ 9,610	-$ 9,610	$ 1,130	$ -	$ 1,130	$ 23,734
47	1860	Meters	$ 254,843	-$ 193,343	$ -	-$ 54,357	$ 7,143	$ 640,595	$ 193,343	-$ 193,343	-$ 6,826	$ 7,143	$ 317	$ 6,826
47	1860	Meters (Smart Meters)	$ 622,999	-$ 135,346	$ 9,666	$ -	$ 497,319	$ -	$ 146,730	-$ 146,730	$ 42,488	$ -	$ 42,488	$ 454,830
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 862,329	-$ 252,894	$ 13,386	$ -	$ 622,821	$ 875,715	$ 252,894	-$ 252,894	$ 33,825	$ -	$ 33,825	$ 588,996
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 39,383	-$ 23,356	$ 457	$ -	$ 16,484	$ 39,840	$ 23,356	-$ 23,356	$ 2,966	$ -	$ 2,966	$ 13,518
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 57,839	-$ 50,774	$ 1,404	$ -	$ 8,468	$ 59,243	$ 50,774	-$ 50,774	$ 2,803	$ -	$ 2,803	$ 5,665
10	1930	Transportation Equipment	$ 204,794	-$ 198,402	$ -	$ -	$ 6,392	$ 189,046	$ 198,402	-$ 198,402	$ 2,556	$ -	$ 2,556	$ 3,836
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 29,580	-$ 16,019	$ -	$ -	$ 13,562	$ 29,580	$ 16,019	-$ 16,019	$ 2,279	$ -	$ 2,279	$ 11,283
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 6,018	-$ 4,466	$ -	$ -	$ 1,552	$ 6,018	$ 4,466	-$ 4,466	$ 207	$ -	$ 207	$ 1,345
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	-$ 254,514	$ 254,514	$ -	$ -	$ -	-$ 220,028	-$ 28,084	$ 28,084	$ -	$ -	$ -	$ -
N/A	etc.	Construction in progress	$ -	$ 804,777	$ 707,031	$ -	$ 1,511,809		$ -	$ -	$ -	$ -	$ -	$ 1,511,809
	etc.	Contributions & Grants	$ -	-$ 226,430	$ -	$ -	-$ 226,430		$ -	$ -	-$ 6,402	$ -	-$ 6,402	-$ 220,028
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ -	$ -	$ -
							$ -		$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 5,534,825**	**-$ 1,333,797**	**$ 845,104**	**-$ 54,357**	**$ 4,991,775**	**$ 5,444,724**	**$ 2,246,603**	**-$ 2,246,603**	**$ 184,710**	**$ 7,143**	**$ 191,854**	**$ 4,799,922**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -						$ -	$ -
		Total PP&E	**$ 5,534,825**		**$ 845,104**	**-$ 54,357**	**$ 4,991,775**		**$ 2,246,603**		**$ 184,710**	**$ 7,143**	**$ 191,854**	**$ 4,799,922**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)												
		Total									**$ 184,710**			

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	$ 184,710

Year 2015 IFRS

			Cost						Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance		Additions	Disposals	Closing Balance	RRR	Opening Balance		Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 66,759	$ -	$ 5,813	$ -	$ 72,572	$ 224,875	$ 19,751	$ -	$ 19,862	$ -	$ 39,613	$ 32,959
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 5,980	$ -	$ -	$ -	$ 5,980	$ 8,588	$ -	$ -	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 374,745	$ -	$ 1,947	$ -	$ 376,692	$ 484,749	$ 9,831	$ -	$ 9,845	$ -	$ 19,676	$ 357,016
47	1820	Distribution Station Equipment <50 kV	$ 975,050	$ -	$ 320,188	$ -	$ 1,295,238	$ 1,461,098	$ 27,936	$ -	$ 29,807	$ -	$ 57,743	$ 1,237,495
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 423,658	$ -	$ 88,560	$ -	$ 512,217	$ 657,558	$ 19,143	$ -	$ 20,115	$ -	$ 39,258	$ 472,959
47	1835	Overhead Conductors & Devices	$ 237,159	$ -	$ 27,607	$ -	$ 264,766	$ 540,579	$ 10,363	$ -	$ 10,700	$ -	$ 21,063	$ 243,703
47	1840	Underground Conduit	$ 39,269	$ -	$ -	$ -	$ 39,269	$ 113,855	$ 2,748	$ -	$ 2,748	$ -	$ 5,496	$ 33,773
47	1845	Underground Conductors & Devices	$ 135,067	$ -	$ -	$ -	$ 135,067	$ 265,913	$ 9,978	$ -	$ 9,714	$ -	$ 19,692	$ 115,375
47	1850	Line Transformers	$ 201,804	$ -	$ 11,110	$ -	$ 212,914	$ 439,950	$ 9,934	$ -	$ 9,613	$ -	$ 19,547	$ 193,367
47	1855	Services (Overhead & Underground)	$ 24,864	$ -	$ 667	$ -	$ 25,531	$ 35,141	$ 1,130	$ -	$ 1,156	$ -	$ 2,286	$ 23,245
47	1860	Meters	$ 7,143	$ -	$ -	$ -	$ 7,143		$ 317	$ -	$ 317	$ -	$ 634	$ 6,509
47	1860	Meters (Smart Meters)	$ 497,319	$ -	$ 8,016	-$ 8,843	$ 496,492	$ 648,612	$ 42,488	$ -	$ 42,698	-$ 1,138	$ 84,049	$ 412,443
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 622,821	$ -	$ -	$ -	$ 622,821	$ 875,715	$ 33,825	$ -	$ 34,271	$ -	$ 68,096	$ 554,725
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 16,484	$ -	$ 7,254	$ -	$ 23,739	$ 47,095	$ 2,966	$ -	$ 3,395	$ -	$ 6,361	$ 17,378
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 8,468	$ -	$ -	$ -	$ 8,468	$ 59,243	$ 2,803	$ -	$ 2,195	$ -	$ 4,998	$ 3,470
10	1930	Transportation Equipment	$ 6,392	$ -	$ -	$ -	$ 6,392	$ 189,046	$ 2,556	$ -	$ 2,556	$ -	$ 5,112	$ 1,280
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 13,562	$ -	$ -	$ -	$ 13,562	$ 29,580	$ 2,279	$ -	$ 2,279	$ -	$ 4,558	$ 9,004
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 1,552	$ -	$ -	$ -	$ 1,552	$ 6,019	$ 207	$ -	$ 207	$ -	$ 414	$ 1,138
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	$ -	$ -	$ -	$ -	$ -	-$ 306,163	$ -	$ -	$ -	$ -	$ -	$ -
N/A	2055	Construction in progress	$ 1,511,809	$ -	$ 141,544	$ -	$ 1,653,353		$ -	$ -	$ -	$ -	$ -	$ 1,653,353
	etc.	Contributions & Grants	-$ 226,430	$ -	-$ 93,493	$ -	-$ 319,923		-$ 6,402	$ -	-$ 6,561	$ -	-$ 12,963	-$ 306,960
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -
			$ -				$ -		$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 4,991,775**	**$ -**	**$ 519,213**	**-$ 8,843**	**$ 5,502,145**	**$ 5,829,751**	**$ 191,854**	**$ -**	**$ 194,918**	**-$ 1,138**	**$ 385,633**	**$ 5,116,512**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -						$ -	$ -
		Total PP&E	**$ 4,991,775**		**$ 519,213**	**-$ 8,843**	**$ 5,502,145**		**$ 191,854**		**$ 194,918**	**-$ 1,138**	**$ 385,633**	**$ 5,116,512**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)												
		Total									**$ 194,918**			

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	$ 194,918

Year 2016 **IFRS**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: CGAAP to IFRS Adjustments	Cost: Additions	Cost: Disposals	Cost: Closing Balance	RRR	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: CGAAP to IFRS Adjustments	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 72,572	$ -	$ 3,999	$ -	$ 76,571	$ 76,571	$ 39,613	$ -	$ 14,127	$ -	$ 53,740	$ 22,831
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 5,980	$ -	$ -	$ -	$ 5,980	$ 5,980	$ -	$ -	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 376,692	$ -	$ 59,244	$ -	$ 435,936	$ 435,936	$ 19,676	$ -	$ 9,931	$ -	$ 29,607	$ 406,329
47	1820	Distribution Station Equipment <50 kV	$ 1,295,238	$ -	$ 54,101	$ -	$ 1,349,340	$ 1,349,340	$ 57,743	$ -	$ 36,218	$ -	$ 93,961	$ 1,255,379
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 512,217	$ -	$ 68,412	-$ 2,839	$ 577,790	$ 577,790	$ 39,258	$ -	$ 21,617	-$ 482	$ 60,393	$ 517,397
47	1835	Overhead Conductors & Devices	$ 264,766	$ -	$ 69,003	$ -	$ 333,769	$ 333,769	$ 21,063	$ -	$ 11,059	$ -	$ 32,122	$ 301,647
47	1840	Underground Conduit	$ 39,269	$ -	$ -	$ -	$ 39,269	$ 39,269	$ 5,496	$ -	$ 2,698	$ -	$ 8,194	$ 31,075
47	1845	Underground Conductors & Devices	$ 135,067	$ -	$ 11,013	$ -	$ 146,080	$ 146,080	$ 19,692	$ -	$ 9,386	$ -	$ 29,078	$ 117,002
47	1850	Line Transformers	$ 212,914	$ -	$ 5,696	$ -	$ 218,610	$ 218,610	$ 19,547	$ -	$ 9,495	$ -	$ 29,042	$ 189,568
47	1855	Services (Overhead & Underground)	$ 25,531	$ -	$ 241	$ -	$ 25,772	$ 25,772	$ 2,286	$ -	$ 1,175	$ -	$ 3,461	$ 22,311
47	1860	Meters	$ 7,143	$ -	$ -	$ -	$ 7,143	$ 526,354	$ 634	$ -	$ 316	$ -	$ 950	$ 6,193
47	1860	Meters (Smart Meters)	$ 496,492	$ -	$ 27,626	-$ 4,906	$ 519,211	$ -	$ 84,049	$ -	$ 43,292	-$ 1,076	$ 126,264	$ 392,947
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 622,821	$ -	$ 52,500	$ -	$ 675,321	$ 675,321	$ 68,096	$ -	$ 34,446	$ -	$ 102,542	$ 572,779
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 23,739	$ -	$ -	$ -	$ 23,739	$ 23,739	$ 6,361	$ -	$ 3,495	$ -	$ 9,856	$ 13,883
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ 6,392	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 8,468	$ -	$ 844	$ -	$ 9,312	$ 9,312	$ 4,998	$ -	$ 1,669	$ -	$ 6,667	$ 2,645
10	1930	Transportation Equipment	$ 6,392	$ -	$ -	$ -	$ 6,392	$ 6,392	$ 5,112	$ -	$ 1,280	$ -	$ 6,392	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 13,562	$ -	$ 7,415	$ -	$ 20,977	$ 20,977	$ 4,558	$ -	$ 2,053	$ -	$ 6,611	$ 14,366
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 1,552	$ -	$ -	$ -	$ 1,552	$ -	$ 414	$ -	$ 207	$ -	$ 621	$ 931
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	2055	Construction in progress	$ 1,653,353	$ -	$ 1,153,904	$ -	$ 2,807,257	$ 2,807,257	$ -	$ -	$ -	$ -	$ -	$ 2,807,257
	etc.	Contributions & Grants	-$ 319,923	$ -	-$ 17,741	$ -	-$ 337,664		-$ 12,963	$ -	-$ 8,375	$ -	-$ 21,338	-$ 316,326
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
			$ -				$ -		$ -		$ -	$ -	$ -	$ -
		Sub-Total	**$ 5,502,145**	**$ -**	**$ 1,496,257**	**-$ 7,746**	**$ 6,990,656**	**$ 5,829,751**	**$ 385,633**	**$ -**	**$ 194,088**	**-$ 1,559**	**$ 578,162**	**$ 6,412,494**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -						$ -	$ -
		Total PP&E	**$ 5,502,145**		**$ 1,496,257**	**-$ 7,746**	**$ 6,990,656**		**$ 385,633**		**$ 194,088**	**-$ 1,559**	**$ 578,162**	**$ 6,412,494**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)												
		Total									**$ 194,088**			

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	$ 194,088

Year 2017 **IFRS**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: CGAAP to IFRS Adjustments	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: CGAAP to IFRS Adjustments	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 76,571	$ -	$ 31,000	$ -	$ 107,571	$ 53,740	$ -	$ 12,938	$ -	$ 66,678	$ 40,893
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 5,980	$ -	$ -	$ -	$ 5,980	$ -	$ -	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 435,936	$ -	$ 3,525,000	$ -	$ 3,960,936	$ 29,607	$ -	$ 17,718	$ -	$ 47,325	$ 3,913,611
47	1820	Distribution Station Equipment <50 kV	$ 1,349,340	$ -	$ 5,000	$ -	$ 1,354,340	$ 93,961	$ -	$ 36,785	$ -	$ 130,746	$ 1,223,594
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 577,790	$ -	$ 60,000	$ -	$ 637,790	$ 60,393	$ -	$ 24,586	$ -	$ 84,979	$ 552,811
47	1835	Overhead Conductors & Devices	$ 333,769	$ -	$ 29,584	$ -	$ 363,353	$ 32,122	$ -	$ 11,822	$ -	$ 43,944	$ 319,409
47	1840	Underground Conduit	$ 39,269	$ -	$ -	$ -	$ 39,269	$ 8,194	$ -	$ 2,553	$ -	$ 10,747	$ 28,522
47	1845	Underground Conductors & Devices	$ 146,080	$ -	$ 10,000	$ -	$ 156,080	$ 29,078	$ -	$ 9,483	$ -	$ 38,561	$ 117,519
47	1850	Line Transformers	$ 218,610	$ -	$ 9,000	$ -	$ 227,610	$ 29,042	$ -	$ 9,664	$ -	$ 38,706	$ 188,904
47	1855	Services (Overhead & Underground)	$ 25,772	$ -	$ 2,500	$ -	$ 28,272	$ 3,461	$ -	$ 1,221	$ -	$ 4,682	$ 23,590
47	1860	Meters	$ 7,143	$ -	$ -	$ -	$ 7,143	$ 950	$ -	$ 317	$ -	$ 1,267	$ 5,876
47	1860	Meters (Smart Meters)	$ 519,211	$ -	$ 30,169	$ -	$ 549,380	$ 126,264	$ -	$ 43,425	$ -	$ 169,689	$ 379,691
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 675,321	$ -	$ 2,000	$ -	$ 677,321	$ 102,542	$ -	$ 35,388	$ -	$ 137,930	$ 539,391
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 23,739	$ -	$ 3,500	$ -	$ 27,239	$ 9,856	$ -	$ 3,254	$ -	$ 13,110	$ 14,129
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 9,312	$ -	$ 2,600	$ -	$ 11,912	$ 6,667	$ -	$ 1,568	$ -	$ 8,235	$ 3,677
10	1930	Transportation Equipment	$ 6,392	$ -	$ -	$ -	$ 6,392	$ 6,392	$ -	$ -	$ -	$ 6,392	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 20,977	$ -	$ 1,000	$ -	$ 21,977	$ 6,611	$ -	$ 2,625	$ -	$ 9,236	$ 12,741
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 1,552	$ -	$ 1,000	$ -	$ 2,552	$ 621	$ -	$ 270	$ -	$ 891	$ 1,661
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	etc.	Construction in progress	$ 2,807,257	$ -	-$ 2,807,257	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.	Contributions & Grants	-$ 337,664	$ -	$ -	$ -	-$ 337,664	-$ 21,338	$ -	-$ 8,851	$ -	-$ 30,189	-$ 307,475
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 6,990,656**	**$ -**	**$ 905,096**	**$ -**	**$ 7,895,752**	**$ 578,162**		**$ 204,766**	**$ -**	**$ 782,929**	**$ 7,112,824**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 6,990,656**		**$ 905,096**	**$ -**	**$ 7,895,752**	**$ 578,162**	**$ -**	**$ 204,766**	**$ -**	**$ 782,929**	**$ 7,112,824**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total								**$ 204,766**			

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	$ 204,766

Year 2018 IFRS

			Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	CGAAP to IFRS Adjustments	Additions	Disposals	Closing Balance	Opening Balance	CGAAP to IFRS Adjustments	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 107,571	$ -	$ 1,000	$ -	$ 108,571	$ 66,678	$ -	$ 15,871	$ -	$ 82,549	$ 26,022
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 5,980	$ -	$ -	$ -	$ 5,980	$ -	$ -	$ -	$ -	$ -	$ 5,980
N/A	1805	Land	$ 20,000	$ -	$ -	$ -	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 3,960,936	$ -		$ -	$ 3,960,936	$ 47,325	$ -	$ 89,526	$ -	$ 136,851	$ 3,824,085
47	1820	Distribution Station Equipment <50 kV	$ 1,354,340	$ -		$ -	$ 1,354,340	$ 130,746	$ -	$ 32,665	$ -	$ 163,411	$ 1,190,929
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 637,790	$ -	$ 81,500	$ -	$ 719,290	$ 84,979	$ -	$ 27,064	$ -	$ 112,042	$ 607,247
47	1835	Overhead Conductors & Devices	$ 363,353	$ -	$ 27,930	$ -	$ 391,283	$ 43,944	$ -	$ 12,302	$ -	$ 56,246	$ 335,037
47	1840	Underground Conduit	$ 39,269	$ -	$ -	$ -	$ 39,269	$ 10,747	$ -	$ 2,553	$ -	$ 13,300	$ 25,969
47	1845	Underground Conductors & Devices	$ 156,080	$ -	$ 20,000	$ -	$ 176,080	$ 38,561	$ -	$ 9,662	$ -	$ 48,223	$ 127,857
47	1850	Line Transformers	$ 227,610	$ -	$ 17,350	$ -	$ 244,960	$ 38,706	$ -	$ 9,994	$ -	$ 48,700	$ 196,260
47	1855	Services (Overhead & Underground)	$ 28,272	$ -	$ 3,500	$ -	$ 31,772	$ 4,682	$ -	$ 1,321	$ -	$ 6,003	$ 25,769
47	1860	Meters	$ 7,143	$ -	$ -	$ -	$ 7,143	$ 1,267	$ -	$ 317	$ -	$ 1,584	$ 5,559
47	1860	Meters (Smart Meters)	$ 549,380	$ -	$ 14,300	$ -	$ 563,680	$ 169,689	$ -	$ 44,908	$ -	$ 214,597	$ 349,083
N/A	1905	Land	$ 28,300	$ -	$ -	$ -	$ 28,300	$ -	$ -	$ -	$ -	$ -	$ 28,300
47	1908	Buildings & Fixtures	$ 677,321	$ -	$ 2,000	$ -	$ 679,321	$ 137,930	$ -	$ 35,522	$ -	$ 173,452	$ 505,869
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 27,239	$ -	$ 3,750	$ -	$ 30,989	$ 13,110	$ -	$ 3,406	$ -	$ 16,516	$ 14,473
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 11,912	$ -	$ 4,500	$ -	$ 16,412	$ 8,235	$ -	$ 1,717	$ -	$ 9,952	$ 6,460
10	1930	Transportation Equipment	$ 6,392	$ -	$ -	$ -	$ 6,392	$ 6,392	$ -	$ -	$ -	$ 6,392	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 21,977	$ -	$ -	$ -	$ 21,977	$ 9,236	$ -	$ 2,569	$ -	$ 11,805	$ 10,172
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ 2,552	$ -	$ -	$ -	$ 2,552	$ 891	$ -	$ 333	$ -	$ 1,224	$ 1,328
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	2055	Construction in progress	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.	Contributions & Grants	-$ 337,664	$ -	$ -	$ -	-$ 337,664	-$ 30,189	$ -	-$ 8,851	$ -	-$ 39,040	-$ 298,624
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	etc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 7,895,752**	**$ -**	**$ 175,830**	**$ -**	**$ 8,071,582**	**$ 782,929**		**$ 280,878**	**$ -**	**$ 1,063,807**	**$ 7,007,776**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 7,895,752**		**$ 175,830**	**$ -**	**$ 8,071,582**	**$ 782,929**		**$ 280,878**	**$ -**	**$ 1,063,807**	**$ 7,007,776**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)											
		Total								**$ 280,878**			

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	$ 280,878

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 shows 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]

	Historical (actual)									
	2013	2013	2014	2014	2015	2015	2016	2016	2017	2017
	Plan	Actual	Board Approved	Actual	Plan	Actual	Plan	Actual	Plan Y/E	Projected Y/E
CATEGORY	$	$	$	$	$	$	$	$	$	$
System Access				-$43,596		-$160		$39,670	$51,669	$51,669
System Renewal				$98,281		$449,412		$251,920	$3,619,584	$3,619,584
System Service				$0		$0		$0	$0	$0
General Plant				$29,031		$13,067		$64,758	$41,100	$41,100
Total			$1,560,990	$83,713	$1,560,990	$462,319	$1,560,990	$356,348	$3,712,353	$3,712,353
Capital Contribution						$93,493		$93,493		
Net Capital				$83,713	$368,826	$334,608		$83,713	$3,712,353	$3,712,353
System O&M				$232,855		$235,940		$236,871	$296,376	$296,376

	Forecast (planned)				
	2018	2019	2020	2021	2022
	Test	Test+1	Test+2	Test+3	Test+4
CATEGORY	$	$	$	$	$
System Access	$36,800	$86,895	$31,010	$31,510	$31,610
System Renewal	$117,780	$131,825	$488,350	$149,205	$139,500
System Service	$10,000	$10,000	$10,000	$10,500	$10,500
General Plant	$11,250	$8,800	$11,900	$11,900	$9,000
Total	$175,830	$237,520	$541,260	$203,115	$190,610

[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

Capital Contribution					
Net Capital	$175,830	$237,520	$541,260	$203,115	$190,610
System O&M	$300,107	$295,674	$322,178	$329,586	$374,253

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

Reporting basis	**Reporting basis**		CGAAP	NewCGAAP	NewCGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	**USoA**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
System access	**System access**								
Metering	Sub 115kv for station betterment and dismantle building	1815	$8,890						
New 3 phase lines	New commercial service	1830	$63,385						
Loop system	Existing subdivision	1845	$4,936						
New services	Connecting new customers to grid	1855	$2,234	$960	$1,095	$667	$241		
Smart meter	Smart meter	1860	$619,033	$4,100	-$44,691	-$827	$22,720.00		
New subdivision rock	New subdivision rock	1845					$11,013		
New subdivision rock	New subdivision rock	1850					$5,696		
New subdivision	New subdivision	1845						$10,000	
New services	Connecting new customers to grid	1855						$2,500	
Smart meter	Smart meter	1860						$30,169	
	For HHI use and /or subdivision	1850						$9,000	
New subdivision	New subdivision	1845							$10,000
New services	Connecting new customers to grid	1855							$3,500
Smart meter	Smart meter	1860							$14,300
	For HHI use and /or subdivision	1850							$9,000
	Sub-total system access		$698,478	$5,060	-$43,596	-$160	$39,670	$51,669	$36,800
Contributed capital									
		1995							
	Contributed capital		$0	$0	$0	$0	$0	$0	$0
Total system access	**Total system access**		**$698,478**	**$5,060**	**-$43,596**	**-$160**	**$39,670**	**$51,669**	**$36,800**

2014 – 2018 System Access

System Access investments are projects required in order for HHI to meet its obligations under the DSC and whose timetables are driven by others. HHI is obligated to connect new load and new renewable generation. The scheduling of investment needs is usually coordinated to meet the needs of third parties. HHI is also required to respond to the road authorities by obligations under the Public Service Works on Highways Act. The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs. HHI also needs to ensure energy metering accuracy. Smart Meters have a fixed number of years for which they are certified.

Replacement or recertification of Smart Meters is a legislated requirement and the investment is recorded in this category.

Historical project information and project descriptions are in Appendix A of the DSP while forecast project information and descriptions are in Appendix B of the DSP.

The planned annual capital investments during the forecast period for connecting new customers and providing system access are in the $30,000 to $40,000 range. This is consistent through the forecast period. The exception is 2019 when HHI is making provision for Smart Meter replacement.

There are no projects initiated by other authorities, nor by system expansion requirements nor by renewable energy generation. There are only small customer service type activities.

Table 10 - OEB Appendix 2-AA System Renewal Variances

System renewal	System renewal	USoA	2012	2013	2014	2015	2016	2017	2018
Faulty transformer	Sub 115 kv	1815	$16,000			$1,946.90	$59,244		
Sub 44kv	Sub 44kv	1820	$4,632		$42,750	$320,188.00	$54,101		
Asset management plan	Replace poles, fixtures as per asset management plan	1830	$17,517	$85,061	$24,310	$88,559.57	$65,573		
Asset management plan	Replace 3/0 primary with new 336 mcm	1835	$27,773	$5,920	$31,221	$27,607.26	$69,003		
Capital acquisition	Lightning arresters (polymer)	1850		$20,047		$11,110.00			
	Sub 115kv for station betterment	1815						$3,525,000	
	Insulators etc.	1820						$5,000	
	Replace poles, fixtures as per asset management plan	1830						$60,000	
	Change insulators for polymer	1835						$21,720	
	Lightning arresters (polymer)	1850						$7,864	
	Structure a reclosers	1815							
	Structure a reclosers	1820							
	Replace poles, fixtures as per asset management plan	1830							$81,500
	Replace 3/0 primary with new 336 mcm (Wilson to Caisse)	1835							$10,000
	Change insulators for polymer	1835							$17,930
	Lightning arresters (polymer)	1850							$8,350
	Sub-total system renewal		$65,922	$111,028	$98,282	$449,412	$247,921	$3,619,584	$117,780
Contributed capital									
		1995							
	Contributed capital		$0	$0	$0	$0	$0	$0	$0
Total system renewal	Total system renewal		$65,922	$111,028	$98,282	$449,412	$247,921	$3,619,584	$117,780

2014 – 2018 System Renewal

System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

System renewal is a mix of projects related to assets nearing the end of life and projects to replace equipment that has reached end of life (emergency replacement). The former group of projects is identified and prioritized in the Asset Management system. Historical project information and project descriptions are in Appendix A of the DSP while forecast project information and descriptions are in Appendix B of the DSP.

The main drivers of system renewal projects are the aging infrastructure within the service area and the alterations at the 44kV MS.

All the material projects are in this category:

- pole replacement program,
- main feeder conductor upgrade,
- 44kV station alterations,
- Porcelain Insulator replacement, and
- Lightning Arrestor replacement.

This program resulted from the visual inspection of distribution plant as part of the asset management program, the analysis of the age distribution of poles, equipment failures and experienced system limitations.

Table 11 - OEB Appendix 2-AA System Service Variances

System service	System service	USoA	2012	2013	2014	2015	2016	2017	2018
Asset management plan	New 336 mcm to new commercial customer	1835	$42,115						
44 kv transformer station	Addition new transformer	1820		$841,977					
	New subdivision rock								
	Existing subdivision	1845							$10,000
	Sub-total system service		$42,115	$841,977	$0	$0	$0	$0	$10,000
Contributed capital									
		1995							
	Contributed capital		$0	$0	$0	$0	$0	$0	$0
Total system service	Total system service		$42,115	$841,977	$0	$0	$0	$0	$10,000

2014 – 2018 System Service

System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. General Plant investments are not part of its distribution system (e.g. fleet, tools, land, etc.). These projects provide system support and improve operational efficiencies.

There are no material investments in the General Plant category.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B of the DSP.

There is one planned investment in this category, the creation of a loop feed on present underground radial feeds. Planned expenditure is about $10,000 per year.

Table 12 - OEB Appendix 2-AA General Plant Variances

General plant	General plant	USoA	2012	2013	2014	2015	2016	2017	2018
Computer equipment	Computer hardware	1920	$2,656	$2,961	$1,404		$844		
Software	Software for different applications	1611	$44,232	$24,254	$13,784	$5,812.80	$3,999		
Tolls an equipment	Lin crew equipment	1940	$2,967	$1,584					
Capital investment	Building	1908		$38,205	$13,386		$52,500		
Capital investment	Office furniture (shredder and fire proof safe)	1915		$5,599	$457	$7,254.44			
Tolls an equipment	Power tools lineman equipment	1950		$1,655					
Transportation equipment	Transportation equipment	1930							
Pole testing device	Pole testing device	1940					$7,415		
	Building	1908						$2,000	
	Office furniture	1915						$3,500	
	Computer hardware-server	1920						$2,600	
	Software ns upgrade	1611						$31,000	
	Tools s line crew	1940						$1,000	
	Powered tools line crew	1950						$1,000	
	Building	1908							$2,000
	Office furniture	1915							$3,750
	Computer hardware-server	1920							$4,500
	Software ns upgrade	1611							$1,000
	Sub-total general plant		$49,855	$74,258	$29,030	$13,067	$64,758	$41,100	$11,250
Contributed capital									
	System access	1995				-$93,493	-$17,741		
	Contributed capital		$0	$0	$0	-$93,493	-$17,741	$0	$0
Total system service	Total system service		$49,855	$74,258	$29,030	-$80,426	$47,017	$41,100	$11,250
Total capital expenditures			856,370	1,032,324	83,716	368,826	334,608	3,712,353	175,830
Yearly additions					845,104	519,213	1,496,257	905,096	175,830
Yearly disposal					-54,357	-8,843	-7,746	0	0
Construction in progress					707,031	141,544	1,153,904	-2,807,257	0
Variance to yearly additions					0	0	1	0	0

2014-2018 General Plant

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. General Plant investments are not part of its distribution system (e.g. fleet, tools, land, etc.). These projects provide system support and improve operational efficiencies.

There are no material investments in the General Plant category.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B of the DSP.

The total annual investment in this category is between about $9.000 and $12,000. There are no material projects in this category.

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]

	OEB	Description	2014 Additions	2014 Disposal	2015 Additions	2015 Disposal	2016 Additions	2016 Disposal	2017 Additions	2018 Additions
Distribution Plant	1611	Computer Software (Formally known as Account 1925)	$13,784		$5,813		$3,999		$31,000	$1,000
Distribution Plant	1815	Transformer Station Equipment >50 kV	$0		$1,947		$59,244		$3,525,000	
Distribution Plant	1820	Distribution Station Equipment <50 kV	$42,750		$320,188		$54,101		$5,000	
Distribution Plant	1830	Poles, Towers & Fixtures	$24,310		$88,560		$68,412	-$2,839	$60,000	$81,500
Distribution Plant	1835	Overhead Conductors & Devices	$31,221		$27,607		$69,003		$29,584	$27,930
Distribution Plant	1845	Underground Conductors & Devices	$0		$0		$11,013		$10,000	$20,000
Distribution Plant	1850	Line Transformers	$0		$11,110		$5,696		$9,000	$17,350
Distribution Plant	1855	Services (Overhead & Underground)	$1,095		$667		$241		$2,500	$3,500
Distribution Plant	1860	Meters (Smart Meters)	$9,666	-$54,357	$8,016	-$8,843	$27,626	-$4,906	$30,169	$14,300
General Plant	1908	Buildings & Fixtures	$13,386		$0		$52,500		$2,000	$2,000
General Plant	1915	Office Furniture & Equipment (10 years)	$457		$7,254		$0		$3,500	$3,750
General Plant	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,404		$0		$844		$2,600	$4,500
General Plant	1940	Tools, Shop & Garage Equipment	$0		$0		$7,415		$1,000	$0
General Plant	1950	Power Operated Equipment	$0		$0		$0		$1,000	$0
Other		Construction in progress	$707,031		$141,544		$1,153,904		-$2,807,257	$0
Other		Contributions & Grants	$0		-$93,493		-$17,741		$0	$0
		Sub-Total	$845,104	-$54,357	$519,213	-$8,843	$1,496,257	-$7,746	$905,096	$175,830

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

2.2.2 ACCUMULATED DEPRECIATION

HHI has adopted depreciation rates based on the Kinectrics Asset Depreciation Study which can be found at this link. https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf. The rates used are presented below, and the Continuity Schedules of the Accumulated Depreciation are presented in the table below.

HHI's depreciation expense policy and methodology are provided on the next page. The depreciation expenses continuity schedules are shown at Section2.1.4

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

Table 14 - Depreciation Rates since 2014 Board Approved

Account	Description	Years (f)
1611	Computer Software (Formally known as Account 1925)	5.00
1815	Transformer Station Equipment >50 kV	45.00
1820	Distribution Station Equipment <50 kV	45.00
1830	Poles, Towers & Fixtures	45.00
1835	Overhead Conductors & Devices	60.00
1840	Underground Conduit	50.00
1845	Underground Conductors & Devices	30.00
1850	Line Transformers	40.00
1855	Services (Overhead & Underground)	30.00
1860	Meters	25.00
1860	Meters (Smart Meters)	15.00
1908	Buildings & Fixtures	5.00
1908	Buildings & Fixtures - Equipment	10.00
1908	Buildings & Fixtures - Equipment	15.00
1908	Buildings & Fixtures - Driveways	20.00
1908	Buildings & Fixtures - Major Repairs	25.00
1908	Buildings & Fixtures - Brick Store etc	50.00
1915	Office Furniture & Equipment (10 years)	10.00
1920	Computer Equipment - Hardware	5.00
1920	Computer Equip.-Hardware(Post Mar. 19/07)	5.00
1930	Transportation Equipment	5.00
1930	Transportation Equipment	8.00
1940	Tools, Shop & Garage Equipment	10.00
1945	Measurement & Testing Equipment	10.00
1950	Power Operated Equipment	8.00
2055	Construction in progress	38.15

2.2.3 CAPITALIZATION POLICY

HHI'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. HHI does not currently capitalize interest on funds used for construction.

HHI'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 a 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 HHI 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.

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[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

HHI 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). HHI 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 HHI's calculations in determining its Allowance for Working Capital.

Table 15 - Allowance for Working Capital

	CGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**Last Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	96,550	51,300	55,990	68,472	113,406	95,593
3550-Distribution Expenses - Maintenance	205,700	181,555	179,949	168,399	194,970	204,514
3650-Billing and Collecting	426,315	395,636	409,354	418,864	462,696	476,632
3700-Community Relations	200	-	-	-	-	-
3800-Administrative and General Expenses	395,900	340,177	299,046	341,082	422,354	433,375
6105-Taxes other than Income Taxes	-	15,264	15,126	14,843	-	-
	2,000	2000				
Total Eligible Distribution Expenses	1,126,665	983,932	959,466	1,011,660	1,193,426	1,210,114
3350-Power Supply Expenses	16,503,476	11,405,626	10,727,236	10,793,747	20,864,807	19,641,415
Total Expenses for Working Capital	17,630,141	12,389,558	11,686,701	11,805,407	22,058,232	20,851,530
Working Capital factor	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital	2,291,918	1,610,643	1,519,271	1,534,703	2,867,570	1,563,865

2.3.2 LEAD LAG STUDY[13]

HHI 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.

HHI 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]

HHI 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, HHI 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. HHI 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 HHI'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	$16,934,748
Transmission Network	$1,136,614
Transmission Connection	$587,110
Wholesale Market Service	$551,228
Rural Rate Protection	$45,936
Smart Meter Entity Charge	$52,451
Low Voltage	$211,425
TOTAL	$19,519,602

Table 17 - Calculation of Commodity

Customer Class Name	Last Actual kWh's	non-RPP	RPP
Residential	48,033,529	1,304,037	46,729,492
General Service < 50 kW	18,569,272	2,562,886	16,006,386
General Service > 50 to 4999 kW	73,896,610	73,896,610	-0
Unmetered Scattered Load	293,553	-	293,553
Sentinel Lighting	88,568	4,458	84,110
Street Lighting	643,599	643,599	-0
TOTAL	141,525,131	77,767,991	63,757,140
%	100.00%	54.95%	45.05%

<u>Forecast Price</u>			
HOEP ($/MWh)		$24.63	
Global Adjustment ($/MWh)		$84.50	
Adjustments			
TOTAL ($/MWh)		$109.13	$112.39
$/kWh		*$0.10913*	*$0.11239*
%		55.20%	44.80%
WEIGHTED AVERAGE PRICE	$0.1106	$0.0602	$0.0506

Table 18 - Electricity Projections

		2017			2018		
Customer							
Class Name		Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	52,857,999	0.1156	$6,110,385	49,928,066	$0.11060	$5,521,976
General Service < 50 kW	kWh	19,885,125	0.1156	$2,298,720	18,782,887	$0.11060	$2,077,362
General Service > 50 to 4999 kW	kWh	88,798,720	0.1156	$10,265,132	83,876,583	$0.11060	$9,276,635
Unmetered Scattered Load	kWh	309,434	0.1156	$35,771	444,435	$0.11060	$49,154
Sentinel Lighting	kWh	93,360	0.1156	$10,792	86,990	$0.11060	$9,621
Street Lighting	kWh	678,417	0.1156	$78,425	664,563	$0.11060	$73,500
TOTAL		161,944,638		$18,720,800	153,118,961		**$16,934,748**

The Commodity share of the Cost of Power is calculated in the same manner as has been previously approved by the OEB in HHI'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	kWh	52,857,999	0.0072	$381,051	49,928,066	0.0078	$387,863
General Service < 50 kW	kWh	19,885,125	0.0066	$131,237	18,782,887	0.0071	$133,583
General Service > 50 to 4999 kW	kW	188,567	2.6887	$507,007	211,046	2.8974	$611,487
Unmetered Scattered Load	kWh	309,434	0.0066	$2,042	444,435	0.0071	$3,161
Sentinel Lighting	kW	265	2.0285	$538	238	2.1860	$521
Street Lighting	kW	1,849	2.0279	$3,749	1,844	2.1853	$4,029
TOTAL		73,241,390		$1,021,874	69,366,673		**$1,136,614**

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	kWh	52,857,999	0.0036	$189,733	49,928,066	0.0041	$204,172
General Service < 50 kW	kWh	19,885,125	0.0032	$62,980	18,782,887	0.0036	$67,773
General Service > 50 to 4999 kW	kW	188,567	1.3018	$245,480	211,046	1.4831	$313,003
Unmetered Scattered Load	kWh	309,434	0.0032	$980	444,435	0.0036	$1,604
Sentinel Lighting	kW	265	2.0549	$545	238	2.3410	$558
Street Lighting	kW	1,849	1.0063	$1,860	1,844	1.1465	$2,114
TOTAL		73,241,390		$499,717	69,366,673		**$587,110**

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	kWh	52,857,999	0.00360	$190,289	49,928,066	0.00360	$179,741
General Service < 50 kW	kWh	19,885,125	0.00360	$71,586	18,782,887	0.00360	$67,618
General Service > 50 to 4999 kW	kWh	88,798,720	0.00360	$319,675	83,876,583	0.00360	$301,956
Unmetered Scattered Load	kWh	309,434	0.00360	$1,114	444,435	0.00360	$1,600
Sentinel Lighting	kWh	93,360	0.00360	$336	86,990	0.00360	$313
Street Lighting	kWh	678,417	0.00360	$2,442	664,563	0.00360	$2,392
TOTAL		161,944,638		$583,001	153,118,961		**$551,228**

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, HHI 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	kWh	52,857,999	0.00130	$68,715	49,928,066	0.00030	$14,978
General Service < 50 kW	kWh	19,885,125	0.00130	$25,851	18,782,887	0.00030	$5,635
General Service > 50 to 4999 kW	kWh	88,798,720	0.00130	$115,438	83,876,583	0.00030	$25,163
Unmetered Scattered Load	kWh	309,434	0.00130	$402	444,435	0.00030	$133
Sentinel Lighting	kWh	93,360	0.00130	$121	86,990	0.00030	$26
Street Lighting	kWh	678,417	0.00130	$882	664,563	0.00030	$199
TOTAL		161,944,638		$210,528	153,118,961		**$45,936**

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, HHI 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	kWh	4,830	0.79000	$45,788	4,836	0.79000	$45,845
General Service < 50 kW	kWh	613	0.79000	$5,814	618	0.79000	$5,854
General Service > 50 to 4999 kW	kW	88	0.79000	$833	89	0.79000	$842
TOTAL		5,531		$52,435	5,542		**$52,541**

In compliance with this order, HHI 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
4075-Billed - LV	($51,804)	($51,300)	$90,976	$90,976	$90,976
4750-Charges - LV	$85,933	$89,485	$211,136	$211,136	$211,136

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

Customer Class Name		RTSR Rate	Not Uplifted Volumes	Revenue	% Alloc
Residential	kWh	**$0.0036**	48,228,553	$173,115	34.01%
General Service < 50 kW	kWh	**$0.0032**	18,143,532	$57,464	11.29%
General Service > 50 to 4999 kW	kW	**$1.3018**	211,046	$274,744	53.97%
Unmetered Scattered Load	kWh	**$0.0032**	429,307	$1,360	0.27%
Sentinel Lighting	kW	**$2.0549**	238	$490	0.10%
Street Lighting	kW	**$1.0063**	1,844	$1,856	0.36%
TOTAL			**67,014,523**	**$509,029**	**100.00%**

Low Voltage Charges Rate Rider Calculations

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	34.01%	71,805	48,228,553	$0.0015	kWh
General Service < 50 kW	11.29%	23,835	18,143,532	$0.0013	kWh
General Service > 50 to 4999 kW	53.97%	113,959	211,046	$0.5400	kW
Unmetered Scattered Load	0.27%	564	429,307	$0.0013	kWh
Sentinel Lighting	0.10%	203	238	$0.8523	kW
Street Lighting	0.36%	770	1,844	$0.4174	kW
TOTAL	**100.00%**	211,136	67,014,523		

Low Voltage Charges to be added to power supply expense for bridge and test year.

Customer		**Revenue**	**Expense**					
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate
Residential	kWh	4075	4750	50,145,146	$0.0007	$35,102	48,228,553	**$0.0015**
General Service < 50 kW	kWh	4075	4750	18,864,553	$0.0006	$11,319	18,143,532	**$0.0013**
General Service > 50 to 4999 kW	kW	4075	4750	188,567	$0.2419	$45,614	211,046	**$0.5400**
Unmetered Scattered Load	kWh	4075	4750	293,553	$0.0006	$176	429,307	**$0.0013**
Sentinel Lighting	kW	4075	4750	265	$0.3818	$101	238	**$0.8523**
Street Lighting	kW	4075	4750	1,849	$0.1870	$346	1,844	**$0.4174**
TOTAL		**0**	**0**	69,493,936		$92,658	67,014,523	

2.4 SMART METER DEPLOYMENT & STRANDED

2.4.1 DISPOSITION OF SMART METERS AND TREATMENT OF STRANDED METERS

HHI'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 further 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

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

HHI 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 minimum performance standards for electricity distribution systems in Ontario, and inspection requirements for distribution equipment. Over the years HHI has diligently maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. The constant maintenance of its equipment has permitted HHI 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 HHI'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.

HHI 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 HHI plans to take over the next 5-10 years to bring about the desired future.

- Priority will be given to HHI'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 significant 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 to extend their reliable, useful lives.

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

HHI'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 spending 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

HHI 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

HHI 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

Hawkesbury Hydro Inc.

Distribution System Plan

Date
June 8, 2017

Submitted by
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Table of Contents

EXECUTIVE SUMMARY

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

HHI'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 cost-effectively support HHI's desired outcomes and provides value to the customer. HHI is committed to adhering to its DS Plan 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.

HHI 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, HHI 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 HHI has made between 2013 and projected for 2017.

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Actual	Projected Y/E
CATEGORY	$	$	$	$	$
System Access	$5,060	-$43,596	-$160	$39,670	$51,669
System Renewal	$111,028	$98,281	$449,412	$251,920	$3,619,584
System Service	$841,977	$0	$0	$0	$0
General Plant	$74,259	$29,031	$13,067	$64,758	$41,100
Total	$1,032,324	$83,713	$462,319	$356,348	$3,712,353
Capital Contribution			$93,493	$17,741	
Net Capital	$1,032,324	$83,713	$368,826	$334,608	$3,712,353

Table ES-1: Historical Capital Investments by Year

As can be seen, Capital Investment has been very modest with the exception of System Renewal investment. This investment is driven by the need to replace end-of-life distribution plant. For 2013 the System Service category captures the cost of MS 43 substation upgrade. Subsequent substation investments are captured in the System Renewal category. Because the investments in the historical period have been referenced in previous rate filings no reclassification of the 2013 MS upgrade has been made, but it would be more correct to categorize this investment as System Renewal as was done in subsequent years. EB-2011-0173 provided HHI with the funds to upgrade both its stations. The funds provided were $1,517,813 for MTS 55 and $712,909 for MS 43. These project costs were exceeded, and the timing of the projects was changed significantly in part because of an in-service failure of a new MS transformer at MS 43. Further details are provided in Appendix C and D. The large station investments overshadow the normal end of life plant replacements that HHI completes. Poles are tested and replaced as indicated by the testing; main feeder capacity is brought up to capacity requirements by replacing under-sized old wire at a modest pace and failing porcelain insulators, and porcelain lightning arrestors are also being replaced at a modest pace.

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

	2018	2019	2020	2021	2022
	Test	Test+1	Test+2	Test+3	Test+4
CATEGORY	$	$	$	$	$
System Access	$36,800	$86,895	$31,010	$31,510	$31,610
System Renewal	$117,780	$131,825	$488,350	$149,205	$139,500
System Service	$10,000	$10,000	$10,000	$10,500	$10,500
General Plant	$11,250	$8,800	$11,900	$11,900	$9,000
Total	$175,830	$237,520	$541,260	$203,115	$190,610
Capital Contribution					
Net Capital	$175,830	$237,520	$541,260	$203,115	$190,610

Table ES-2: Forecast Capital Investments by Year

As can be seen from the table, System Renewal investments continue at a moderate pace. The exception is 2020 when station work is proposed at MS 43 to improve transformer utilization and remove the need to take a station outage affecting about 1200 customers when transferring load from one transformer to the other. This proposed change will allow HHI to implement an industry best practice design.

In developing its long-term DS Plan, HHI'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. HHII will continue to advance conservation and demand management.

Distribution System Plan

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 filing of asset management and capital expenditure plan information in support of a rate application and a distributor's Distribution System Plan (DS Plan).

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

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

HHI 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.

Utility Overview

The Town of Hawkesbury is a picturesque and bilingual community of over 10,000 residents located on the banks of the Ottawa River; the Town of Hawkesbury has a team dedicated to the attraction and retention of business. Hawkesbury is rated as one of the most bilingual areas in Ontario with nearly 70% of its residents fluent in French and English, Canada's two official languages. In fact, most of the population is made up of French-speaking Ontarians (Franco-Ontarians).

The Town is well known for its picturesque "Market-style" Main Street, populated by niche boutiques and restaurants as well as its significant business park, both providing abundant and diverse employment to the region.

Given its privileged location between Montreal and Ottawa, over 4.7 million individuals reside within a 100 km radius of Hawkesbury.

Hawkesbury is located off County Road 17, 10 minutes from TransCanada Highway 417 and the Long Sault Interprovincial Bridge means that Hawkesbury is within minutes of Highway 50 and Route 148.

CN Railways also has an operational line which conveniently provides rail access to Hawkesbury's Business Park.

Two international airports are within an hour's drive.

Hawkesbury is well situated to provide easy market access through Montreal's International Port and the Port of Prescott.

Hydro Hawkesbury Inc. continues to innovate and to provide the best products and services to its customers and the community. Hydro Hawkesbury employees are committed to providing the best service in a manner that best suits its customers.

Hydro Hawkesbury Inc. is a licensed distributor in the Province of Ontario. It is licensed by the Ontario Energy Board (OEB), ED-2003-0027, and is regulated by the (OEB). Its sole shareholder is the Town of Hawkesbury.

HHI distributes electricity to nearly five thousand five hundred (5500) customers and employs seven (7) individuals. It is a utility that is embedded in Hydro One and receives its supply at 44kV from Longueuil TS via the 26M24 feeder. Longueuil TS is supplied from Hydro One's 230kV system. It receives its other supply at 115kV. The connection point of Hawkesbury MTS #1 is via circuit 79M1, which is an extension of circuit H9A from Hawthorne TS.

As the local distribution company, HHI has two primary responsibilities. First, it is responsible for the safe and reliable delivery of electricity to its customers, and second, it bills for its services and the services provided by other organizations in Ontario's electricity system.

HHI was first incorporated on Monday, October 18, 1954, at a special meeting, as the Hydro-Electric Commission of the Town of Hawkesbury. In November 2000 following deregulation, it was incorporated under the name of Hydro Hawkesbury Inc. HHI is incorporated under the Ontario Business Corporations Act and is 100% owned by the Town of Hawkesbury.

Strategic Priorities

HHI's strategic priorities are defined in its corporate goals and reflect its mission and value statements:

- To form partnerships and alliances with other local distribution companies for economies of scale and cost-sharing opportunities
- To invest in the development of our staff to provide an employee-oriented, high-performance culture of organizational effectiveness that emphasizes empowerment, quality, productivity, goal attainment and ongoing development of a superior workforce
- To stay current with industry, sector and regulatory changes
- To pursue new business opportunities, partnerships and best management practices in our quest to meet or exceed financial expectations of our community by cost sharing, efficiency gains, cost savings, improve reliability, superior customer service and protecting the environment
- To investigate roles and opportunities that HHI can pursue in generation and promoting conservation and demand management initiatives.

Distribution System Plan

Our Vision

HHI will strive to be acknowledged as a leader among electric utilities in the areas of safety, reliability, customer service, and least cost service.

Our Mission

Hydro Hawkesbury Inc.'s mission is to provide fast and efficient customer service. Our superior quality service maximizes the efficiency of operations in the most cost-effective manner possible. This means a commitment to become a practical, simple and fast company which offers its customers the information and services they need. We are also committed to operating in an environmentally responsible manner.

Leadership Team

HHI is operated by a Board of five Directors who are all appointed by the Town of Hawkesbury. These directors have terms that coincide with the Municipal Council terms and appointments for the Board are made after the new Council is in place. The current Board is made up of three council members and two members from the community at large.

The Board has hired a staff of seven to operate the day to day affairs of the utility.

These are:

- A General Manager
- An Accountant
- A Customer Service Representative- Billing
- Two Customer Service Representatives
- Two linesmen

2018, the line persons plan to retire, and it is HHI's intent not to replace them. Instead, HHI will engage contractor services for the operation and maintenance of their system as well as capital construction.

The Current Distribution System

HHI has two Municipal station locations. One is supplied at 115kV and is on the west side of town, and the other is supplied at 44kV and is on the east side of town. Each station provides a 12.4kV distribution voltage however because the high voltage supplies are different there is a 30-degree phase angle difference between the two 12.4kV MS's. This means that the two systems cannot be paralleled. Any load transfer between the 44kV sourced and the 115kV sourced 12.4kV system must be an open transition. This results in outages to customers which is undesirable. As a result of this situation, HHI has worked towards having two independent 12.4kV systems with tie capabilities that can be used if needed. It does this at 115kV by having two transformers supplied from the same 115kV supply and having two secondary (12.4kV) transformer buses with a normal open tie breaker and three feeders, two fed from one transformer and one fed from the other. These three feeders can be paralleled and load can be transferred by closed transition. The other station supplied at the 44kV has two feeders that have interconnections and can be paralleled, and load can be transferred by closed transition. This 44 kV supplied MS has one transformer supplying load while there is another transformer in the station yard on potential but not supplying load.

Drivers and Influencers

- Customer demand
- System reliability
- Municipal driven
- Capacity requirements
- Asset management capital expenditures (regulatory and legislative requirements)
- Infrastructure renewal
- Smart metering

Strategy

HHI's DS Plan is designed to present a fully integrated approach to capital expenditure planning. This includes comprehensive documentation of its asset management process to support its future five-year capital expenditure plan and detailing the history of its past five years' activities. HHI 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 alignment with RRFE objectives – customer focus, operational effectiveness, public policy responsiveness and financial performance.

HHI has relied on the OEB's Filing Requirements for Electrical Transmission and Distribution Applications Chapter 5 (March 28, 2013) to guide its presentation of its policies, practices and decision-making processes.

[5.2] Distribution System Plan

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

HHI 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 listed below, based on the 'trigger' driver of the expenditure:

System access—investments are modifications (including asset relocation) to the distribution system HHI is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via HHI's distribution system.

System renewal— investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of HHI's distribution system to provide customers with electricity services.

System service—investments are modifications to HHI's distribution system to ensure the distribution system continues to meet HHI's operational objectives while addressing anticipated future customer electricity service requirements.

General plant—investments are modifications, replacements or additions to HHI's assets that are not part of the 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.

The purpose of this DS Plan is to present HHI's Asset Management Strategy and to provide justifications for the capital investments required to maintain its core business: supplying reliable electrical services to its customers at a reasonable cost. This requires:

- a thorough understanding of the age, condition and performance of its assets,
- documenting its inspection practices in accordance with the DSC,
- describing its maintenance activities in accordance with good utility practice,
- ensuring that all aspects of employee and public safety are addressed in compliance with all regulatory and legal obligations,
- forecasting and planning for the future growth of load customers and renewable generation facilities,
- recognizing and addressing constraints in the current distribution system and anticipating future capacity requirements,
- demonstrating that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements, and
- developing a five-year forward looking capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base.

Distribution System Plan

In striving to achieve the corporate vision and asset management objectives, HHI is guided by the OEB's four key target objectives referenced in the Renewed Regulatory Framework for Electricity Distributors (RRFE)

- Customer focus,
- Operational effectiveness,
- Public policy responsiveness, and
- Financial performance.

This requires conformance with all applicable laws, regulations, codes, and standards. To help achieve the foregoing, HHI's overall guiding principle for asset management is to meet all regulated requirements and performance standards and minimize the cost to HHI's customers when staff acquire and subsequently maintain assets.

[5.2.1] Distribution System Plan Overview

The electric distribution system is capital intensive. Prudent capital investments are documented within HHI's DS Plan for the 2013-2022 periods. The DS Plan documents the practices, policies and processes that ensure investment decisions support HHI's desired outcomes in a responsible, cost-effective manner and provides value to the customer. The DS Plan integrates qualitative and quantitative information which results in an optimal investment plan and includes:

- Customer value considerations,
- Alignment with public policy objectives,
- Regional planning considerations,
- Renewable generation considerations,
- System expansion considerations, and
- System renewal considerations.

(5.2.1a) Key elements of the DS Plan that affect the rate proposal

(Key elements of the DS Plan that affect its rates proposal especially business conditions driving the size and mix of capital investments needed to achieve planning priorities)

HHI's DS Plan documents the capital and maintenance activities that HHI has completed or plans to complete in the 2013-2017 historical period, plans for the 2018 Test Year and plans for the 2019-2022 forecast period. The current date for information contained in this Consolidated DS Plan is December 31, 2016.

This is the first DS Plan filed by HHI and as such there are no changes from any previously filed plan.

As per Section 2.4.5 of the Chapter 2 filing requirements, HHI's revenue requirement is less than $10 Million and therefore HHI is using $50,000 as the default materiality threshold. HHI will be reporting on investments or variances above this value.

It is expected that the operational and service requirements driving HHI capital expenditures, and found within its DS Plan, will generally remain consistent through the 2018 to 2022 planning window. The projected expenditures for 2018 and going forward reflect:

- the typical spending needs of a distribution electric utility serving a mature and stable customer base,
- the focused planned capital sustainment investments required to replace the aging assets found in HHI distribution system, and
- the focused planned capital investments to provide the necessary firm station capacity for reliable supply for its customers.

Specific investment category spending requirements include:

- System Renewal investments required to replace end of life assets including poles and transformers,
- System Renewal investments to provide reliable firm station supply capacity,
- System Service investments are minimal, and
- General plant investments to meet the office and IT needs.

HHI in the 2013 to 2017 historical period carried out part of the station projects it was forecasting to complete per EB-2011-0173. In completing the first station work unexpected site issues caused the cost to escalate. In addition after the station transformer was in service for about a year (just beyond the warranty period), the new transformer failed and the old transformer needed to be put back in service. This caused delays and added costs. Appendix C provides the details about the stations and the costs.

HHI's planning and investment processes follow good utility practices that are executed through the Distribution System Plan. Good utility practices have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. There are a number of key elements that contribute to the planning of investments through the period of the DS Plan:

- Customer service,
- Outputs of HHI's asset management program – including maintenance and EOL replacement,
- Coordination with municipally (town and county) planned projects,
- Regulatory obligation, and
- At present there is no load growth expectation through developments.

In order to maintain current and accurate information in its database, HHI has maintains a condition assessment of the plant in its system. This information is resident in Excel spreadsheets that serve as a centralized data repository for asset information. This information is updated from time to time and as maintenance and capital projects are completed.

A capital investment prioritization process, aligned with corporate and asset management objectives, has been developed to prioritize discretionary capital investments. This occurs during the budgeting part of the planning process. During the budget process, capital investments are identified and investment justifications are put together for each one that identifies the cost of the project and its expected benefits. A value and risk deferral assessment of the investment is performed. Investment scores determine priority of the investment for current or future budget periods.

HHI 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 HHI has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. HHI has been prudent when incurring costs, since the most recent valid customer satisfaction survey results indicate that the cost of electricity is a moderate to very significant strain on the household budget. Hence the price of electricity is an important factor to customers.

With a view to prudently controlling all expenditures and therefore moderating any increases in its customers' bills, HHI has not implemented newer technologies such as SCADA or GIS.

HHI's DS Plan ensures that the current and future distribution system can deliver power at the quality and reliability levels desired by customers and the lifetime usage is extended by balancing preventative maintenance, life-extending refurbishment, and end-of life replacements. In short, the system will meet the customers' needs for quality and reliability of power at a reasonable and affordable cost.

HHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system.

HHI's DS Plan demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of non-discretionary investments, specifically those related to replacement or renewal of end-of-life plant.

(5.2.1 b) Sources of Cost Savings

(Sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution)

HHI's planning, prioritization and investment processes follow good utility practices that are executed through the DS Plan. Good utility practices have inherent cost savings through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. Some specific HHI Distribution System Plan cost savings are expected to be achieved using the following:

- Pole condition inspections and comprehensive data collection provides a better understanding of each asset's stage in its lifecycle which will lead to more cost effective decisions with respect to maintenance, refurbishment and replacement decisions. Particularly with the new pole testing equipment more accurate objective assessments of pole condition are expected.
- Proactive maintenance and replacement of plant reduces reactive maintenance costs and improves service to the customer resulting in fewer and shorter duration outages, which in turn has a beneficial impact on the cost of outages to customers. A structured program of maintenance and renewal with planned rate increases will avoid disruptive rate spikes when addressing the volume of plant reaching end of life.

(5.2.1 c) Period covered by DS Plan

The DS Plan covers the historical period of 2013 with 2017 being the bridge year and a forecast period of 2019 to 2022 with 2018 being the test year. The data for 2017 will be three months actual and nine months of forecast spending.

(5.2.1 d) Currency of Information

Unless otherwise noted, all information contained in the DS Plan is current as of December 31, 2016.

(5.2.1 e) Changes to Asset Management Processes

As this is the first DS Plan to be filed by HHI, there are no changes to report.

(5.2.1 f) Contingent Aspect

At this time, there are no planned activities that are contingent upon the outcome of ongoing or future activities.

While HHI has and will continue to consult with third parties, the information presented in the DS Plan is based on best available information.

[5.2.2] Coordinated Planning with Third Parties

(To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate)

(5.2.2a) Description of the Consultations

(The purpose of the consultation e.g. Regional Planning Process; whether the distributor initiated the consultation or was invited to participate in it; the other participants in the consultation process e.g. customers; transmitter; OPA; the

nature and prospective timing of the final deliverables, if any, that are expected to result from or otherwise be informed by the consultation(s) e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan; and will the consultation(s) have or are they expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.)

In preparing this DS Plan, HHI has considered the needs of its customers, as well as Hydro One, the Town of Hawkesbury, and the IESO.

Customer Engagement

"Putting the Consumer First" was part of the title of the Report of the Ontario Distribution Sector Review Panel. Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer focus is primarily on the overall costs of their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

Commercial Customers

As of the latest discussions, commercial customers within the service area are not planning any significant or material modifications within the service period. Planning and consultation is conducted with customers on a regular basis primarily to engage and promote participation in CDM programs. In addition to this, HHI uses this opportunity to discuss power quality, other reliability issues and future system planning.

Residential Customers

HHI values its customers and regularly seeks feedback to ensure that their needs are met and to receive suggestions on how HHI can improve their overall customer experience and include

- person to person communication,
- inserts in hydro bills,
- website interaction,
- community meetings and events, and
- surveys.

HHI is one of the few electric utilities to operate a full service customer counter with daily customer interaction. Customers who want to open a new account, move, pay bills, or have concerns or comments can come to our office or contact us by telephone, email, and fax. Customers appreciate the opportunity to deal with a local person and know that their concerns are treated with urgency and respect. HHI also uses mail inserts to provide customers with information about hydro, energy conservation including coupons, and demand management.

HHI has launched a new user friendly website at the end of 2016. Relative to the previous website it will be easier to read, feature greater emphasis on conservation, demand management and how to reduce their energy costs, and provide information about HHI, and responds to customers' questions and concerns. HHI's customers can already access their accounts 24/7 to view energy consumption which is updated nightly via smart meters, and check their account balance and payment history.

HHI completed a Customer Satisfaction Survey in 2014, and an Electrical Safety Awareness Survey in 2016. It is completing another on line Customer Satisfaction survey but to date the response has been underwhelming such that no valid results have been achieved.

In the 2014 customer satisfaction survey that HHI commissioned the utility received about a 3% response from the community. The survey covered a wide range of issues relating to customer satisfactions, service levels, reliability, conservations and bill impact. The survey completed in 2014 contained separate questionnaires for French and English speaking customers.

The respondents were residential customers. The results of the survey showed that more than 97% of HHI's customers rated the service they receive from the LDC as between good and excellent. From a reliability perspective, 94% rated HHI's performance as good to excellent. When it comes to communications, 81% believed that HHI was between good and excellent in communicating with them. 76% indicated that the Hydro bill was a large or a moderate strain on their household budget.

Hydro One

HHI is an embedded utility in Hydro One and receives its supply at 44kV from Longueuil TS via the 26M24 feeder. Longueuil TS is supplied from Hydro One's 230kV system. HHI receives its other supply at 115kV. The connection point of Hawkesbury MTS #1 is via circuit 79M1, which is an extension of circuit H9A from Hawthorne TS.

HHI distributes electricity to the Town of Hawkesbury at a primary distribution voltage of 12.4kV. HHI does not host any utilities.

HHI's distribution system is fully embedded in the Hydro One Networks Inc. ("Hydro One") distribution system through Hawkesbury MTS and Longueil TS.

To date there have been no constraints identified by Hydro One regarding any of the feeders that service and supply HHI.

Operations coordination between HHI and Hydro One happens where necessary. Hydro One identifies planned outages and switching plans. Hydro One also supplies a weekly Ontario Grid Control Centre update to inform customers of significant events associated with its transmission and distribution systems.

HHI assists applicants from Renewable Energy Generators (REG) in its service territory as part of the Condition Impact Assessment process for FIT applicants through Hydro One.

Town of Hawkesbury

HHI maintains a close relationship with the Town of Hawkesbury and its Department of Development and Works Planning. Discussions include planned activities that can affect budgets, and scheduling and coordination on a per project basis and during construction season.

The town is mature and stable with respect to growth and development. New residential subdivisions are added to the town every few years. Commercial and Industrial growth is minimal.

Neighboring Utilities

HHI is embedded in Hydro One.

(5.2.2b) Integrated Regional Resource Planning

HHI's distribution system is fully embedded in the Hydro One Networks Inc. ("Hydro One") distribution system through Hawkesbury MTS and Longueil TS. The IESO notes that both stations are part of the regional planning process for Greater Ottawa Region, and that HHI was part of the working group for the Outer Ottawa Sub-Region.

Regional planning for the Outer Ottawa sub-region commenced with the development of the Needs Assessment that Hydro One completed on July 28, 2014. The Needs Assessment identifies the 115 kV circuit, 79M1 supplying Hawkesbury MTS, as approaching its voltage limit, and a load restoration need involving the 230 kV circuit D5A supplying Longueil TS. For the voltage issue it is recommended that Hydro One and area LDCs, including HHI, continuously monitor and assess the voltage situation and install reactive compensation if required. On September 22, 2015, Hydro One also completed the Local Planning Report on load restoration for the Outer Ottawa sub-region. Hydro Hawkesbury Inc. was part of the study team for the Local Planning Report. The report concludes that the IESO Ontario Resource and Transmission Assessment Criteria for load restoration on the D5A circuit will be met with existing procedures, and therefore, no capital investment is required to address this need. The report indicates that no further regional coordination necessary as the need identified for Outer Ottawa sub-region can be addressed directly by the transmitter and area LDCs.

(5.2.2c) Comment Letter from IESO Regarding REG Investments

HHI has six micro-FIT and one FIT projects connected. The capacity connected is 126.5 kW. There are no outstanding applications and there are no new applications at this time.

HHI has no requirements for REG capacity at this time. HHI's REG investment plan was forwarded to the IESO and the comment letter from the IESO is attached in Appendix F of this DS Plan.

[5.2.3] Performance Measurement for Continuous Improvement

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

(5.2.3a) Metrics used to Monitor DS Planning Performance

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

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

Based on Chapter 5 filing guidelines that indicate that the LDC shall identify and define methods and metrics used to monitor distribution system planning, and in conjunction with Report of the Board – Performance Measurement for Electricity Distributors a Scorecard Approach (EB-2010-0379) dated 5 March 2014, the OEB asks distributors to focus on the one measure that they believe most effectively reflects their performance in system plan implementation.

Monitoring system performance provides HHI with the information required to appropriately adjust its plans or to identify remedial steps to ensure that distribution assets achieve their design life and are capable of serving under peak demand conditions. Performance monitoring is geared to achieve desired results on its four target performance outcomes:

- Customer focus,
- Operational effectiveness,
- Public policy responsiveness, and

- Financial performance.

The Service Quality Requirements within Section 7 of the DSC indicate a prescribed measurement and expected level of performance that defines a baseline for the quality of service delivered by electricity distributors. In addition to these and other metrics mandated by the OEB, HHI monitors a number of performance measures that may assist in the utility's continuous improvement activities and in satisfying customer requests.

Customer-Oriented Performance

- Feedback,
- Service reliability,
- Bill impacts,
- Billing accuracy,
- Power quality, and
- O&M cost per customer.

Feedback

As a utility serving a small community, customer concerns are communicated quite easily just by interaction and customer feedback. That said, HHI commissioned and participated in an independent customer survey in 2014 as part of its commitment to put its customers first. The top two needs identified through customer interaction were:

1. Price - customers are very concerned about price and increased utility bills. Most seniors need more education on the support programs available to assist low income households.
2. Reliability - Customers are pleased at our level of reliability as it is an important issue to them. Customers equate safety with reliability as electricity is an essential service.

Bill Impacts

In the annual budgeting process, HHI takes care to avoid large swings in costs by planning gradual changes to capital expenditures which subsequently minimizes the impact on customer bills where possible. The key factors used in reviewing proposed budget increases include: quality of service improvements to customers, improvements in reliability, and changes in revenue requirements year over year.

HHI rebased its rates through a cost of service application in 2014 (EB-2013-0139). In subsequent years IRM or Annual IR applications were filed resulting in the approval of adjustments to rates. The annual distribution rate impacts through the historical period are shown in the table below:

Class	2014	2015	2016	2017
Residential	-3.48%	2.20%	5.59%	1.30%
GS < 50 kW	-6.43%	-1.21%	4.98%	-0.05%
GS > 50 kW	-28.36%	-28.23%	-15.46%	0.55%

Figure 1: Historical Annual Distribution Rate Adjustment Impacts

Service Reliability

Guidance provided by the OEB in the recently published Report of the Board: Electricity Distribution System Reliability Measures and Expectations (EB-2014-0189), indicates that it would like to use the average or arithmetic mean of the previous five years (or historical period) of data to establish performance expectations for the forecast period. Specifically, the OEB referred to SAIDI and SAIFI as the two reliability indicators that would benefit from using targeted goals.

HHI uses the CAIDI, SAIDI and SAIFI reliability indexes to monitor system reliability performance.

HHI collects a variety of statistics and analyzes the data to assess system performance and to act as inputs to its asset management program and capital prioritization processes. The data is also used as a tool to improve restoration time and drive/support policy.

HHI monitors the reliability performance of its system. While no one wants to have power interruptions, HHI's customers have not raised any special concerns in this area of performance. Power quality is not and has not been an issue raised by the public in the HHI service area. HHI will address power quality issues in the service area as they arise.

Efficiency and Cost-Effectiveness

HHI measures efficiency and cost effectiveness through the progress of projects in the current year capital program. Because HHI contracts out most of its capital work it monitors the progress through regular project meetings for large projects and due dates for smaller projects.

Asset and/or Systems Operations Performance

HHI does not have a formal worst performing feeder analysis, but it does monitor the number and types of outages on particular feeders to be able to generate and prioritize capital projects.

HHI monitors safety and safety related incidents within the service area. Contact with distribution equipment by the general public in addition to employees is tracked. HHI has completed a customer engagement campaign in 2016 to raise the level of awareness of electrical safety.

HHI monitors its compliance with Ontario Regulation 22/04 for design, construction and maintenance. Practices are audited by a third party on an annual basis and HHI tracks the non-compliances and Needs Improvements comments.

(5.2.3b) Summary of Performance Trends

(Provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index. Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

Service Reliability

HHI uses the CAIDI, SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain a tight control over their capital and maintenance spending. The Maintenance Program is primarily condition based. The maintenance component addresses statutory requirements such as inspection per the DSC, as well as prudent "testing" of the plant to help identify end of life conditions for poles.

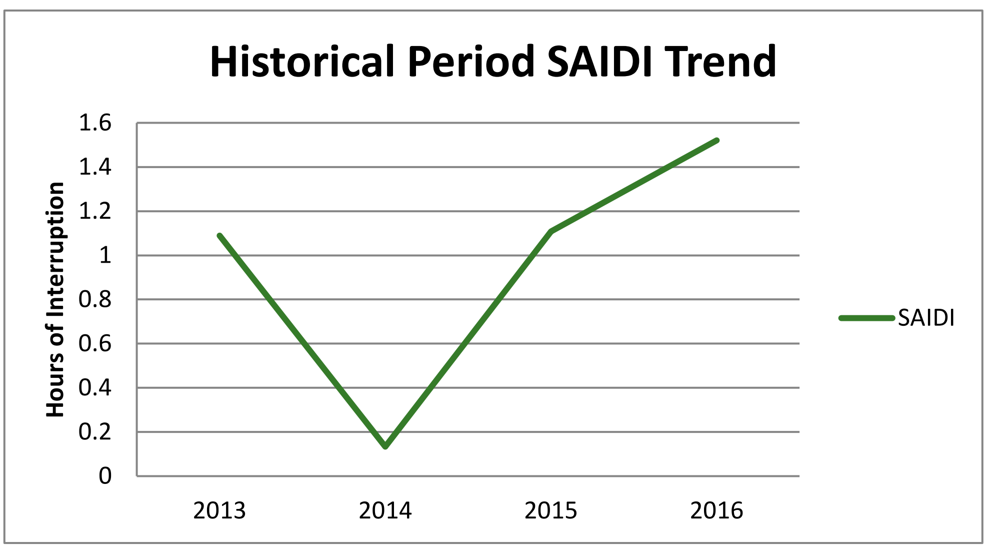


Figure 2: Historical Period - SAIDI Trend

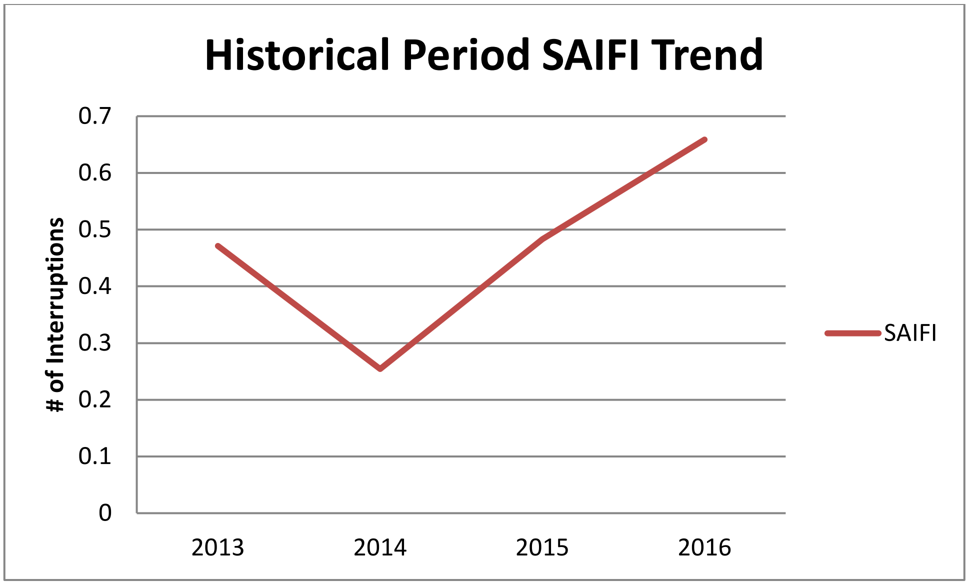


Figure 3: Historical Period – SAIFI Trend

HHI collects and reports outage data using the standard format and codes specified in the RRR document. The data is transferred to an Excel spreadsheet for ease of producing standard and custom reliability reports. Calculations are made to determine the reliability indices SAIDI, SAIFI, and CAIDI. The data are sorted to determine cause and affected components.

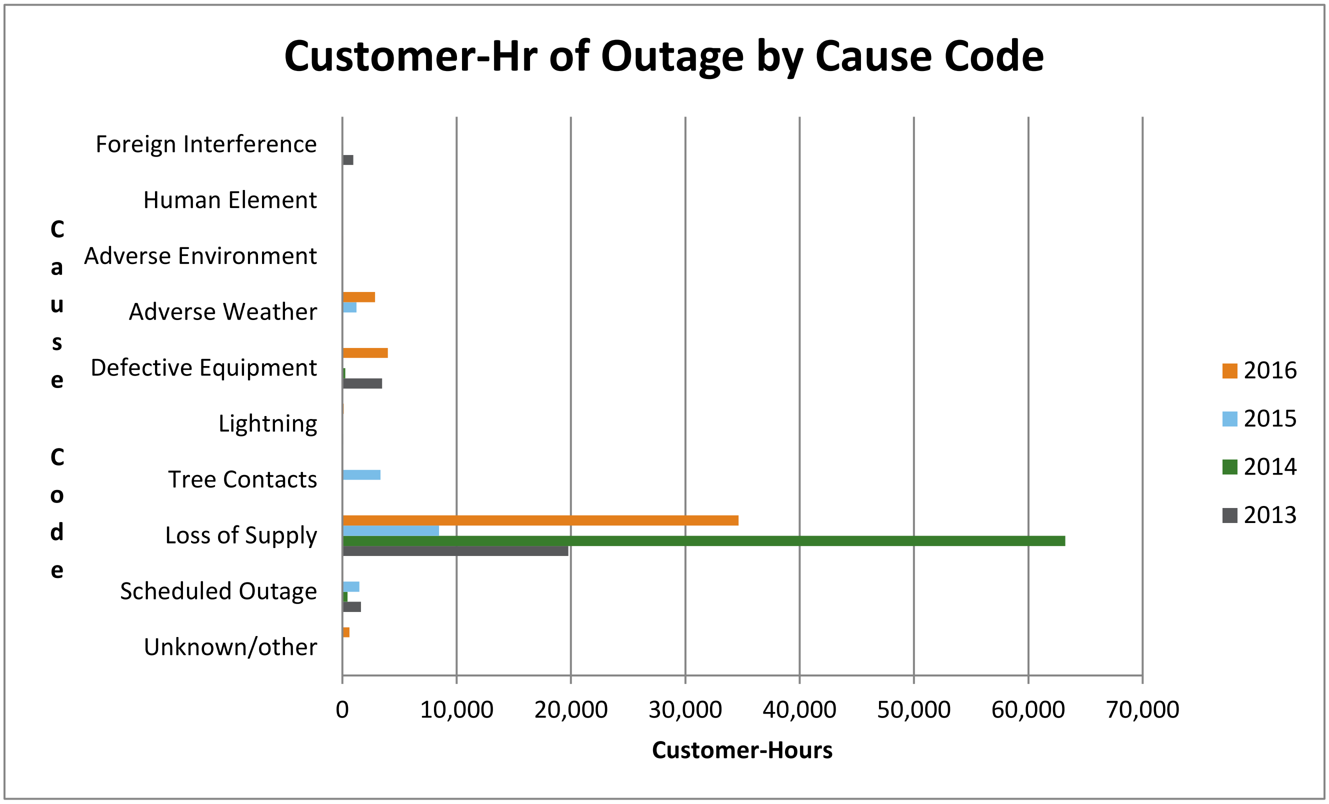
Reliability statistics for the historical period are presented as follows:

	2013	2014	2015	2016
CAIDI	16.63	0.52	2.30	2.30
SAIDI	1.09	0.13	1.11	1.52
SAIFI	0.47	0.25	0.48	0.65

Figure 4: Reliability Statistics for the Historical Period Excluding Loss of Supply

Outage Causes

Outages are categorized by cause codes; the number of customers affected and the duration of a given outage are collected and reported. As HHI continues with its capital replacement and infrastructure renewal programs, the number of outages due to equipment and vegetation has been continued to be low. HHI believes that by continuing its steady improvements to the system, the reduced outages trend will continue.



Cause Code	0	1	2	3	4	5	6	7	8	9
	Unknown/ other	Scheduled Outage	Loss of Supply	Tree Contacts	Lightning	Defective Equipment	Adverse Weather	Adverse Environm ent	Human Element	Foreign Interfer ence
2013	0	1,626	19,762	0	70	3,467	8	0	0	954
2014	0	453	63,244	0	0	253	0	0	0	47
2015	0	1,473	8,461	3,323	0	46	1,234	30	0	26
2016	621	61	34,655	0	108	3,987	2,870	58	0	6

Figure 5: Customer –Hours of Outage by Cause

The majority of outages in the historical period have been caused by scheduled outages, loss of supply, defective equipment or weather. As a result of the new station transformer failure in 2013, HHI has placed added importance on having backup capability at the municipal station level to ensure a continued reliable supply of electricity to its customers. The 2013 Defective Equipment customer hours were mainly due to the 44kV station transformer failure. The 2016 Defective Equipment failure was a blown 115 kV fuse at the 115kV station. HHI's maintenance and inspection program has been an effective means of replacing infrastructure at EOL. HHI has no control over either weather or loss of supply but has effectively managed its outages through the historical period. HHI will continue to diligently maintain, inspect and service its equipment so that useful life is maximized. HHI has had Defective Equipment outages as a result of porcelain line insulators failing and as a result of porcelain insulated air gap type lightning arrestors. HHI is addressing these problems by initiating a replacement program which will proceed over several years and at a modest pace.

Standard Performance Indicators - ESQRs

Indicator	OEB Minimum Standard	2012	2013	2014	2015
Low Voltage Connections	90%	100	100	100	100
High Voltage Connections	90%	100	100	100	N/A
Telephone Accessibility	65%	99.9	100	99.9	81.9
Appointments Met	90%	97.8	97.4	100	100
Written Response to Enquiries	80%	100	100	100	100
Emergency Urban Response	80%	100	100	100	N/A
Emergency Rural Response	80%	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10%	0.1	0	0	6.2
Appointment Scheduling	90%	100	100	100	94.9
Rescheduling Missed Appointments	100%	100	100	N/A	N/A

Reconnection Performance Standard	85%	100	100	100	100

Figure 5: Standard Performance Indicators

Standard Performance Indicators – Scorecard

HHI's belief in continuous improvement is reflected in all areas of its operations. Similar to most utilities in Ontario, HHI must replace aging distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to strategic replacement of aging assets, HHI continues to focus on core maintenance activities, such as distribution station maintenance, and vegetation control, including tree trimming activities, to reduce the disruption of electricity distribution to our customers. HHI focuses on short and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

Performance Outcomes	Performance Categories	Measures	2013	2014	2015	Industry Target
Customer Focus	Service Quality	New Residential/Small business Services Connected On Time	100%	100%	100%	90%
		Scheduled Appointments met on Time	97.4%	100%	100%	90%
		Telephone Calls Answered on Time	100%	99.90%	99.90%	65%
	Customer Satisfaction	First Contact Resolution		94%	94%	
		Billing Accuracy		99.90%	99.90%	98%
		Customer Satisfaction Survey Results		92%	92%	

Figure 6: Scorecard – Customer Focus

Year over year, HHI has consistently exceeded the OEB targets for customer satisfaction and service quality as part of the customer focus section of the scorecard. When corporate and asset management objectives are aligned with OEB performance outcomes and when HHI involves customers in discussions to understand their preferences and concerns, the result is an increased level of satisfaction. HHI's customer service representatives answer a changing number of phone calls per year within the 30-second window prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of HHI's dedication to being an organization focused on customer service.

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	Industry Target	HHI Target
Operational Effectiveness Continuous Improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Safety	Level of public awareness				78%		
		Level of compliance with O'Reg. 22/04		C	C	C		C
		Serious electrical Incident Index	# of general public incidents	0	0	0	0	0
			Rate per 10,100,1000 km of line	0	0	0	0	0
	System Reliability	Average number of Hours that power to a customer is Interrupted		1.09	0.13	1.11		0.67
		Average number of times power to a customer is Interrupted.		0.47	0.25	0.48		0.5
	Asset Management	Distribution System Plan Implementation Progress			46%	In Progress		
	Cost Control	Efficiency Assessment		1	1	1		
		Total Cost per Customer		$284	$260	$261		
		Total cost per km of line		$23,045	$21,050	$21,120		

Figure 7: Scorecard – Operational Effectiveness

The operational effectiveness portion of the scorecard shows HHI's continuous improvement in productivity and cost performance including reliability and quality objectives. HHI has exceeded the targets in each category in addition to demonstrating an exemplary Cost Control Efficiency Assessment. This is attributed to prudent management of the system, its asset management process, and method of capital project prioritization. HHI notes that its total cost per customer is the lowest in the industry. Going forward HHI will continue to implement productivity and efficiency improvements to maintain this record while maintaining the reliability and quality of its distribution system.

Performance Outcomes	Performance Categories	Measures	2013	2014	2015	Industry Target	HHI Target
Public Policy Responsiveness	Conservation & Demand Management	Net Cumulative savings			14.68%		7.92 GWh
Distributors deliver on obligations mandated by the government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments completed on time	N/A	N/A	N/A		
		New Micro-embedded Generation Facilities Connected on Time		100%		90%	

Figure 8: Scorecard – Public Policy Responsiveness

In response to public policy, HHI has not managed to attain its CDM targets through the historical period. In the historical period HHI has 1 FIT project and 6 Micro-Fit projects. All are completed and all are connected to the grid. There are no further projects or applications in process at this time. With respect to conservation programs, typically the prime candidates for demand savings programs are large industrial and manufacturing customers. The HHI region has a shrinking industrial and manufacturing customer base, so the opportunities for significant demand savings in HHI are minimal. However, HHI is continuing to offer a number of provincial initiatives to further reduce the peak demand requirements.

Performance Outcomes	Performance Categories	Measures		2013	2014	2015
Financial Performance Financial viability is maintained and savings from operational effectiveness	Financial Ratios	Liquidity: Current ratio (current assets/Current liabilities)		.97	.95	1.0
		Leverage: Total debt (includes short term debt) to Equity ratio		.43	.39	.35
		profitability : Regulatory Return on Equity	Deemed (included in rates)	8.01%	9.36%	9.36%
			Achieved	1%	12.48%	19.72%

are sustainable						

Figure 9: Scorecard – Financial Performance

HHI reports on financial ratios to ensure that financial viability of the utility is maintained and to demonstrate that savings achieved in the operational effectiveness portion are sustainable. The ratios provide a perspective regarding liquidity, the degree of leveraging and profitability.

Cost Effectiveness and Efficiency

HHI's historical three-year cost per customer has averaged $269 per customer.

HHI's past three-year cost per kilometer of line has averaged $21,738 per km of line.

HHI's Efficiency Assessment rating is 1.

(5.2.3c) Impact on Performance and the DS Plan

Explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

Customer Service Feedback

HHI completed a customer surveys in 2014. Customers are surveyed to solicit high-level feedback regarding their perception of HHI's performance and where they think HHI could improve service. The survey results indicate that customer satisfaction is high; that the cost of power is a concern for many people and that the customers are satisfied with HHI's reliability. HHI does its best to ensure that there is education within the community regarding pricing, conservation programs and ways and means to reduce power bills.

Customer-Oriented Performance: Service Reliability

HHI calculates and monitors reliability statistics for all customers within the service area. These statistics are calculated based both on all outages and also for all interruptions excluding loss of supply. HHI's capital project planning and implementation will assist in shortening the duration and reducing the frequency of outages in the service area.

Customer-Oriented Performance: Power Quality

HHI will continue to ensure that ratepayers in the service area are supplied with reliable and quality power.

Cost Efficiency and Effectiveness – Project Progress

HHI measures and tracks the progress of projects in the current year capital program. Because most capital work is contracted out there is a schedule the contractor is working to and regular reviews are carried out to ensure the schedule is being met. This is done to ensure successful project completion by year end.

Asset/Systems Operations Performance: Safety

HHI monitors safety related incidents. With the majority of its field work contracted out HHI has a lower exposure to safety incidents. Never-the-less, HHI insists that its contractors abide by current industry safety practices. HHI has conducted surveys and programs to raise the public level of electrical safety awareness and will identify further requirements in this area as needed.

Asset/Systems Operations Performance: Reg. 22/04

HHI monitors and tracks its compliance with Ontario Regulation 22/04 for design, construction and maintenance. HHI has a steady track record through the historical period and met targets for zero non-compliance during audits and due diligence inspections.

[5.3] Asset Management Process

(5.3.1) Asset Management Process Overview

(This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates.)

Key elements of the process that drive the composition of HHI's proposed capital investments are highlighted along with HHI's asset management philosophy. The relationship between RRFE outcomes, corporate goals, asset management objectives, and the linkage to the selection and prioritization of HHI's planned capital investments is explained.

The components of the asset management process that HHI has used to prepare its capital expenditure plan are identified, including inputs, the data sets, primary process steps and outputs. The information generally used throughout the DS Plan is based on available information established between early-2015 to mid-2015, and should be considered as current.

This is the first DS Plan to be filed by HHI, and as such, there are no important changes to the asset management process identified from a previously filed DS Plan.

Looking forward, the next steps planned to improve HHI's asset management process have also been identified in as much detail as is available.

The HHI asset management plan for 2018-2022 proposes annual investments to upgrade or replace aging conductors, insulators, lightning arrestors, and wooden poles. Also HHI plans to invest in the improvement of its 44kV supplied station to allow both transformers to carry load and switch load between transformers without the need for planned outages on the whole station affecting more than 1,000 customers each time.

(5.3.1a) HHI's Asset Management Objectives

(A description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments)

HHI's asset management objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan necessary to sustain HHI's electrical distribution system. The objectives provide guidance to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets. The objectives identify an initial starting point and are developed, enhanced, or adjusted so that they are aligned with HHI's business environment. The qualitative asset management objectives have been integrated into HHI's Capital Investment Process (CIP) to prioritize investments for five years including the bridge and test years.

HHI's asset management objectives are linked to the corporate vision and mission. Asset management objectives describe the specific and measurable outcomes required of the asset management system and are used to measure the success of the Asset Management Plan.

HHI's multi-level commitment to its stakeholders is reflected in these asset management objectives:

- to construct, maintain and operate all assets in a condition safe to staff, contractors and the public,
- to actively manage distribution assets to optimally balance system investments and reliability,
- to align asset investments with customer expectations of cost, reliability and service performance,
- to continually seek out, develop and deliver sustainable cost efficiencies relating to asset deployment, operations and maintenance,
- to manage the pace and magnitude of asset investments over the long term, to level customer rate impacts while maintaining corporate financial stability and continuing to deliver economically reliable power to customers,
- to ensure that environmental considerations are taken into account in the design and management of the distribution system,
- to satisfy growth and loading needs by managing capacity and asset utilization, and
- to incorporate and leverage the benefits of new technology as appropriate.

The goals and objectives are used throughout HHI's asset management approach and are embedded within the asset management policy, strategies, and plan. Key tactical initiatives are included to achieve the objectives. The goals and objectives will have targets established to determine the measure of success of the asset management programs and practices. Conceptually, objectives will most likely revolve around, but not be limited to safety, reliability and cost efficiency.

The table below shows the linkages between RRFE Outcomes, corporate objectives and asset management objectives:

RRFE Outcomes	Corporate Objectives	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Safety first	Construct, maintain and operate all assets in a safe manner	1. Lost/non-lost time 2. ESA Non-Compliance	1. WSIB rate class 10 year benchmarks 2. Zero (Max 1 N)
Operational Effectiveness	Reliability in electricity delivery	Actively manage distribution assets to optimally balance system investments and reliable supply of electricity delivery	1. SAIDI 2. SAIFI	1. SAIDI within range of past 5-year performance 2. SAIFI within range of past 5-year performance
Customer Focus	Excellence in customer service	Align asset investments with customer expectations of cost, reliability and service performance	1. Customer Survey	1. Customer survey results => previous year for : a) Customer Care b) Company Image c) Mgmt Operations
Financial Performance	Financial integrity	Manage the pace and magnitude of asset investments over the long term, to level customer rate impacts while maintaining corporate financial stability and continuing to deliver economically reliable power to customers	1. Investment spending 2. Investment scheduling	1. OM&A expenditure +/- 15% to estimate; Capital expenditure +/- 15% to estimate 2.>80% annual projects/ programs completed on time
Public Policy Responsiveness	CDM	Ensure that conservation programs are implemented and effective.	1. Cumulative Energy Savings	1. HHI target of 7.92 GWh cumulative

Figure 10: Linkages between Corporate Objectives and RRFE Outcomes

(5.3.1b) Asset Management Components

(Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments)

- *asset register*

- *asset condition assessment*
- *asset capacity utilization/constraint assessment*
- *historical period data on customer interruptions caused by equipment failure*
- *reliability-based 'worst performing feeder' information and analysis*
- *reliability risk/consequence of failure analyses)*

Asset Management Process

In KPMG's March 10, 2009 report to the Board, titled Review of Asset Management Practices in the Ontario Electricity Distribution Sector (the "KPMG Report"), KPMG referred to a concise definition of asset management to highlight the main elements as: a process to optimize performance, costs and risks relevant to service delivery. This summary definition was supplemented, by five main processes:

- inspection,
- maintenance,
- capital planning,
- capital financing, and
- information management.

Four to six key practices for each process describe an ideal asset management approach, referred to as the "maturity model".

HHI's approach to asset planning covers the five key processes identified in the KPMG Report and meets the requirements of the OEB. HHI's review begins with a review of system performance and whether that performance meets management objectives.

The conditions of assets are assessed based on field inspections, life expectancy, fault frequency, maintenance costs and customer service impacts. Assets are replaced when required to maintain distribution service and system reliability (non-discretionary expenditures) or when replacement is determined to be more economic from a ratepayer perspective than asset refurbishment and/or ongoing maintenance (discretionary sustainment capital).

HHI uses several sources of data to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. The sources of data feeding into the asset management process include:

- customer engagement activities,
- inspection and maintenance programs,
- system loading vs. capacity,
- reliability information,
- internal and external drivers,
- asset condition assessment, and
- outage information.

There are a number of internal and external drivers which have an impact on and contribute to the asset management process. Within most driver categories, there can be two distinct needs types: non-discretionary needs requiring HHI to address them, and discretionary needs for which HHI has to make a decision—whether or not the need must be addressed immediately, at some future time, or not at all. Drivers include:

- safety,
- customer considerations,
- regulatory initiatives,
- elimination of safety or environmental/health risks,
- system reliability,
- municipally-driven projects,
- infrastructure renewal projects,
- fleet/tools, and
- information technology and corporate administration.

In general, the overall approach used to select the candidate capital projects to be considered in any year has been consistent. The criteria considered encompasses:

- employee, contractor, and public safety,
- system reliability,
- service quality,
- rate impact,
- operational efficiency,
- cost effectiveness,
- environmental effects,
- project interdependencies
- regulatory compliance, and
- stakeholder concerns.

Although safety and compliance are prerequisites for all projects, the weighting of the other criteria can vary depending on the current system requirements and the relative impact of each project. While judgment is required when operating under the current or the proposed planning approach, the decision-making process has been improved through enhanced access to system and asset data.

Capital spending is driven by capital needs' identification. Projects are identified as potential candidates for the annual budget, and the total projected capital expenditures for the year are assessed with regard to:

- previous spending levels,
- rate impacts,
- customer service value,
- shareholder investment and,
- the requirement to proceed with non-discretionary projects.

The budgeting process involves both a bottom-up and top-down approach. Once assessed against the factors, the capital plan and the finance plan is submitted to the HHI Board of Directors for discussion and approval. The accompanying finance plan is assessed to ensure that the OEB deemed equity structure is maintained and there are no adverse impacts on the debt service coverage ratios. The approved capital budget sets the spending envelope for the current year.

HHI's overall capital budget spend envelope is set during the annual budget review but capital spending within the envelope may be adjusted throughout the year to meet changing capital requirements on an as-required basis through quarterly reviews.

These reviews identify any material dollar reallocations, both increases and decreases to individual approved capital project budgets while maintaining the overall approved capital budget spend envelope. For example, capital funds may be required for a non-discretionary spend due to storm damage from extreme weather conditions, or a road relocation project that had not been previously identified by municipal or county road authorities. Any capital project in which detailed engineering design identified a difference between the preliminary planning estimate and the detailed engineering design would be reviewed. Project interdependencies, resource availability, cost and risk assessments, and capital availability could cause reconsideration. Over the last four years, HHI's adapted Capital Investment Process (CIP) has been used to effectively manage its assets and capital expenditures. Similar to the process in the KPMG report, the current CIP meets HHI's regulatory, safety, operational and customer needs.

Non-Discretionary vs. Discretionary Capital Projects

Non-discretionary capital projects are automatically included in the capital budget based on their need and include:

- emergency replacement of failed equipment (system renewal),
- safety-related projects (system service),
- new/enhanced customer service connections (system access),
- plant relocation projects necessitate by road construction (system access),
- mandated service obligations—regulatory, legal, or road authority (system access), and
- renewable energy projects (system access).

All other projects not mandated are deemed discretionary. Evaluating the absolute or relative importance of these proposed investments in distribution assets can be an intricate task. There are often competing requirements for available resources in any year. The decision to recommend an individual project in the current year is made by senior management based upon consultation with stakeholders, established criteria and the best information available at the time.

HHI uses a combined needs and risk-based approach to considering discretionary capital projects. This evaluation generally takes into account a range of criteria including: health and safety concerns, load and customer growth projections, regulatory and environmental requirements, system reliability, life expectancy, operational efficiency, and optimal lifecycle costs.

The criteria below, applied to discretionary candidate capital projects, is used to convert subjective (qualitative) issues into objective (quantitative) understanding to aid in project to project comparisons.

Public safety considers whether there is any impact on public safety, or, is the project very likely to reduce risk of a public injury or damage over the next 10 years. Where the risk of public safety is known and the probability of occurrence and degree of harm are significant, remedial action is taken and the investment is treated as non-discretionary.

Worker safety considers whether there is any impact on worker safety, or is the project likely to reduce risk of a worker injury. The same approach is used as in the response to public safety concern described above.

Regulatory considers to what extent the project relates to the OEB requirements including RRFE objectives, and to what extent the license or business may be affected.

Environment impairment considers the impact on risk of environmental impairment, and whether or not the project would reduce the risk of an environmental incident once every 10 years. The degree of harm, probability of occurrence and financial impact of deferred remediation are assessed.

Environment footprint considers the project impact on HHI's environmental footprint, or whether it will reduce the company's Green House Gasses (losses, emissions, wastes, etc.). As a leader in conservation and energy efficiency, HHI must be true to its values in this area and as it sets a high standard for its customers to encourage CDM, energy efficiency and renewable generation.

Reliability considers to what extent the project impacts the power system reliability and customer service. If it will definitely eliminate a sustained feeder outage, the economic benefit can be quantified. If the reliability improvement is more global as with redundancy investments, then the benefit is qualitative.

Power quality considers the project impact on power quality. HHI must deliver a specific quality of power (voltage, regulation, etc.); investments required to maintain this level of service can range from non-discretionary where the power standard is not maintained to discretionary when the quality is acceptable.

Customer satisfaction considers the project impact on HHI's ability to maintain or improve Electricity Service Quality Requirements (ESQRs). At a certain level, investment in this area may be considered non-discretionary when a distributor is ordered to improve its service quality and an asset investment is required. Where the distributor is performing at an acceptable ESQR level, increased investment to enhance service would normally be considered as discretionary spending.

Customer perception considers whether the project has a perceived value to the public. A project may be perceived as having a negative impact on the public, the immediate area or an individual customer. In each case, while customer perception must be considered and appropriately managed as part of any project, perception will not be the only deciding factor.

Financial considers whether a project will have a positive impact or return on investment.

End of Life (EOL) considers whether the asset in question has more than 50% remaining expected life, or, if it is within two years of expected or predicted useful operability. The closer an asset is to its expected obsolescence and/or end of life, the higher the need to replace in order to avoid a service disruption or a safety issue. The replacement of critical assets that have exceeded their life expectancy could be considered as non-discretionary investments in certain situations if there is a safety or reliability concern.

Maintainability considers whether workers will be able to continue to maintain the system or the equipment, and whether actions will improve the ease, degree, and frequency of maintenance. Investments that facilitate maintenance, improve employee morale and/or lower maintenance costs are classified as discretionary sustainment.

Operability considers whether workers will be able to continue to operate the system or the equipment, and if it will improve the ease and flexibility of system operations. Investments that facilitate system operations, improve employee morale and/or lower operating costs are classified as discretionary sustainment.

Asset Management Components

Asset Register

HHI's database for all of its distribution assets is contained in Excel Spreadsheets. The asset source data in the spreadsheets feeds the Asset Condition Assessment process. Details of each asset is collected and updated accordingly. Asset data was initially input from a multitude of sources including, but not limited to: construction as built records, legacy records, annual inspection and maintenance program results, trouble calls, fault information, etc. As the asset is visited through planned inspections or maintenance, the asset data is verified, corrected or updated. The information in the spreadsheets, such as location, asset ratings or specifics of the asset, installation date, manufacturer or supplier, asset style, last inspection date, last maintenance date, etc., in whole will describe the asset. Search and filter functions will allow specific fields to identify specific assets based on search criteria.

Asset Condition Assessment

HHI maintains a full schedule of distribution asset inspection and maintenance programs operating on a three-year rotation as required by the OEB's DSC . In-field inspection, maintenance, testing, operational data, and action taken is collected and recorded by the company and is used to maintain and update the asset source data and support HHI's operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance, but results from the inspection and maintenance programs allow a continual update of the asset database. The programs mean that assets are visited regularly and their condition assessed so any necessary actions are taken as promptly as possible in a proactive approach based on what is found, in particular if any safety hazard or concern is identified. As with every other Ontario distributor, HHI's inspection and maintenance programs are audited on a yearly basis as required by Ontario Regulation 22/04. HHI has achieved compliance in this portion of the audit each year, since the regulation came into effect in 2004.

An asset condition assessment process (ACA) is used which involves the collection and interpretation of condition and performance data of key assets, evaluates the condition of the asset, detects and quantifies long-term degradation of the asset, serves as an aid in prioritizing and allocating sustainment resources in order to be able to make informed capital investment decisions. The ACA model receives inputs from a variety of sources in the asset management lifecycle. The result of the ACA is an optimized lifecycle plan based on asset sustainability.

HHI has demarcated three inspection zones for its service territory. Each zone contains about one-third of the assets of the whole service territory. Each zone is visually inspected one every three years.

In addition to the visual inspections, poles that are within five years of their depreciated end of life are inspected and tested. HHI has purchased a new pole testing device together with Cooperative Hydro Embrun and this device is used to provide a better assessment of the condition of the pole and the need for replacement. Poles that are adequate are scheduled for retesting in five years.

Asset Capacity Utilization/Constraint Assessment

The design of HHI's distribution system reflects industry practices and safety standards. HHI places a high level of importance on ensuring its distribution system reliability meets the expectations of its customers. HHI strives to continually improve its processes for collecting, measuring, analyzing and utilizing outage information in order to effectively manage distribution system reliability in its service territories.

When there has been a failure of an asset, root cause analysis is used to determine the cause of the failure and if failure trending exists, targeted plant replacements are made to try to mitigate any future failures.

Outages are monitored by a third party and mostly on a reactive basis. As HHI does not have a SCADA system or an OMS system, it relies upon an after-hours phone system linked to local first responders within the Town of Hawkesbury to provide outage notification. Due to the nature of the service area, HHI is quickly apprised of the condition of the distribution system.

Historical Period Data on Customer Interruptions

HHI has experienced the following defective equipment outages between 2013 and 2016:

Year	Customer–Hours Cause: Defective Equipment	Explanation
2013	3,467	July – 3322 customer-hours as a result of the failure of the new 43T2 MS transformer
2014	253	Various small outages
2015	46	Various small outages
2016	3,987	April - 3520 customer-hours due to a blown 115kV fuse at the MTS supplying 55T1

Figure 11: Defective Equipment outages 2013 to 2016

HHI is putting emphasis on its station configuration and backup capability so that it is able to supply its customers in the failure of one of its station transformers with a minimum of customer interruption time. Since 2013 HHI has two transformers in good condition at its 44kV supplied MS. However only one transformer is supplying power to customers and the other is on potential only and not connected to the 12.4kV system. In 2020 HHI plans to make alterations to this configuration to allow both transformers to supply load and to allow either transformer to supply the entire load without customer outages being required. Similarly the 115kV sourced MTS is being rebuilt and one new larger capacity transformer is being installed with one old transformer being retained for back-up. The two stations are out of phase because of the different source voltages, namely 115kV and 44kV, therefore each station needs to have its own backup capability. Any load transfers between the MS and the MTS needs to be “open before close” and will involve a power interruption to some customers.

(5.3.2) Overview of Assets Managed

(Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed.

(a description and explanation of the features of the distribution service area e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan)

(5.3.2a) Service Area

The service area that HHI operates in is entirely an urban area with no rural portions. The service territory is the Town of Hawkesbury with an area of area of 8.6 square kilometers.

HHI distributes electricity to nearly five thousand five hundred (5500) customers and employs seven individuals.

The Town of Hawkesbury's population has decreased by 2.9% to 10,551 from 2006 to 2011, and has experienced only very small infrastructure growth.

The climate in the HHI service area is a humid continental climate with four distinct seasons, warm summers, cold snowy winters and no dry season. The average annual temperature in Hawkesbury is 11C with a range between -18C and 27C. Extreme temperatures are possible and the extremes range from -44C to 38C. The average annual precipitation is 811mm, with rain in the summer months and snow in the winter months. Average monthly precipitation is 68mm.

(5.3.2b) Description of System Configuration

(a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations)

HHI is a utility that is embedded in Hydro One and receives its supply at 44kV from Longueuil TS via the 26M24 feeder. Longueuil TS is supplied from Hydro One's 230kV system. It receives its other supply at 115kV. The connection point of Hawkesbury MTS #1 is via circuit 79M1, which is an extension of circuit H9A from Hawthorne TS.

HHI owns and operates one MS supplied at 44kV and one MTS supplied at 115kV. Its distribution voltage is 12.4kV. A salient feature of the distribution system is that the 12.4kV from the MS and from the MTS is not in phase and thus cannot be paralleled. This presents challenges for system operation since outages need to be taken to transfer load between the two systems. HHI has taken the design view that to the extent possible each system should be self-contained with capacity and flexibility to operate without needing to transfer load between the MS and the MTS. This design requirement has impacted their capital program and is reflected in their forecast period and potentially beyond 2022.

HHI has two transformers at its MS each rated at 44kV to 12.4kV with a capacity of 10/13.3/16.7 MVA ONAN/AF/AF. At present one transformer 43T2, supplies a bus structure with two overhead egress feeders each protected with 520A oil insulated reclosers and with bypass fuses. The other transformer 43T1 is currently on potential but not connected to the system. If the 43T1 were connected to the bus structure the two transformers would be in parallel. As it is now the 43T1 is on standby in the event of 43T2 problems. HHI plans to make improvements to this arrangement in 2020.

HHI has two transformers at its MTS where by the end of 2017 55T3 will be rated 115kV to 12.4kV with a capacity of 15/20/25 MVA ONAN/AF/AF and 55T2 will be rated 115kV to 12.4kV with a capacity of 7.5/10/12.5 MVA ONAN/AF/AF. There are three overhead feeders emanating from the MTS, each transformer feeds a transformer bus and has a transformer isolating switch. There is also a switch to allow the two transformer busses to be interconnected. The T3 transformer bus supplies 55F1 and 55F2 while the T2 transformer bus supplies 55F3. There is also a spare position for a future 55F4. Each feeder is protected by 520A oil insulated reclosers and with bypass fuses.

HHI conducts monthly inspections of each of its substations while maintaining a substation maintenance program. This program includes annual transformer oil testing at both sites and a routine rotating maintenance shutdown every five years at each substation. Shutdown activities include load interrupter switch maintenance, general cleaning and inspections, and electrical diagnostic testing such as transformer insulation resistance and turns ratio testing. Routine reclosure protection setting verification and oil maintenance is also completed. The utility employs a qualified contractor to perform this work.

HHI's distribution system is made up of approximately 43 km of 3 phase circuits and 25 km of single phase circuits, and 686 overhead distribution transformers, 85 single phase pad-mount transformers and 60 three phase pad mount transformers. There are no significant drivers for expansion and growth in the area.

(5.3.2c) Description of System Profile and Condition

(Information in tables and/or figures by asset type where available on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled)

HHI conducts regular line patrols. As part of these periodic visual inspections, the patrols look at visible overhead plant including poles, conductor, switches and cutouts as examples. Any anomalies are noted and flagged for more in-depth inspection and investigation. All overhead plant is inspected at periodic intervals based on the DSC. Typical useful lives can be summarized in the table below:

Description	Useful Life (yrs.)	Quantity in System	Strategy
Poles	50	1400	Risk-based replacement
Conductor	50	80	Condition-based replacement
Transformers	40	831	Run to failure
Reclosers	40	7	Condition-based replacement

Figure 12: Overhead Asset Strategy

Poles

HHI currently has approximately 1400 poles across its service area. Poles regularly undergo visual inspection during periodic line patrol inspections. This condition assessment is correlated with risk parameters based on the location and use of the pole to determine which poles require replacement in a year. Also when the pole is within five years of its financial depreciation it is tested to determine its condition. HHI has purchased a pole testing device to have more scientific factual data on which to base its replacement decision. If a pole test indicates it is in good condition it is retested in another five years.

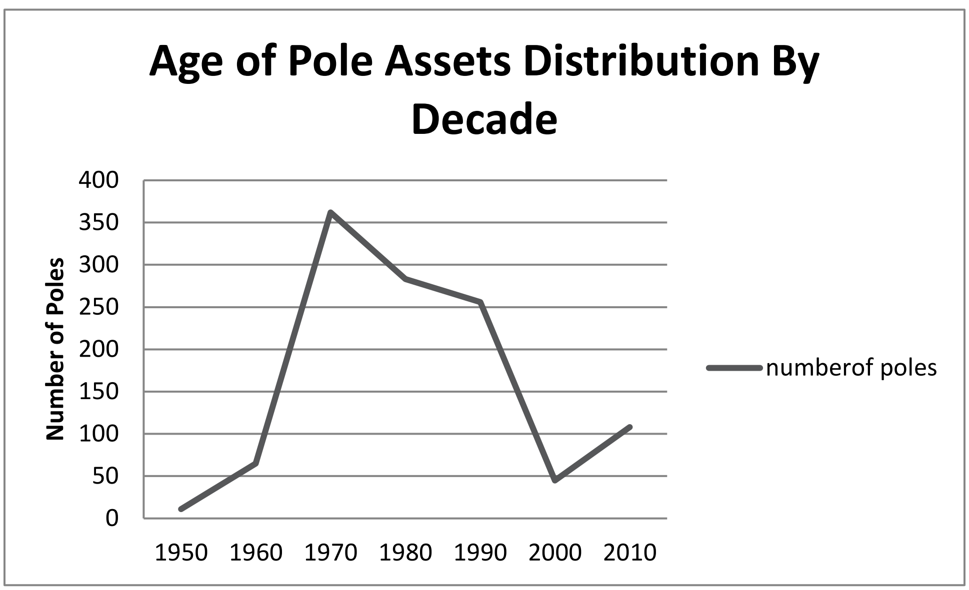


Figure 13: Pole Age Distribution

Conductor

HHI predominately had 3/0 ACSR conductor installed throughout its system. A 2007 Utility Load Flow and Evaluation Study carried out by Stantec Consulting Ltd. indicated that all main feeder conductor should be upgraded to 336 MCM ACSR in order to improve system voltage drop, improve load transfer capability and reduce system losses. HHI has been addressing this conductor upgrade at a modest but steady pace.

Transformers, Switches and Protection

HHI currently has approximately 831 distribution transformers in service. This is in addition to four power transformers that form the core of the distribution station network in the system. Power transformers are inspected regularly according to the DSC, and pole and pad-mount transformers are inspected by line patrol and during condition assessments.

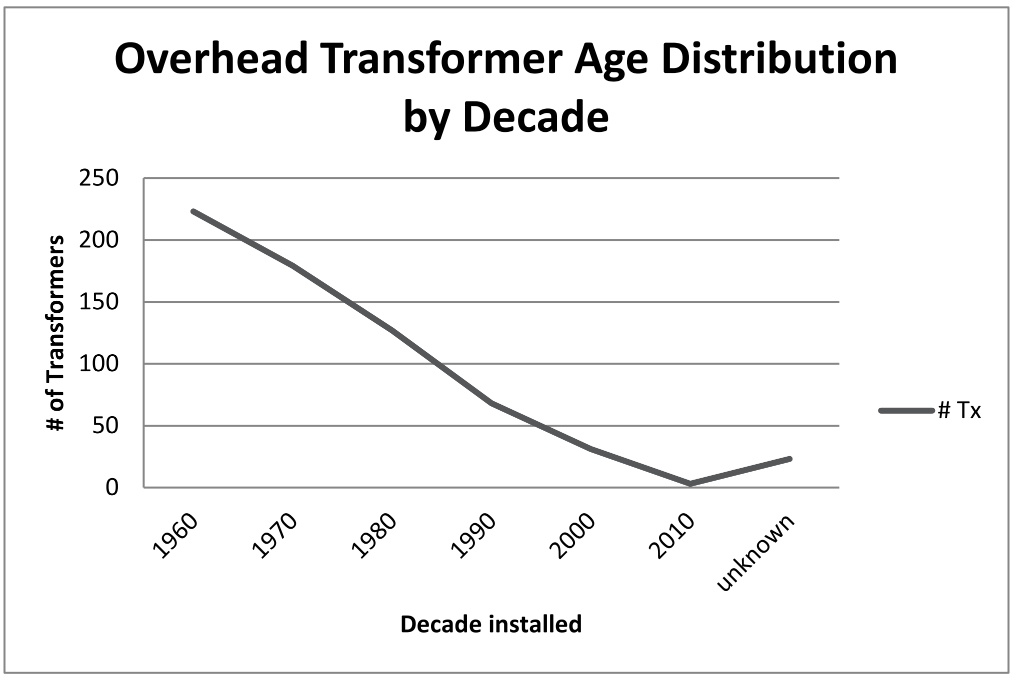


Figure 14: Overhead Transformer Age Distribution

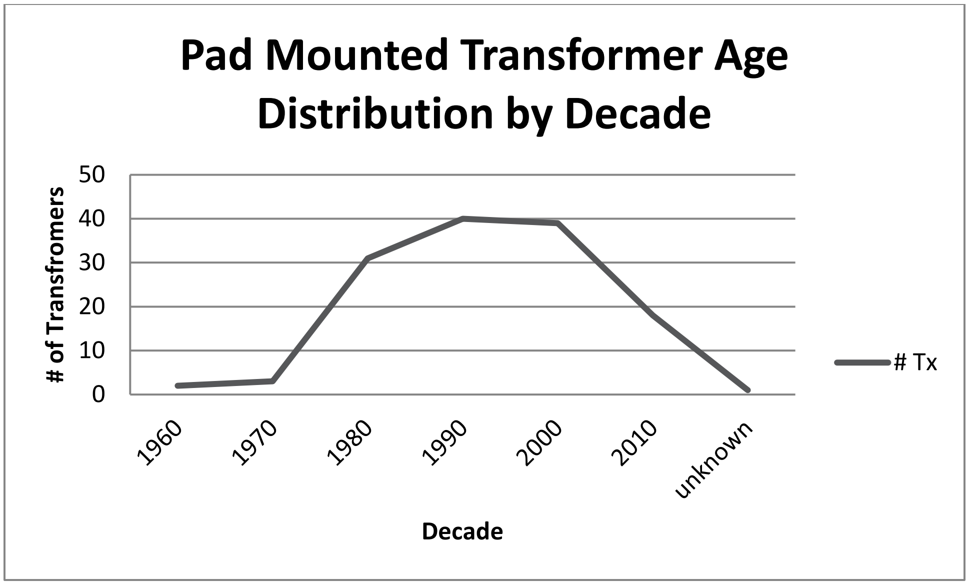


Figure 15: Pad-Mounted Transformer Age Distribution

Underground Asset Details

While primarily overhead, HHI has and operates underground plant, primarily in newer residential areas. This underground plant typically involves XLPE cable installed in direct-buried (DB) or concrete-encased (CE) ducts. Voltage is transformed and maintained through the use of pad-mount transformers.

(5.3.2d) System Asset Utilization

(An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets)

HHI's system losses are monitored on an annual basis. System design and operations is managed such that system losses are maintained within OEB thresholds as defined in the OEB Practices Relating to Management of System Losses. HHI ensures that the OEB threshold of 5% is not exceeded. The replacement of main feeder 3/0 ACSR with 336MCM ACSR conductor also reduces the losses.

(5.3.3) Asset Lifecycle Optimization Policies and Practices

(An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending

(5.3.3a) Asset Lifecycle Optimization Policies and Practices

(A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

- *a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;*
- *a description of maintenance planning criteria and assumptions; and*
- *a description of routine and preventative inspection and maintenance policies, practices and programs (can include references to the DSC).*

HHI has practices that reflect practical and prudent business approaches to implementing its Vision and Core Values. The following description of the practices demonstrates that HHI follows documented steps in the management of its assets, all of which aid in the reliable delivery of power to its customers.

HHI owns all the distribution assets within its service area. HHI is responsible for the management of all its distribution assets.

The asset register for field assets consists of a spreadsheet for each asset type. This allows the capture of data that is adequate for HHI to manage its assets. Asset data was gathered and input from a multitude of sources including construction as built records and legacy records. The system stores the annual inspection and maintenance program results including inspection dates, transformer maintenance records, third-party attachments for poles, etc. As the asset is visited through planned inspections or maintenance, the asset data is verified or corrected. The information in the spreadsheet, such as location, asset ratings or specifics of the asset, and installation date describes the asset.

The asset register is intended to hold asset attribute information as well as historical financial information over each asset's lifecycle. Currently, the spreadsheet holds locational data, attribute data and historical non-financial information (i.e. inspection history, tests, etc.). It is the intent of HHI, over time, to continue to populate the spreadsheets with additional non-financial and historic financial data as appropriate and useful.

HHI maintains the efficiency and reliability of its distribution system through an active inspection, maintenance and asset management program that focuses on customer service, employee safety and cost-effective maintenance, refurbishment and replacement of assets that can no longer meet acceptable utility standards.

Maintenance Planning

In the course of fulfilling its asset management responsibilities, HHI engages in the following type of maintenance programs:

- Predictive maintenance
  - Inspections address risk management by actively assessing condition of plant visually. Inspections are required to meet regulatory requirements, and are performed on a rotation—one-third of the system each year.
  - Testing addresses risk management by actively assessing condition of plant. It is more detailed and more focused than inspection and typically involves the measurement of some aspect of the asset. This is done on an interval basis determined by the rate of deterioration of the asset.
- Preventative maintenance
  - Maintenance activities to extend the trouble-free operation of assets, making the assets economical and reliable, are performed on a cyclical basis and usually coincide with the inspection cycle.
- Condition-based or reactive maintenance
  - Corrective action and follow-up activities are necessary when a plant malfunctions or is out of specification. Occasionally, replacement is the most cost-effective way to remedy the situation.

HHI completes inspections as prescribed in the DSC, and in a manner and frequency that addresses public safety and cost efficiency. Predefined geographical areas are designated for inspection based on a three-year cycle. The individual areas to be inspected are marked on a map and are printed for the inspection crews.

After the inspections are completed, the maps and deficiency reports are returned, processed and converted into a form to document follow-up and ensure completion within a reasonable time period.

The information is retained and available for review or verification if needed.

Predictive Maintenance of Overhead Distribution Assets

Inspections

Asset condition is determined using visual inspection. This is driven by the requirements of the DSC and 'Appendix C' in particular. The entire service area is inspected on a three-year cycle. The overhead and underground assets inspection areas are identified on maps—one set of maps for a particular inspection year. The overhead area uses a street map since the plant is visible when inspecting. The underground maps show the type of plant and the location of the plant to aid in the inspection. The process identifies what to inspect, how to record deficiencies, document what needs to be corrected, and when the inspection is completed.

There are separate databases containing the information of transformers and switches with pertinent device information such as nameplate data and device characteristics, and location.

There are two distribution stations in the service area and these stations are visually inspected on a regular basis by HHI. Detailed technical inspection and maintenance activities for the substations are carried out on contract.

In general, the condition of assets is determined to ensure that:

- they are safe for the public and for competent knowledgeable staff to work on using approved procedures,
- they are working within specifications,
- they are within the device current and voltage capabilities,
- there is no deterioration to impair the 'normal' function of the asset, and
- they are as secure as they were when initially installed properly.

Assets must meet the requirements of the DSC, Ontario Regulation 22/04 and the relevant environmental standards such as the regulations addressing the use, storage and handling of PCBs.

The Minimum Inspection Requirements (Appendix 'C' of the OEB's DSC), details the inspection standards and cycles required within the Code. Appendix 'C' Table C-1 defines Patrol inspection and identifies the maximum intervals for the inspection cycle patrols, which for most urban facilities including HHI is three years.

HHI's supply area is served by a mostly urban distribution system supplying the Town of Hawkesbury. Its supply area consists of a single contiguous geographical zone which HHI divides into three vegetation management/inspection zones. Systematic and routine visual patrols are conducted to comply with the OEB inspection requirements (at a minimum). HHI inspects the overhead distribution system in each inspection zone, completing approximately one-third of the distribution system each year, as per the DSC's 'Minimum Inspection Requirements'. The visual inspections of the major distribution facilities meet the level of detail for the patrol inspection definition in the DSC.

The visual patrol inspects and assesses the condition of overhead assets, including wood poles and their supports and attachments, pole-mount distribution transformers, switches and surrounding vegetation. A lengthier description is provided later. Historically, the line patrol would only produce a Line Inspection Deficiency Report highlighting deficiencies. Today, HHI uses a line inspection record to document the completion/date of inspection, the name of the inspector, when a defect is identified during the inspection, the equipment, location and condition details are listed. Line inspection records are submitted to supervisors for review. Follow-up maintenance is prioritized and scheduled, and a line advice notice is issued to a crew to correct defects. Data from inspection activities are compiled and used for reporting.

In addition to fulfilling the requirements of the DSC, the inspections allow for deficiencies and the general condition of system components and related peripheral equipment and hardware, including vegetation growth, to be realized and documented with sufficient lead time and for subsequent analysis in support of maintenance and capital planning activities.

Poles

Scheduled visual inspections of HHI poles are conducted on a three-year cycle satisfying the inspection requirements of the DSC. The condition-based assessment allows HHI to monitor and identify defects such as the integrity of the pole, concerning the condition of the pole, supports and attachments including conductor, cross arms, guys and guy guards, cable dips, etc. Defects and concerns are identified on the Line Inspection Record and detailed further through commentary on the Trouble Report.

Conductors

During the annual visual inspections, the conductors are inspected for obvious signs of deterioration. Concerns are noted on the inspection sheets and followed up.

Overhead Distribution Transformers, Switches, Protective Devices and Vegetation Growth

Inspections of pole-mounted transformers, switches and vegetation growth are also completed as part of the cyclical visual patrol of the overhead distribution system. Deficiencies related to the transformers, switches and excess vegetation are noted on the Line Inspection Record and addressed through reactive maintenance programs.

The condition of overhead system assets is also inspected during preventative maintenance activities, mainly as a result of vegetation management.

Overhead transformers are inspected visually and problems are corrected. The strategy for this asset class is to replace based on asset condition. Feeder rebuilds and service connections trigger a review of transformer loading and sizing, and units are upgraded and/or replaced.

Overhead switches are inspected as per DSC requirements and are maintained as per the manufacturer's recommendations.

Overhead fused switches or cutouts are inspected as per DSC requirements and are also inspected when they are operated manually or after they operate automatically. Damaged cutouts are replaced.

Preventative Maintenance of Overhead Assets

Vegetation Management

Vegetation management, or tree trimming, is a preventative maintenance program scheduled on a three-year cycle, in which one of each of the three vegetation management zones of the distribution system is completed each year by contractors. Patrol inspections occur on a weekly basis and any areas requiring attention are documented and scheduled.

HHI staff monitors vegetation growth which can vary because of weather conditions and by plant species. In an exceptional growing season due to frequent rain, certain areas may be vulnerable to tree contacts two to three years from now, requiring earlier action. Since some species of plants/trees grow faster than others, HHI uses a shorter trimming cycle particularly because trimming would be too severe if left for the regular cycle. Vegetation management including tree-trimming can also be scheduled as part of preparation for a capital project.

Staff also responds to requests from the citizens to trim or remove trees in proximity to power lines.

Condition-based Maintenance of Overhead Assets

Following pole inspections and line inspections

Trouble reports are completed for poles requiring attention and identified during the inspection program. The Trouble Reports are prioritized based on safety and risk for follow-up repair; repairs are tracked, documented and signed off when complete as per the ESA requirements.

Following vegetation management

Vegetation management, while separate from any inspections, does place HHI staff or contractors at a specific site on the distribution system. It is prudent to observe and report any defects discovered regardless of the reason. All items of concern that are observed when performing vegetation management are recorded on Trouble Reports. The Trouble Reports are prioritized based on safety and risk for follow-up repair; repairs are tracked, documented and signed off when complete as per the ESA requirements.

Predictive Maintenance of Underground Assets

Underground Inspections

Similar to the general overhead process of inspection and condition assessment, the underground distribution system is also inspected on a three-year cyclical basis to assess the condition of underground assets including pad-mount transformers, submersible transformers, underground switches, transformer vaults and civil structures. The buried assets cannot be totally inspected visually like the overhead assets, but care is taken to inspect all assets that can be seen to assess their condition. The Line Inspection Record documents the inspection completion, date of inspection and the inspector. The equipment, location and condition details of defects identified are documented in the Trouble Report. The Line Inspection Record and the Trouble Report are reviewed by supervisors. Maintenance is prioritized and scheduled, and the Trouble Report is issued to a crew to correct the defect(s). Data from inspection activities are compiled and used for reporting.

Underground Distribution Transformers

Inspections of pad-mount transformers occur within the visual patrol of the underground distribution system and are therefore inspected on a three-year cycle. Approximately one-third of the transformers within HHI's distribution system are inspected on an annual basis. Enclosures are opened to allow a visual check of the condition of the plant. The Line Inspection Record is used to document deficiencies such as broken bushings, oil leaks or paint chips, and condition of the concrete base—bases with cracks or deteriorated are identified for replacement.

Underground System Switchgear

Inspections of pad-mounted switches occur as part of the visual patrol of the underground distribution system and on a three-year cycle. Approximately one-third of the switches within HHI's distribution system are inspected on an annual basis. Inspection includes opening the enclosures so a visual check can be made of the condition of the plant. Deficiencies such as broken bushings, oil leaks or paint chips, among others, are noted on the Line Inspection Record.

Underground Cable

Underground primary cable has not failed in HHI's system. Cable terminations are inspected visually in switching units and in transformers. Unless specific issues are identified, they are run to failure.

Underground secondary cable terminations are visually inspected at the transformer when the transformer inspection is carried out. Unless specific issues are identified, they are run to failure.

Condition-based Maintenance of Underground Assets

HHI uses the inspection form for items that are discovered in visual inspections. The inspection form identified defect is classified as needing attention immediately or in a less time critical manner. Trouble reports are completed and recorded in the database. The work is dispatched to the appropriate crew(s) and the work is completed. Once the work is completed appropriate sign-offs are made to ensure the distribution system is safe for the public and staff and that the system is restored to proper working order. The original inspection forms are filed by year and are available for review if needed. The signed off trouble reports are logged in the electronic database and the paper copy signed off is retained by year and report number.

Inspection and Condition Assessment of Distribution Stations

HHI owns two municipal distribution stations in the Town of Hawkesbury. Regular monthly inspections are carried out on the distribution station yard and equipment and these are recorded on forms. In addition, regular planned maintenance consisting of oil testing is carried out by a specialized contractor on a one-year cycle. Any defects or deficiencies discovered are corrected as part of planned maintenance activities. If a major deficiency is discovered as a result of the monthly inspection process, this is addressed based on the risk.

Preventative and Condition-based Maintenance for Distribution Stations

HHI contracts with a specialized contractor to have the stations maintained on a five-year cycle and includes a thorough condition review and correction of all deficiencies.

Any deficiencies reported as a result of the monthly inspections are addressed when the report is submitted. Minor repairs such as light bulb replacements are completed as part of the inspection. Other aspects relating to the security and the appearance of the station, such as the perimeter fence, building access integrity, vegetation within the fenced enclosure and any other work, is scheduled based on urgency and crew availability. The same urgency classification scheme is used as with overhead or underground asset deficiencies.

(5.3.3b) Lifecycle Risk Management Policies and Practices

(A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures).

Risk is managed by being aware of the failures that can occur on the power system and by being aware of their consequences. The replacement and mitigation of such hazards begins in more populated areas and finishes in areas where there are least likely to be people. Similarly, pole replacement is scheduled to take place at a steady pace beginning with the poles in the worst condition. Capital expenditure selection generally is based on the following in priority order:

- Safety impact on the public and staff,
- Regulatory requirement or obligation,
- Reliability impact,
- outage causes and frequency,
- restoration capability, and
- power quality.

The timing and pace of the work is determined by the following:

- Capability to complete the work,
- Financial ability to pay for the work, and
- Completing the expenditures that provide the greatest benefit.

Operations

If a major deficiency is discovered as a result of the monthly inspection process, the deficiency is addressed based on safety and risk.

The Line Inspection Record documents inspection completion, date of inspection and the person completing the inspection. The record can also indicate the equipment, location and condition details if a defect is identified. This information is also documented on HHI's Trouble Report; the latter notes the location of the defect and allows for the inspector to comment on the condition of the underground asset(s). The Line Inspection Record and the Trouble Report are submitted to supervisors for review. Follow-up reactive maintenance is prioritized based on safety and risk and scheduled, and a Trouble Report issued to a crew to correct the defect(s). Data from inspection activities are compiled and used for reporting. Repairs are tracked and when completed, signed off as per the ESA requirements.

The signed-off trouble reports are logged into the electronic database and the paper copy signed off is retained by year and report number.

Items of concern are reviewed and discussed by HHI staff or more formally through regular departmental meetings in which maintenance activities are addressed. These and other meetings also serve as the general forum for addressing distribution network items that may impact system performance and result in additional maintenance or capital investments.

HHI regularly reviews the industry standard reliability performance indices namely SAIFI, SAIDI and CAIDI. Outages are reviewed and actions are taken to address the causes of outages that have a common root.

Risk Management and Capital Projects

The inclusion of performance data in the preparation of the capital budget is the result of direct involvement and information about system performance. It takes place as a matter of course because of the knowledge and experience of the senior leadership team. Feedback from customers is also used when considering projects for the capital budget.

Similarly for maintenance and inspection processes, detailed instructions are revised based on experience and history.

(5.4) Capital Expenditure Plan

(A distributor's DS Plan details the program of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.)

As noted above, a DS Plan must include information on prospective investments over a minimum five-year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five-year period prior to the initial year of the forecast period.

(5.4.1) Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) *information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';*

b) *total annual capital expenditures over the forecast period, by investment category (see section 5.4);*

c) *a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;*

d) *a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;*

e) *information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;*

f) *a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;*

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- *in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);*
- *to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and*
- *to study or demonstrate innovative processes, services, business models, or technologies.*

(5.4.1a) Capability to Connect New Load or Generation

As HHI is embedded in Hydro One, the upstream capacity will depend on the allocation that Hydro One provides on the given supply feeders.

HHI is supplied in part by Longueuil TS a 230kV to 44kV station which is owned and operated by Hydro One. The station capacity information which can be found at http://www.hydroone.com/Generators/Documents/HONI_LSC.PDF indicates that the station is not constrained and as such additional Renewable Energy Generation (REG) can be accepted at this time. The remaining supply is from HHI's MTS connected to the 115 kV transmission system. This station is also not constrained.

There are no outstanding active applications for any REG projects at this time. Hence HHI has no requirement for REG enabling projects at this time and no system access projects for REG are included in the budget forecast.

(5.4.1b) Forecasted Capital Expenditures

HHI's customer base is mature and stable. There is only one very small new development anticipated in the service territory and there are not any significant changes anticipated to the customer base whether residential, commercial or industrial. Consequently there is no real growth driver for capital plant. The system peak load is approximately 32,500 kW and the system has served this load. However, because the system has two stations that are out of phase, after the 2017 capital work is completed HHI is planning to change the bus and transformer connection capability at its 44kV supplied MS to provide for the utilization of both transformers in the station and the ability to transfer load without the requirement of a planned outage to all the customers connected to the MS.

The current capital expenditures over the forecast period are shown below.

	Forecast (planned)				
	2018	2019	2020	2021	2022
OEB CATEGORY	$	$	$	$	$
System Access	$36,800	$86,895	$31,010	$31,510	$31,610
System Renewal	$117,780	$131,825	$488,350	$149,205	$139,500
System Service	$10,000	$10,000	$10,000	$10,500	$10,500
General Plant	$11,250	$8,800	$11,900	$11,900	$9,000
Total	$175,830	$237,520	$541,260	$203,115	$190,610

Figure 16: Forecasted Capital Expenditures by Investment Category

The following projects are the most financially significant:

- Pole replacement program
- 3/0 conductor replacement
- 44kV station improvements
- Porcelain Insulator replacements
- Porcelain Lightning Arrestor Replacement

These are all system renewal projects. The forecast cost for these projects is shown below.

Forecast period	2018	2019	2020	2021	2022	Total
Replace Poles	$81,500	$87,700	$88,100	$88,100	$90,000	$435,400
3/0 wire upgrade	$10,000	$15,000	$15,000	$15,855	$18,000	$73,855
44kV Station	$0	$0	$340,000	$0	$0	$340,000
Porcelain Insulator replacement	$17,930	$13,125	$27,750	$27,750	$14,000	$100,555
L/A replacement	$8,350	$16,000	$17,500	$17,500	$17,500	$76,850

As can be seen from the table the pole replacement project and the 44kV station project exceed the materiality threshold.

(5.4.1c) Effect of Planning on Capital Expenditures

HHI has a developed a prudent capital budgeting process combined with a system of capital project prioritization that takes into account customer preferences, business performance and accountability. This system reflects its long-term strategy and addresses the need for HHI to remain flexible enough to respond to priority shifts as they occur. The capital budget process takes into account the relative priorities of the proposed investments including both non-discretionary and discretionary budget items.

Non-Discretionary items include:

- Load growth and the utility obligation to connect new customers,
- Projects to accommodate the Town of Hawkesbury, Prescott- Russell County or other regional and Ministerial requirements, and
- Projects or expenditures to satisfy regulatory initiatives, environmental or health and safety risks and the company's conditions of service.

Discretionary items include:

- EOL plant renewal projects, and
- Tools.

System Access

The planned annual capital investments during the forecast period for connecting new customers and providing system access are in the $30,000 to $40,000 range. This is consistent through the forecast period. The exception is 2019 when HHI is making provision for Smart Meter replacement.

There are no projects initiated by other authorities, nor by system expansion requirements nor by renewable energy generation. There are only small customer service type activities.

System Renewal

The main drivers of system renewal projects are the aging infrastructure within the service area and the alterations at the 44kV MS.

All the material projects are in this category:

- pole replacement program,
- main feeder conductor upgrade,
- 44kV station alterations,
- Porcelain Insulator replacement, and
- Lightning Arrestor replacement.

This program resulted from the visual inspection of distribution plant as part of the asset management program, the analysis of the age distribution of poles, equipment failures and experienced system limitations.

System Service

There is one planned investment in this category, the creation of a loop feed on present underground radial feeds. Planned expenditure is about $10,000 per year.

General Plant

The total annual investment in this category is between about $9,000 and $12,000. There are no material projects in this category.

(5.4.1d) Material Capital Investment Projects

Materiality Threshold

Based on Section 2.4.5 of the Chapter 2 filing requirements, the materiality threshold is set based on the revenue requirement of the utility. For utilities with a revenue requirement of less than $10 Million, the materiality threshold is set at $50,000. Consequently, HHI will be reporting on all projects, variations or variances that are above this limit. The tables in section 5.4.1b above provide a list of material capital projects and their costs planned for the forecast period.

A list of all planned investments for the forecast period can be found in Appendix B with a brief description of each project.

(5.4.1e) Material Impacts of IRRP

HHI serves the Town of Hawkesbury located in northeastern Ontario on the Ottawa River.

HHI's distribution system is fully embedded in the Hydro One Networks Inc. ("Hydro One") distribution system through Hawkesbury MTS and Longueuil TS. The IESO notes that both stations are part of the regional planning process for Greater Ottawa Region, and that HHI was part of the working group for the Outer Ottawa Sub-Region.

Regional planning for the Outer Ottawa sub-region commenced with the development of the Needs Assessment that Hydro One completed on July 28, 2014. The Needs Assessment identifies the 115 kV circuit, 79M1 supplying Hawkesbury MTS, as approaching its voltage limit, and a load restoration need involving the 230 kV circuit D5A supplying Longueuil TS. For the voltage issue it is recommended that Hydro One and area LDCs, including HHI, continuously monitor and assess the voltage situation and install reactive compensation if required. On September 22, 2015, Hydro One also completed the Local Planning Report on load restoration for the Outer Ottawa sub-region. Hydro Hawkesbury Inc. was part of the study team for the Local Planning Report. The report concludes that the IESO Ontario Resource and Transmission Assessment Criteria for load restoration on the D5A circuit will be met with existing procedures, and therefore, no capital investment is required to address this need. The report indicates that no further regional coordination necessary as the need identified for Outer Ottawa sub-region can be addressed directly by the transmitter and area LDCs.

(5.4.1f) Customer Engagement Activities

HHI engages its customers in various forms and assesses the effectiveness of these activities. Historically, customer interaction has identified the preference of low-cost hydro rates as an important feature to customers. Survey results indicate satisfaction with current service and reliability performance levels. That is an indication that plan efforts to maintain historical levels are reasonable. Concern about rates supports the need to consider rate mitigation efforts while managing risk. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

HHI regularly engages with its customers on its website and distributes information on its plans directly and as well information is distributed through Town Council reporting.

HHI has been trying to conduct a customer survey in 2016 and is currently soliciting customer input but it has not been successful in achieving a sufficient volume of feedback to produce results that can be considered valid representations of the customers' opinion.

(5.4.1g) System Development

In developing its five-year forecast, HHI must balance the requirements of non-discretionary obligations with discretionary projects that have been evaluated and prioritized. The current level of investment on system renewal has maintained the reliability of the distribution system.

(5.4.1h) Capital Costs – Customer Driven Projects

HHI, in direct response to customer requests has implemented a number of features on its website. Customers had requested access to their usage and billing data and in response, HHI provided customers, once registered, to log into the system and view their usage and billing data. HHI further combined this access with bill explanations to ensure that customers had an understanding of the different parts of their electricity bill.

In addition to providing online access to information, HHI has also made information and resources related to conservation programs accessible by customers through their website. This includes links to the IESO, OEB and CDM reports for those customers who wish a deeper understanding of the programs implemented by HHI.

(5.4.1i) Capital Costs – Technology-based Opportunities

There are no capital projects that are technology based.

(5.4.2) Capital Expenditure Planning Process Overview

(The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).)

With its corporate emphasis on business performance and accountability, HHI has developed a prudent capital budget process and system of prioritization. This system reflects its long-term investment strategy, recognizes shorter term requirements, and is capable of addressing the ongoing need for HHI to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, HHI's corporate strategies and regulatory requirements.

(5.4.2a) Capital Objectives – Criteria and Assumptions

The following high-level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget:

- Regulatory initiatives e.g., Smart meters and the Green Energy and Green Economy Act,
- Elimination of safety or environmental/health risks,
- System reliability,

- Municipally-driven projects,
- Infrastructure renewal projects,
- Tools, and
- Information technology and corporate administration.

These drivers align with corporate goals which are aligned with the RRFE outcomes.

New Load Growth and Development Projects

HHI connects between 0 – 25 new customers per year. HHI anticipates that this rate will continue through the forecast period and has budgeted for this in its capital plan under System Access projects. HHI does not consider load growth to be a significant driver of capital projects and spending.

Municipally-driven Projects

HHI works closely with the Town of Hawkesbury Department of Development, Works and Planning to ensure that municipally-driven and HHI-driven projects are coordinated and executed safely and efficiently.

System Reliability

With pockets of aging infrastructure and areas of mixed use adjacent to residential areas, HHI looks to design resilience into its distribution system which, in turn results in reliability for the customer. Through infrastructure renewal and system service projects, HHI expects to see a steady evolution of its measures of system reliability. In areas that experience sustained or frequent outages, HHI targets these sections for improvement and has allocated funding for projects within the overall budget envelope for forecast years.

MS Enhancement

HHI is planning to upgrade the bus and transformer connection capability at its MS in 2020. The existing bus structure dates back to the 1960's and was designed with only one transformer in place. Currently there are two transformers with one connected and the other on potential only for back-up. To connect the second transformer an outage to about 1200 customers is required to install the connections between the transformer on potential and the bus structure. This investment will result in better overall substation utilization and eliminate the need for planned outages to all the customers supplied by the MS to transfer load to the standby transformer.

Pole Replacement Program

HHI has had a pole replacement program in place for a number of years. Following a condition assessment and inspection performed at the beginning of 2017, HHI has prioritized and effectively focused its efforts on the poles in worst condition. HHI has formally instituted a replacement program allocating a significant portion of its system renewal budget to the replacement of poles in poor condition before they cause an outage. HHI has planned for the replacement of about 15 to 20 poles/year each year for the entire forecast period.

Elimination of Environmental/Health or Safety Risks

HHI adheres to its strict safety code thereby preventing incidents and near misses. These actions cannot always remove the risks inherent on the system or due to the nature of the work. Any system state requiring the mitigation of a safety risk would be immediately moved to the forefront of implementation, and the projects within the capital spending envelope would be adjusted to account for this expenditure.

Information Technology and Services

HHI does not have a GIS system and there are no plans for implementing SCADA, and no plans for distribution automation.

Renewable Generation

HHI continues to perform connection impact assessments for FIT applicants in addition to connecting customers with approved FIT contracts when applications are made and approved. These projects are captured under the system access portion of the capital program. HHI does not anticipate any new FIT or Micro FIT connections over the forecast period.

Impact on Customer Bills

HHI has a modest capital plan that has a relatively small impact on customers' power bills. HHI is sensitive to impacts and attempts to only do what is necessary and to smooth the capital expenditures.

(5.4.2b) Non-Distribution System Alternatives

HHI does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief. HHI's activities in this area are delivered through the HHI 2015-2020 CDM programs in accordance with the CDM requirement included in HHI's license as issued by the OEB. HHI's total 2015 – 2020 CDM target is 7,920 MWh. In year one of this period 1,162.44 MWh has been achieved.

HHI's 2015-2020 CDM programs are consistent with OEB policy and the OEB's 2015 CDM Guidelines of putting conservation first into distribution planning. HHI's CDM programs are designed to reduce electricity consumption and draw from the grid upstream of the customer. HHI's CDM program consists of IESO-funded programs.

(5.4.2c) Prioritization and Pacing of Investments

Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet customer or developer requirements. A system of project prioritization is applied that takes into account growth rates, safety, reliability and performance, condition and age, and other drivers internal or external to HHI. Other projects are selected and prioritized based on value and risk assessments for each project. System renewal projects are prioritized based on the selection criteria identified through the asset management system. System service and general plant projects are prioritized based on safety, reliability, customer preferences and internal optimization. In determining reliability priorities, HHI considers the following characteristics of its distribution system:

- Overhead lines take hours to repair while underground cables may take days, and
- The current arrangement at the 44kV MS requires the interruption of power to about 1200 customers or about 1/5 of its total number of customers to transfer load to the transformer on potential.

Project pace for System Access projects is generally determined by external schedules and needs. Although System Renewal, System Service and General Plant projects tend to be lumpy in nature and most are paced to begin and be completed within a particular budget year, HHI takes efforts to smoothen the effect on the budget within a given fiscal year. These three investment types are paced with regard to available resources and managing the program cost impacts on the customer’s bill.

(5.4.2d) Customer Engagement

HHI regularly seeks customer feedback to help shape the direction and development of community investment and outreach as well as preferred methods of communication. It is important to connect with customers to ensure that their expectations are being met and to receive suggestions on how HHI can improve their overall customer experience.

HHI completed a customer survey in 2014 and again in 22016/2017.

HHI is one of the few electric utilities to still operate a full-service customer counter with daily customer interaction. Customers who want to start a new account or move, pay bills, or have concerns or comments can come to the office and our Customer Service Reps will handle their problem or bring the problem to the attention of management for resolution. This face to face communication is much more informative than a survey and customers really appreciate the opportunity to deal with someone locally and know that their concerns are treated with urgency and respect.

HHI is also created a new user-friendly website for customer service interaction that is easier to read, use, and it contains all the relevant information a consumer would require. HHI also recently completed an Electrical Safety Awareness survey which confirmed HHI’s customers are well educated on the hazards associated with the electrical system.

HHI participated in the Electrical Safety Authority Public Awareness Survey in 2016. HHI achieved a Public Safety Awareness Score of 78%. This score is in line with other Ontario LDCs that participated in the survey and reflects the general electrical awareness among ratepayers in the service area

"Putting the Consumer First" was part of the title of the Report of the Ontario Distribution Sector Review Panel. Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

This feedback was subsequently reflected in the current capital expenditure plan.

(5.4.2e) Prioritization of REG Investments

HHI does not anticipate the need for additional renewable enabling investments in the distribution system through the forecast period.

(5.4.3) System Capability Assessment for Renewable Energy Generation

(This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and

e) constraints for an embedded distributor that may result from the connections.)

(5.4.3a) Applications for Renewable Generation Connection

As of January 31, 2017, HHI has connected 126.5 kW of renewable generation to its distribution system including:

- MicroFIT PV Solar: six projects
- Small FIT Solar: one project

There are currently no projects in process nor are there new applications.

(5.4.3b) Renewable Generation Connection Forecast

HHI is not expecting any new FIT or Micro-FIT applications or projects in the forecast period.

(5.4.3c) Capacity to Connect REG

Since there currently are no projects or applications for REG connections, no good assessment of capacity to connect is possible. Available capacity is relevant when the size of the REG source is known. Capacity currently exists at the 44kV supply as well as the 115kV supply.

Summary of Forecast Expenditures/Planned Development

To date there have been no constraints to renewable generation connection identified in the system and hence no planned investment for capacity increases.

(5.4.4) Capital Expenditure Summary

The Capital Expenditure Summary provides a snapshot of HHI's capital expenditures over the ten year DS Plan window. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories on the basis of the primary driver for the investment. All historical expenditures up to 2016, in the bridge year (2017), and proposed for the 2018 to 2022 Capital Expenditure Plan are categorized as follows:

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

All proposed expenditures in 2018 to 2022 are listed in Appendix B together with project descriptions. The historical expenditures 2013 to 2017 are listed in Appendix A together with project descriptions. The Capital Investment Plans for both the historical as well as the forecast period are categorized using the OEB classification.

The categorization is derived from the capital expenditure planning process that prioritizes items based on whether they are discretionary or non-discretionary. These, in turn, were developed from HHI's annual performance reporting, asset management strategy and the regional planning process. HHI's systems planning for new load and forecasts for renewable generation are captured within this DS Plan.

As previously indicated, HHI does not anticipate major expenditures to accommodate renewable energy generation projects.

Figure 31 includes the historical 2012 to 2015 expenditures, as well as the current year (2016), the test year (2017), as well as the forecast expenditures from 2018 to 2021.

	Historical (actual)					Forecast (planned)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Actual	Projected Y/E	Test	Test+1	Test+2	Test+3	Test+4
CATEGORY	$	$	$	$	$	$	$	$	$	$
System Access	$5,060	-$43,596	-$160	$39,670	$51,669	$36,800	$86,895	$31,010	$31,510	$31,610
System Renewal	$111,028	$98,281	$449,412	$247,921	$3,619,584	$117,780	$131,825	$488,350	$149,205	$139,500
System Service	$841,977	$0	$0	$0	$0	$10,000	$10,000	$10,000	$10,500	$10,500
General Plant	$74,259	$29,031	$13,067	$64,758	$41,100	$11,250	$8,800	$11,900	$11,900	$9,000
Total	$1,032,324	$83,716	$462,319	$356,348	$3,712,353	$175,830	$237,520	$541,260	$203,115	$190,610
Capital Contribution			$93,493	$17,741						
Net Capital	$1,032,324	$83,716	$368,826	$334,608	$3,712,353	$175,830	$237,520	$541,260	$203,115	$190,610
System O&M	$302,571	$232,855	$235,940	$236,871	$296,376	$300,107	$295,674	$322,178	$329,586	$374,253

Figure 17: Capital Expenditure Summary

(5.4.5) Justifying Capital Expenditures

The capital expenditures of HHI are modest and consequently there are few distinct projects to be reported on. Budgeting is typically done using the financial account structure, but reported using the OEB investment categories. There are only a few projects that exceed the materiality threshold in the forecast period.

(5.4.5a) Overall Plan

(To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- *comparative expenditures by category over the historical period;*
- *the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;*
- *the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);*
- *information related to the distributor's system capability assessment (see section 5.4.3))*

The comparative expenditures by investment category through the entire DS Plan period made by HHI are shown in the figure 31 above. Historical plan data has not been provided since a DS Plan has not been previously filed with the OEB.

System Access

System Access investments are projects required in order for HHI to meet its obligations under the DSC and whose timetables are driven by others. HHI is obligated to connect new load and new renewable generation. The scheduling of investment needs is usually coordinated to meet the needs of third parties. HHI is also required to respond to the road authorities by obligations under the Public Service Works on Highways Act. The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs. HHI also needs to ensure energy metering accuracy. Smart Meters have a fixed number of years for which they are certified. Replacement or recertification of Smart Meters is a legislated requirement and the investment is recorded in this category.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B.

System Renewal

System renewal is a mix of projects related to assets nearing end of life and projects to replace equipment that has reached end of life (emergency replacement). The former group of projects are identified and prioritized in the Asset Management system.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B.

System Service

System Service investments are required to provide for continued service reliability and to meet operational objectives. HHI is investing in converting underground radial feeds into looped feeds. This is being done on a moderate pace at a cost of about $10,000 per year until completed.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B.

General Plant

General Plant investments are not part of its distribution system (e.g. fleet, tools, land, etc.). These projects provide system support and improve operational efficiencies.

There are no material investments in the General Plant category.

Historical project information and project descriptions are in Appendix A while forecast project information and descriptions are in Appendix B.

Impact of System Investment on O&M

System investments will result in:

- the addition of incremental plant,
- the relocation/replacement of existing plant,
- the replacement of end of life plant with new plant, and
- new/replacement system support expenditures.

In general, incremental plant additions will be integrated into the asset management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs. However the replacement of end of life plant will tend to reduce trouble calls as a result of failures.

Forecast O&M costs for the 2018 – 2022 periods are:

2018	2019	2020	2021	2022
$300,107	$295,674	$322,178	$329,586	$374,253

Figure 18: Forecasted O&M Costs

Replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the DSC). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall, the plan system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes.

Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair-related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair-related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions.

In a few areas, cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital).

If assets approaching end of life are replaced at a rate that maintains equipment class average condition then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year).

Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall, this is expected to put downward pressure on O&M repair related costs.

In summary, the system investments will result in some upward growth-related and support-related O&M pressures, and downward repair related O&M pressures. Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

Investment Drivers

The following high-level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget:

- regulatory initiatives e.g., Smart meters and the Green Energy and Green Economy Act,
- elimination of environmental/health or safety risks,

- system reliability,
- infrastructure renewal projects,
- fleet/tools, and
- information technology and corporate administration.

Their input result in three main drivers of HHI's capital investments. These drivers align with corporate goals which are aligned with the RRFE Outcomes:

1. Obligation to connect a customer in accordance with Section 28 of the Electricity Act, 1998, Section 7 of HHI's Electricity Distribution License and the DSC.
2. System implementation activity to ensure maintenance of system reliability.
3. Planned system renewal spending to proactively replace plant at end of life in order to meet HHI's commitment to maintain a safe and reliable supply of electricity to its customers.

The specific investments drivers for each category are described below:

System Access

Customer service requests: continued development of the Town of Hawkesbury requiring new customer connections (site redevelopment; subdivisions). The historical trend has seen decreasing investments due to economic conditions. Forecasts assume decreasing investment needs due to market saturation.

System Renewal

There are four main drivers of System Renewal Projects:

- Failure risk: multiyear planned pole replacement programs that address assets in “very poor” and “poor” condition. The historical trend has seen increasing investments due to aging infrastructure. Forecast investments will remain at relatively high levels as equipment replacements and feeder rebuilds are completed.
- High-Performance risks: overhead line rebuilds. Historical investments have been a combination of line sections that require complete rebuild (poles, conductors, insulators, etc.) and dispersed pole replacement work. Forecast investments will target specific sections of line requiring complete rebuild.
- System flexibility at the MS level. Achieve a configuration that meets the load transfer requirement without causing a large number of customer interruptions.
- Emergency needs: emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

System renewal spending will continue to focus on planned proactive pole and main feeder conductor replacement programs at increased levels to that seen in the historical period. Specific high-performance risk areas will be prioritized during the 2018- 2022 period at levels similar to that in the historical period.

System Service

System constraints: new system investments, line extensions and feeder interconnections to accommodate grid load growth. These investments have been very small. Converting underground radial feeds to looped underground feeds is the only project.

System service spending will continue to focus on maintaining operational performance and capacity.

General Plant

These have been minor and will continue to be minor particularly as HHI plans to contract out all its plant maintenance and repair work with the retirement of its line and meter staff in 2018.

System Capability Assessment

There are no new REG connections anticipated in the forecast period therefore there is no work required for connections or capacity shortfall on the system that needs to be addressed.

(5.4.5b) Material Investments and Justification

Material project justifications can be found in Appendix C and E.

Generally the justifications cover the forecast period projects. However in the case of the investments in the 44kV MS and the 115kV MTS the justifications provide historical information from 2013 to the present as well as forecast investments to provide a more comprehensive understanding of these projects.

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Appendix A

Historical Capital Projects 2013 to 2017

CAPITAL 2013

Category		Actual	Project total	Category total
	All amounts are in $			
System Access				
	New Customers Connections	$960		
	Smart Meters	$4,100		
	Total System Access			$5,060
System Renewal				
	Replace Poles, Fixtures as per Asset Management Plan	$85,061		
	Replace 3/0 primary with New 336 MCM	$5,920		
	Transformer inventory capitalized. 2-3 phase pad mounted transformers and one pole mounted transformer.	$20,047		
	Total System Renewal			$111,028
System Service				
	Addition new 44 kV transformer	$841,977		
	Total System Service			$841,977
General Plant				
	Computer Hardware	$2,961		
	Software for different applications	$24,254		
	Line crew equipment	$1,584		
	Building	$38,205		
	Office furniture	$5,599		
	Power tools lineman equipment	$1,655		
	Total General Plant			$74,258
	2013 Capital Total			**$1,032,324**

2013 Project Descriptions

System Access

New Customer Connections **$960**

Cost of connecting new customers to the power grid.

Smart Meters **$4,100**

Meters required for new customer connections as well as replacements for defective meters.

System Renewal

Pole replacement **$85,061**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Replace 3/0 primary wire with 336 MCM AL **$ 5,920**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

Transformer Inventory capitalization **$20,047**

This project capitalizes the purchase of 2 pad mount transformers and one pole mount transformer for inventory.

System Service

New 44 kV transformer **$841,977**

This is the purchase of a new 44kV to 12.4kV transformer and the site preparation. This was approved in EB 2011-0173 at $712,909. The additional $129,068 was incurred due to site conditions. The soil was very wet and marshy. When the crew tried to install a switch close to the structure there was significant ground shifting and a soil engineer was called in. Measures and procedures were put in place to provide drainage while construction was carried out. This caused extra work and a two-week delay in completion. Additional information can be found in Appendix C which details the history of the station and provides justifications for the actions taken.

General Plant

Computer Hardware **$2,961**

Replace workstation.

Software Upgrades for various applications **24,254**

Applications upgraded or annual fee for licensing: Accpac, Hansen, Erth Holdings, CUPR, D&A Business, web presentment for customer interaction, Asset Management software to support OEB requirement on asset management plan.

Line Crew Equipment **$1,584**

Miscellaneous hand tools for the line crew.

Building **$38,205**

The building was 21 years old. There was an insect infestation in a curtain wall due to water infiltration each time it rained. The cost of correction was $11,941. Carpets were replaced in the common area and two offices ($13,891), 2 out of 5 furnaces needed to be replaced in the office area on the bottom floor (7,924) and a roof inspection required the replacement of existing caulking and deteriorating Butyl tape ($4450)

Office Furniture **$5,999**

This project provides for the replacement of a shredder and the installation of a fireproof safe.

Power Tools Line Crew **$1,655**

This project provides for miscellaneous power tools for the line crew.

2014 Capital

Category	Description	Actual	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New customer Connections	$1,095		
	Smart Meters	($44,691)		
	Category Total			**($43,596)**
System Renewal				
	44kv Substation	$42,750		
	Replace poles per the asset management plan	$24,310		
	Replace 3/0 primary with new 336 MCM	$31,221		
	Category Total			**$98,281**
System Service				
	None			**$0**
General Plant				
	Computer Hardware	$1,404		
	Software	$13,784		
	Building	$13,386		
	Office furniture and equipment	$457		
	Category Total			**$29,031**
	2014 Total Capital			**$83,716**

2014 Capital Project Descriptions

System Access

New Customer Connections **$1,095**

Cost of connecting new customers to the power grid.

Smart Meters **($44,691)**

Meters required for new customer connections as well as replacements for defective meters and adjustments.

System Renewal

Repairs and inspection of the 43T1 transformer **$42,750**

This was the cost to remove the old transformer which was producing high levels of dissolved combustible gas in the transformer oil on the 43T1 transformer (44kV to 12.4kV). This work is described further in Appendix C.

Pole replacement **$24,310**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Replace 3/0 primary wire **$ 31,221**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

System Service

None

General Plant

The whole category of expenditure is below the materiality threshold.

The most significant expenditures are for annual licensing and software upgrades and replacing three of five furnaces.

2015 CAPITAL PROGRAM

Category	Description	Actual	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New customer connections	$667		
	Smart Meters	($827)		
	Category Total			**($160)**
System Renewal				
	115kV transformer oil costs.	$1,947		
	Substation 44 kV	$320,188		
	Replace poles and attachments per Asset Management Plan	$88,560		
	Replace 3/0 conductor with 336 MCM conductors.	$27,607		
	Lightning arrester replacement	$11,110		
	Category Total			**$449,412**
System Service				
	None	$0		
				$0
General Plant				
	Software for different Applications	$5,813		
	Office Equipment	$7,254		
	Category Total			**$13,067**
	2015 Total Capital			**$462,319**
	Contributed Capital	$93,493		$93,493
	2015 Net capital			**$368,826**

2015 Capital Project Descriptions

System Access

New Customer Connections **$667**

Cost of connecting new customers to the power grid.

Smart Meters **($827)**

Meters required for new customer connections as well as replacements for defective meters and adjustments.

System Renewal

Faulty 115 kV Transformer **$1,947**

Oil containment system cost.

44kV MS transformer repair. **$320,188**

Refurbish old Ferranti transformer after failure of the new Pioneer transformer. See Appendix C for details.

Pole replacement **$88,560**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Replace 3/0 primary wire **$ 27,607**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

Porcelain Air gap Lightning Arrestor replacement. **$11,110**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

System Service

None

General Plant

This total category is below the materiality threshold. The majority of the costs are for software licensing and a new printer/scanner.

2016 Capital Program

Category	Description	Actual	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Services	$241		
	Smart Meters	$22,720		
	New Subdivision - Rock	$16,709		
	Category Total			**$39,670**
System Renewal				
	115 kV MTS new protection installation	$59,244		
	44 kV MS Commissioning rebuilt transformer and ancillary equipment.	$54,101		
	Pole replacement program	$65,573		
	Line conductor replacement 3/0 to 336 MCM AL	$69,003		
	Category Total			**$247,921**
System Service				
	Category Total			**$0**
General Plant				
	Computer Hardware	$844		
	Software for Different Applications	$3,999		
	Building investments	$52,500		
	Tools- Pole Testing Device	$7,415		
	Category Total			**$64,758**
	2016 Total Capital			**$356,348**
	Contributed Capital	**$17,741**		**($17,741)**
	Net 2016 Capital			**$334,608**

2016 Capital Project Descriptions

System Access

The total category spending is below the materiality threshold. The expenditures are as follows.

New Customer Connections **$241**

Cost of connecting new customers to the power grid.

Smart Meters **$22,720**

Meters required for new customer connections as well as replacements for defective meters and adjustments.

Rock Subdivision **$16,709**

A new subdivision built in 2016. It is being installed in phases.

System Renewal

115 kV MTS new protection installation **$59,244**

The replacement of the transformer and the refurbishment of the station required an upgrade to the station protection. This project accomplishes this protection upgrade.

44kV MS commissioning of rebuilt transformer **$54,101**

This project covered the cost of installing and commissioning the rebuilt transformer making it ready for service. This work was completed in 2015 but the invoicing was not received until 2016. See Appendix C for station details.

Pole replacement program **$65,573**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Line Conductor replacement **$69,003**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

System Service

None

General Plant

Computer Hardware **$844**

Purchase of miscellaneous hardware.

Software **$3,999**

Annual licensing and website upgrade.

Building **$52,500**

As part of normal due diligence, HHI had the condition of the roof of the office / service center assessed. The assessment recommended that the roof be replaced. This project carries out the refurbishment of the roof at 850 Tupper St office and service center. This is a flat roof.

Pole testing device **$7,415**

A pole testing device was purchased in order to provide better information on the condition of the poles tested. This was purchased together with Cooperative Hydro Embrun with each utility paying half the purchase cost. This was done in order to reduce the capital cost for each utility.

2017 Capital Projects

Category	Description	Forecast Y/E	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,000		
	New customer connections	$2,500		
	Meters - Commercial change to Smart Meters, new customer meters and defective meter replacement	$30,169		
	Transformers - inventory (subdivision)	$9,000		
	Category Total			**$51,669**
System Renewal				
	115 kV MTS upgrade	$3,525,000		
	44kV MS 44kV Insulator replacement	$5,000		
	Pole replacement program	$60,000		
	Porcelain insulator replacement	$21,720		
	Porcelain air gap lightning arrestor replacement	$7,864		
	Category Total			**$3,619,584**
System Service				
	None	$0		
	Category Total			**$0**
General Plant				
	Building	$2,000		
	Office equipment	$3,500		
	Computer hardware	$2,600		
	Software North Star upgrade	$31,000		
	Hand tools line crew	$1,000		
	Power tools line crew	$1,000		
	Category Total			**$41,100**
	2017 Total Capital			**$3,712,353**

2017 Capital Project Descriptions

System Access

New Subdivision **$10,000**

This project provides servicing for a new subdivision being built.

New Customer Connections **$2,500**

Cost of connecting new customers to the power grid.

Meters **$30,169**

This project provides new customer meters and replacements for defective meters. In addition it continues the change out of old commercial meters with new smart meters.

Transformers –inventory **$9,000**

Transformers are capitalized on receipt from the vendor. These transformers are intended to be used in the new subdivision.

System Renewal

115kV MTS upgrade **$3,525,000**

This project represents the cost of upgrading the existing 115kV MTS. This project installs a 15/20/25 MVA transformer as well as transformer pads and electrical connections. This work is the work that was identified in EB-2011-0173. Additional information can be found in Appendix XX.

44kV MS -44kV insulator replacement **$5,000**

Replacement of the old 44 kV insulators in the station.

Pole replacement **$60,000**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Porcelain Insulator replacement **$21,720**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

Porcelain Air gap Lightning Arrestor Replacement **$7,864**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done over X years in order to minimize the impact on rates.

System Service

None

General Plant

Building	**$2,000**

Repair a column in front of the building at 850 Tupper St.

Office Equipment	**$3,500**
Replacement computer workstations.	**$2,600**
Software: North Star system upgrade	**$31,000**
Hand Tools line crew	**$1,000**
Power Tools line crew	**$1,000**

Appendix B

Forecast Capital Projects 2018 to 2022

CAPITAL 2018

Category	Description	Forecast	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,000		
	New Customer connections	$3,500		
	Smart Meters new	$3,300		
	Smart Meters for retest	$11,000		
	Transformers inventory	$9000		
	Category Total			**$36,800**
System Renewal				
	Pole replacement	$81,500		
	3/0 Conductor Upgrade	$10,000		
	Porcelain Arrestor Replacement	$8,350		
	Porcelain Insulator replacement	$17,930		
	Category Total			**$117,780**
System Service				
	close loops on u/g radial feeds	$10,000		
	Category Total			**$10,000**
General Plant				
	Computer hardware	$4,500		
	Computer Software	$1,000		
	Building	$2,000		
	Office Equipment	$3,750		
	Category Total			**$11,250**
	Total Capital			**$175,830**

2018 Capital Project Descriptions

System Access

New Subdivision **$10,000**

This project provides servicing for a new subdivision being built.

New Customer Connections **$3,500**

This project provides the connections to the new customers anticipated in 2018.

Smart Meters **$3,300**

This project provides for new Commercial meters and residential meters anticipated.

Smart Meters for retest **$11,000**

This provides for the beginning of the Smart meter replacement.

Transformer – inventory **$9,000**

This project provides for the capitalization of transformers that will be designated for the new subdivision.

System Renewal

Pole replacement **$81,500**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

3/0 Conductor upgrade **$10,000**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project to be completed in 2020.

Porcelain Lightning Arrestor Replacement **$8,350**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

Porcelain insulator replacement **$17,930**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

System Service

Close Loops on u/g radial feeds **$10,000**

HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the primary cable fails. The modern design is to install a looped feed with a normal open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually so this is a proactive project that will mitigate future adverse reliability impacts.

General Plant

Computer Hardware **$4,500**

This provides for a replacement computer.

Computer Software **$1,000**

This provides for licencing and minor upgrades.

Building **$2,000**

This provides for miscellaneous repairs to the front door.

Office Equipment **$3,750**

This is a provision for miscellaneous office equipment replacement.

2019 Capital Program

Category	Description	Forecast	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,000		
	Transformers-inventory new subdivision	$9,000		
	new services	$3,600		
	metering for 115kV MTS	$6,000		
	Commercial meters	$2,295		
	Smart meter replacement	$56,000		
	Category Total			**$86,895**
System Renewal				
	Pole replacement	$87,700		
	3/0 Conductor upgrade	$15,000		
	Replace Porcelain insulators	$13,125		
	Replace Porcelain lightning arrestors	$16,000		
	Category Total			**$131,825**
System Service				
	close loops on u/g radial feeds	$10,000		
	Category Total			**$10,000**
General Plant				
	Building capital	$3,000		
	Office Equipment	$3,800		
	Computer hardware	$1,000		
	Software	$1,000		
	Category Total			**$8,800**
	Total Capital			**$237,520**

2019 Capital Project Descriptions

System Access

New Subdivision **$10,000**

This project provides services for a new subdivision being built.

Transformers –inventory for new subdivision **$9,000**

This project provides for the capitalization of transformers that will be designated for the new subdivision.

New Services **$3,600**

Cost of connecting new customers to the power grid.

Metering for 115kV MTS **$6,000**

This provides metering at the MTS to comply with IESO requirements.

Commercial meter **$2,295**

Meters for new commercial accounts and replacements as needed.

Smart meter replacement **$56,000**

This item provides for Meters for new residential accounts and replacement of defective meters. This item also provides for Smart Meter testing and replacement.

System Renewal

Pole replacement **$87,700**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

3/0 conductor upgrade **$15,000**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project.

Replace Porcelain Insulators **$13,125**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

Replace Porcelain lightning arrestors $16,000

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

System Service

Close Loops on u/g radial feeds $10,000

HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the primary cable fails. The modern design is to install a looped feed with a normal open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually so this is a proactive project that will mitigate future adverse reliability impacts.

General Plant

Building $3,000

This is a provision for minor capital repairs.

Office Equipment $3,800

This is a provision for office equipment replacement.

Computer Hardware $1,000

This is a provision for computer hardware replacement.

Software $1,000

This is a provision for software licencing and minor upgrades.

2020 Capital Program

Category	Description	Forecast	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,000		
	New customer services	$3,700		
	Smart meters	$6,000		
	Commercial Smart meters	$2,310		
	Transformers -inventory - subdivision	$9,000		
	Category Total			**$31,010**
System Renewal				
	Pole replacement	$88,100		
	3/0 Conductor upgrade	$15,000		
	Replace Porcelain Insulators	$27,750		
	Replace porcelain lightning arrestors	$17,500		
	44kV MS Alterations	$340,000		
	Category Total			**$488,350**
System Service				
	Close loops on u/g radial feeds	$10,000		
	Category Total			**$10,000**
General Plant				
	Misc. Building	$3,000		
	Office Equipment	$3,900		
	Computer hardware	$4,000		
	Software	$1,000		
	Category Total			**$11,900**
	Total Capital			**$541,260**

2020 Capital Project Descriptions

System Assess

New Subdivision **$10,000**

This project provides services for a new subdivision being built.

New Services **$3,700**

Cost of connecting new customers to the power grid.

Smart meter replacement **$6,000**

Meters for new residential accounts and replacements.

Commercial meter **$2,310**

Meters for new commercial accounts and replacements as needed.

Transformers –inventory for new subdivision **$9,000**

This project provides for the capitalization of transformers that will be designated for the new subdivision.

System Renewal

Pole replacement **$88,100**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

3/0 conductor upgrade **$15,000**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project.

Replace Porcelain Insulators **$27,750**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

Replace Porcelain lightning arrestors **$17,500**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

44 kV MS Alterations **$340,000**

It is proposed that the two transformers at the MS site will be reconfigured so that they can each supply load without being in parallel. Appendix C provides more detail about what is proposed.

System Service

Close Loops on u/g radial feeds **$10,000**

HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the primary cable fails. The modern design is to install a looped feed with a normal open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually so this is a proactive project that will mitigate future adverse reliability impacts.

General Plant

Building **$3,000**

This is a provision for minor capital repairs.

Office Equipment **$3,900**

This is a provision for office equipment replacement.

Computer Hardware **$4,000**

This is a provision for computer hardware replacement.

Software **$1,000**

This is a provision for software licencing and minor upgrades.

2021 Capital Program

Category	Description	Forecast	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,500		
	Transformers -inventory-subdivision	$9,000		
	new services customer	$3,700		
	Smart meters	$6,000		
	Smart meters Commercial	$2,310		
	Category Total			**$31,510**
System Renewal				
	Pole replacement	$88,100		
	Replace Porcelain Insulators	$27,750		
	Replace porcelain lightning arrestors	$17,500		
	3/0 Conductor upgrade	$15,855		
	Category Total			**$149,205**
System Service				
	close loops on u/g radial feeds	$10,500		
	Category Total			**$10,500**
General Plant				
	Building Miscellaneous	$3,000		
	Office Equipment	$3,900		
	Computer hardware	$4,000		
	Software	$1,000		
	Category Total			**$11,900**
	Total Capital			**$203,115**

2021 Capital Project Descriptions

System Access

New Subdivision **$10,500**

This project provides servicing for a new subdivision being built.

Transformers –inventory for new subdivision **$9,000**

This project provides for the capitalization of transformers that will be designated for the new subdivision.

New Services **$3,700**

Cost of connecting new customers to the power grid.

Smart meter replacement **$6,000**

Meters for new residential accounts and replacements.

Commercial meter **$2,310**

Meters for new commercial accounts and replacements as needed.

System Renewal

Pole replacement **$88,100**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Replace Porcelain Insulators **$27,750**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

Replace Porcelain lightning arrestors **$17,500**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively either in service and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

3/0 conductor upgrade **$15,855**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project.

System Service

Close Loops on u/g radial feeds **$10,500**

HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the primary cable fails. The modern design is to install a looped feed with a normal open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually so this is a proactive project that will mitigate future adverse reliability impacts.

General Plant

Building **$3,000**

This is a provision for minor capital repairs.

Office Equipment **$3,900**

This is a provision for office equipment replacement.

Computer Hardware **$4,000**

This is a provision for computer hardware replacement.

Software **$1,000**

This is a provision for software licencing and minor upgrades.

2022 Capital Program

Category	Description	Forecast	Project Subtotal	Category Total
	All amounts are in $			
System Access				
	New Subdivision	$10,500		
	Transformers - inventory -capital- new subdivision	$9,000		
	new customer services	$3,800		
	Smart meters Residential	$6,000		
	Smart meters Commercial	$2,310		
	Category Total			**$31,925**
System Renewal				
	Pole replacement	$90,000		
	Replace Porcelain insulators	$14,000		
	Replace porcelain lightning arrestors	$17,500		
	3/0 Conductor upgrade	$18,000		
	Category Total			**$139,500**
System Service				
	Close loops on u/g radial feeds	$10,500		
	Category Total			**$10,500**
General Plant				
	Miscellaneous building	$3,000		
	Office Equipment	$3,900		
	Computer hardware	$1,100		
	Software	$1,000		
	Category Total			**$9,000**
	Total Capital			**$190,610**

2022 Capital Project Descriptions

System Access

New Subdivision **$10,500**

This project provides services for a new subdivision being built.

Transformers –inventory for new subdivision **$9,000**

This project provides for the capitalization of transformers that will be designated for the new subdivision.

New Services **$3,800**

Cost of connecting new customers to the power grid.

Smart meter Residential **$6,000**

Meters for new residential accounts and replacements.

Commercial meter **$2,310**

Meters for new commercial accounts and replacements as needed.

System Renewal

Pole replacement **$90,000**

As part of its asset management program, poles are tested when they are within 5 years of their forecast depreciation end of life. The testing program identified the poles that needed to be replaced. This project captures the cost of doing the replacement work.

Replace Porcelain Insulators **$14,000**

Porcelain line insulators are known to develop cracks over time due to repeated stress. HHI has found small cracks in some of its post insulators but has not experienced any failures yet. This project begins to replace the porcelain units on a modest pace in order to ensure the continued reliability of its system. In this way future outages that will be inevitable if no action is taken will be prevented.

Replace Porcelain lightning arrestors **$17,500**

Porcelain air gap type arrestors are known to fail in service. These devices create a safety hazard when they fail in service. Typically air gap lightning arrestors may fail explosively and create a hazard for anyone in the immediate vicinity either general public or a worker. This failure type and mechanism has been documented and is well known in the industry. HHI has had failures with these lightning arrestors. Because the failures will continue to occur in future with this design of equipment, HHI intends to replace all the lightning arrestors of this type with polymer insulated solid dielectric valve blocks to remove the hazard. This will be done at a modest pace in order to minimize the impact on rates.

3/0 conductor upgrade **$18,000**

The wire being replaced is 3/0 ACSR. It is being replaced by 336 MCM ACSR. The original wire is very weathered and brittle and is undersized for main feeder load transfers. This is a multi-year project.

System Service

Close Loops on u/g radial feeds **$10,500**

HHI has radial underground feeds in some of its subdivisions. It is recognized that this design has the potential to create long customer outages if the primary cable fails. The modern design is to install a looped feed with a normal open point to allow faster restoration in the event of a single contingency failure. This project provides for the second source of supply for the radial feeds. This project addresses the problem but on a multi-year basis at a very modest pace since this has not been the cause of customer outages to date. However, cables fail eventually so this is a proactive project that will mitigate future adverse reliability impacts.

General Plant

Building **$3,000**

This is a provision for minor capital repairs.

Office Equipment **$3,900**

This is a provision for office equipment replacement.

Computer Hardware **$1,100**

This is a provision for computer hardware replacement.

Software **$1,000**

This is a provision for software licencing and minor upgrades.

Appendix C

Justification to Rebuild MS 43 Bus Structure

JUSTIFICATION TO REBUILD MS 43 BUS STRUCTURE

Station Project History and Context

Prior to 2011 the HHI distribution system consisted of two station sites. One was at the west end of town and was supplied at 115kV and the other was at the east end of town and was supplied at 44kV. While the secondary voltage on each station was 12.4kV the two systems are out of phase and cannot be paralleled. This means taking an outage if load is transferred between the two stations. So these are open transition transfers. Load transfers between feeders emanating from the same station can be made in a closed transition mode meaning making and then break a parallel.

The 115kV supplied station is designated as 55 and the 44kV supplied station is designated as 43. These designations will be used to indicate which station is referenced to make the dialogue less cumbersome.

Prior to 2011 station 55 consisted of two transformers each one being 115kV to 12.4/7.24kV grounded wye secondary and was rated at 7.5MVA ONAN/10MVA ONAF/12.5MVA ONAF/AF. The station configuration is a "Jones Scheme" with two transformers, a transformer breaker for each transformer, each transformer feeding a bus which in the case of 55T1 has two feeders connected and in the case of 55T2 has one feeder and provision for a second feeder. There is also a bus tie device to allow the two transformer buses to be connected. This would be used if a transformer failed or was taken out of service for maintenance. The closing of the bus tie and opening one transformer breaker transfers the load to the other transformer. With this scheme the maximum load on the station needs to be less than or worse case, equal to the emergency rating on one transformer. If the units are identical as in this case the maximum load that can be handled in this way is 12.5 MVA. If the transformers are not identical then the firm rating is the emergency rating of the smallest unit. This is because it is not known which unit will fail the larger or the smaller one.

In 2006 55T1 showed elevated levels of dissolved gas in the transformer oil sample and in 2009 55T2 showed similarly elevated gas levels. The transformers were de-gassed and in 2010 both on load tap changes were given an overhaul. No further oil sample data have indicated that new problems have occurred to date.

The original station schematic drawing, Figure 1, is on the next page. To view the PDF double click on the drawing.

Station 43 had a simpler configuration. It consisted of one transformer feeding a bus structure and supplied two feeders. The transformer was a 44kV to 12.4/7.24 kV grounded wye secondary and was rated at 10MVA/13.33MVA/16.67MVA for ONAN/AF/AF operation. Transformers are considered to be at normal operation when within the ONAN rating. The other higher ratings are abnormal or emergency ratings and are not normal operation but used for system events putting abnormal loads and stresses on the transformer.

The picture Figure 2 shows the 43T1 in its original location and the structure with the feeder positions. In this picture 43T1 is on potential but not connected to the structure and not supplying load.

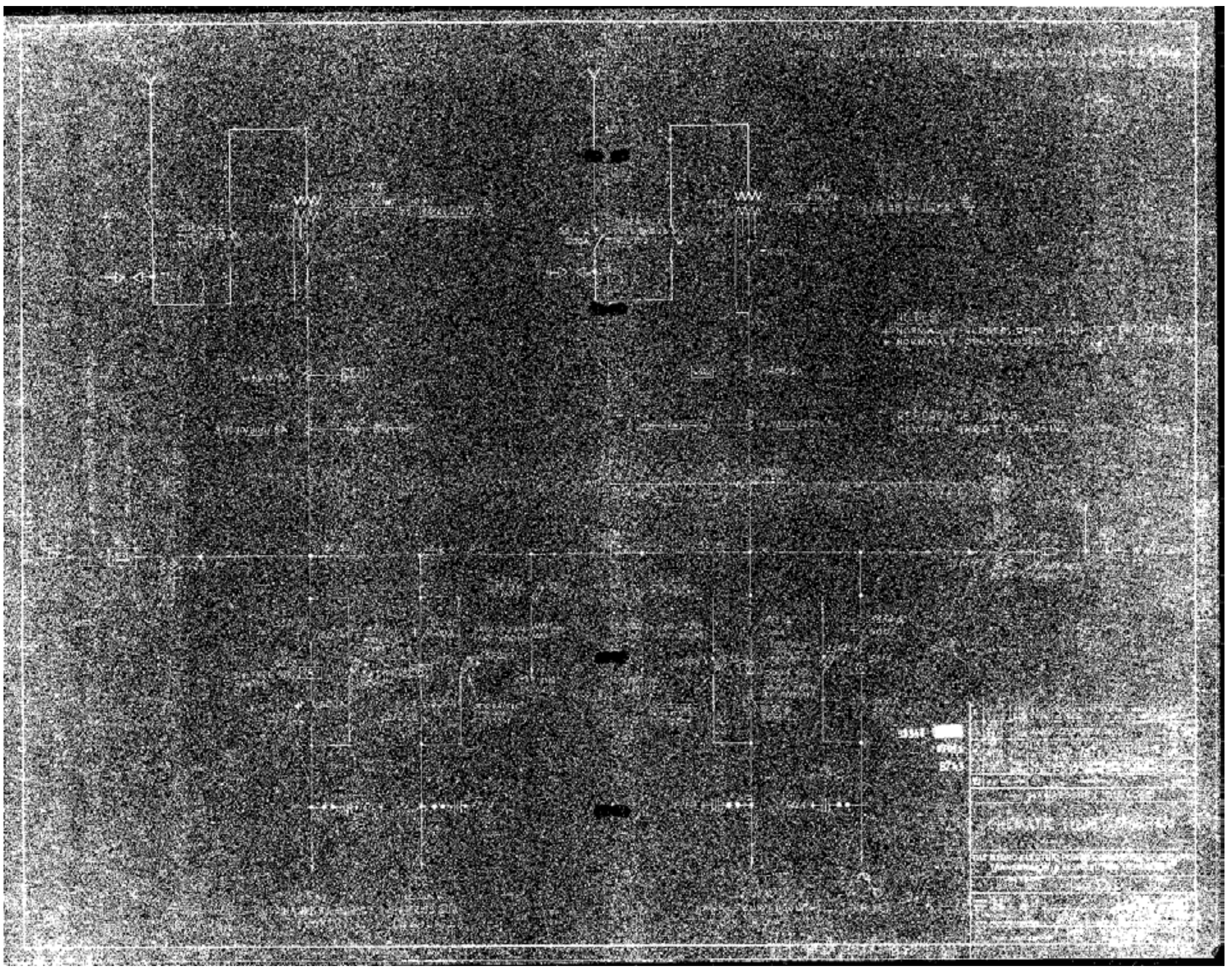

Figure 1 Station 55 Station Schematic

Figure 2. 43T1 and Two Feeder Structure

In 2011 HHI received permission through EB-2011-0173 to replace the existing old, near end of life, transformers at station 55 with a 15/20/25 MVA unit [ONAN/AF/AF] and to replace the transformer at station 43 since it was giving high levels of dissolved gas in oil values indicating that a reaction was taking place in the insulation in the windings that would result in failure of the unit. The funds to do the work were granted so that the Station 55 allowed project costs were $1,517,813 and the station 43 allowed project costs were $712,909.

HHI started by addressing the most urgent situation first namely the station 43 transformer replacement. The plan was to purchase a new transformer and sell the old transformer for scrap. The transformer was purchased and was installed and in-service as 43T2 on or about April 2012. There were cost overruns due to the site conditions and the amount of water on the site. Special measures were required to be able to dig the pad and foundation structures and pour concrete. A soil engineer was consulted but extra work needed to be done to stabilize the soil and the moisture in the ground. The following pictures show the site today and the wet area it is.

Figure 3: Wet environment -1

Figure 4: Wet Environment -2

The following picture shows the 43T2 transformer and line to the existing feeder structure.

Figure 5: 43T2 in place.

The area where the transformer pad and the pads for the steel poles including the one at the very left of the picture were all in swampy land since the old fence was between the first steel post left of the transformer and the second one on the left side of the picture. The total extra cost for the soil engineer, water mitigation and pumping every day as well as delays in the work amounted to $129,068 in extra costs.

These costs are shown in the 2013 capital costs.

HHI decided to keep the 43T1 transformer on potential for a time as a safety measure to make sure the 43T2 transformer was working as expected. In hindsight this was a good decision.

After a little over a year in service in July 2013 43T2 failed in service. By this time it was out of warranty. It was isolated and 43T1 was put into service again. There was no alternative to this since the 12.4kV load exceeded the capability of 55T1 and 55T2. This caused HHI to reconsider the decision to have only one transformer at station 43.

After some preliminary examination on site, it was determined that 43T2 needed to be sent to the manufacturers' facility for further evaluation and a status report. The unit was shipped to Pioneer and cause analysis was carried out. There currently is litigation outstanding between Pioneer and a sub-assembly supplier.

43T2 was rewound and had a new on load tap changer installed, was shipped to HHI's station 43, and went into service as 43T2 in April 2014. 43T1 was taken out of service the same date.

Based on the experience of having a transformer failure and considering the impossible supply situation if there was no second transformer HHI decided that rather than sell the old unit for scrap it would investigate first if there was an obvious reason for the gas production and if it could be found what would it take to fix it, and if the gas source could not be found or fixed what was the cost of rewinding the unit? The 42T1 transformer was made ready and shipped to the GE repair shop in Stoney Creek in June 2014 at the cost of $42,750. The first investigation was carried out but no cause was found. Then the rewind was considered.

HHI decided to proceed with the rewind in order to have the ability to supply all customers in a first contingency situation involving station 43 in particular. The cost of the rewind was $320,188. The transformer was installed and commissioned in 2015. The commissioning which took place in 2015 was not billed until 2016. The cost was $52,971. The cost shown in 2016 is for $52,971 plus $1,130 for some ancillary equipment for a total reported in 2016 of $54,101.

While these events directly affected station 43 they have also indirectly affected the station 55 work. It was not possible to proceed with the station 55 work until station 43 was secure. After the 43T2 transformer failed the system was at risk because 43T1 was still producing gas indicating a serious problem. When 43T2 was rewound and in service the higher priority for HHI was to secure the supply at station 43 with some backup capability. Once this was secure HHI preceded with the station 55 works since it could now confidently move load from one transformer at station 55 to 43T2. Hence the delay to do major reconstruction at station 55 until the capability of station 43 was resolved.

Another impact of the 43T2 failure was the realization that first contingency capability was important to provide. Initially when 43T2 was purchased the plan was to remove 43T1 and scrap it and have only 43T2 supplying the load. After the failure of 43T2 it was realized that without a backup transformer the load could not be carried. Hence the 43T1 transformer was repaired by rewinding the high voltage and low voltage coils the unit was placed on its pad and left on potential so that it was available if a transformer failure occurred. This also provided for firm capacity to transfer load while the station 55 work was being carried out. This also impacted on the station 55 configurations. The T1 / T2 configuration was initially to be only a T1 with a larger transformer. But after the failure of 43T2 this was reconsidered and a T1 / T2 configuration was implemented to again retain first contingency capability.

For station 43 the current configuration allows one transformer to be connected to the two feeders emanating from the station. This is a backup situation and provides the capability to deal with a first contingency at the MS but it is not ideal. HHI is proposing to make some alterations to the connection capabilities in 2020. It wants to provide the ability similar to station 55 so that there are effectively two separate busses fed by the two transformers with bus tie capability and transformer isolation switches. [Creating a "Jones" scheme]. This arrangement would allow either transformer to be taken out of service for maintenance without causing a planned outage as is required now. It also improves system switching flexibility. A final design has not been developed at this time so the costs are budget estimates.

General Information on the Project

The total capital investment over the historical and forecast period is:

Historical Investments					
2013	**2014**	**2015**	**2016**	**2017**	**Total**
$841,977	$42,750	$320,185	$54,101	$5,000	$1,264,013

Table 1: Historical Investments

Forecast Investments					
2018	**2019**	**2020**	**2021**	**2022**	**Total**
$0	$0	$340,000	$0	$0	$340,000

Table 2: Forecast Investments

There are no related customer attachments as this is work to be carried out in HHI's substation. The work is planned to be designed, contracted and constructed in 2020. Once this work is completed the station will be complete and no further capital work is expected to be needed.

All the work will be contracted out including the design and construction work. HHI is not aware of any risks in the construction of the project. The site conditions have been addressed and any work required takes place close to the center of the graveled yard. The new design will need to take into account that any new structure or facilities cannot require the existing feeders to be out of service while the new construction is in progress.

There is not an equivalent project that was carried out in the past by HHI. The previous work was the purchase and installation of a new transformer. The additional costs were removing, rebuilding and reinstalling faulty transformers and dealing with site conditions.

There are no REG investments included in this project.

No “Leave to Construct” permission is required for this project.

Evaluation Criteria and Information Requirements for each Project

Efficiency, Customer Value and Reliability.

After the failure of the new 43T2 transformer HHI realized that it could not operate its system on the basis of prime load only but also needed to consider first contingency events in order to ensure its customers had a reliable supply. HHI made the investments in the historical period in making the transformers available but the remaining infrastructure namely the bus structure proving supply to the feeders was not altered. This provides a backup capability at the transformer level but to connect the backup transformer requires a planned interruption to all, approximately 1200, customers connected to MS 43. These customers need to be interrupted to allow the backup transformer to be connected to the bus structure and also to disconnect the backup transformer from the bus structure. This project creates the infrastructure to allow each transformer to supply one feeder and to allow the feeders to be transferred to one transformer without the need for interruptions. This will improve the outage performance of the connected customers and will improve the utilization of both transformers.

This project was deferred until 2020 after the MTS 55 work in order to reduce system risk. There are only two stations in HHI’s system so doing significant work at both stations simultaneously provides limited power restoration options. Also both the MTS and the MS investments are large and lumpy meaning they are not easily or economically spread out over time.

With this investment it will be much more efficient and cost effective to transfer loads at MS 43. In addition customers will experience fewer planned power interruptions and the station transformer utilization will be improved.

The project does not have a final design at this time. HHI is interested in a design that meets the operating requirements in a modest cost effective manner. An initial proposal for a duplicate bus structure complete with reclosers and pad mounted switches with the capability to select one source or the other has been rejected as too expensive. A suitable lower cost design is still being worked on.

The design work and all the construction work will be contracted out.

Safety

During power interruptions the risk to the public is higher. This may be as simple of lights going off in the home or traffic lights on the roads. So if outages particularly planned outages for large areas can be prevented this has a positive impact on the community.

In addition while there are sequential steps to follow to connect the standby transformer to the bus structure safely there is a tendency to rush because of the number of people out of power. Rushing can lead to missed steps in the isolation of the station or it can lead to slips and falls when making the connections between the transformer and the bus structure. Outages almost always result in a heightened sense of urgency and pressure to go faster to reduce the outage time.

Cyber Security and Privacy

Not applicable.

Co-ordination, Interoperability

Not applicable.

Economic Development

Not applicable.

Environmental Benefits

Not applicable.

Category-specific requirements for each project/activity

This is a system renewal project.

The bus structure was originally designed as one transformer, two feeder distribution station. With HHI's experience with the failure of a new transformer the ability to supply customers in the event of a first contingency station transformer event became an important design parameter. Two transformers are available but the arrangement has significant operational shortcomings in the present configuration. There are customer planned outages to about 1200 customers for each load transfer from T2 to T1 and there are safety implications for the public as well as for operating staff. Outages for load transfer between transformers are likely to be in the order of 30 minutes to one hour for each transfer on a planned basis.

Both power transformers are less than five years old and both have rewound high and low voltage coils. The bus structure is a 1960's vintage structure so in the order of 50 years old. The problem is not the age of the structure but the lack of switches to allow the switching flexibility needed to operate the system and utilize the two transformers economically.

With the proposed functionality there would be fewer planned outages which would result in improved customer satisfaction.

This is a single large size investment and is the only one of this magnitude in the forecast period. The other years in the forecast period have at least three projects that combine to about $130,000 to $150,000 per year combined.

O&M costs are not likely to be significantly affected if the project is completed or not.

With the current configuration it is more likely that the supply transformer will exceed the ONAN rating and be stressed or worked into the emergency range. This will be prevented when the proposed changes are implemented and each transformer supplies the load for one feeder under normal circumstances. The total transformer losses will also be reduced.

Appendix D

Information about MTS 55 Rebuild

Information About MTS 55 Rebuild

Station Project History and Context

Prior to 2011 the HHI distribution system consisted of two station sites. One was at the west end of town and was supplied at 115kV and the other was at the east end of town and was supplied at 44kV. While the secondary voltage on each station was 12.4kV the two systems are out of phase and cannot be paralleled. This means taking an outage if load is transferred between the two stations. So these are open transition transfers. Load transfers between feeders emanating from the same station can be made in a closed transition mode meaning making and then break a parallel.

The 115kV supplied station is designated as 55 and the 44kV supplied station is designated as 43. These designations will be used to indicate which station is referenced to make the dialogue less cumbersome.

Prior to 2011 station 55 consisted of two transformers each one being 115kV to 12.4/7.24kV grounded wye secondary and was rated at 7.5MVA ONAN/10MVA ONAF/12.5MVA ONAF/AF. The station configuration is a "Jones Scheme" with two transformers, a transformer breaker for each transformer, each transformer feeding a bus which in the case of 55T1 has two feeders connected and in the case of 55T2 has one feeder and provision for a second feeder. There is also a bus tie device to allow the two transformer buses to be connected. This would be used if a transformer failed or was taken out of service for maintenance. The closing of the bus tie and opening one transformer breaker transfers the load to the other transformer. With this scheme the maximum load on the station needs to be less than or worse case, equal to the emergency rating on one transformer. If the units are identical as in this case the maximum load that can be handled in this way is 12.5 MVA. If the transformers are not identical then the firm rating is the emergency rating of the smallest unit. This is because it is not known which unit will fail the larger or the smaller one.

In 2006 55T1 showed elevated levels of dissolved gas in the transformer oil sample and in 2009 55T2 showed similarly elevated gas levels. The transformers were de-gassed and in 2010 both on load tap changes were given an overhaul. No further oil sample data have indicated that new problems have occurred to date.

The original station schematic drawing, Figure 1, is on the next page. To view the PDF double click on the drawing.

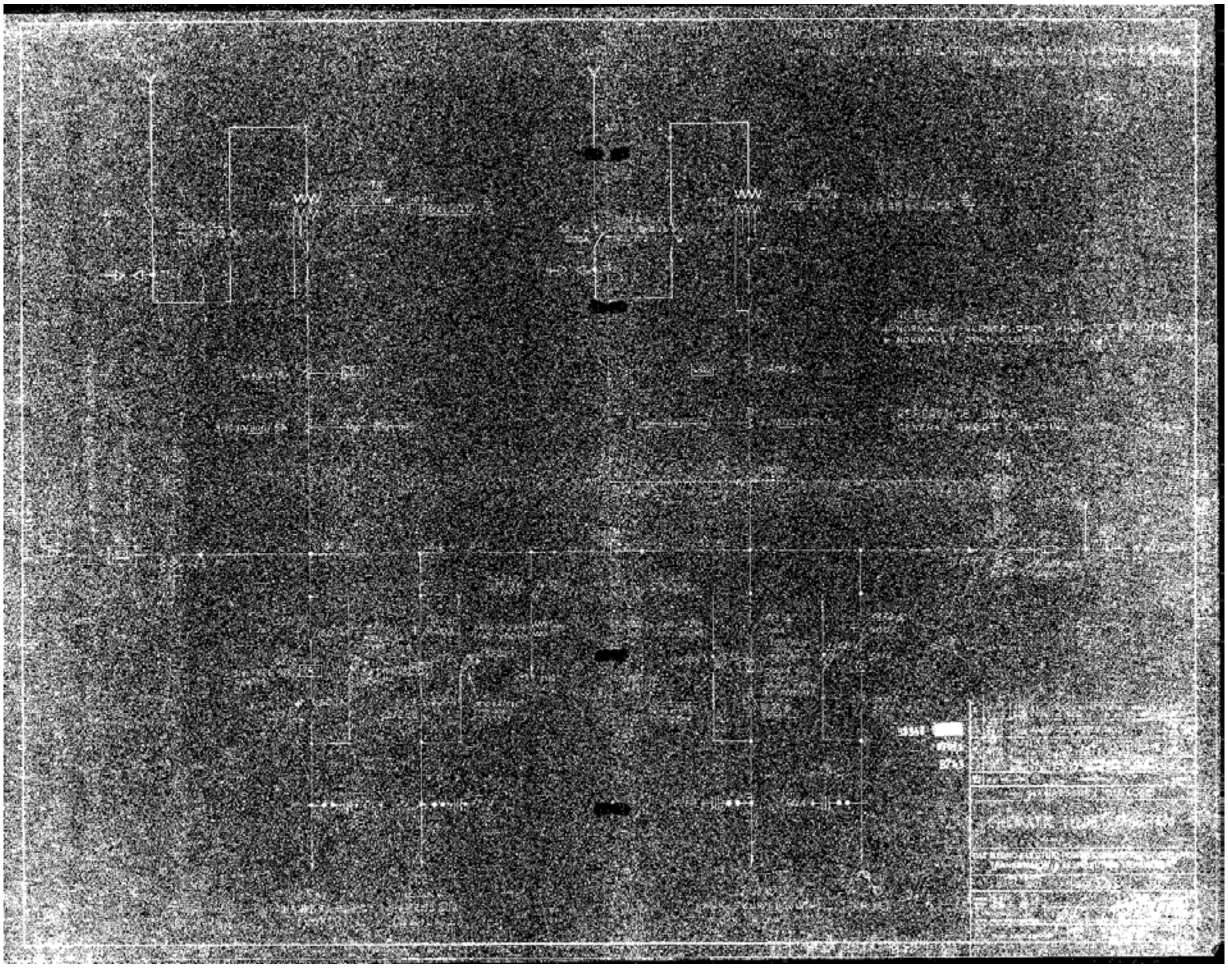

Figure 1 Station 55 Station Schematic

In 2011 HHI received permission through EB-2011-0173 to replace the existing old, near end of life, transformers at station 55 with a 15/20/25 MVA unit [ONAN/AF/AF] and to replace the transformer at station 43 since it was giving high levels of dissolved gas in oil values indicating that a reaction was taking place in the insulation in the windings that would result in failure of the unit. The funds to do the work were granted so that the Station 55 allowed project costs were $1,517,813 and the station 43 allowed project costs were $712,909.

Because the transformer condition of the 43T1 transformer was more critical this project proceeded first. The description of what happened to that installation is documented in Appendix C.

As a result of a failure of the new transformer at station 43 HHI reconsidered its prime load only approach and adopted a first contingency design at its MS and MTS. Because the two systems are out of phase each station [MS and MTS] requires the capability to carry all the load of the station on the remaining transformer if it is to be able to withstand a first contingency event at the power transformer level. This had two impacts for MTS 55. First, the project was delayed because of the transformer problems at MS 43. Once these were resolved and the MS 43 transformers were supplying load or on potential then the MTS plan was reconsidered and one of the old transformers

[7.5/10.12.5 MVA] was retained to maintain the load transfer capability in the event of a single contingency event involving a station transformer. Because of the larger transformer new transformer pads were designed and the ultimate capability was to accommodate two transformers rated 15/20/25 MVA.

The figure 2 below shows the station layout relative to the old transformer pads. To view the PDF double click on the drawing.

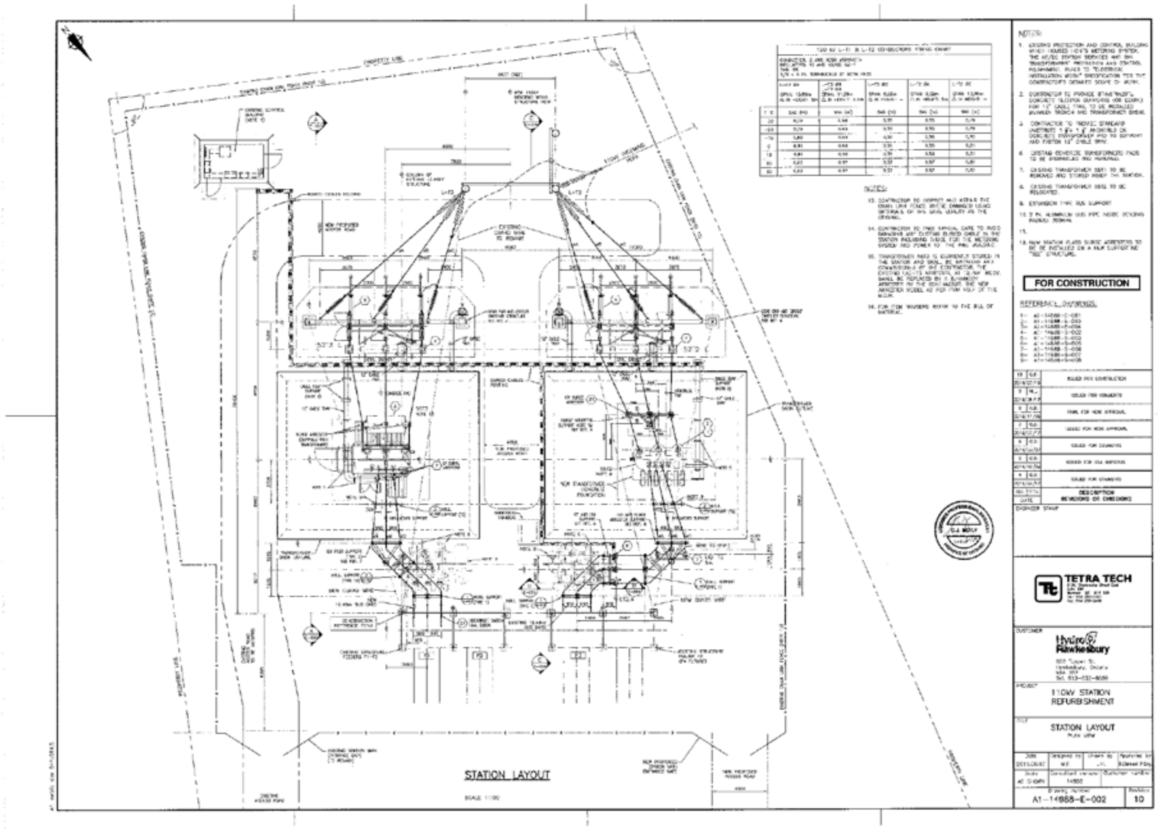

Figure 2: Station Layout

This station construction is in progress and is expected to be complete and in service before the end of 2017 and before the winter peak load. Approximately 3.5 MVA was transferred to MS 43 in the relatively low load period between winter and summer. MS 43 was supplying about 11.5 MVA with the current one transformer carrying load and the other only on potential arrangement.

The current investment for the current MTS is $3,525,000. The investment identified for the MTS based on EB-2011-0173 was $1,517,813. The differences are due to:

- Inflation due to delays. These delays were because of unforeseen failure events involving the new 43T2 transformer.
- There have been substantial changes required and costs incurred to meet requirements of authorities having jurisdiction (IESO, Hydro-One, and the MOE).

- Engineering costs were underestimated in the initial budget. There were issues with the ratings of equipment specified. They were not adequate for connection to the grid and higher rated equipment needed to be procured.
- There were engineering scope changes based on new reliability design criteria such as having a second transformer at the station.

The current project which is scheduled to be completed in 2017 is what HHI plans to complete with no other investment planned to the end of the forecast period. There may be a transformer upgrade in the future but this would be subject to future load studies and contingency analysis.

Appendix E

Justification to Replace Wood Distribution Poles

Justification to Replace Wood Distribution Poles

General Information on the Project

HHI has approximately 1400 poles. HHI tests the poles when they are 5 years from being depreciated. They also test poles that appear deteriorated on the three-year visual inspection. The poles are tested using a pole testing machine HHI purchased last year together with Cooperative Hydro Embrun. This test equipment gives objective values concerning the condition of the tested pole. If the reading indicates that pole strength degradation warrants replacement it is scheduled for replacement. Otherwise it is scheduled for a retest in 5 years. Each year poles are tested and the defective poles are scheduled for replacement.

The historical and forecast investments for pole replacement are indicated below.

2013	2014	2015	2016	2017	Total
$85,061	$24,310	$88,560	$69,572	$60,000	$327,503

Table 1 Historical Pole Replacement Investments

2018	2019	2020	2021	2022	Total
$81,500	$87,700	$88,100	$88,100	$90,000	$435,400

Table 2: Forecast Pole Replacement Investments

The replacement is typically like for like. However if there are several poles in need of replacement then the block of the street is rebuilt and constructed to current standards. In this way open wire services are replaced with triplex and the open wire secondary bus on the street is also replaced. This stays within the context of like for like in principle. There is a trend to increase this activity because the plant that was installed to accommodate the growth that took place in the 60's and 70's is now approaching its end of life. This is also reflected in the pole age distribution information in Section 5.3.2.

There is negligible impact on O&M costs as a result of this replacement.

There are no risks to the completion of this work at this time. The work is contracted out and it is well known within the line trade.

Evaluation Criteria and Information Requirements for the Project

Efficiency, Customer Value, Reliability

The trigger is that through testing it is determined that the pole is no longer able to perform its function. This increases the risk out power failures if the pole breaks in service and this also may be a hazard to the public. Not all poles need to be replaced immediately but they need to be replaced in a reasonable period of time. So there is some discretion in the scheduling of the work. Because the volume is relatively low, up to about 20 poles per year, they are usually completed in the year they are discovered.

Once a pole has deteriorated to the point it no longer is able to meet the design requirements for its function there are no economical alternatives to replacement.

Safety

There are safety implications for line staff particularly if they need to climb the pole for any reason. The added load of a person climbing the pole may cause the pole to break and risks injuring the linesperson. Also if the pole is subjected to winds that are within the design loadings the pole may break and cause an electrical hazard for the public or an obstruction hazard if it falls to the ground particularly if it falls onto a roadway.

Cybersecurity, 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.

This project addresses the replacement of end of life plant from the distribution system. In doing this HHI enhances the safety of the public and its contractors and enhances the reliability experienced by its customers. These are all part of HHI's policies and practices and are also part of HHI's legal responsibility.

The poles to be replaced are determined by testing. Poles that are still adequate for the job per the test results are not replaced but retested in five years.

Because HHI is proactive in testing and replacing defective poles it does not experience significant reliability issues caused by defective poles. If pole failures become more predominant then the current customer satisfaction level with system reliability may well be adversely affected. Further once there is a lack of confidence it will take a lot of effort to gain the confidence back.

Since most of HHI's customers are residential the impact for most of the year is low. However HHI has a number of electric heat customers who would be adversely affected in winter conditions.

This program while over the materiality threshold is relatively modest at up to about 20 poles per year.

The replacement is mostly like for like except where there are several defective poles on a street block in which case the entire block is replaced and the line rebuilt to current standard.

Appendix F

IESO Letter of Comment

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

IESO Letter of Comment

Hydro Hawkesbury Inc.

Renewable Energy Generation Plan

March 6, 2017

Independent Electricity System Operator

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

HHI 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]

HHI 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, HHI is not considering a generation facility. [24]

2.5.6 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

HHI is not proposing any special or different approach to funding its capital expenditure[25]

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[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

HHI received approval for an ICM a rate adder to recover an investment through the OEB's Incremental Capital Module back in 2012. The rate rider expired in 2014 when the utility included the costs in its 2014 Cost of Service Application [26] Since the ICM rate rider expired with the approval of the in the utility's 2014 Cost of Service application, HHI does not need to balance 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]

HHI 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 HHI 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.

HHI's ESQR has 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]

HHI 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

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%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Appointment Scheduling	65.0%	100.0%	100.0%	100.0%	100.0%	98.3%
Appointments Met	90.0%	97.8%	97.4%	100.0%	100.0%	95.2%
Telephone Accessibility	80.0%	99.9%	100.0%	99.9%	99.9%	100.0%
Rescheduling a Missed Appointment	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	99.6%
Emergency Urban Response	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Micro-embedded generation facilities	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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	0.777	4.606	11.331	2.638	7.653	0.758	1.090	0.133	1.109	1.393
SAIFI	0.889	1.673	5.073	1.444	1.823	0.693	0.472	0.254	0.483	0.603
5 Year Historical Average										
SAIDI					5.401					0.896
SAIFI					2.180					0.501

2014 Causes of interruptions			
Code	**Description**	**Total customer affected**	**Total customer hours**
0	Unknown/other	0	0
1	Scheduled outage	1073	453.33
2	Loss of supply	27216	63243.61
3	Tree contact	0	0

[31] MFR - Completed Appendix 2-G

4	Lightning	0	0
5	Defective equipment	302	252.98
6	Adverse/weather	0	0
7	Adverse environment	1	0.4
8	Human element	0	0
9	Foreign interference	60	46.82

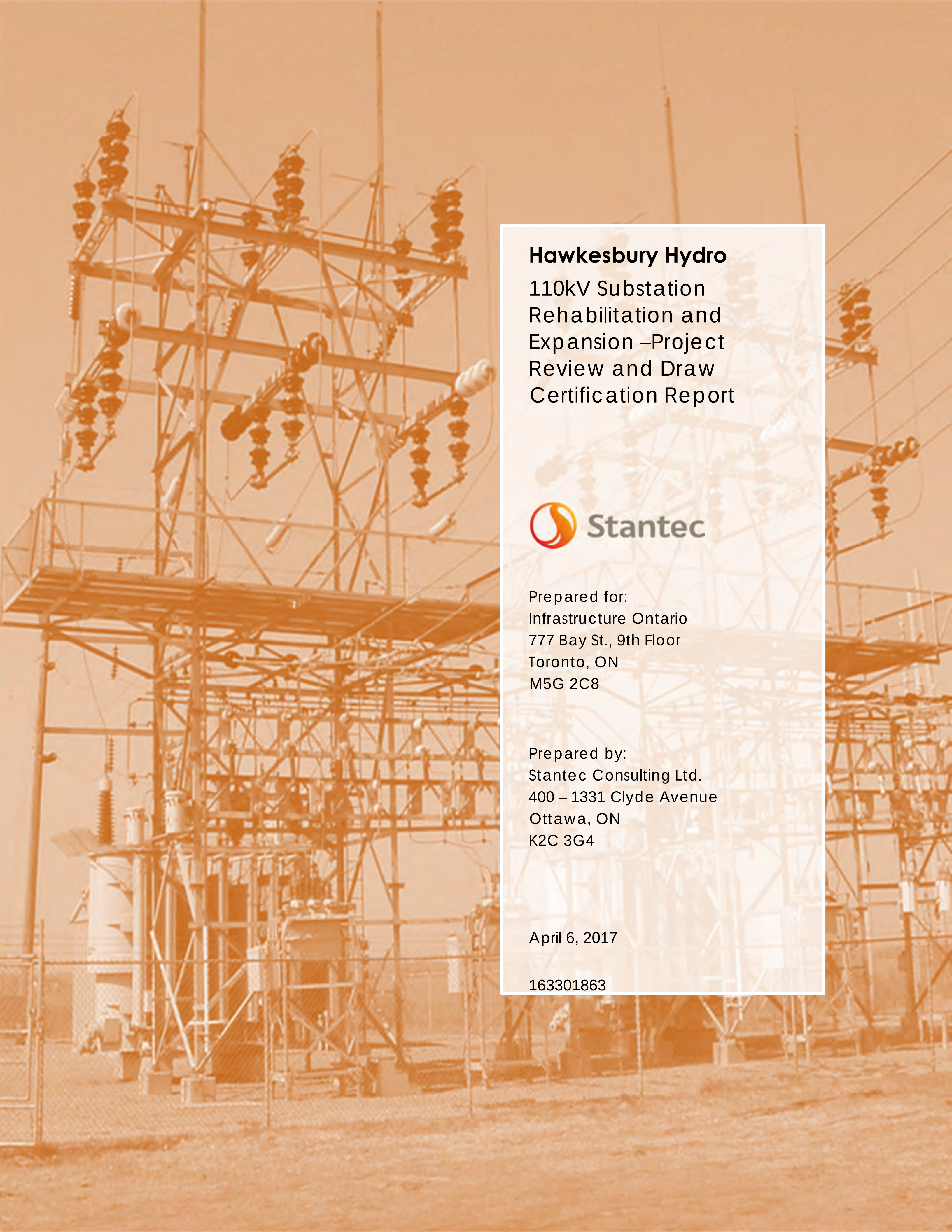
2015 Causes of interruptions			
Code	**Description**	**Total customer affected**	**Total customer hours**
0	Unknown/other	0	0
1	Scheduled outage	541	1473.15
2	Loss of supply	5316	8461.3
3	Tree contact	1329	3322.5
4	Lightning	0	0
5	Defective equipment	138	45.88
6	Adverse/weather	617	1234
7	Adverse environment	19	30.25
8	Human element	0	0
9	Foreign interference	27	26.12

2016 Causes of interruptions			
Code	**Description**	**Total customer affected**	**Total customer hours**
0	Unknown/other	0	0
1	Scheduled outage	60	60.49
2	Loss of supply	6751	34654.73
3	Tree contact	0	0
4	Lightning	0	0
5	Defective equipment	1641	4077.32
6	Adverse/weather	1083	2870.33
7	Adverse environment	78	58.22
8	Human element	0	0
9	Foreign interference	479	645.16

APPENDIX

LIST OF APPENDICES

Appendix A – Stantec Ottawa Report



Hawkesbury Hydro

110kV Substation Rehabilitation and Expansion –Project Review and Draw Certification Report

Prepared for:
Infrastructure Ontario
777 Bay St., 9th Floor
Toronto, ON
M5G 2C8

Prepared by:
Stantec Consulting Ltd.
400 – 1331 Clyde Avenue
Ottawa, ON
K2C 3G4

April 6, 2017

163301863

Table of Contents

Appendices

1 EXECUTIVE SUMMARY

1.1 OVERVIEW

Hawkesbury Hydro initially engaged the services of BPR in 2012 to provide project management, electrical and civil/structural engineering design and construction supervision services for the upgrades to their 110kV existing substation. Since then, most of the major equipment to be installed under the project has been pre-purchased, and some construction has been carried out, including the installation of a new control building within the substation.

In January, 2015, Stantec Ottawa was approached by Hawkesbury Hydro to provide technical assistance with the 110kV substation project and to satisfy Infrastructure Ontario's Independent Engineer reporting requirements.

In April, 2016, after discussion with Infrastructure Ontario, Stantec Ottawa introduced Hawkesbury Hydro to the Stantec Montreal power systems group. Stantec Montreal was enlisted to act as Hawkesbury Hydro's technical consultant, providing review and project administration services to help assemble a complete package for tendering the outstanding construction work and overseeing the project through completion. Stantec Montreal and Tetra-Tech began working collaboratively, managed to secure the two remaining approvals required for the substation project to go forward, from the Ministry of the Environment, and Hydro One, and tendered the remaining construction work to a list of qualified contractors.

The project was awarded to the successful bidder, Eptcon Ltd. for **$1,540,799.20** (taxes excluded) and construction began on September 26, 2016. Much of the civil and foundations work for the new substation equipment was completed in the subsequent months until construction was suspended in December, 2016. Hawkesbury Hydro and the project team decided to delay the risky portion of the construction activities (i.e. those involving transformer outages) until the Spring, when lighter loading levels were anticipated. Construction is scheduled to resume the week of April 10, 2017 and finish less than 2 months later.

1.2 PROJECT BUDGET

The project budget is currently estimated at **$3,728,010**, which includes a $375,200 contingency.

1.3 SOURCE OF FUNDING

The project was initially being funded by Infrastructure Ontario, subject to the terms outlined in the Financing Agreement dated February 15, 2012, providing funding of $2.3M, of which $1.55M was allocated for the 110kV substation project. An amending agreement is now in effect between Hydro Hawkesbury and Ontario Infrastructure and Lands Corporation, effective April 28, 2016. A second financing agreement was executed May 2016 providing additional funding of $1.93M from Infrastructure Ontario to Hawkesbury Hydro, $1.48M of which to be used to fund the 110kV substation project. Total funding from Infrastructure Ontario for the 110kV substation project, combining the two agreements (Loans #11050 and #15100) is **$3.03M**. Hydro Hawkesbury is required to inject $322,810 of their own funds to cover cost overruns.

1.4 COST TO DATE AND COST TO COMPLETE

Cost to date is **$2,520,473.96** and cost to complete is **$1,207,505.04** (including the $375,200 contingency). In the event that there are no additional unforeseen project cost escalations, and the contingency is not required, the cost to complete is currently **$832,305.04**.

1.5 SCHEDULE AND CASH FLOW

The latest schedule prepared by the contractor, Eptcon, in December has been included under Appendix I. The schedule indicates that Eptcon was scheduled to remobilize at the end of March and complete the May 25, 2017. Remobilization has been delayed until next week (April 9th) so the construction end date might shift slightly also, into the beginning of June. Eptcon is in the process of updating the construction schedule.

The funding in place from Infrastructure Ontario is expected to cover all project costs except for **$322,810** to be injected by Hydro Hawkesbury immediately, to offset the amount requested in the current draw. In the event that any additional costs should arise, requiring any portion of the contingency to be used, these additional costs will be identified and must be covered by Hydro Hawkesbury's cash reserves.

1.6 REQUESTED DRAWDOWN

A drawdown of **$765,130.86** is requested by Hawkesbury Hydro for April 18, 2017 to cover the cost of the first two progress claims submitted by Eptcon for work completed before November 30, 2016, as well as invoices for equipment, engineering and indirect costs from vendors including Mindcore, General Electric, Tetra Tech, and Stantec.

1.7 OTHER ITEMS FOR LENDER'S CONSIDERATION

Hydro Hakesbury and Eptcon entered into a CCDC2 Stipulated Price Contract for the completion of the upgrades to the 110kV substation. Since contract execution, one change order has been approved for $18,998.11 for the replacement of the substation fence. This cost is to be covered by Hydro Hawkesbury and represents the only change order approved to date. There are no contemplated change notices pending for the project.

2 TERMS OF REFERENCE

2.1 ENGAGEMENT

The Power Systems Group within Stantec Ottawa has been providing engineering services to Hawkesbury Hydro for more than 10 years. During this time, Stantec has performed a utility load flow study comprising the entire distribution system of the Town Hawkesbury, assisted Hawkesbury Hydro with the development of non-utility generation connection procedures, designed overhead distribution systems and provided technical expertise on a number of other projects. Through successful execution of a several projects over the past decade, Stantec has gained a thorough understanding of Hawkesbury Hydro's distribution system and business.

The contract for the design of the new 110kV substation was initially awarded to BPR, an entity of Tetra Tech, following tendering of an RFP and a competitive bid process in 2012, during which Stantec was also a bidder.

In January 2015, Stantec was enlisted by Hawkesbury Hydro to provide technical assistance with the 110kV substation rehabilitation/expansion. Hawkesbury Hydro met with Stantec to provide a project briefing and relayed a number of concerns regarding the content and completeness of the design documents, and issues with equipment specified and purchased to date.

2.2 SCOPE AND OBJECTIVES OF REVIEW

The documentation reviewed by Stantec includes the most recent drawings and specifications prepared by BPR, as well as all background information, reports, approvals and relevant correspondence, which have been made available by Hawkesbury Hydro.

The objectives of Stantec's third party review of the project were to evaluate degree of completeness, technical merit, and feasibility of works outlined in the drawings and specifications prepared by BPR, as well as ensure clear delineation of responsibility with regards to purchasing of equipment, installation, testing and commissioning activities required.

Stantec also conducted a review of the substation in April 2015, and evaluated new equipment installed or stored on the site as part of this project, and subsequently, any documentation and correspondence leading to the purchased thereof.

While fulfilling Infrastructure Ontario's Independent Engineer reporting requirements, the intent of the review is also to assist Hawkesbury Hydro in receiving a documents package from BPR that completely defines the project, and would be suitable for tendering to a list of qualified contractors.

Stantec's objectives were in line with Hawkesbury Hydro's intent to have their 110kV substation rehabilitated under a Fixed Price Contract, similar to the CCDC 2 'Stipulated Price Contract', published by the Canadian Construction Documents Committee.

2.3 METHODOLOGY

Stantec's review of the project was undertaken using the following methodology:

- Conduct a project briefing with Hawkesbury Hydro
- Perform a site review of the 110kV substation
- Acquire and review all available background documentation and correspondence
- Review the latest drawings and specifications
- Provide a list of questions and concerns for review and comment by BPR
- Review the modified drawings and specifications and provide additional comments, as required

Following the review of the site, design documents, and background documentation and correspondence, Stantec issued a set of comments to BPR, through Hawkesbury Hydro. A copy of Stantec's review comments, along with BPR's responses, has been attached as Appendix A. Stantec's comments are shown in regular/black text, and BPR/Tetra Tech's (TT) initial responses to the comments are shown below in red text. Where further discussion was warranted, responses are followed by another iteration of Stantec comments and TT responses, shown in regular/black text and blue text, respectively.

Some of TT's responses to Stantec's review comments demonstrate reluctance to assume technical and oversight responsibility for key aspects of the design. This assessment is solely based, however, on comparison between the design documents produced by TT and their mandate, as outlined in their fee proposal, attached as Appendix B.

2.4 CONDITIONS PRECEDENT UNDER THE FINANCING AGREEMENT

The conditions outlined in the amending agreement (AA) between Hydro Hawkesbury Inc. and Ontario Infrastructure and Lands Corporation (OILC), dated April 28, 2016 include but are not limited to the following:

- OILC agrees to provide financing in the amount of **$2,300,000.00** to the Borrower, Hydro Hawkesbury Inc. Of the total $2.3M initially funded by OILC, $750K was allocated for another project, and the remaining **$1.55M** for the 110kV substation project.

- The Borrower shall maintain a Debt Service Coverage Ratio at **1.3 to 1 or higher** for the term of this Agreement; such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable. Debt "Service Coverage Ratio" is defined as earnings before interest, taxes, depreciation and amortization, divided by interest and principal payments.

- The Borrower shall maintain a Debt to Assets Ratio at **60% or lower** for the term of this Agreement; "Debt to Assets Ratio" is defined as all interest bearing debt divided by total assets.

The above conditions effectively replaced the financial covenants outlined in the original financing agreement (FA), executed in February, 2012.

A second financing agreement for an additional loan of **$1,930,000.00** was executed between OILC and Hawkesbury Hydro May, 2016. $450K of this second loan is to fund another project, and **$1.48M** to fund the 110kV substation project.

3 DESCRIPTION OF PROJECT

3.1 THE PROJECT STRUCTURE

Hawkesbury Hydro initially engaged the services of BPR in 2012 to provide project management, electrical and civil/structural engineering design and construction supervision services for the addition of a new 110kV/12.48kV 25MVA transformer in the existing Hawkesbury Hydro substation. The agreed upon scope of work and deliverables are outlined in BPR's professional services proposal, attached hereto as Appendix B.

Hawkesbury Hydro's intent was to have their 110kV substation rehabilitated under a Fixed Price Contract, similar to the CCDC 2 'Stipulated Price Contract', published by the Canadian Construction Documents Committee. To this end, the Consultant, BPR, was to generate a set of tender documents (drawings and specifications) that would completely define the project. With the finished documents, a Request for Proposal (RFP) would be issued to various constructors to provide firm prices to complete the work. BPR should be available to assist in the tendering process, answering technical questions from bidders, offering assistance in evaluation of the submitted bids, perform all site reviews, review payment certificates, and other technical tasks on behalf of Hawkesbury Hydro throughout the project until successful completion. The owner may pre-purchase large or long delivery items, but based on specifications provided by and shop drawing reviews conducted by the Consultant. It is also the Consultant's responsibility to ensure that the installation, warranty, testing and commissioning of pre-purchased equipment is properly accounted for in the tender documents, to ensure the cost to perform all required tasks is appropriately accounted into the contractor bids.

Some issues noted with the project structure in the Initial Project Review were as follows:

- The Consultant has provided design services but has yet to produce a complete and thorough design package that can be used to solicit bids for a Fixed Price Contract to complete the outstanding work.
- The Consultant has solicited some information from various regulatory authorities, including the IESO, Hydro-One, and the OEB; however, but there have been substantial changes required and costs incurred to meet requirements of authorities having jurisdiction. This may be due to the Consultant's failure to confirm some requirements with the authority having jurisdiction, properly incorporate them into the design, or may be as a result of the authorities having jurisdiction failing to provide timely and/or comprehensive responses to TT.
- The Owner has pre-purchased some of the large equipment with long lead times; the Consultant has not updated the drawings and specifications accordingly, to clearly identify the contractor's scope of work regarding pre-purchased equipment.
- The Owner has directed some work, including letting contracts to sub-contractors, scheduling construction, and otherwise organizing the on-going completion of the project; these tasks should be the responsibility of the Consultant and the contractor. The owner should not be required to act as the constructor themselves. Under normal circumstances, as is the case with Hawkesbury Hydro, the owner does not have the

appropriate capabilities, insurance, or capacity to act as the constructor.

- The Owner had employed a Construction Manager (CM) at one point to try to bring the project back on track, but the CM was not successful in managing the work acceptably.
- Several engineers have been involved with the project since its original inception, due to departure of personnel from TT. It should be ensured that TT has all required personnel in place to fulfill the requirements of their contract with Hawkesbury Hydro and that all parties agree on the responsibilities of TT, going forward, to see the project through construction completion.

All of these initial issues have been addressed through the combined efforts of Stantec Montreal and Tetra-Tech. Hydro Hawkesbury has entered into a CCDC 2 'Stipulated Price Contract' with Eptcon, for completion of the substation refurbishment.

3.2 THE SITE

The project site is Hawkesbury Hydro's existing 110kV substation, located on the south side of Main St. W, in Hawkesbury, Ontario, as shown in Figure 1 below. Two 110kV/12.48kV 7.5/10/12.5MVA ONAN/ONAF/ONAF transformers currently operate within the substation supplied by a feeder out of the Hydro One Hawthorne Transmission Station.

Figure 1: Hawkesbury Hydro 110kV Substation

3.3 THE SYSTEM

The purpose of the 110kV substation refurbishment project is to replace one of the existing transformers (T1) with a 15/20/25MVA ONAN/ONAF/ONAF transformer to increase the substation capacity. The new transformer would be supplied by a new 145kV, 1200A, 40kA-rated circuit switcher. The design is to include a new concrete pad and oil containment for the new transformer as well. A second circuit switcher, concrete pad, etc. is to be included to support the future replacement of transformer T2. The most recent design drawings and specifications have been included herewith as Appendix C.

3.4 ENERGY PRODUCTION

Electricity distributed through the town at 12.47kV from the Hawkesbury Hydro substation is received at 115kV from Hydro One's Hawthorne Transmission Station. The estimated peak demand on the Hawkesbury Hydro substation is expected to reach 20MVA in 2016, and 21.9MVA by the year 2025 based on a peak demand of 19.4MVA, recorded in January, 2013. Replacement of T1 with a 25MVA transformer will increase the substation's overall capacity from 25MVA to 37.5MVA, providing redundancy sufficient for the support of peak loading conditions into the future.

3.5 FINANCIAL ANALYSIS

Hydro Hawkesbury filed a Cost of Service application in 2013 for rates effective January 1, 2014.

The current rates, approved during this proceeding, were based on the following deemed cost of capital parameters:

Capitalization/Cost of Capital

Capital Structure:	
Long-term debt Capitalization Ratio (%)	56.00%
Short-term debt Capitalization Ratio (%)	4.00%
Common Equity Capitalization Ratio (%)	40.00%
	100.00%
Cost of Capital:	
Long-term debt Cost Rate (%)	3.94%
Short-term debt Cost Rate (%)	2.11%
Common Equity Cost Rate (%)	9.36%

On an approved Rate Base of $6,386,201, the utility collects, through its current rates, $385,394 to cover its return on investments. This amount covers a Deemed Interest Expense in the amount of $146,295 and Return on Deemed Equity of $239,099.

Debt Service Reserve works as an additional security measure for lenders. It is generally a deposit which is equal to a given number of months projected debt service obligations. Hawkesbury Hydro does not currently have a Debt Service Reserve or a Maintenance Reserve.

The following table shows the value of Hawkesbury Hydro's assets including its Rate Base, where Rate Base = Net Fixed Assets + Working Capital Allowance. The table compares the capital spending approved by the Ontario Energy Board (OEB) with the 2014 Actuals. The reason for the underspending in capital assets is in part due to unforeseen issues with the substation project.

	OEB Approved 2014	Actual 2014
Utility Income	**239,099**	**372,868**
Gross Fixed Assets (year end)	7,129,008	6,956,532
Capital Expenditures (additions)	**1,807,902**	**138,072**
Accum Depreciation	-2,261,013	-2,257,966
Net Fixed Assets	4,867,996	4,698,567
Average Net Fixed Assets	4,094,282	4,395,783
Utility Rate Base	6,386,201	6,004,701
Deemed Equity Portion of Rate Base	2,554,480	2,401,880
Income/(Equity Portion of Rate Base)	9.36%	15.52%
Indicated Rate of Return	6.03%	6.32%
Approved Rate of Return	6.03%	6.03%
Sufficiency / (Deficiency) in Return	0.00%	0.28%
Equity	*40%*	*40%*
Short Term Debt	*4%*	*4%*
Long Term Debt	*56%*	*56%*
Equity Return	*9.36%*	*9.36%*
Short Debt Return	*2.11%*	*2.11%*
Long Debt Return	*3.94%*	*3.94%*
Tax Rate	*15.50%*	*15.50%*
Net Revenue Sufficiency / (Deficiency)	**0**	**16,949**

3.6 OPERATIONS AND MAINTENANCE

Hawkesbury Hydro's substation equipment is operated and maintained in accordance with equipment manufacturers' recommendations. Hawkesbury Hydro has oil sampling and testing performed annually on their substation transformers. Subsequent shutdowns are performed, if/as required to correct any anomalies. General Electric is typically hired to conduct electrical maintenance and testing of the equipment within both Hawkesbury Hydro substations.

4 PERMITS, APPROVALS, ETC.

4.1 APPROVALS

4.1.1 Ontario Power Authority (IESO)

The Independent Electricity System Operator (IESO) granted conditional approval for the transformer replacement at Hawkesbury Hydro's 110kV substation in July, 2013. Their System Impact Assessment report is attached hereto as Appendix D.

4.1.2 Ministry of the Environment

The Ministry of Environment (MOE) Environmental Compliance Approval Application for the project, attached as Appendix E, was submitted June, 2015. The application includes other documents, as follows:

- Environmental Response Plan submitted by Hawkesbury Hydro
- Acceptance letter from Southern Nation Conservation
- Acceptance letter from Town of Hawkesbury
- Design Brief by TetraTech (TT or BPR)

The pending MOE application indicates that a secondary containment system is to be installed for the substation oil-filled transformers consisting of geocomposite clay liner based basins, and an "Imbiberbeads" type drain shut-off system to block drainage in the event of a spill. The Consultant's design documents contradictorily show a Sorbweb system, which cannot be installed. The manufacturer, Albarrie GeoComposites, suspended all quotations, deliveries, and installations of the system in September, 2013, pending investigation of an oil spill. This issue was among the review comments submitted by Stantec (Appendix A), as well as concerns related to the delay in receiving MOE approval. Environmental Compliance Approval was granted by the MOE on February 1, 2016, and is attached hereto as Appendix E.

4.1.3 Hydro One

Hydro One reviewed partially completed drawings and specifications back in April, 2015, and indicated their approval for the proposed loadbreak switches. Initially, circuit switchers that did not meet Hydro One and IESO requirements were prepurchased. Hawkesbury Hydro was subsequently required to purchase additional loadbreak switches for installation upstream of the circuit switchers. Hydro One approval of the revised design was secured May 26, 2016.

4.1.4 Notice to Proceed (NTP)

As this project is an upgrade of existing plant, the NTP is not applicable.

4.1.5 Regional/County/Municipal

Plans were initially submitted to the Town of Hawkesbury for review in April of 2014. Due to the location of the substation, and potential impact on the municipal water system, the Town of Hawkesbury indicated that a building permit application was required, as well as environmental approval. Of particular concern was the secondary containment system proposed for the transformers.

The building permit application was completed and submitted in December, 2014. The documentation submitted included the plans and specifications, as well as a design brief and a description of the proposed confinement basins and "Imbiberbeads" drain shut-off system.

Upon review of the application and supplementary documents, the Town of Hawkesbury concluded that a permit would not be required. They do however require site observations reports to be submitted for their records and have requested notification upon completion of construction, as expressed via letter on January 19, 2015. Appendix F contains this letter, along with the other correspondence between Hawkesbury Hydro and the Town of Hawkesbury relating to the substation upgrades.

4.1.6 Building Permits/SPA/Zoning

A building permit for the installation of the prefabricated building to house the substation protection equipment was issued in January, 2014 and is attached hereto as Appendix G. As indicated in the previous section, an additional permit for the substation works is not required.

4.2 CONTRACTS

4.2.1 EPC Contract

An engineering procurement construction contract does not apply in the case of this project. As described in Section 3.1, the engineering services are provided under the terms of the BPR services proposal and the construction will be executed under a CCDC Stipulated Price Contract, following a competitive bid process.

4.2.2 Land Tenure

The 0.758 acre land on which the 110kV substation is built was transferred to Hawkesbury Hydro from Hydro One Networks, Inc. in 2001. The land/deed transfer is included under Appendix F, among the documentation submitted as part of the building permit application to the Town of Hawkesbury.

4.2.3 Infrastructure Ontario Financing Agreement(s)

Hydro Hawkesbury Inc. and Ontario Infrastructure and Lands Corporation (OILC) executed their original financing agreement in February, 2012. In the agreement, OILC agreed to provide financing in the amount of $2.3M to the Borrower, Hydro Hawkesbury Inc. Of this $2.3M total, **$1.55M** was allocated for the funding of the 110kV substation project. In May, 2016, Hydro Hawkesbury Inc. and OILC entered into a new financing agreement whereby OILC committed to an additional total loan amount of $1.93M, with **$1.48M** allocated for the funding of the 110kV substation project. The total amount of OILC funding provided for the upgrades to Hawkesbury Hydro's 110kV substation is **$3.03M**, the sum of the funds allocated to the project within each of the two financing agreements.

4.2.4 Construction Contract

The CCDC2 Stipulated Price Contract entered into by Hawkesbury Hydro and Eptcon for the completion of the 110kV substation upgrades is attached hereto as Appendix N.

5 PROJECT BUDGET

5.1 BUDGET (INCLUSIONS/EXCLUSIONS, ETC.)

In April, 2015 Tetra-Tech total submitted a revised budget estimate of $2,830,300, which was approximately $1.2 million dollars in excess of what was originally estimated. Stantec identified some items that appeared to have been unaccounted for in Tetra-Tech's estimate in November 2015. As such, the project budget was adjusted to **$3,030,800** and a new financing agreement was executed in May 2016 between to provide the additional funding. Of the $3,030,800 total estimated budget in November 2015, almost $1.47M had already been spent and the estimated cost to complete was therefore approximately $1.56M with $945K allocated for construction costs, $377K for indirect costs, and a $275K contingency. When the project was tendered in the fall of 2016, the lowest bidder was Eptcon with a cost of $1.54M, almost $600K more than what was left in the budget to fund construction. The bids were higher than expected due to the accelerated construction period and associated overtime costs that were not accounted for because the 2015 budget was not revisited before going to tender. Tetra Tech confirmed, however, that the main reason the budget was underestimated was because they had failed to account for project costs previously expended. Using the cost contingency, and savings on some of the indirect costs allowed for, the budget was revised to **$3,219,623.75** in the November, 2016 Drawdown and Certification Report.

Following submission of the November 2016 report and Hydro Hawkesbury's drawdown request, Tetra Tech revisited the project budget and additional costs came to light that had not been accounted for previously. These were fees imposed by the Electrical Safety Authority for an additional review of construction plans and specifications for approval, as well as additional engineering fees for Tetra Tech for construction support. As a result of Hydro Hawkesbury's decision to delay the construction until the spring of 2017, additional fees were negotiated with Stantec Ottawa to extend the term of I.E. reporting responsibilities. These additional costs further increased the project budget to **$3,335,969** (rounded up by Tetra Tech to $3,336,000), with no contingency.

At the request of Infrastructure Ontario, Stantec Ottawa prepared a report identifying any risks of future cost escalation. A proposal to increase Stantec Ottawa's level of oversight for the remainder of the project was additionally requested by I.O. The identified risks were quantified and summed to arrive at a total contingency of $375,200. Including Stantec's additional fees, but excluding the contingency, the updated budget is $3,352,810. Also including the contingency, the estimated budget was increased to **$3,727,979** (rounded up to $3,728,010) broken down as follows.

Item	Budget (2015)	Current Budget	Costs to Date	Costs to Complete
Construction Costs				
Civil and Structural	$607,030.00	$985,512.00	$811,425.68	$174,086.32
Electrical	$1,404,420.00	$1,718,317.00	$1,232,612.88	$485,704.12
Decontamination (if required)	$99,470.00	$0.00	$0.00	$0.00
Sub-total	**$2,110,920.00**	**$2,703,829.00**	**$2,044,038.56**	**$659,790.44**
Indirect Costs				
Engineering and Services	$373,442.00	$364,792.00	$339,735.90	$25,056.10
Hydro One Fees	$60,000.00	$60,000.00	$60,000.00	$0.00
IESO Fees	$1,450.00	$1,450.00	$1,450.00	$0.00
Pre-op Commissioning	$94,445.00	$76,886.00	$0.00	$76,886.00
Construction Admin/Mgmt	$65,000.00	$75,600.00	$48,100.00	$27,500.00
3rd party review & IE reporting	$50,000.00	$70,222.00	$27,149.50	$43,072.50
Sub-total	**$644,337.00**	**$648,950.00**	**$476,435.40**	**$172,514.60**
Contingency	$275,543.00	$375,200.00	$0.00	$375,200.00
Total	**$3,030,800.00**	**$3,727,979.00**	**$2,520,473.96**	**$1,207,505.04**

5.2 PROJECT EQUITY

Project equity does not apply in this case, as the project is being funded by debt.

5.3 WORK IN PLACE AND COST TO COMPLETE

$2,520,473.96 has been spent on the 110kV substation refurbishment project to date, leaving an estimated cost to complete of **$1,207,505.04**, including the $375,200.00 contingency. If none of the contingency is required, the cost to complete the project will be **$832,336.04**.

5.4 MARGIN CALCULATION

1. FUNDING SUMMARY

Source of Fundung	Original FA	Current FA/ Reporting Budget	Advance to Date	Current Release	Balance on Sources
IO Construction Loan #11050	$1,550,000.00	$1,550,000.00	$1,432,533.10	$117,466.90	$0.00
Borrower's Equity	$50,000.00	$322,810.00	$0.00	$322,810.00	$0.00
IO Construction Loan #15100	$0.00	$1,480,000.00	$0.00	$647,663.96	$832,336.04
	$1,600,000.00	$3,352,810.00	$1,432,533.10	$1,087,940.86	$832,336.04

2. PRIMARY MARGIN

Gross Cost to Date	$2,610,376.50
Less HoldBack	$89,902.54
Net Cost to Date	2,520,473.96
Less Borrower's Cash Injection	322,810.00
Maximum Loan Available	2,197,663.96
Previously Advanced	1,432,533.10
Current Advanceable	$765,130.86
Requested Amount	*765,130.86*

3. SECONDARY MARGIN

3,030,000.00	Loan Amount
$832,336.04	Less Cost to Complete
2,197,663.96	
$322,810.00	Add Borrower's Cash Injection
2,520,473.96	Maximum Loan Available
1,432,533.10	Previously Advanced
$1,087,940.86	Current Advance
	(including borrower's injection)

5.5 CONSTRUCTION BUDGET

Based on the current contracts in place and a $375,200 contingency, the total construction cost is now estimated at **$3,727,979**.

5.6 HOLDBACK

A holdback of $39,509.80 was deducted from Eptcon’s first progress claim of $395,098.00 for work completed before October 31, 2016. A holdback of $50,392.74 was deducted from Eptcon’s subsequent claim for work completed in November, 2016. The total holdback amount is currently $89,902.54. 10% holdback will be applied to all of Eptcon invoices until project completion and application for holdback release, in accordance with the terms of executed CCDC2 Stipulated Price Contract.

5.7 ADVANCE RECOMMENDATION AND DRAW DOCUMENTS

After their own cash injection of $322,810.00, Hawkesbury Hydro has requested an advance of **$765,130.86** for April 18, 2017 to cover the project costs they have paid since the previous draw. Stantec has reviewed the latest construction schedule, as well as the invoices paid by Hawkesbury Hydro during this period. Stantec Ottawa additionally visited the substation on February 3, 2107 to verify construction progress.

Based on review of the invoices, other documentation and the construction progress, we recommend payment of the amount requested. Stantec confirms that none of the costs claimed are for changes to the contract, or other items unaccounted for in the current budget. Any such costs will be identified, and covered by Hawkesbury Hydro (i.e. the contingency).

6 CONSTRUCTION

All of the major substation equipment required for construction completion has been delivered and is either being stored within the substation or the adjacent lot, which has been rented by the contractor. Much of the civil and foundations work for the new substation equipment was completed in the Fall of 2016 and the project was on track for completion by its target date of December 15, 2016. In mid-November, the decision was made by Hawkesbury Hydro to delay the remainder of the construction until the spring to reduce the risk of an outage in December, during peak loading conditions.

During the changeover, the Hawkesbury Hydro customers are required to be supported by a single transformer for a significant period of time. Hawkesbury Hydro is able to divert some customers to its 44kV substation through switching, but there is a still a higher risk associated with having only one transformer in service in the 115kV station, instead of two. This condition is much less risky in the spring, when the loading levels on Hawkesbury power system are substantially lower.

Following remobilization, next week, Transformer T1 will be taken offline and moved to its new concrete pad. The system will be supplied only by Transformer T2 for a few weeks, while the structures, cabling, and protection work are completed for new Transformer T3, circuit switcher and loadbreak switch and the equipment is moved into placed and tested. Following energization of Transformer T3, Transformer T2 will be taken offline and the entire system will be supplied by the new Transformer T3 for the first few weeks of May, while the circuit switcher, loadbreak switch, and additional work is completed to reconnect Transformer T1 into the system.

6.1 CHANGE ORDERS

The decision to delay the remainder of the construction until the Spring of 2017 did not result in additional costs from the contractor, Eptcon, because their costs for remobilization, additional labor, etc. were offset by the overtime costs built into their original bid price, due to the accelerated schedule that was originally mandated by the tender documents.

There have been no change orders approved to the Eptcon contract to date with the exception of one for $18,998.11. This change order was for the elective replacement of the substation fencing and has not been captured in the budget. None of this $18,998.11 has been paid by Hawkesbury Hydro or invoiced by Eptcon to date. When this change order or any portion thereof is invoiced, the amount will be paid by Hawkesbury Hydro and excluded from any drawdown requests. There are no other change orders approved or pending contemplated change notices (CCN’s) on the project.

6.2 CONSTRUCTION SCHEDULE

Construction began on September 26, 2016 and was originally expected to be completed by December 15, 2016. The contractor’s latest schedule is attached hereto as Appendix I, which was prepared following Hawkesbury Hydro’s decision to delay the project until the Spring of 2017. The schedule shows a remobilization date of March 29, 2017 (last week). Eptcon has not remobilized yet, as the date was pushed back due to weather conditions. Eptcon is in the process of preparing an updated schedule to reflect the actual remobilization date, which is now scheduled for April 10th. Once the revised schedule has been received, the target completion date will be confirmed. As per the current schedule, the target completion date is May 25, 2017. This may be pushed back until early June as a result of the delayed remobilization.

It appears, however, that Eptcon has some buffer built into the schedule and the delayed remobilization should therefore be unlikely to impact the schedule or cost; the remaining construction work was originally scheduled to be completed within a 4-5 week period at the end of 2016 and now the same work has been spread over a 2 month period.

6.3 STATUTORY DECLARATION/WSIB CERTIFICATES

A copy of the contractor's WSIB certificate and registration are attached hereto as Appendix O.

6.4 SITE VISIT REPORTS

Two site reports, from Tetra Tech visits on October 13th and October 18th, are included under Appendix P.

6.5 PHOTOS

Stantec (Ottawa) visited the substation February 3, 2017. No work was in progress, as construction was suspended in December, 2016. Foundations for equipment were visible but nearly 100% snow-covered, as shown in the photos below.

Figure 2: 110kV Substation

Figure 3: 110kV Substation

Stantec (Ottawa) visited the site on October 27th to review the construction progress. Eptcon's subcontractor, Hawkins, was on site digging. They were on schedule to complete concrete work by the end of the following week (November 4th). Photos from this visit are included below.

Figure 4: 110kV Substation

Figure 5: 110kV Substation

Figure 6: 110kV Substation

Figure 7: 110kV Substation

Figure 8: 110kV Substation

In June 2016, Infrastructure Ontario visited the site with Hawkesbury Hydro, Tetra Tech and Stantec. Photos from this visit, which occurred prior to the recommencement of construction by Eptcon, are included below.

Figure 9: 110kV Substation

Figure 10: New Transformers and Equipment to be Installed

Figure 11: Existing Transformer, New and Existing Poles

Photographs from a previous site visit conducted by Stantec in April, 2015 are shown below.

Figure 12: New 110kV Poles

Figure 13: Pre-purchased Equipment Stored in Substation

Figure 14: New Controls Building

6.6 ISSUES GIVING RISE TO DELAYS/COST OVERRUNS

The anticipated construction cost, based on Eptcon's base contract, is approximately **$600K** in excess of the most recently completed construction budget. The fact that the lowest bid (Eptcon's) was higher than the estimated cost may have been partially due to the condensed schedule. Tetra Tech did not update the project budget in 2016 prior to tender to account for the project's accelerated schedule and, in their 2015 budget, they did not account for costs that had been spent to date.

Following submission of the November 2016 report and Hydro Hawkesbury's drawdown request, Tetra Tech revisited the project budget and additional costs came to light that had not been accounted for previously. These were fees imposed by the Electrical Safety Authority for an additional review of construction plans and specifications for approval, as well as additional engineering fees for Tetra Tech for construction support. As a result of Hydro Hawkesbury's decision to delay the construction until the spring of 2017, additional fees were negotiated with Stantec Ottawa to extend the term of I.E. reporting responsibilities and provide additional oversight on behalf of Infrastructure Ontario.

Stantec Ottawa prepared a report in February, 2017, identifying potential risks of future cost escalations or delays. These risks are summarized as follows:

- Weather conditions (could lead to delays)
- Errors/omissions in construction documents
- Issues with circuit switcher after long term storage
- Moisture content in transformer oil
- Other issues with transformer after long term storage
- Unforeseeable site conditions
- Electrical outage/failure

The decision to delay the remainder of the construction work has reduced the risk of further cost escalation (due to electrical outage/failure) by allowing two of the 115kV substation transformers to continue to operate until April, when lighter electrical loading conditions are expected. Weather could still be a factor, as it has an impact on the system loading and could delay resumption of civil work, but Hawkesbury Hydro will be monitoring the system loading daily and Eptcon's schedule appears conservative and so should not be impacted overall by delays due to weather.

The remaining risks have been quantified and totaled to arrive at a $375,200 contingency.

7 PROFESSIONAL CONSULTANT'S REPORTS REVIEWS

7.1 DUE DILIGENCE REPORTS

Tetra Tech completed a ground grid study in October, 2014, attached hereto as Appendix J.

7.2 ENVIRONMENTAL SITE ASSESSMENTS

This is discussed previously in Section 4.1.2.

7.3 GEOTECHNICAL REPORTS

Houle Chevrier Engineering, Ltd. conducted a geotechnical investigation and subsequently prepared a report in August 2012. The geotechnical report is attached hereto as Appendix K.

APPENDIX A
DESIGN REVIEW COMMENTS

Stantec Consulting Ltd.
400 - 1331 Clyde Avenue,
Ottawa ON K2C 3G4
Phone: 613-722-4420
Fax: 613-722-2799

June 30, 2015
File: 163301863

Attention: Michel Poulin
Hawkesbury Hydro
850 Tupper Street
Hawkesbury, ON K6A 3S7

Dear Mr. Poulin,

Reference: 14988 – Hydro Hawkesbury 110kV Station Retrofit

This document includes all mark-ups noted on the "Hydro Hawkesbury 110kV Station Retrofit Electrical Installation Work", Technical Specification prepared by BPR (Tetra Tech), dated September 18th, 2013 and on the 110kV Station Refurbishment drawings prepared by Tetra Tech, Issued for Comment, dated 2015-03-27. The purpose of this document is to simply ensure all mark-ups identified on the technical specification and drawings are clearly understood; therefore, this document must be read in conjunction with the marked-up technical specifications and drawings. Red text is the response from Tetra Tech, while the following black text is our response again. Note the abbreviations for Hawkesbury Hydro (HH) and Tetra Tech (TT). Note that a few more comments have been added.

SPECIFICATION COMMENTS

The following section clarifies the mark-ups noted on the Technical Specification; therefore, the comments in the section should be read while referencing the technical specification mark-ups.

GENERAL NOTES:

- The technical specification is insufficient to provide complete guidance to a contractor for the purpose of bidding. A complete tender package should be prepared that references or includes a detailed contract similar to the requirements of the Canadian Construction Document Committee's CCDC 2 with typical front end contractual and bidding requirements. Although the technical specification provides general equipment and commissioning requirements it does not detail any contractual obligations of the contractor. The technical specification does not making any reference to the required qualifications of the contractor, insurance requirements, warranty requirements, shop drawing submission requirements, regularly scheduled construction meetings, time frame for which the project is to be completed, details of how the commissioning process is to be completed, etc. Currently the documentation evaluated is insufficient for Hawkesbury Hydro to engage in a contract with a construction contractor as the terms of the contract are not established with the technical specification. Tetra Tech has prepared the technical specification only. All commercial clauses are out of scope. The technical specification should include all Div 01, 02, and other sections that are relevant to this project, and only refer to the typical CCDC contract. If HH wants to modify the standard CCDC front end contractual and bidding requirements, they may then do so as their prerogative. Should be confirmed with HH.
- The most recently issued technical specification is close to a year and a half older than the most recent drawings issued. As a result, with many significant items of equipment having already been purchased, many of the tasks outlined in the technical specification are no longer relevant. The tender documents should be carefully reviewed and modified to clarify the tasks the contractor shall perform to successfully complete the project. The intent of this

package was to send it to a general contractor, not to split items to different contractor. Agreed, this would be the preferred method. Ok

- Have the interrupting ratings of the downstream equipment been evaluated against the increased fault levels? The fault levels supplied by the new transformer are not substantial but the lowest rated devices within the 12.47kV network should be reviewed and evaluated against the new fault levels. Even if the verification of downstream equipment is out of scope. As the maximum fault level is 5.58 kA. We assume the equipment will still have the appropriate capacity. The impact of increased fault current should always be reviewed at least on the devices directly fed by the increased supply, especially the immediately downstream distribution system. The existing switches will be replaced by appropriate switches.

SECTION 2 - SCOPE OF WORK

- The specification references Sorbweb, our understanding is an Imbiber systems is being proposed, this change should be integrated into the tender documents. Note that the consultant must ensure any approvals will be, or can be granted, before proceeding to tender. In process with Ministry of the Environment. Is there an estimated time for approval? Note that if this process will take too long it may be beneficial to move to some other type of oil containment system, such as that provided by CI Agent. TT will confirm the estimated time with the designer.
- Reference is made to installing the new control building, this should be removed, but any remaining requirements to modify, integrate, or commission the new building should be clearly added. To be incorporated to the document. Ok.
- The specification is stating that new bushing current transformers (CTs) will need to be installed on the existing transformer 55T2. Are these CTs being installed inside the transformer or over the exterior portion of the bussing? The method in which the CTs are installed should be clarified and the specification of the CTs should be specific. They will be mounted onto the exterior portion of the bushing. Ok, ensure specifications are added for exterior type instrument transformers. OK
- The specification states the transformer manufacture will off load the transformer. Is this still the case, as the transformer is already on site? The Transformer is already on site. Ok, modify specifications to suit. OK
- Reference to the supply, installation, and commissioning of the two new 3000A, 115 kV operational disconnects should be added to the specification. To be incorporated in the document. Ok.

SECTION 3 - WORK EXCLUDED

- Will the contractor not have to install the transformer? By M. Poulin The client cannot take on the responsibility of a constructor, the design should include ensuring the general contractor takes responsibility for testing the transformer, moving and installing the transformer, then retesting and commissioning the transformer. Who is responsibility for the warranty should be clarified within the tender design. This questions shall be answered by HH. As they have managed the contract of the procurement and installation of the power transformer.

SECTION 5 - STANDARDS

- The system designer should complete a design that meets CSA and IEEE requirements as well as account for HONI and IESO requirements. No comment from TT. The design meets the requirements.

SECTION 6 - TECHNICAL REQUIREMENTS

6.1.1 Has a lightning protection study already been completed? Not included in the scope. The existing ground wires are kept. Ok.

6.2.2 Once the ground grid is backfilled the ground grid should be tested to confirm its impedance matches that defined in ground grid study. To be incorporated to the document. Ok.

Confirm ground current used in ground grid analysis meets the requirements of Hydro One. Hydro One has often requested that higher-than-actual ground fault currents be used in analysis and design of the ground grid electrode. The sentence from the ground grid study is unclear as to where the line to ground fault level was derived from.

> The maximum symmetrical line to ground fault current is 1.761kA with X/R=3.83 without considering the contribution of incoming line from the HONI station and distribution lines.

The effect of the transmission overhead ground wires and neutral conductors of the distribution lines is not considered in the study. Where transmission line overhead ground wires or neutral conductors are connected to the substation ground, a substantial portion of the ground fault current is diverted away from the substation ground grid. Confirm ground current used in ground grid analysis meets the requirements of Hydro One, the data from the fault simulation is for existing conditions in 2012 and may not meet future supply growth.

The values received will be checked with Hydro One.

SECTION 7 - STATION YARD ELECTRICAL EQUIPMENT INSTALLATION

7.1 This section should be reviewed and updated to reflect the current status of the project.

How are you to prove that the contractor damaged the transformer? Typically transformers are supplied and installed by the contractor such that the contractor is responsible for the integrity of the transformer until the transformer's ownership is turned over to the owner at the end of the project. It will be difficult for the contractor to take responsibility for a transformer they did not supply or off load initially. The transformer should be tested before and after the transformer is installed on its pad to ensure the transformer's condition is known before it is relocated by the contractor. By M. Poulin. The client cannot take on the responsibility of a constructor, the design should include ensuring the general contractor takes responsibility for testing the transformer, moving and installing the transformer, then retesting and commissioning the transformer. Who is responsibility for the warranty should be clarified within the tender design.

This question shall be answered by HH as they have decided to split the activities and to manage the different contractors.

7.3 The transformer's mid tap is 110kV with an upper tap of 115kV. Has the high side tap setting been confirmed with Hydro One so it can be set appropriately prior to energization? Will have to be coordinated with the commissioning team. This should be a design team confirmation. The Transmission System Code, Appendix 1 requires transformers to be able to operate at 115kV plus a potential overvoltage of 6%, or 121.9kV. The maximum tap voltage of the provided transformer is 115.5kV, the maximum operating voltage without risk of over-fluxing should be confirmed. TT will confirm with HONI.

SECTION 9 - P&C BUILDING

9.1 This section should be modified since the P&C building is already installed on site. Ok

9.2.1 Define 'Blanked'. To be incorporated in the document. Ok.

9.3.1 The numbering for the 'Protective Relay' should be 9.3.3. To be incorporated in the document. Ok.

DC control drawings should be made showing which I/O's are to be monitored. DC Control schematics are done by GE. GE's drawings do not specify which I/O are to be monitored, this would be the responsibility of the designer to select which I/O he requires to be monitored.

In the specification, it was mentionned that the relays shall have enough I/O to connect the power transformer and circuit switcher alarms and contact. All required alarms and contact should be connected to the P&C panels.

Stantec

SECTION 10 - COMMISSIONING

10.2 Define 'PUI'. No comment from TT.

Should clarify who completes relay logic programming. The programming is done by GE. Ok, clarify within tender documents.

Should specify the requirements for test documentation to provide a comprehensive documented baseline for annual maintenance testing and verification. No comment from TT.

10.3.1 Add commissioning requirements for new 3000A, 115kV disconnect. To be incorporated in the document Ok.

10.3.3 Power factor (Doble) testing of the transformer should be done. To be incorporated in the document. Ok.

10.3.4 Can the ground grid be isolated to allow the fall of potential test to be completed? If not recommend utilizing Tunable Voltmeter or similar method of measuring ground grid impedance. To be incorporated in the document Ok.

DRAWING COMMENTS

DWG A1-14988-E-001

- TT – Are there HONI requirements for transfer trip signals? No, according Hydro One requirements, transfer trip is not required as long as we have a load break switches upstream the circuit switchers Ok.
- Will/Has HONI accepted 51B protection as back-up protection? Why not add 87 as well? Are they permitting the use of the same CTs for the A protection and B protection? Are separate relays being provided for A and B protection? The latest SLD revision includes Hydro One comments. The submissions that you originally provided to both the IESO and HONI show a single overcurrent/differential protection relay, the response from the IESO indicates that the application can continue assuming protection according to the Transmission System Code schedules E, F, and G of Appendix 1. Schedule E clause 1.3.1.2 directs that components common to the two systems should not be used (i.e. current transformers) while 1.3.1.10 require separate voltage transformer windings and separate current transformers. Section 1.3.1.11 requires separately fused and monitored DC sources for each protection system. We did not see any HONI response that directly addressed this issue or accepted the proposed installation as was provided. Can you provide the HONI response accepting the configuration as shown?

  See the attached email from Hydro One

- Can both transformers be paralleled together? Under any situation? If so protection may have to be revised as per HONI TSC, Appendix 1. The transformers are not operating in parallel. How will make-before-break switching be completed without ever operating the transformers in parallel? HH will continue to operate as they are currently doing.
- Why has the MCOV rating of the lightning arrestors been specified so high? The ratings were specified by the others. Who specified the LA's and were they specified incorrectly? The LA manufacturer should be contacted to confirm whether those ratings are appropriate for the proposed usage and properly protect the assets.

  We will replace them by one of 8.4kV MCOV with a duty cycle of 10kV

- The new differential relays being applied to the existing transformer use primary current transformers with a 600:5 ratio, while the Full Load Amps of the transformer is only 62.75 Amps. These current transformers may be too large for proper and sensitive differential protection of this transformer, potentially smaller multi-ratio CTs should be used to accommodate both existing and future transformer sizes? Ok will be corrected.

DWG A1-14988-E-005

- Ground grid analysis must account for wet, dry and frozen ground conditions. Ground grid study should be revised to account for all conditions and account for all ground rods. The ground grid analysis for wet, dry frozen would not change safety requirement considering:
  - The resistivity of the superficial surface layer of clear stone would not much altered with the weather
  - Safety margin
  - Low soil resistivity
  - Conservative study assumption (Split factor is not considered)

  The implication of frozen conditions are that the resistance of any grounding electrodes within the frozen zone are increased by a large factor (10 or more typical), and thus the overall resistance increases substantially, especially without any ground rods. This often results in a GPR rising above acceptable limits. While the resistivity of the surface layer of clear stone may not change much, the overall magnitudes of Step and Touch voltage may change substantially, thus the report should be updated to include all potential conditions. This is required per the Ontario Electrical Safety Code 25th edition, clause 36-304. Will be done.
- Ground rods should be installed to help stabilize the ground grid's impedance in frozen soil conditions. No comment from TT. May be required when study is updated to confirm frozen conditions. Ok
- The maximum permissible step and touch voltages in ground grid report are higher than those permitted by the Ontario Electrical Safety Code, why is that? The maximum permissible step and touch voltages in the grounding report are calculated taken in account the superficial surface layer of 150 mm of clear stone having a resistivity 3000 Ohms-m and the soil resistivity measured on site. These values are lower than those permitted by the Ontario electrical safety code OESC. According to the OESC if only a 150 mm clear stone ground surface layer is considered the tolerable step voltage is 3143 V and the tolerable touch is 885 V for 0.5 s fault duration. Ok.
- The ground fault report indicates a fault level of 1.761kA to ground was used to complete the study, has Hydro One indicated this is the worst case fault level and that this is the fault level to design to? The grounding system design is based on the provided maximum fault to ground provided by Hydro Hawkesbury (See annex B of the grounding report). HONI must be contacted to provide the maximum fault currents to account for both existing and future conditions of maximum ground current to ensure a safe grounding electrode. The data from the fault simulation is for existing conditions in 2012 and may not meet future supply The values received will be checked with Hydro One.
- Increase separation of transformer pigtail ground conductors to avoid accidental disconnection of both grounds. Will be corrected on the drawing.

DWG A1-14988-E-010

- Are duplicate wire numbers being shown on drawing? Yes
- Will breaker fail protection be added in the event the circuit switcher does not operate? No, Load break switch as back up.
- Will the circuit switch's disconnect be automatically operated in the event the circuit switcher fails to open under a fault condition. No (according to Siemens drawings)
- Is HONI not requiring a transfer trip signal to be received? No as long as we have load break switches
- IESO requires monitoring, refer to IESO document 2013-EX655 issued on July 5, 2013 in response to this project, how will this be provided? Another email stated that no monitoring is required

Stantec

Reference: 14988 – Hydro Hawkesbury 110kV Station Retrofit

DWG A1-14988-E-011

- Have burden calculations been performed on current transformer wiring, especially with the fairly long distance to the P&C building? The calculation has been done but as the building was installed at a different location and the relays are different from the ones which have been specified, we assumed that GE did the calculation. This will have to be done by the design team as they will be taking design responsibility as the Engineer of Record. We will make sure that the calculation will be provided

DWG A1-14988-E-014

- Where are the control drawings for the 52T3-LBS disconnect? The load break switches are not purchased. Ok.
- Based on the letter issued by Hydro One on February 10, 2015, "Both the circuit switches and new [3000A] switch would operate from same protection signals." Is this device a rated interrupting device? Is the 3000A rating of the disconnect being relied on to interrupt the fault as it is greater than the available fault levels? Could fault levels increase at the site beyond 3000A? Are shop drawings available for review? The bottles on the LBS have an interrupting capacity of 3000A. That is the load breaking capacity, what is the interrupting rating of the switch? The rated switching currents are

Rated Maximum Voltage (kV)	Load and loop curren (Amps
145	3000

- Has Hydro One accepted the potential transformer configuration for metering? Yes. Ok.
- The current being sensed by the GE T35 relay and the SEL-551 relay will be split between the two relays. Wiring needs to be corrected such that both relays see the total current from the current transformers. Will be corrected on next revision. Ok.

DWG A1-14988-E-015

- The current being sensed by the GE T35 relay and the SEL-551 relay will be split between the two relays. Wiring needs to be corrected such that both relays see the total current from the current transformers. Will be corrected on next revision. Ok.

DWG A1-14988-E-016

- Drawings 014 and 015 show a SEL-551. Drawing 016 shows an SEL 587 with a transformer differential function. What relay is being specified? A SEL-551 is specified and it will be corrected on next revision. Ok.

Dwg A1-14988-E-017

- Drawings 014 and 015 show a SEL-551. Drawing 017 shows an SEL 587 with a transformer differential function. What relay is being specified? A SEL-551 is specified and it will be corrected on next revision. Ok.

Letter of Recommendation for the new 145kV Motorized Load Break Switch

- Hydro Hawkesbury will need to make sure the battery capacity is sized properly to supply both switches. Based on the battery capacity, the supply voltage should be selected with the supplier when the purchase order will be sent. Both these technical decisions are part of the design process that TT will have to confirm to make sure they are providing a comprehensive construction tendering package, they cannot rely on HH to take responsibility for these portions of the engineering design for this project which should be within Tetra Tech's scope.

  TT has provided performance specification for the DC system. We do not have any engineering documents other than the drawings provided by GE.

-END-

Sincerely,

Stantec Consulting Ltd.

Derek van Gaal, P.Eng.
Associate, Power Systems Engineer
Phone: 613-724-4340
Derek.vangaal@stantec.com

Peter Dyck, P.Eng.
Principal, Power Systems Engineer
Phone: 613-724-4403
peter.dyck@stantec.com

APPENDIX B
BPR ENGINEERING PROPOSAL

Hydro Hawkesbury

Detailed engineering proposal-115kV station retrofit

PROFESSIONAL SERVICES PROPOSAL

BPR Ref.: 14988

May 25th 2012
Revision : 0

POWER DIVISION

TABLE OF CONTENTS

1 PROJECT DESCRIPTION

The project consists in the addition of a new 110kV/12.48kV 25MVA power transformer at the Hawkesbury power station. Also, two new circuit switchers and transformer pad will be added to improve on the transformer protection that is currently by fuses.

The installation of the new transformer is required since the two (2) existing transformers are aging.

This proposal is for the professional services described in the mandate.

2 MANDATE

BPR's mandate will consist of the following:

- Coordination with Hydro One for the addition of the transformer. Station modifications such as capacity increase must be coordinated with Hydro One;
- Project management, coordination, meeting and scheduling with Hydro Hawkesbury;
- Short circuit current calculation taking into account the addition of the new equipment. The addition of the transformer will increase the available short circuit current at the 12.5kV bus. A verification is required in order to ensure that the existing equipments have the proper short circuit withstand capacities;
- Electrical engineering for the installation of the new transformer. The engineering will include:
  - Preparation of the technical specifications and list of potential bidders for the purchase of the new transformer and the 115 kV switches equipment
  - Technical tender analysis for the transformer & 115 kV switches purchase;
  - Transformer & 115 kV switches manufacturers drawings review and approval;
  - Transformer factory witness testing (Based on 2 days of testing). (Travelling time and expenses excluded);
  - Transformer factory witness test report;
  - Protection and control drawings for the transformer and 115kV Circuit switcher;
  - Layout drawing of the station with new equipment arrangements;

  - Resistivity Study and analysis;
  - Ground grid study and drawings;
  - Preparation of the construction technical specification;
  - Technical assistance for bidders site visit (construction);
  - Technical specification for the testing, commissioning and start-up of the new installation and modified equipments;

- Civil/structural engineering for the installation of a new transformer. The engineering will include:
  - Site surveys;
  - Geotechnical study an service coordination;
  - Geotechnical study interpretation of results;
  - Oil containment design for the new transformer (Sorbweb system);
  - New transformer foundation design;
  - New 12.5kV bus steel structure & foundation design;
  - New 115kV equipment steel structure foundation design;
  - Fence modification design for station entrance relocation;
  - Site preparation and surfacing of portion of station that is touched by the construction.
  - Preparation of the civil construction technical specification;
  - On site technical assistance & supervision during commissioning and start-up of the new equipments

- 12 on site visits for technical assistance and supervision during preliminary site visits, construction, commissioning and start-up of the new equipments.

3 INFORMATION AND SCOPE OF WORK

In order to perform this mandate, it's assumed that Hydro Hawkesbury will provide the following information to BPR:

- Existing station drawings;
- Hydro One contact person information;

All data and information contained herein are contractual. Any modification to one or the other may lead to a revision of this proposal.

4 SCHEDULE

The engineering activities will be scheduled with Hydro Hawkesbury, though most activities are scheduled for 2012.

5 PROFESSIONAL FEES

The engineering activities for the completion of this mandate, will be invoiced at a fix price as shown below. Prices shown do not include expenses. Expenses will be charged separately**.**

Coordination and project management:	5000$
Civil engineering:	45 000$
Electrical Engineering:	50 000$
Total:	100 000$

6 PROJECT TEAM

The proposed team of professionals for this project consists of :

Name	Professional status
Mr. Guillaume St-laurent, P.Eng.	Electrical Engineer
Mr. Denis Clément, P.Eng. PMP	Electrical engineer
Mr. Marcel Fortin, Eng.	Transformer specialist
Mr. François LaFontaine, P.Eng.	Civil engineer
Mrs. Vanessa Pace	Civil Engineer

7 PROJECT MANAGERS

Hydro Hawkesbury: Mr. Michel Poulin

BPR: Mr. Denis Clément, P.Eng. PMP

8 ADDITIONAL SERVICES

The services listed below are available but not included in the present proposal:

- Station exterior lighting;
- Protection study and relay setting sheets;
- Laboratory and analysis fees.
- Full time field supervision.
- Drafting of commercial clauses and purchase orders.
- All different authorities permits.

9 RESPONSIBILITY AND COMPENSATION INSURANCE

During the undertaking of the project, BPR will maintain in force a civil responsibility insurance policy comprising a $1,000,000 limit and a professional responsibility insurance policy (error or omission) comprising a $5,000,000 limit.

BPR's professional responsibility for error or omission is limited to recoverable amounts in virtue of the professional responsibility insurance policy subscribed by BPR.

Furthermore, BPR's responsibility for all other fault, whatsoever cause arising, is limited recoverable amounts in virtue of the general civil responsibility insurance policy subscribed by BPR.

10 TERMS AND CONDITIONS

Monthly invoicing is based on progress.

The engineering activities will begin after the written acceptance of our proposal.

All traveling and transportation expenses, including meals and airline tickets will be charged at cost plus 10 %.

Car expenses will be charged at .45$/km.

The prices submitted do not include goods and services tax nor the Quebec sales tax; they will be added to our professional fees invoice.

Payment: net 30 days. 1% per month for outstanding balance.

Hoping everything will be satisfactory, we remain,

Yours truly,

Denis Clément, P.Eng. , PMP

Project Director

Jean-Claude Maurice, P.Eng.
V.P. T&D Energy

APPENDIX C
DRAWINGS AND SPECIFICATIONS

Please note that the Drawings and Specifications are large and cannot be emailed. Hard copies can be provided upon request.

APPENDIX D
IESO CONDITIONAL APPROVAL

Invoice

Power to Ontario.
On Demand.

Independent Electricity
System Operator
Station A, Box 4474
Toronto, Ontario M5W 4E5
t 905 855 6100
www.ieso.ca

INVOICE DATE: 06-Nov-13
DUE DATE: Net 10 Days
INVOICE NUMBER: 3533

TO: **Hydro Hawkesbury Inc.**
850 Tupper St.
Hawkesbury, ON
K6A 3S7

GST Number: 870513959RT0001

Attention: **Michel Poulin - Manager**
michelpoulin@hydrohawkesbury.ca

Contact Information:
Eddie Markovic Phone: 905.855.6398 Fax: 905.855.6459 email: eddie.markovic@ieso.ca

Description: Hydro Hawkesbury Inc. expedited projects (formal assessment not required)

Services: **Q2 & Q3 2013:** $1,450.00 **($Cdn)**
10 hours dedicated to the following projects:
Project
2013-EX655 Replace T1 at Hawkesbury MTS michelpoulin@hydrohawkesbury.ca

Connection assessment invoices are considered obligations under the market rules and are payable within ten business days **of receipt.** – ***Chapter 4, Section 6.1.21***

Identify reimbursement cheque with this number: **Invoice #** **3533**

Subtotal:	$1,450.00
HST (13.0%):	$188.50
	$1,638.50

Total Due **$1,638.50 ($Cdn)**

REMIT CHEQUE PAYMENTS TO:

Independent Electricity System Operator
Station A, Box 4474
Toronto, ON
M5W 4E5
Attention: Accounts Receivable

Or send wire payment (with invoice number) to:

Independent Electricity System Operator
Account Number: 0429444
Transit Number: 10202
Bank ID Number: 004
TD Bank - 55 King Street West, Toronto, Ontario M5K 1A

Project Status Report

Upon completing this application form, please send it to the IESO through either one of the following methods:

By Email to:	connection.assessments@ieso.ca
By Courier to:	Independent Electricity System Operator 655 Bay Street, Suite 410 P.O. Box 1 Toronto, ON M5G 2K4 Attn: Connection Assessments
By Fax to:	(905) 855-6319

All information submitted in this process will be used by the *IESO* solely in support of its obligations under the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998,* the *Market Rules* and associated policies, standards and procedures and its licence. All information submitted will be assigned the appropriate confidentiality level upon receipt.

PART 1 – GENERAL INFORMATION

Organization Name: Hydro Hawkesbury

CAA ID No.: 2013-EX665

Main Contact

Name: Michel Poulin   Position: Manager

Telephone No.: 613-632-6689   Fax No.: 613-632-8603

Email Address: michelpoulin@hydrohawkesbury.ca

PART 2 – PROJECT STATUS

Please indicate the current and expected level of project activity by placing a ☒ in the table below.

1	Project is currently active, and is expected to be completed.	☐
2	Project is on hold, but is expected to be completed.	☒
3	Project is not currently active, and there is no intention to complete the connection proposal.	☐

If the level of activity is either 1 or 2 above, please complete Table 1. Otherwise, please proceed to Part 3.

TABLE 1 - PROJECT STATUS

	Activity or Milestone	Status Code(*)	Actual or Expected Completion Date	Comments
1	Project financing	P	November 2014	From Infrastructure Ontario
2	Regulatory approvals obtained	C	October 2014	In our 2013CoS
3	Transmitter Connection Cost Recovery Agreement (CCRA)	C		
4	Construction of Facility	H	End of September	
5	IESO Registration	P		
6	Commissioning of Facility	N		
7	Facility placed in service	N		

(*) Status Code: C - Complete, P - In progress, H- On hold, N - Not started, NA - Not applicable

PART 3 – CERTIFICATION

The undersigned hereby declares that the information contained in and submitted in support of this documents is, to the best of the connection applicant's knowledge, complete and accurate. By signature the connection applicant agrees that the information may be provided to the affected transmitter(s).

Michel Poulin
Name (Please Print)

Manager
Title

Signature

Aug 21, 2014
Date

PART 4 – FOR IESO USE ONLY

Received by: ____________________ Date Received: ____________________

CAA ID No.: ____________________

July 5, 2013

Mr. Michel Poulin
Manager
Hydro Hawkesbury Inc.
850 Tupper St.
Hawkesbury, Ontario
K6A 3S7

ieso
Power to Ontario.
On Demand.
Station A, Box 4474
Toronto, ON
M5W 4E5

Dear Mr. Poulin:

Replacement of T1 at Hawkesbury MTS
Notification of Conditional Approval of Connection Proposal
CAA ID Number: 2013-EX655

Thank you for the information regarding the proposed replacement of T1 at Hawkesbury MTS. The IESO has concluded that the proposed changes will not result in a material adverse impact on the reliability of the integrated power system. The IESO is therefore pleased to grant **conditional** approval as detailed in the attached expedited System Impact Assessment report. Please note that any material changes to your proposal may require a re-assessment by the IESO and may nullify your conditional approval.

You may now initiate the IESO's **Facility Registration/Market Entry** process. To do so, please contact Registration & Compliance Support at market.entry@ieso.ca as soon as possible prior to your expected energization date. The SIA report, attached hereto, details the requirements that your company must fulfill during this process, including demonstrating that the equipment *as installed* will not be materially different from the equipment *as approved* by the IESO. The document entitled Market Entry: A Step-by-Step Guide describes the key steps in the Market Entry process.

When your company has successfully completed the IESO's **Facility Registration/Market Entry** process, the IESO will provide you with a **final approval**, thereby confirming that the facility is fully authorized to connect to the IESO-controlled grid.

For further information, please contact me via connection.assessments@ieso.ca.

Yours truly,

Michael Falvo

Michael Falvo
Manager – Market Facilitation
Telephone: *(905) 855-6209*
Fax: *(905) 855-6319*
E-mail: *mike.falvo@ieso.ca*
cc: *IESO Records*

1.0 GENERAL DESCRIPTION & PROPOSED MODIFICATIONS

Hydro Hawkesbury is proposing to replace T1 at Hawkesbury MTS with a larger unit. In addition, circuit switchers will be installed on the HV side to replace existing fuses and disconnect switches for both the new transformer and the existing transformer. The circuit switchers will trip during fault conditions.

The expected in-service date for the replacement T1 is December 2013.

Hawkesbury MTS is a 110/12.48 kV customer transformer station on the 115 kV circuit 79M1 out of Hawthorne TS via the 115 kV circuit H9A.

The technical specifications of the existing and replacement transformers are given in the following table.

Hawkesbury MTS		
All values for replacement equipment are specified at the time of order. Actual values to be provided prior to in-service dates.		
Transformer	**Existing T1 & T2**	**Replacement T1**
Configuration	Three phase	Three phase
Transformation (kV)	110/12.48	110/12.48
Winding Configuration	Delta/Wye	Delta/Wye
Thermal Rating	7.5 MVA ONAN 10.0 MVA ONAF 12.5 MVA ONAF	15.0 MVA ONAN 20.0 MVA ONAF 25.0 MVA ONAF
Continuous Thermal Rating (winter 10°C)	12.5 MVA	25.0 MVA
10-DAY Thermal Rating (winter 10°C)	12.5 MVA	28.75 MVA
15-MIN Thermal Rating (winter 10°C)	Not applicable	Not applicable
Positive Sequence Impedance (H-L)	R = 0.319% X = 8.9% on 7.5 MVA base	R = 0.44% X = 10.15% on 15.0 MVA base
Impedance to Ground	HV – ungrounded LV – grounded	HV – ungrounded LV – grounded
Under-load tap-changer	12.48 ± 10% kV 16 Steps	12.48 ± 15% kV 32 Steps

Table 1 – Comparison of Transformer Parameters at Hawkesbury MTS

The technical specifications of the new circuit switchers are given in Table 2 below.

Hawkesbury MTS Circuit Switcher Specifications	
	Replacement
Configuration	3 phase
Maximum Continuous Rated Voltage (kV)	145
Continuous Current Rating (A)	1200
Short Circuit Symmetrical Duty (kA)	40 kA

Table 2 – Specifications of new circuit switcher at Hawkesbury MTS

2.0 TECHNICAL ASSESSMENT

2.1 10-Day Winter Transfer Capabilities

The 10-DAY winter transfer capability for a DESN is determined by removing the transformer with the highest 10-DAY thermal rating from service.

The 10-DAY winter ratings of the two transformers at Hawkesbury MTS are listed in the table below.

10-DAY Winter Thermal Ratings (10°C) for Transformers T1/T2 at Hawkesbury MTS		
Transformer	Existing T1 & T2	New T1 & Existing T2
T1	O/S (12.5 MVA)	O/S (28.75 MVA)
T2	12.5 MVA	12.5 MVA
10-DAY Winter Transfer Capability (with highest rated transformer out of service)	**12.5 MVA**	**12.5 MVA**

Table 3 – 10-DAY Winter Thermal Ratings for T1/T2 DESN at Hawkesbury MTS

For the T1/T2 DESN at Hawkesbury MTS, the existing 10-DAY winter transfer capability is 12.5 MVA. The 10-DAY winter transfer capability will remain the same when the new T1 is put into service.

2.2 Peak Loads and Projections

Revenue meter information from December 27, 2011 through April 8, 2013 was used to evaluate the load on the T1/T2 DESN at Hawkesbury MTS. The peak load of 19.4 MVA on the T1/T2 DESN at Hawkesbury MTS occurred on January 23, 2013 at 17:30. The figure below shows the loading at the LV side of T1 and T2.

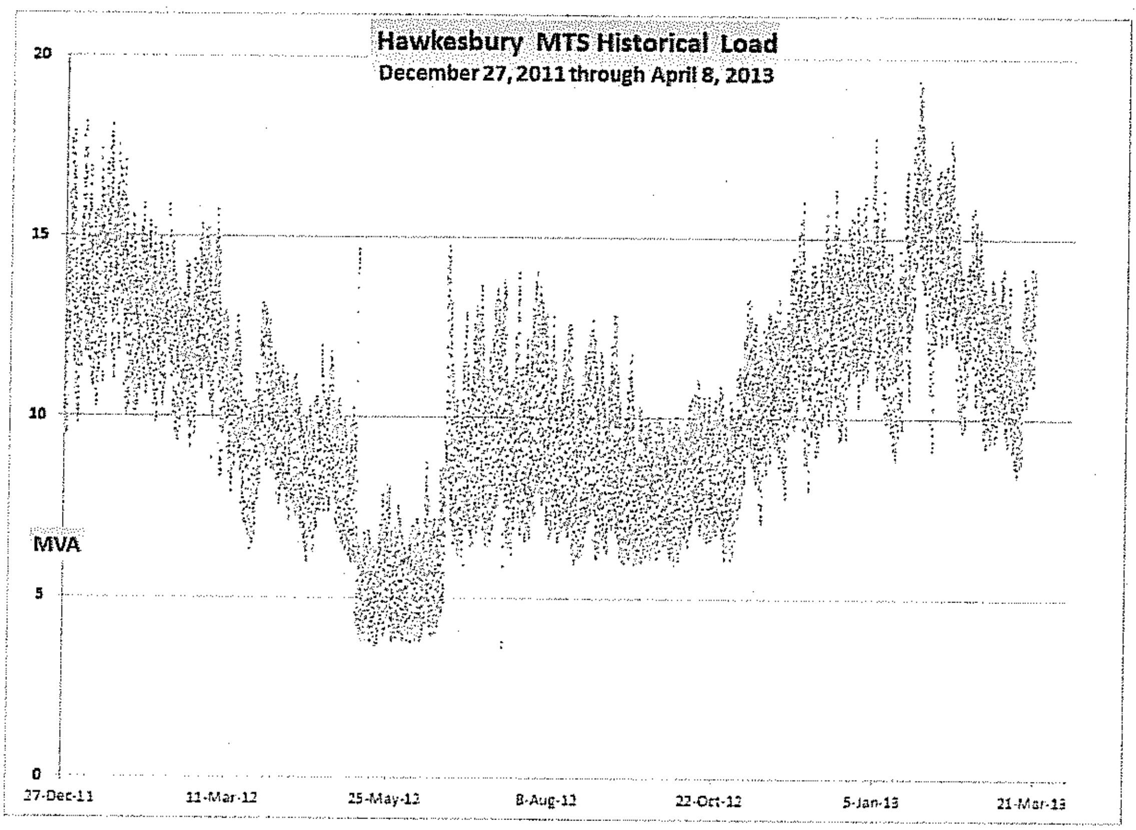


Figure 1 – T1/T2 DESN Load at Hawkesbury MTS

The peak load at Hawkesbury MTS is higher than the current 10-DAY winter capability of 12.5 MVA.

The load on T1 and T2 at Hawkesbury MTS is projected to increase by 1% annually as shown in the table below.

Hawkesbury MTS T1/T2 Projected Peak Load Growth		
Year	Projected Peak Load (MVA)	10-DAY Winter Capability (MVA)
2013	19.4	12.5 (assumed)
2014	19.6	12.5 (assumed)
2015	19.8	
2016	20.0	
2025	21.9	

Table 4 – T1/T2 Projected Load Growth at Hawkesbury MTS

The projected peak load will exceed the new 10-DAY winter capability of 12.5 MVA for the T1/T2 DESN at Hawkesbury MTS. Since the applicant has stated that they are able to transfer load as required to another 44 kV MTS this is not a concern. In addition, the old 12.5 MVA transformer will be kept on site for a spare.

2.3 Load Angle & Power Factor

The Market Rules require that Hydro Hawkesbury have the capability to maintain a power factor (pF) within the range of 0.9 lagging and 0.9 leading as measured at the defined metering points at Hawkesbury MTS. This power factor range translates into a load angle range of ± 0.45 radians. All the points above 0.45 radians indicate a lagging power factor below 0.9. All points below -0.45 radians indicate a leading power factor below 0.9.

Revenue meter information from December 27, 2011 through April 8, 2013 was used to evaluate the load angle at Hawkesbury MTS. The figure below illustrates the load angle on the LV side of Hawkesbury MTS for instances when the load is above 80% of the peak load.

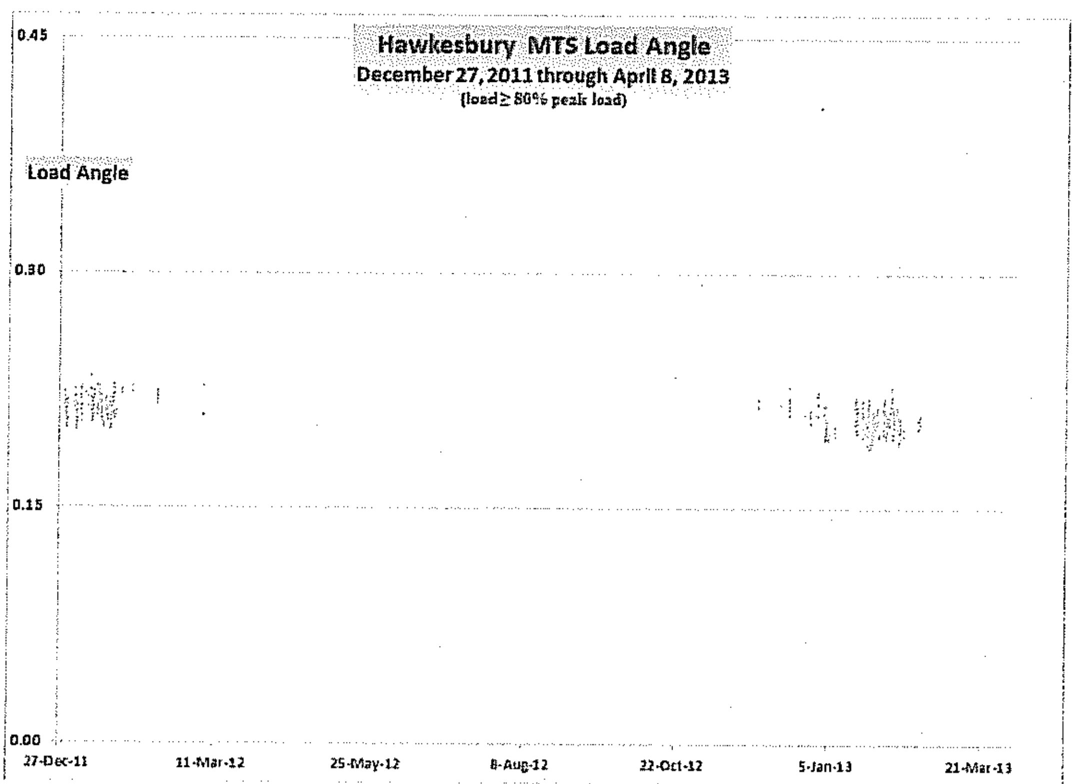


Figure 2 – Load Angle at Hawkesbury MTS

Between December 27, 2011 and April 8, 2013, the load angle at Hawkesbury MTS was within the IESO required limits for instances when the load is above 80% of the peak load.

2.4 Conclusions

It can be concluded that the replacement of T1 at Hawkesbury MTS with a new transformer will not result in a material adverse impact on the reliability of the IESO-controlled grid provided that all requirements in this report are met.

3.0 REQUIREMENTS

The applicant must notify the IESO as soon as it becomes aware of any changes to the assumptions made in the connection assessment. The IESO will determine whether these changes require a re-assessment.

Reactive Power Requirements

The Market Rules require that Hydro Hawkesbury have the capability to maintain a power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined metering points at Hawkesbury MTS.

Monitoring Requirements

The Market Rules (Chapter 4 section 7.4) require that the connection applicant shall provide the IESO on a continual basis with on-line monitored quantities as specified in Appendix 4.17. Among other things, end to end telemetry testing must be completed by the applicant along with the IESO to ensure that standards are met and sign conventions are understood.

Protection Requirements

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

Provided that the TSC requirements are satisfied, the IESO does not have additional requirements.

Connection (Transmission) Facilities

Bold-Italic	Essential for Assessment
Bold	Essential for Hydro One - to be provided prior to Connection
Normal (shaded)	Typical values will be assumed if not given
Normal	Only required upon request

If the connection from the load to the transmitter consists of different sections, then the applicant must complete a table for each overhead circuit section and for each underground circuit section.

Provide a detailed single line diagram of the load facilities.

Transmission connection	***Point of connection to IESO controlled grid:*** ***- circuit operating nomenclature or terminal station name***			
	- circuit section			
	- tower number			
	- GPS coordinates			
Overhead Circuit section Complete one table for each overhead circuit section	***Identifier (to be provided on drawing)***			
	Voltage (kV)			
	Length (km)			
	Phase conductor size (kcmil)			
	Phase conductor type (ASC, ACSR, ACSS, ACCR, etc.)[1]			
	Phase conductor stranding (# of Al strands, # of Steel strands)			
	Phase conductors per bundle, spacing if more than one (mm)			
	Geometry of all phase and skywires for each tower type (m)			
	Ground resistivity (ohms-meters)			
	Skywire size (kcmil)			
	Skywire type (Alumoweld, EHS, HS)[1]			
	Skywire stranding (# of Al strands, # of Steel strands)			
	Skywire number if more than one			
	Positive sequence impedance (R, X in ohms, B in mhos or if in per unit specify bases)			
	Zero sequence impedance (Ro, Xo in ohms, Bo in mhos or if in per unit specify bases)			
	Mutual Impedance (parallel circuit identifier, Rm, Xm in ohms or if in per unit specify bases)			
	Winter thermal : Continuous, Long-term, Short-term ***(see table below for rating assumptions***			
	Summer thermal ratings: Continuous, Long-term, Short-term ***(see table below for rating assumptions***			

Overhead Transmission Lines - Rating Assumptions for System Impact Assessment studies

Rating	Conductor Temperature	Pre-load	Summer	
			Ambient Temp	Wind Speed
Continuous	93°C (or sag temperature if lower)	N/A	**Summer** 35°C South of Barrie & 30°C North of Barrie **Winter** 10°C	0 to 4 km/hr 15 km/hr within 50 km of wind farm**
Long-Term Emergency **(Limited to 50 hr/year on all conductors)**	127°C (or sag temperature if lower)	N/A		
Short-Term Emergency **(15-minute limited-time rating)**	150°C (or sag temperature if lower) (Limited to 127°C for HAC* conductors))	Continuous Rating at 93°C		

1 If the conductor type is new then additional information may be required.

2 If the location of the project is north of the City of Barrie, then provide summer ratings based on 30°C and 4 km/h wind speed

Connection (Transmission) Facilities (cont)

Bold-Italic	Essential for Assessment
Bold	Essential for Hydro One - to be provided prior to Connection
Normal (shaded)	Typical values will be assumed if data not provided
Normal	Only required upon request

Underground Circuit Section Complete one table for each underground circuit section	***Identifier (to be provided on drawing)***				
	Voltage (kV)				
	Length (km)				
	BIL rating				
	Phase conductor size (kcmil)				
	Distance from the "from" terminal (km)				
	Maximum operating temperature (ºC)				
	Phase conductor type [1]				
	Insulation type				
	Semiconductor shield type				
	Shield grounding				
	Metallic sheath type				
	External layer type				
	Geometry of all phases				
	Ground resistivity (ohms-meters)				
	Cable construction				
	Installation type (e.g. direct buried, in duct, etc.)				
	Positive sequence impedance (R, X in ohms, B in mhos or if in per unit specify bases)				
	Zero sequence impedance (Ro, Xo in ohms, Bo in mhos or if in per unit specify bases)				
	Continuous, 15-Minute and 24-Hour thermal ratings (A)	***Winter***			
		Summer			
Main Buses Complete one table for each bus	Identifier (to be provided on drawing)				
	Station				
	Voltage (kV)				
	Summer continuous (A)				
	Winter continuous (A)				
	Maximum operating temperature (ºC)				
	Conductor size (kcmil)				
	Conductor type (ASC, ASCR, Al tube)				
Surge Arresters	Identifier				
	Station				
	Manufacturer				
	Serial number				
	Voltage rating (kV)				
	Type (e.g. ZnO, SiC)				
	Class (e.g. secondary, distribution, intermediate, station)				

1 If the conductor type is new then additional information may be required.

Connection (Transmission) Facilities (cont)

Bold-Italic	Essential for Assessment
Bold	Essential for Hydro One - to be provided prior to Connection
Normal	Typical values will be assumed if not given
Normal	Only required upon request

Transformers Complete one table for each transformer	***Number and Identifier of identical units (e.g., 3 units - T1, T2, T3)***		55T3			
	Station		Hawkesbury MTS			
	Serial Number (must be provided prior to Connection)					
	Manufacturer		Pennsylvania Transformer Technology			
	Configuration (e.g. 3 phase or three single phase units)		3 Phase			
	Phase Location if single phase (e.g. R, W, B)					
	Cooling types (e.g. ONAN, ONAF, OFAF)		ONAN	ONAF	ONAF	
	Associated Thermal Rating for each cooling type (MVA)		15	20	25	
	Winter (10ºC) continuous, 10-DAY and 15-MIN thermal ratings	(A)				
		(MVA)				
	Summer (35ºC) continuous, 10-DAY and 15-MIN thermal ratings[1]	(A)			151	
		(MVA)			28.75	
	Connection for each winding H, X, Y (e.g. wye, delta, zig-zag)		Deta (HV)	Wye (LV)		
	Rated voltage for each winding, e.g. HV, LV, tertiary (kV)		110	12.48		
	Rated capability for tertiary winding, if applicable (A, MVA)					
	Impedance to ground for each winding H, X, Y (ohms) (U – Ungrounded; R – Resistance; X – Reactance, e.g. 16 R)					
	Off–load taps (kV)					
	In-service off-load tap position (kV)					
	Under-load taps (max tap (kV), min tap (kV)), number of steps)		126.5	93.5	33 Steps	
Positive Sequence Impedance	(see IEEE C57.12.90 for measurement techniques)	***Positive Sequence Impedance (%)***	***HX***	***HY***	***XY***	
		R	0.44			
		X	10.15			
		Base MVA	15			
Zero Sequence Impedance (only required for transformers with 1 or 2 external neutrals)	H winding energized all others open	Closed Tertiary	H	X	HX	XH
		R				
		X				
		Base MVA				
	H winding energized X winding shorted	Open Tertiary	H	X	HX	XH
		R				
		X				
		Base MVA				

1 If the location of the project is north of the City of Barrie, then provide summer ratings based on 30°C and 4 km/h wind speed

Connection (Transmission) Facilities (cont)

Bold-Italic	Essential for Assessment
Bold	Essential for Hydro One - to be provided prior to Connection
Normal	Typical values will be assumed if not given
Normal	Only required upon request

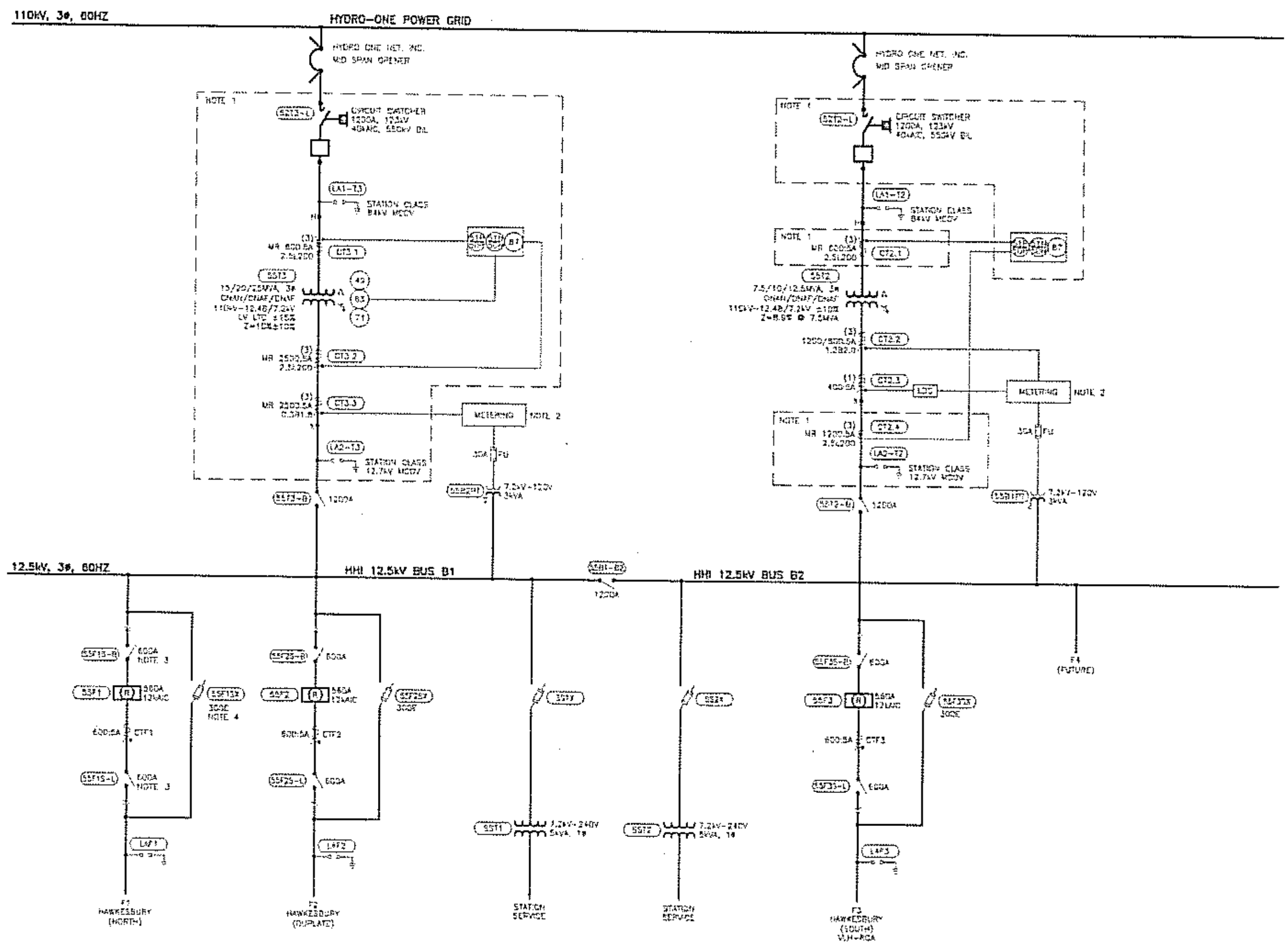
Shunt Capacitors Complete one table for each type of shunt capacitor	***Identifier***	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Rated voltage (kV)	
	Rated capability (Mvar)	
	Discharge time (ms)	
	Current limiting reactor (mH or Ω)	
	Bank arrangement (e.g. delta, wye, double-wye, etc)	
	Surge capacitor (μF)	
	Description of automatic switching	Attach file
	Anticipated switching restrictions	Attach file
Shunt Reactors Complete one table for each type of shunt reactor	***Identifier***	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Rated voltage (kV)	
	Rated capability (Mvar)	
	Winding configuration (e.g. delta, wye)	
	Description of automatic switching	Attach file
	Description of anticipated switching restrictions	Attach file

All files and diagrams provided as attachments are to be signed and sealed by a Professional Engineer.

Connection Transmission Facilities (cont)

Bold-Italic	Essential for Assessment
Bold	Essential for Hydro One - to be provided prior to Connection
Normal (shaded)	Typical values will be assumed if not given
Normal	Only required upon request

Circuit Breakers Complete one table for each type of circuit breaker	***Identifier***	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Maximum continuous rated voltage (kV)	
	Interrupting time (ms)	
	Interrupting media (e.g. air, oil, SF_6)	
	Rated continuous current (A)	
	Rated symmetrical and asymmetrical short circuit capability (kA)	
Circuit Switchers Complete one table for each type of circuit switcher	***Identifier***	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Maximum continuous rated voltage (kV)	
	Interrupting time (ms)	
	Interrupting media (e.g. air, oil, SF_6)	
	BIL voltage (kV)	
	Rated continuous current (A)	
	Rated symmetrical short circuit capability (kA)	
Disconnect Switches Complete one table for each type of disconnect switch	***Identifier***	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Maximum continuous rated voltage (kV)	
	Continuous current rating (amps) (Non-Ground Switches only)	
	Rated symmetrical short circuit capability (kA)	
Wavetraps	Identifier	
	Station	
	Manufacturer	
	Serial number (must be provided prior to Connection)	
	Continuous current rating (amps)	
DC Lines	***Identifier***	
	Complete steady state (load flow) parameters and dynamic	
FACTS Devices (e.g., dynamic reactive devices, series compensation, etc.)	***Identifier***	
	Complete steady state (load flow) parameters and dynamic parameters	



NOTES:

1. NEW EQUIPMENT
2. HYDRO ONE INC. METERING.
3. DISCONNECT 55F#5-B AND 55F#5-L NORMALLY CLOSED AND OPEN WHEN BREAKER 55F# IS OUT OF SERVICE (THIS IS TYP. FOR BREAKERS 55F1, 55F2 AND 55F3).
4. FUSE DISCONNECT 55F#5X NORMALLY OPEN AND CLOSED WHEN BREAKER 55F# IS OUT OF SERVICE (TYP. FOR BREAKERS 55F1, 55F2 AND 55F3).

REV	BY	DESCRIPTION
0 2013/04/08	V.L.	ISSUED FOR ESO AND HONI ASSESMENT
D 2013/01/09		ISSUED FOR HONI APPROVAL
B 2012/12/21	M.F.	ISSUED FOR TENDER
A 2012/09/28	M.F.	ISSUED FOR TENDER
REV DATE	BY	DESCRIPTION REVISIONS OR ERASSIONS

ENGINEER STAMP

G. LAGUERRE
130196259

TETRA TECH

CUSTOMER
Hydro Hawkesbury
850 Tupper St.
Hawkesbury, Ontario
K6A 3S7
Tel. 613-632-6689

PROJECT
110kV STATION REFURBISHMENT

TITLE
SINGLE LINE DIAGRAM

Date	Designed by	Drawn by	Approved by
2012-09-24	M.Foreal	L.Kozel	G.Laguerre P.Eng
Scale	Consultant number	Customer number	
NONE	14958		

Drawing number	Revision
A1-14958-E-001	0

A1 metric size 841x594

APPLICATION FOR NEW OR MODIFIED CONNECTIONS

hydro one

Mail Application to the following address:

Attn: Manager
Customer Business Relations
Hydro One Networks Inc.
483 Bay Street, North Tower (TCT14)
Toronto, ON, M5G 2P5

or

Send electronically by attaching this completed document using the following link: New or Modified Connection Application.

Subject: Customer Application For New or Modified Connections

All information submitted in this process will be used by Hydro One Networks solely in support of its obligations under the Transmission System Code, Electricity Act, 1998, the Ontario Energy Board Act, 1998, the IESO Market Rules, OEB approved Connection Procedures and its transmission license. All information submitted will be assigned the appropriate confidentiality level upon receipt.

New Connection: ☐ **Modification to an Existing Connection Facility:** ☒

Project Name: Hydro Hawkesbury 110 kV Station Retrofit

PART 1 – GENERAL INFORMATION

Organization Name: Hydro Hawkesbury Inc	
Organization Short Name: (Maximum 12 keystrokes) HHI	
Mailing Address: 850 Tupper St.	
City/Town: Province/State: Hawkesbury, Ontario	
Postal/Zip Code: K6A 3S7	Country: Canada
Fax No.: 613-632-8603	
Email Address: michelpoulin@hydrohawkesbury.ca	
Main Contact	
Name: Michel Poulin	
Position/Title: Manager	
Telephone No.: 613-632-6689	Fax No.: 613-632-8603
E-mail Address michelpoulin@hydrohawkesbury.ca	

APPLICATION FOR NEW OR MODIFIED CONNECTIONS

PART 2 – REQUIRED DOCUMENTATION ATTACHED BY CUSTOMER APPLICANT

LOAD CUSTOMERS

☒ In-service date.

☒ Indicate whether new or existing connection requiring expansion, describe project.

☒ Connection location / address.

☒ Forecasted new load that will be guaranteed by the Customer (initial, intermediate & ultimate) including size and date. Identify seasonal/monthly variations in load (summer or winter peak). Provide the 5 most recent years or historical load pertaining to existing facilities as identified by Hydro One Networks, if connected less than 5 years the most year or years.

☒ Identify nature of business (specify industry) and any specific reliability requirements.

☒ Provide the technical information identified in Appendix A of this application entitled "New or Modified Customer Facility Technical Information for Load Customers".

☒ Identify SCADA requirements for New or Modified Facility as identified in Appendix B entitled "New or Modified Customer Facility SCADA Requirements for Load Customers.

☒ Identify the name, address and contact information of the New or Modified Facility Meter Service Provider and Market Participant name.

GENERATORS

☐ In-service date.

☐ Indicate whether new or existing connection requiring expansion, describe project.

☐ Connection location / address, total generation including number of units, size of units and power factor

☐ Forecasted new seasonal/monthly operating schedule including output by generating unit.

☐ Identify nature of business (specify industry) and any specific reliability requirements.

☐ Provide the technical information identified in Appendix B of this application entitled "New or Modified Customer Facility Technical Information for Generator Customers".

☐ Identify SCADA requirements for New or Modified Facility as identified in Appendix B entitled "New or Modified Customer Facility SCADA Requirements for Generator Load Customers.

☐ Identify the name, address and contact information of the New or Modified Facility Meter Service Provider and Market Participant name.

APPLICATION FOR NEW OR MODIFIED CONNECTIONS

PART 3 – CERTIFICATION

The undersigned hereby declares that the information contained in and submitted in support of this document is, to the best of the connection applicant's knowledge, complete and accurate.

Michel Poulin	Manager
Name	Title
	April 22, 2013
Signature	Date

PART 4 – PERMISSION

The undersigned Customer hereby allows if required by Hydro One Networks, the IESO to release a copy of any connection assessment and or facility registration documents associated with the Customer Application related to any new, modified or replacement Customer Facilities that the Customer has submitted to the IESO.

Michel Poulin	Manager
Name	Title
	April 22, 2013
Signature	Date

PART 5 – FOR HYDRO NETWORKS INC. USE ONLY

Received by:		Date Received:	
Date of Request(s) for Additional Information:			
Date Requested:		Date Received:	
Date Requested:		Date Received:	
Application Completion Date:			

APPLICATION FOR NEW OR MODIFIED CONNECTIONS

Appendix A: Hydro One Account Executive and System Planner will assist customers in determining which documents are required by Hydro One Networks.

New or Modified Load Customer Facility Technical Information

In accordance with section 6.1.11 of the Transmission System Code, Hydro One Networks requires customers connecting any new, modified or replacement customer facilities to provide the following completed IESO connection assessment and facility registration documentation:

- ❑ System Impact Assessment Application for Load Customers
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Final System Impact Assessment Report for Load Customers
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Feasibility Study Application for Load Customers
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Final Feasibility Study Report
  - ❑ Attached
  - ❑ To be provided by .

In addition to the above, Hydro One may require the following documents in order to access the impact on the reliability of the customers new, modified or replacement facility on the transmission system if they are not included in the IESO documentation:

- ❑ Single line diagram illustrating all protection schemes, 3 wire and/or DC elementary wiring drawings maybe required.
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Power transformer nameplate data.
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Relay settings & verification tests
  - ❑ Attached
  - ❑ To be provided by .

- ❑ High voltage equipment operating & protection philosophy that are impactive on the transmission system
  - ❑ Attached
  - ❑ To be provided by .

- ❑ Tripping Matrix as per required by the code.
  - ❑ Attached
  - ❑ To be provided by

APPLICATION FOR NEW OR MODIFIED CONNECTIONS

Appendix B

Transmission System Connection Application Form For Generators

It is important that the Generator provide all of the information requested below. Failure to do so could delay the results of the assessment.

All technical documents must be signed and sealed by a licensed Ontario Professional Engineer.

Date: (dd/mm/yyyy) **Contact Person Name:**
Signature:

1. **Project Name:** _____

2. **Project Dates:** Proposed Start of Construction: _____ (dd/mm/yyyy)
   Proposed In-Service: _____ (dd/mm/yyyy)

3. **Project Size:** Number of Units _____
   Nameplate Rating of Each Unit _____ kW
   Number of Phases (1 or 3) _____
   Proposed Total Capacity _____ kW

4. **Project Location:** City / Town / Township:
   Lot Number:
   Concession Number:

5. **Project Information:**

	Generator	Owner	Consultant
Company/Person:			
Contact Person:			
Mailing Address:			
Telephone:			
Fax:			
Email			

6. **Hydro One Account Number:** _____

(Only for existing customers intending to install generation for load displacement.)

7. **Intent of Generation**:

☐ Sale of Power ☐ Load Displacement

8. **Project Type:**

☐ Wind Turbine ☐ Hydraulic Turbine ☐ Steam Turbine ☐ Solar
☐ Recip. Engine ☐ Gas Turbine ☐ Fuel Cell ☐ Biomass
☐ Co-generation ☐ Other (specify) _____

9. **Generator Facility Type:**

a. **Generation Facility Voltage:** _____ Volts ☐ AC ☐ DC

Type:
Rotating generators: ☐ Synchronous ☐ Induction ☐ N/A
☐ Other (Please Specify)
Non-Rotating DC generation: ☐ Photovoltaic Arrays ☐ Fuel Cells
☐ Batteries ☐ N/A
☐ Other (Please Specify)

Document List

Item No.	Requirement	Drawing/Document Title	Reference Number
1	A one-line diagram showing the connection and switching arrangement		
2	If the interconnection is with a local distributing company (LDC), a one-line drawing is also required showing the LDC facilities between the point of interconnection of your generator and their interconnection with Hydro One facilities. This one-line drawing must contain sufficient technical data of the LDC facilities so that we can model the interconnection. This must include voltage levels, conductor sizes, conductor impedances, conductor length, transformer ratings (voltage, winding MVA, winding configuration, tap settings etc), switch and breaker ratings, normally open or normally closed switches, etc.		
3	A large-scale map or drawing showing the location of the exact point of the proposed interconnection with Hydro One facilities.		
4	Machine type, manufacturer, manufacturer models of generator and excitation systems		

5	Machine ratings (MVA, power factor, MW, voltage etc.)		
6	X"d of the machine on it own MVA base.		
7	Winding configuration of the generator (wye, delta etc.)		
8	Generator transformer type and ratings (MVA), voltage ratings of all windings)		
9	Generator transformer impedance on its own MVA base		
10	Generator transformer tap data, in particular the tap that the transformer is to be operated on		
11	Winding configuration (wye, delta, etc.) for each transformer winding, plus the impedance of any grounding reactors or resistors		
12	Nominal voltage (or base voltage) (For Conductor)		
13	Conductor length		
14	Conductor impedance data (R, X, & B) expressed in pu on the conductor base voltage and 100 MVA		
15	Size for feeder and/or transmission line that is not in HON's system. (For Conductor)		
16	A drawing showing the proposed tap location and tapping arrangement		
17	Voltage ratings (For Breaker)		
18	Breaker interrupting medium (e.g. SF6, oil etc.)		
19	Breaker rated fault interrupting capacity (in either kA or MVA)		
20	Breaker opening time (in cycles or ms)		
21	Modeling data of any series or shunt capacitors, reactors and/or static VAR compensators (SVC) that are part of the installation		
22	Configuration and grouping of the individual units. This can be provided as part of the one-line referred to above (For Wind Farms Only)		
23	A description of the Operating philosophy for the wind farm or wind park (For Wind Farms Only)		
24	PTI/PSSE Generator Model for steady-state load flow, short circuit and dynamic/transient stability studies		

APPENDIX E

MOE ENVIRONMENTAL COMPLIANCE APPROVAL

ENVIRONMENTAL COMPLIANCE APPROVAL

NUMBER 1295-A6HJKG
Issue Date: February 1, 2016

Hydro Hawkesbury Inc./Hawkesbury Hydro Inc.
850 Tupper Street
Hawkesbury, Ontario
K6A 3S7

Site Location: 990 Main Street West
Town of Hawkesbury, United Counties of Prescott and Russell

You have applied under section 20.2 of Part II.1 of the *<u>Environmental Protection Act</u>, R.S.O. 1990, c. E. 19 (Environmental Protection Act) for approval of:*

the establishment of sewage Works for the collection, transmission, treatment and disposal of drainage water at the Hydro-Hawkesbury substation located in the Town of Hawkesbury, consisting of the following:

- two (2) new rectangular-shaped spill containment areas, one to be located underneath and around the new transformer 55T2 and the other to be located underneath and around the new transformer 55T3, with both transformers being located in the southern portion of the station and each transformer having an oil volume of approximately 24.2 cubic metres, with the spill containment areas having a minimum combined containment volume of approximately 55.5 cubic metres, with each spill containment area having a minimum depth of approximately 0.60 metres and each comprised of:

    - an excavated containment basin, having a length of approximately 14.5 metres and a width of approximately 12 metres, with the floor lined with a geo-composite clay liner that is impermeable to water and oil; and

    - a layer of fire-quenching stone to be placed within the spill containment area, having a minimum depth of approximately 0.55 metres;

  each drained via a 200 millimetre diameter ductile iron pipe to a drainage sump chamber located between the two spill containment areas;

- one (1) imbiber beads drain shut-off system to be installed within a drainage sump chamber that has a length of approximately 1.9 metres, a width of approximately 1.6 metres and a depth of approximately 2.4 metres, to be located between the two spill containment areas, with the imbiber system being comprised of two (2) chambers, each having approximate dimensions of 0.51 metres by 0.51 metres and a depth of 0.79 metres, and each consisting of:

  - o a powder-coated grate screen with a silt filter grate cover;

  - o two (2) units of imbiber beads/sand disc, each with a silt filter cover, designed such that the imbiber beads swell and solidify on contact with the oil and thus remove oil and stop the flow of oil;

  - o a shut-off disc for each unit;

  drained via a 200 millimetre diameter PVC outlet pipe to the existing roadside ditch located along Main Street West, and ultimately to an unnamed watercourse that is tributary to the Ottawa River;

all other controls, electrical equipment, instrumentation, piping, pumps, valves and appurtenances essential for the proper operation of the aforementioned sewage Works;

all in accordance with supporting documents listed in Schedule 'A'.

For the purpose of this environmental compliance approval, the following definitions apply:

"Approval" means this entire document and any schedules attached to it, and the application;

"Director" means a person appointed by the Minister pursuant to section 5 of the EPA for the purposes of Part II.1 of the EPA;

"District Manager" means the District Manager of the Ottawa District Office of the Ministry;

"EPA" means the Environmental Protection Act, R.S.O. 1990, c.E.19, as amended;

"Grab sample" is defined in Section 3.1.1 of the Ministry publication, "Protocol For the Sampling and Analysis of Industrial/Municipal Waste Water" dated January 1999, and as amended;

"mg/L" means milligrams per Litre;

"Ministry" means the ministry of the government of Ontario responsible for the EPA and OWRA and includes all officials, employees or other persons acting on its behalf;

"Owner" means Hydro Hawkesbury Inc./Hawkesbury Hydro Inc. and its successors and assignees;

"OWRA" means the Ontario Water Resources Act, R.S.O. 1990, c. O.40, as amended;

"Professional Engineer" means a person entitled to practice as a Professional Engineer in the Province of

Ontario under a licence issued under the Professional Engineers Act;

"Quarterly" means four times over a year, relatively evenly spaced where possible, commencing with the start-up of the Works;

"ug/L" means micrograms per litre; and

"Works" means the sewage Works described in the Owner's application, and this Approval.

You are hereby notified that this environmental compliance approval is issued to you subject to the terms and conditions outlined below:

TERMS AND CONDITIONS

1. GENERAL CONDITION

(1) The Owner shall ensure that any person authorized to carry out work on or operate any aspect of the Works is notified of this Approval and the conditions herein and shall take all reasonable measures to ensure any such person complies with the same.

(2) Except as otherwise provided by these conditions, the Owner shall design, build, install, operate and maintain the Works in accordance with the description given in this Approval, and the application for approval of the Works.

(3) Where there is a conflict between a provision of any document in the schedule referred to in this Approval and the conditions of this Approval, the Conditions in this Approval shall take precedence, and where there is a conflict between the documents in the schedule, the document bearing the most recent date shall prevail.

(4) Where there is a conflict between the documents listed in the Schedule submitted documents, and the application, the application shall take precedence unless it is clear that the purpose of the document was to amend the application.

(5) The Conditions of this Approval are severable. If any Condition of this Approval, or the application of any requirement of this Approval to any circumstance, is held invalid or unenforceable, the application of such condition to other circumstances and the remainder of this Approval shall not be affected thereby.

2. EXPIRY OF APPROVAL

This Approval will cease to apply to those parts of the Works which have not been constructed within five (5) years of the date of this Approval.

3. CHANGE OF OWNER

(1) The Owner shall notify the District Manager and the Director, in writing, of any of the following

changes within thirty (30) days of the change occurring:

(a) change of Owner;

(b) change of address of the Owner;

(c) change of partners where the Owner is or at any time becomes a partnership, and a copy of the most recent declaration filed under the Business Names Act, R.S.O. 1990, c.B17 shall be included in the notification to the District Manager; and

(d) change of name of the corporation where the Owner is or at any time becomes a corporation, and a copy of the most current information filed under the Corporations Information Act, R.S.O. 1990, c. C39 shall be included in the notification to the District Manager.

(2) In the event of any change in ownership of the Works, the Owner shall notify in writing the succeeding owner of the existence of this Approval, and a copy of such notice shall be forwarded to the District Manager.

(3) The Owner shall ensure that all communications made pursuant to this condition will refer to this Approval's number.

4. CONSTRUCTION

(1) The Owner shall ensure that the design and construction of the Works is supervised by a Professional Engineer.

(2) Upon construction of the Works, the Owner shall prepare a statement, certified by a Professional Engineer, that the Works are constructed in accordance with this Approval, and upon request, shall make the written statement available for inspection by Ministry staff.

5. OPERATION AND MAINTENANCE

(1) The Owner shall ensure that the Works and related equipment and appurtenances which are installed or used to achieve compliance with this Approval are properly operated and maintained. The Owner shall check the Works on a monthly basis, as a minimum, and keep a record of the inspections in a log-book at the site. Upon the request of the Owner, the District Manager may reduce the frequency of inspection, in writing.

(2) The Owner shall carry out on a regular basis specific maintenance requirements and scheduling to ensure proper operation of the Works. These maintenance requirements shall, at minimum, meet those recommended by the manufacturer of the imbiber system;

(3) The Owner shall use best efforts to immediately identify and clean up all losses of oil from the transformers.

(4) The Owner shall, upon identification of a loss of oil, take immediate action to prevent the

further occurrence of such loss.

(5) In furtherance of, but without limiting the generality of, the obligation imposed by Subsection (1), the Owner shall ensure that equipment and material for the containment, clean up and disposal of oil and materials contaminated with oil are kept on hand and in good repair for immediate use in the event of:

(a) loss of oil from the transformers and equipment;

(b) a spill within the meaning of Part X of the EPA; or

(c) the identification of an abnormal amount of oil in any part of the Works.

(6) The Owner shall ensure that the oil that is used in all transformers is free from Polychlorinated Biphenyls.

6. OPERATIONS MANUAL

(1) In furtherance of, but without limiting the generality of the obligation imposed by Condition 5, the Owner shall prepare an operations manual prior to the commencement of operation of the Works, that includes, but is not necessarily limited to, the following information:

(a) operating procedures for routine operation of the Works;

(b) inspection programs, including frequency of inspection, for the Works and the methods or tests employed to detect when maintenance is necessary;

(c) repair and maintenance programs, including the frequency of repair and maintenance for the Works;

(d) a spill prevention, control and countermeasures plan to address loss of oil from transformers and a contingency plan to address oil discharge offsite, including procedures for notifying the District Manager; and

(e) procedures for responding to environmental concerns from the public.

(2) The Owner shall maintain the operations manual up to date through revisions undertaken from time to time and retain a copy at the location of the Works for as long as they are in operation. Upon request, the Owner shall make the manual available for inspection and copying by Ministry personnel.

7. EFFLUENT OBJECTIVES

(1) The Owner shall use best efforts to design, construct and operate the Works with the objective that the concentrations of the materials named below as effluent parameters are not exceeded in the effluent from the Works:

Table 1 - Effluent Objectives	
Effluent Parameter	**Concentration Objective** (milligrams per litre unless otherwise indicated)
Oil and Grease	15
Phenolics(4AAP)	20 ug/L

(2) In the event of an exceedance of one of the objectives set out in Subsection (1), the Owner shall:

(a) notify the District Manager as soon as possible during normal working hours;

(b) take immediate action to identify the source of contamination; and

(c) take immediate action to prevent further exceedance.

8. EFFLUENT - VISUAL OBSERVATIONS

Notwithstanding any other Condition in this Approval, the Owner shall ensure, by periodic visual inspection and recording in a log-book, that the effluent from the Works is essentially free of floating and settleable solids and does not contain oil or any other substance in amounts sufficient to create a visible film, sheen, foam or discolouration on the receiving waters.

9. SAMPLES AND MEASUREMENTS

The Owner shall ensure that all samples and measurements taken for the purposes of this Approval are taken at a time and in a location characteristic of the quality and quantity of the effluent stream, over the time period being monitored.

10. EFFLUENT MONITORING

The Owner shall, upon commencement of operation of the sewage works, carry out the following monitoring program:

(1) The Owner shall sample the effluent from the Works in accordance with the monitoring frequency and sample type specified in the table below for each effluent parameter:

Table 2 - Effluent Monitoring (effluent discharged from the imbiber system)	
Frequency	Quarterly
Sample Type	Grab
Parameters	Oil and Grease and Phenolics(4AAP)

(2) In the event of an exceedance of any of the objectives set out in Condition 7, Subsection (1), the Owner shall increase the frequency of sampling of the effluent to once per month, for each month that discharge occurs, until it is demonstrated to the District Manager that the effluent complies with the said objectives.

(3) The methods and protocols for sampling, analysis, and recording shall conform, in order of precedence, to the methods and protocols specified in the following:

(a) Ministry of the Environment publication "Protocol for the Sampling and Analysis of Industrial/ Municipal Wastewater", January 1999, as amended from time to time by more recently published editions; and

(b) the publication "Standard Methods for the Examination of Water and Wastewater", 21st edition, 2005, as amended from time to time by more recently published editions.

(4) After twelve (12) months of effluent monitoring under Subsection (1), with no exceedances of the objectives set out in Condition 7, the effluent monitoring frequency specified in Subsection (1) may be changed to such frequency as the District Manager may specify in writing from time to time.

(5) The Owner shall maintain a log-book at the site for recording all information related to, or resulting from, the operational, inspection, maintenance and monitoring activities required by this Approval and shall retain all such records for a minimum of five (5) years from the date of their creation.

11. REPORTING

(1) The Owner shall prepare, and upon request, submit to the District Manager, a performance report, on an annual basis, within ninety (90) days following the end of the period being reported upon. The first such report shall cover the first annual period following the issuance of this Approval and subsequent reports shall be submitted to cover successive annual periods following thereafter. The reports shall contain, but shall not be limited to, the following information:

(a) a summary and comprehensive interpretation of all monitoring data and a comparison to the effluent objectives outlined in Condition 7, including an overview of the success and adequacy of the Works;

(b) a summary of all maintenance carried out on any major structure, equipment, apparatus, mechanism or thing forming part of the Works;

(c) a summary of the efforts made and results achieved in comparison to the effluent quality objectives in accordance with Condition 7;

(d) an evaluation of the calibration and maintenance procedures conducted on all monitoring equipment;

(e) a description of any operating problems encountered and corrective actions taken; and

(f) any other information the District Manager requires from time to time.

(2) The Owner shall, upon request, make all manuals, plans, records, data, procedures and supporting documentation available to Ministry staff.

(3) In addition to the obligations under Part X of the EPA, the Owner shall, within ten (10) working days of the occurrence of any reportable spill as defined in Ontario Regulation 675/98, loss of any product, by-product, intermediate product, oil, solvent, waste material or any other polluting substance into the environment, or discovery thereof, submit a full written report of the occurrence to the District Manager describing the cause and discovery of the spill or loss, clean-up and recovery measures taken, preventative measures to be taken and schedule of implementation. The District Manager may by written notice waive the requirement of a written report, on a case-by-case basis, when the respective oral report is made.

(4) The Owner shall immediately notify the Ministry's Spills Action Centre of any Works failure or potential Works failure, including any spills.

(5) Reporting in accordance with subsections (3) or (4) does not relieve the Owner of any other regulatory or statutory obligations, including its reporting obligations pursuant to Part X of the EPA, nor does it relieve the Owner of any other obligations imposed by this Approval.

The reasons for the imposition of these terms and conditions are as follows:

1. Condition 1 is imposed to ensure that the Works are built and operated in the manner in which they were described for review and upon which approval was granted. This condition is also included to emphasize the precedence of Conditions in the Approval and the practice that the Approval is based on the most current document, if several conflicting documents are submitted for review. The Works are to be constructed in a timely manner to ensure ongoing protection of the environment.

2. Condition 2 is included to ensure that, when the Works are constructed, the Works will meet the standards that apply at the time of construction to ensure the ongoing protection of the environment.

3. Condition 3 is included to ensure that the Ministry records are kept accurate and current with respect to approved Works and to ensure that subsequent owners of the Works are made aware of the approval and continue to operate the Works in compliance with it.

4. Condition 4 is included to ensure that the Works are constructed, and may be operated and maintained such that the environment is protected and deterioration, loss, injury or damage to any person or property is prevented.

5. Condition 5 is included to ensure that the Works will be operated and maintained in a manner enabling compliance with the terms and conditions of this Approval, such that the environment is protected and deterioration, loss, injury or damage to any person or property is minimized and/or prevented.

6. Condition 6 is included to ensure that an operations manual governing all significant areas of operation, maintenance and repair is prepared, implemented and kept current by the Owner and made

available to the Ministry. Such a manual is an integral part of the operation of the Works. Its compilation and use should assist the Owner in staff training and in identifying and planning for contingencies during possible abnormal conditions. The manual will also act as a bench-mark for Ministry staff when reviewing the Owner's operation of the Works.

7. Condition 7 is imposed to establish non-enforceable effluent quality objectives which the Owner is obligated to use best efforts to meet on an ongoing basis. Also imposed are procedures to be followed to minimize environmental impact in the event the objectives are exceeded.

8. Condition 8 is imposed to ensure that the effluent discharged from the Works meets the Ministry's effluent quality requirements, as specified, on a continuous basis, thus minimizing environmental impact on the receiver.

9. Conditions 9 and 10 are related to sampling, monitoring and record keeping. They have been imposed to require the Owner to demonstrate, when required, that the performance of the Works is at a level consistent with the design and effluent objectives specified in the Approval and does not cause any impairment to the receiving watercourse, and that all pertinent information is available for any future review.

10. Condition 11 is included to provide a performance record for future references, to ensure that the Ministry is made aware of problems as they arise, and to provide a compliance record for all the terms and conditions outlined in this Approval, so that the Ministry can work with the Owner in resolving any problems in a timely manner.

Schedule 'A' forms part of this Approval and contains a list of supporting documentation / information received, reviewed and relied upon in the issuance of this Approval.

<u>SCHEDULE 'A'</u>

1. Environmental Compliance Approval Application submitted by Hydro Hawkesbury Inc./Hawkesbury Hydro Inc., dated June 19, 2015 and received on July 9, 2015, and all supporting documentation and information.

2. Emails, dated January 21, 22 and 27, 2016, from Pascal Le Sauteur of Tetra Tech.

In accordance with Section 139 of the Environmental Protection Act, you may by written Notice served upon me, the Environmental Review Tribunal and in accordance with Section 47 of the Environmental Bill of Rights, 1993, S.O. 1993, c. 28 (Environmental Bill of Rights), the Environmental Commissioner, within 15 days after receipt of this Notice, require a hearing by the Tribunal. The Environmental Commissioner will place notice of your appeal on the Environmental Registry. Section 142 of the Environmental Protection Act provides that the Notice requiring the hearing shall state:

1. The portions of the environmental compliance approval or each term or condition in the environmental compliance approval in respect of which the hearing is required, and;
2. The grounds on which you intend to rely at the hearing in relation to each portion appealed.

The Notice should also include:

3. The name of the appellant;
4. The address of the appellant;
5. The environmental compliance approval number;
6. The date of the environmental compliance approval;
7. The name of the Director, and;
8. The municipality or municipalities within which the project is to be engaged in.

And the Notice should be signed and dated by the appellant.

This Notice must be served upon:

The Secretary* Environmental Review Tribunal 655 Bay Street, Suite 1500 Toronto, Ontario M5G 1E5	AND	The Environmental Commissioner 1075 Bay Street, Suite 605 Toronto, Ontario M5S 2B1	AND	The Director appointed for the purposes of Part II.1 of the Environmental Protection Act Ministry of the Environment and Climate Change 135 St. Clair Avenue West, 1st Floor Toronto, Ontario M4V 1P5

* **Further information on the Environmental Review Tribunal's requirements for an appeal can be obtained directly from the Tribunal at: Tel: (416) 212-6349, Fax: (416) 326-5370 or www.ert.gov.on.ca**

This instrument is subject to Section 38 of the Environmental Bill of Rights, 1993, that allows residents of Ontario to seek leave to appeal the decision on this instrument. Residents of Ontario may seek leave to appeal within 15 days from the date this decision is placed on the Environmental Registry. By accessing the Environmental Registry at www.ebr.gov.on.ca , you can determine when the leave to appeal period ends.

The above noted activity is approved under s.20.3 of Part II.1 of the Environmental Protection Act.

DATED AT TORONTO this 1st day of February, 2016

Fariha Pannu.

Fariha Pannu, P.Eng.
Director
appointed for the purposes of Part II.1 of the *Environmental Protection Act*

JO/
c: Area Manager, MOECC Cornwall Area Office.
c: District Manager, MOECC Ottawa District Office.
Pascal Le Sauteur, Tetra Tech.

Environmental Compliance Approval Application

ontario.ca/environment

Ontario

Print Form Clear Form Save Form

General Information and Instructions

General Information:

Information requested in this form is collected under the authority of the Environmental Protection Act (EPA), Ontario Water Resources Act (OWRA) and Environmental Bill of Rights (EBR), and will be used to evaluate applications for Environmental Compliance Approvals (ECAs) issued under Part II.1 of the EPA. This application form should not be used for *mobile PCB destruction facilities* and *land application sites of septage and biosolids.*

For all questions related to preparing or submitting this form or about the Ministry's collection of information related to applying for an ECA, contact:

Environmental Approvals Access and Service Integration Branch
2 St. Clair Ave. West, Floor 12A,
Toronto, Ontario M4V 1L5.
Telephone outside Toronto 1-800-461-6290
or in Toronto 416-314-8001.

This office can also provide you with copies of application forms and supporting documentation.

Instructions:

1. Applicants are responsible for ensuring that they complete the most recent application form.

   Application forms and information about the required supporting documentation and technical requirements are available from the **Environmental Approvals Access and Service Integration Branch** (the address and phone number are provided in the General Information on this page). As well, you can get this information from your local District Office of the Ministry of the Environment, and on the Resources section of the Ministry of the Environment website at: **www.ene.gov.on.ca/environment/en/resources/index.htm**.

2. A complete application consists of:
   - a completed and signed application form;
   - all required supporting documents and technical requirements identified in:
     i. this form,
     ii. Ministry guidance,
     iii. the Applications for Environmental Compliance Approvals regulation, and
   - payment of the application fee (in Canadian funds) by certified cheque or money order made payable to the Minister of Finance, or credit card payment (for payments up to $10,000). For *Transfer of Review*, make your cheque or money order payable to the appropriate municipality.

The Ministry may return incomplete applications to the applicant. The Director may require additional information of any application initially accepted as complete.

3. Submit the complete application as follows:
   - One (1) paper copy (unless your application is a *Transfer of Review*), one (1) electronic copy and the fee to the **Director, Environmental Approvals Access and Service Integration Branch** at the address provided in the General Information on this page.
   - If your application is a *Transfer of Review*, you must submit two (2) copies of the completed application and the fee to the designated municipal authority.

4. You must also send a copy of the application without the fee to the local Ministry District Office that has jurisdiction over the area where the facilities are located. DO NOT send payment to the District Office.
   - To locate the appropriate local Ministry District Office, visit the Ministry of the Environment website at: **www.ene.gov.on.ca/environment/en/about/regional_district_offices/index.htm**.

5. For Waste Disposal Sites you must also send a copy of the application without the fee to the Clerk's office of the local municipality (both upper and lower tier) in which the facility/proposed facility Is located unless the application is for a revocation or an amendment that is environmentally insignificant or the applicant is a

municipality. DO NOT send any payment information to the municipality.

Information collected by the Ministry of the Environment is subject to the Freedom of Information and Protection of Privacy Act (FIPPA). If you are of the view that any part of application is confidential on the grounds that such information constitutes a trade secret or scientific, technical, commercial, financial or labour relations information, please make this known now. Otherwise, the Ministry may make the information available to the public without further notice to you.

It is an offence under the EPA and OWRA to provide false or misleading information in this application and/or accompanying documents.

The Electronic Form Smart Features

The electronic version of this form incorporates several features to assist you with completing your application.

The electronic form will highlight required information with red and green indicators. Red means that the information is required before the section is complete.

The form will also calculate certain values based on the information you enter and will assist you in ensuring that all required information is included with your application. You can save a copy of this form that includes any information you have entered.

These features are available in Adobe Reader version 8 or above. You can download a copy from the website at: **http://get.adobe.com/reader/otherversions/**.

Smart Features Legend:

These active buttons appear throughout the Application form to provide additional support.

Mandatory fields required to be filled in

☑ Mandatory fields completed

? Click on the question mark icon to receive addtional information.

Print Form — **Print Form Button —** Prints the entire form.

Clear Form — **Clear Form Button —** Clears the entire form.

Save Form — **Save Form Button —** Saves the entire form.

Calculate — **Calculate Button —** Calculates fees.

Ministry of the Environment
Public Information Centre:
Telephone: 416-325-4000
Toll-free: 1-800-565-4923
E-mail: picemail.moe@ontario.ca
www.Ontario.ca/Environment

For Office Use Only			
Reference Number	Payment Received	Date (yyyy/mm/dd)	Initials
	$		

Application Summary

☑ **Applicant Name**

Hydro Hawkesbury Inc.

☑ **Project Name**

110 kV Station refurbishment

☑ **Project Description Executive Summary**

In conjunction with the replacement of two transformers and their foundations, a secondary confinement system is to be installed comprising of geocomposite clay liner based basins. During regular operation, the basins are drained towards a roadside ditch. In case of a spill, the outlet is blocked by an "Imbiberbeads" type drain shut-off system.

Required Information

	Completed (yes or no)
Project Name & Description	Yes
Section 1: Applicant Information	Yes
Section 2: Project Information	Yes
Section 3: Regulatory Requirements	Yes
Section 4: Site Information	Yes
Section 5: Facility Information	Yes
Section 6: Supporting Documentation	Yes
Section 7: Payment Information	No

Application Status Please complete the sections as shown above

Fee Summary:

Administrative Processing	$
Review of EPA s. 9 activities	$
Review of EPA s. 27 activities	$
Review of OWRA s. 53 activities	$
Total Fee	**$**

Calculate

The Ministry may request additional fees upon review of this application.
If you are submitting this form in print version only and are not using the smart calculation feature, please attach the fee calculation separately.

Supplemental Application Information

See help text on required information for this section.

Start date is projected for 2015.

Copy of the application will be transmitted to the MEO Cornwall district office.

☑ 1.1 Applicant Information

Applicant Name (legal name of individual or organization as evidenced by legal documents): Hydro Hawkesbury Inc.

Business Number: 001436779

Business Name ☒ same as Applicant Name: Hydro Hawkesbury Inc.

Business Website Address: www.hydrohawkesbury.ca

Applicant Type:

- ◉ Corporation
- ◯ Individual
- ◯ Partnership
- ◯ Sole Proprietor
- ◯ Federal Government
- ◯ Municipal Government
- ◯ Provincial Government
- ◯ Other (describe):

Primary North American Industry Classification System (NAICS) Code: :22

Other NAICS codes (select all that apply): 221122

Separate list attached? ◯ Yes ◉ No

Business Activity Description: Electrical utilities provider

☑ 1.2 Applicant Physical Address

Civic Address – Street Information (includes street number, name, type and direction): 850 Tupper street

Unit Identifier (suite or unit number):

Survey Address

Lot: Concession: Part: Reference Plan:

Municipality/Unorganized Township or Territory: Hawkesbury

Upper Tier/District:

Province/State: Ontario

Country: Canada

Postal Code/ZIP Code: K6A 3S7

Telephone Number (include area code & ext.): 613-632-6689 ext.

Fax Number (include area code): 613-632-8603

Mobile Number (include area code):

E-mail Address: michelpoulin@hydrohawkesbury.ca

Geo Reference (required)

Description of location	Map Datum	Zone	Accuracy Estimate	Geo-Referencing Method	UTM Easting	UTM Northing
Southwest corner of property	NAD83	18	10m	google earth	532139.00	5049678.00
Physical location of front door or main entrance	NAD83	18	10m	google earth	532223.00	5049664.00

☑ 1.3 Applicant Mailing Address

Same as Applicant Physical Address? (●) Yes ( ) No

Civic Address – Street Information (civic numbering and street information includes street number, name, type and direction)	Unit Identifier (suite or unit number)
850 Tupper street	

Delivery Designator	Delivery Identifier	Postal Station

Municipality/Unorganized Township or Territory	Province/State	Country	Postal Code/ZIP Code
Hawkesbury	Ontario	Canada	K6A 3S7

☑ 1.4 Statement of the Applicant

I am authorized to prepare and submit this application and to make this certification. I have reviewed the complete application and I have made all inquiries that are necessary to declare to the best of my knowledge, information and belief:

- The information contained in this application is complete and accurate.
- The Technical Contact(s) identified in this application has/have been authorized to prepare certain technical material, and act on behalf of the applicant to discuss this application with the Ministry of the Environment and to provide additional information about this application to the Ministry on request.
- The information provided to the Technical Contact(s) in relation to this application is complete and accurate.

Name of Signing Authority (please print)	Title
Michel Poulin	Manager

Telephone Number (include area code & ext.)	ext.	Fax Number (include area code)	Mobile Number (include area code)
613-632-6689		613-632-8603	

E-mail Address	Signature	Date (yyyy/mm/dd)
michelpoulin@hydrohawkesbury.ca	[signature]	2015/06/19

1.5 Statement of the Municipality ☐ N/A

I, the undersigned hereby declare on behalf of the Municipality, that the Municipality has no objection to the construction of the works in the Municipality.

Name and Title (please print)	Name of Municipality
JEANNE CHARLEBOIS, MAYOR	TOWN OF HAWKESBURY

Signature	Date (yyyy/mm/dd)
Jeanne Charlebois	2015-07-07

☑ 2.1 Reason for Application

◉ New ECA ○ Amendment to existing ECA ○ Revocation of existing ECA
○ Administrative amendment to existing ECA ○ Application for renewal of limited operational flexibility ○ Consolidation of existing ECAs

Are you adding a new project type to your site or a new municipal waste category/class code to your waste management systems or a new sewage facility type? ○ Yes ○ No

Is this for *Transfer of Review*? ○ Yes ◉ No

☑ 2.2 Project Type (select all that apply)

Yes	N/A		Limited Operational Flexibility?	Pilot Project?
○	◉	Air – Stationary	☐	☐
○	◉	Air – Mobile	☐	☐
○	◉	Noise	☐	☐
○	◉	Vibration	☐	☐
○	◉	Waste Disposal Site – Landfill site	N/A	☐
○	◉	Waste Disposal Site – Transfer site	☐	☐
○	◉	Waste Disposal Site – Processing site	☐	☐
○	◉	Waste Disposal Site – Composting site	N/A	☐
○	◉	Waste Disposal Site – Thermal Treatment site	N/A	☐

Yes	N/A		Limited Operational Flexibility?	Pilot Project?
◉	○	Sewage – Industrial	☐	☐
○	◉	Sewage – Municipal	☐	☐
○	◉	Sewage – Private	☐	☐
○	◉	Waste Management System – General Waste Management System	N/A	☐
○	◉	Waste Management System – Hauled Sewage (Septage)	N/A	☐
○	◉	Waste Management System – Soil Conditioner for transport to a site for Application on Land	N/A	☐
○	◉	Waste Management System – Mobile Waste Processing	N/A	☐
○	◉	Cleanup of contaminated sites – Mobile	N/A	☐
○	◉	Cleanup of contaminated sites – Site-specific	N/A	☐

☑ 2.3 Approval Information ?

Application initiated by:

◉ Applicant ○ S. 20.18 Order (attach copy) ○ Condition of existing approval ○ Provincial Officer Order (attach copy) ○ Inspection Report (attach copy) ○ Other (specify):

Current Environmental Compliance Approvals that may be changed or amended by this application: ☐ N/A

Separate list attached? ○ Yes ○ No

Environmental Compliance Approval Number	Date of Issuance (yyyy/mm/dd)	Environmental Compliance Approval Number	Date of Issuance (yyyy/mm/dd)

Proposed Environmental Compliance Approvals related to this project: ☒ N/A

Separate list attached? ○ Yes ○ No

Project type	Ministry Reference Number (if applicable)	Have submitted	Have not submitted
		○	○
		○	○
		○	○
		○	○

☑ 2.4 Other Approval/Permits for Facility ☒ N/A ?

Separate list attached? ○ Yes ○ No

List all other instruments (approvals or permits) issued by the Ministry of the Environment or applied for under the Environmental Protection Act, Environmental Assessment Act, Ontario Water Resources Act and Safe Drinking Water Act, 2002 and any Environmental Activity and Sector Registrations that are relevant to this application.

Instrument Type	Instrument Number	Approval or Application Date (yyyy/mm/dd)	Instrument Type	Instrument Number	Approval or Application Date (yyyy/mm/dd)

☑ **2.5 Technical Contacts**

Technical Contact 1

Area of Responsibility (check all that apply) ☐ Air ☐ Noise/Vibration ☒ Sewage ☐ Waste

Name of Technical Contact: Pascal Le Sauteur
Company: Tetra Tech

Telephone Number (include area code & ext.): 418-723-8151 ext. 236
Mobile Number (include area code):
Fax Number (include area code):
E-mail Address: pascal.lesauteur@tetratech.ca

Address Information:

Same as Applicant Mailing Address? ○ Yes ◉ No (If no, please provide technical contact address information below.)

Civic Address – Street Information (includes street number, name, type and direction): 464, boulevard St-Germain
Unit Identifier (suite or unit number):

Delivery Designator:
Delivery Identifier:
Postal Station:

Municipality/Unorganized Township or Territory: Rimouski
Province/State: Quebec
Country: Canada
Postal Code/ZIP Code: G5L 3P1

I have been authorized by the applicant to prepare the technical materials for the area(s) of responsibility identified above that are included in the application. I have reviewed those technical materials and I have made all inquiries that are necessary to declare to the best of my knowledge, information and belief:

- The technical materials contained in this application in respect of the area(s) of responsibility identified above are complete and accurate.
- I have the relevant education and experience necessary to provide this certification.

Signature: Pascal LeSauteur P. Eng.

Date (yyyy/mm/dd): 2015/06/17

☑ Technical Contact 2

Area of Responsibility (check all that apply) ☐ Air ☐ Noise/Vibration ☐ Sewage ☐ Waste

Name of Technical Contact: ________ Company: ________

Telephone Number (include area code & ext.): ________ ext. ____ Mobile Number (include area code): ________ Fax Number (include area code): ________ E-mail Address: ________

Address Information:

Same as Applicant Mailing Address? ◯ Yes ◯ No (If no, please provide technical contact address information below.)

Civic Address – Street Information (includes street number, name, type and direction): ________ Unit Identifier (suite or unit number): ________

Delivery Designator: ________ Delivery Identifier: ________ Postal Station: ________

Municipality/Unorganized Township or Territory: ________ Province/State: ________ Country: Canada Postal Code/ZIP Code: ________

I have been authorized by the applicant to prepare the technical materials for the area(s) of responsibility identified above that are included in the application. I have reviewed those technical materials and I have made all inquiries that are necessary to declare to the best of my knowledge, information and belief:

- The technical materials contained in this application in respect of the area(s) of responsibility identified above are complete and accurate.
- I have the relevant education and experience necessary to provide this certification.

Signature: ________ Date (yyyy/mm/dd): ________

☑ Technical Contact 3

Area of Responsibility (check all that apply) ☐ Air ☐ Noise/Vibration ☐ Sewage ☐ Waste

Name of Technical Contact

Company

Telephone Number (include area code & ext.) ext.

Mobile Number (include area code)

Fax Number (include area code)

E-mail Address

Address Information:

Same as Applicant Mailing Address? ◯ Yes ◯ No (If no, please provide technical contact address information below.)

Civic Address – Street Information (includes street number, name, type and direction)

Unit Identifier (suite or unit number)

Delivery Designator

Delivery Identifier

Postal Station

Municipality/Unorganized Township or Territory

Province/State

Country

Canada

Postal Code/ZIP Code

I have been authorized by the applicant to prepare the technical materials for the area(s) of responsibility identified above that are included in the application. I have reviewed those technical materials and I have made all inquiries that are necessary to declare to the best of my knowledge, information and belief:

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- I have the relevant education and experience necessary to provide this certification.

Signature

Date (yyyy/mm/dd)

☑ Technical Contact 4

Area of Responsibility (check all that apply) ☐ Air ☐ Noise/Vibration ☐ Sewage ☐ Waste

Name of Technical Contact

Company

Telephone Number (include area code & ext.) ext.

Mobile Number (include area code)

Fax Number (include area code)

E-mail Address

Address Information:

Same as Applicant Mailing Address? ◯ Yes ◯ No (If no, please provide technical contact address information below.)

Civic Address – Street Information (includes street number, name, type and direction)

Unit Identifier (suite or unit number)

Delivery Designator

Delivery Identifier

Postal Station

Municipality/Unorganized Township or Territory

Province/State

Country: Canada

Postal Code/ZIP Code

I have been authorized by the applicant to prepare the technical materials for the area(s) of responsibility identified above that are included in the application. I have reviewed those technical materials and I have made all inquiries that are necessary to declare to the best of my knowledge, information and belief:

- The technical materials contained in this application in respect of the area(s) of responsibility identified above are complete and accurate.
- I have the relevant education and experience necessary to provide this certification.

Signature

Date (yyyy/mm/dd)

☑ 3.1 Environmental Bill of Rights (EBR) Requirements

Is this a proposal for a prescribed instrument under the EBR? ○ Yes ◉ No

If yes, is this proposal exempted from the EBR requirements? ○ Yes ○ No

If yes, please check one of the following (Please provide supporting information.)

- ○ This proposal has been considered in a substantially equivalent process of public participation. (EBR, 1993, s.30.)
- ○ This proposal is for an emergency situation. (EBR, 1993, s. 29.)
- ○ This proposal is for an amendment to or revocation of an existing Environmental Compliance Approval that is not environmentally significant. (EBR, 1993, s. 22 (3).)
- ○ This proposal has been subject to or exempted from EAA Requirements or considered in a decision of a tribunal. (EBR, 1993, s. 32.)

☑ 3.2 Environmental Assessment Act (EAA) Requirements

Is the proposed undertaking subject to the requirements of the EAA? ○ Yes ◉ No

If yes, please check one of the following:

○ The undertaking has fulfilled the requirements of the EAA through an exemption provided under:

- ○ Section of Ontario Regulation No. or
- ○ Declaration/Exemption Order Number

If Regulation, Declaration Order or Exemption Order does not refer directly to this undertaking, please provide supporting documentation to explain why it applies to this facility.

○ The proposed undertaking has fulfilled the requirements of the EAA through the completion of a Class EA process:

Name of Class EA:

Schedule/Group/Category (if applicable):

If applicable, please submit a copy of the proof of completion (for example, Notice of Completion).

Was the undertaking subject of a Part II Order request(s)? ○ Yes ○ No If yes, please submit a copy of the Director's or Minister's decision letter.

○ The proposed undertaking has fulfilled all of the requirements for the EAA through:

- ☐ completion of an Environmental Screening Process pursuant to O. Reg. 101/07 of the EAA
- ☐ completion of an Environmental Screening Process pursuant to O. Reg. 116/01 of the EAA

Was the undertaking subject of an elevation request(s)? ○ Yes ○ No If yes, please submit a copy of the Director's decision letter.
If an appeal was made of the Director's decision, please also submit a copy of the Minister's decision letter.

- ☐ completion of an Environmental Screening Process pursuant to O. Reg. 231/08 of the EAA

Was the undertaking subject of an objection(s)? ○ Yes ○ No If yes, please submit a copy of the Minister's decision letter.

○ The proposed undertaking has fulfilled the requirements of the EAA through the completion of an individual Environmental Assessment.

Please submit a copy of the signed Notice of Approval.

☑ 3.3 Consultation/Notification

Are there any consultation/notification activities that you have undertaken to fulfill requirements by other legislation or through voluntary efforts?

◉ Yes ◯ No

If yes, please:

1) describe the consultation/notification activities below; and
2) attach documents describing each of these consultation/notification activities, any changes to the project as a result of these activities and any planned consultation/notification activities in the future.

Approval of the project by the Town of Hawkesbury and the Southern Nation Conservation agency.

Attached documents:

1) Environmental Response Plan submitted by Hydro hawkebury inc.
2) Acceptance letter from Southern Nation Conservation
3) Acceptance letter from Town of Hawkesbury

☑ 4.1 Site Address or Storage Location

Will the vehicles or equipment be stored at more than one location? ○ Yes ○ No
(If yes, please enter all vehicle or equipment storage locations below and attach separate list, as necessary.)

Same as Applicant Physical Address? ○ Yes ◉ No

Primary Civic Address – Street Information (includes street number, name, type and direction) | Unit Identifier (suite or unit number)

Street Information	Unit Identifier
990 Main street west	

Additional Civic Addresses Separate list attached? ○ Yes ◉ No

Additional Civic Addresses	Unit Identifier (suite or unit number)

Primary Survey Address

Lot	Concession	Part	Reference Plan

Additional Survey Addresses Separate list attached? ○ Yes ◉ No

Lot	Concession	Part	Reference Plan
0899	Broken front	14	Prescott (no. 46)

Municipality/Unorganized Township or Territory	Upper Tier/District	Province/State	Country	Postal Code/ZIP Code
Hawkesbury	Prescott and Russell	Ontario	Canada	K6A 0A2

Non-address Information (includes any additional information to clarify the physical location)

☑ Same as Applicant Physical Geo Reference? ○ Yes ◉ No Geo Reference (required)

Description of location	Map Datum	Zone	Accuracy Estimate	Geo-Referencing Method	UTM Easting	UTM Northing
Southwest corner of property	NAD83	18	10	estimate from map	528703.00	5051390.00
Physical location of front door or main entrance	NAD83	18	10	estimate from map	528766.00	5051421.00

☑ 4.2 Site or Storage Location Information

Site Name	Days and Hours of Operation	Ministry of the Environment District Office
110 kV Substation	Full time	Cornwall Area Office

Is the site (property) that is the subject of this application owned by the applicant?
If no, please include the owner's name, address and a signed document indicating that the applicant has the authority to install and operate the proposed activity, or store vehicles or equipment on the land.
◉ Yes ○ No

Is the applicant the operating authority of the site that is the subject of this application?
If no, please include the operating authority name, address and phone number.
◉ Yes ○ No

Is the site located in an area of development control as defined by the Niagara Escarpment Planning & Development Act (NEPDA)?
If yes, please attach a copy of the NEPDA permit for proposed activity.
○ Yes ◉ No

Is the site within an area covered by the Oak Ridges Moraine Conservation Plan?
If yes, please attach proof of municipal planning approval for the proposed activity/work (for example, zoning by-law, letter from municipality, etc.).
○ Yes ◉ No

☑ 4.3 Site Zoning and Classification

Current Land Use	Official Plan Designation	Current Zoning (Please attach zoning map, if available.)
Electrical utility	Community commercial policy area (CC)	Highway commercial district (CH)

Adjacent Land Use (select all that apply)

☒ Industrial ☐ Commercial ☒ Residential
☒ Agricultural ☐ Recreational ☐ Other (specify):

Adjacent Land Zoning

Highway commercial district (CH), Future development (D)

Does the current zoning permit the proposed activity?
◉ Yes ○ No

Does the applicant have correspondence from the municipality to confirm that the current zoning of the property permits the proposed use?
◉ Yes ○ No If yes, please attach correspondence from the municipality.

Does the official plan designation support the proposed activity?
◉ Yes ○ No ○ N/A

4.4 Point of Entry into Ontario (for waste management system vehicles that are stored at an address outside of Ontario)

City in closest proximity to the point of entry	Description of Point of Entry

☑ 4.5 Source Protection/Drinking Water Threats (sewage or waste disposal site applications only)

Check the source protection area(s) where the activity is/will be located:

☐ Ausable Bayfield	☐ Grand River	☐ Raisin Region	☐ Lower Thames Valley
☐ Maitland Valley	☐ Kettle Creek	☒ South Nation	☐ St. Clair Region
☐ Cataraqui Region	☐ Long Point	☐ Grey Sauble	☐ Upper Thames River
☐ Central Lake Ontario	☐ Lakehead	☐ Northern Bruce Peninsula	☐ Crowe Valley
☐ Credit Valley	☐ Mattagami	☐ Saugeen Valley	☐ Ganaraska
☐ Toronto and Region	☐ Mississippi Valley	☐ Sault Ste. Marie	☐ Kawartha-Haliburton
☐ Essex	☐ Rideau Valley	☐ Lake Simcoe & Couchiching/Black River	☐ Lower Trent
☐ Halton	☐ Niagara	☐ Nottawasaga Valley	☐ Otonabee-Peterborough
☐ Hamilton	☐ North Bay Mattawa	☐ Severn Sound	☐ Outside a source protection area
☐ Catfish Creek	☐ Quinte	☐ Sudbury	

Is the proposed activity located or planned to be located in a vulnerable area identified in a local assessment report source protection plan under the Clean Water Act, 2006?

◉ Yes ○ No

If yes, what is/are the vulnerable area(s)/zone(s)?

☐ Wellhead Protection Areas	☒ Surface Water Intake Protection Zones
☐ Highly Vulnerable Aquifers	☐ Significant Groundwater Recharge Areas

Is the activity being applied for identified as a significant drinking water threat in the assessment report for the local source protection area?

◉ Yes ○ No

☑ 4.6 Receiver of Effluent Discharge (sewage applications only)

Intermediate Receiver Name	Watershed Name
Main street west roadside ditch and unamed water course	Ottawa river

☒ Surface Water ☐ Groundwater ☐ Other (specify):

Has the facility received local Conservation Authority clearance? (for stormwater management facility discharging to the natural environment)

◉ Yes ○ N/A If yes, please include a copy of the Conservation Authority clearance.

Final Receivers ☒ N/A

Will the proposed activity discharge sewage to any of the following critical receivers?

☐ Lake Simcoe	☐ Rideau River	☐ Detroit River	☐ Other (specify):
☐ Great Lakes	☐ Rouge River	☐ Bay of Quinte	

Is the receiver a Policy 2 receiver? ○ Yes ○ No

Do you have a Policy 2 deviation approval from the directors? ○ Yes ○ No If yes, please attach a copy of the Director's approval.

5.1 Air

? IF YOUR APPLICATION DOES NOT HAVE AIR EMISSIONS PLEASE PROCEED TO SECTION 5.2

5.1.1 Summary of Equipment that Discharges Contaminants to the Air ?

(√)	Description	Number of Pieces of Equipment
☐	Combustion equipment that uses natural gas, propane, no. 2 oil, landfill gas or sewage treatment gas for fuel for the purpose of providing comfort heating or emergency power, producing hot water or steam, or heating material in a system that does not discharge to the atmosphere (Total Heat input of all units ≤ 50,000,000 kJ/hr)	N/A
☐	Storage tanks	N/A
☐	Welding operations that use a maximum of 10 kilograms of welding rod per hour	N/A
☐	Combustion equipment that uses waste-derived fuel for the purpose of providing comfort heating, burning ≤ 15 litres per hour	
☐	Heat cleaning ovens used for parts cleaning and associated parts washers or degreasing equipment, other than solvent degreasing equipment	
☐	Cooling towers	
☐	Equipment used to control emissions of contaminants, other than a fume incinerator	
☐	Laboratory fume hoods	
☐	Paint spray booths and associated equipment that have a design capacity of up to 8 litres per hour of paint	
☐	Grain dryers	
☐	Any other equipment not listed above with a flow rate of less than or equal to 1.5 m^3 per second	
☐	Any other equipment not listed above with a flow rate of greater than 1.5 m^3 per second	
☐	Equipment that is subject to an Environmental Compliance Approval, and from which there is no proposed increase in the discharge of any contaminant that was previously reviewed by the Director.	N/A

5.1.2 Emission Summary and Dispersion Modelling (ESDM) Report ?

Is the review of an existing, approved ESDM required as part of this proposed application? ○ Yes ○ No

If yes, identify the number of emission sources described in the existing ESDM Report that emit contaminants in common with the sources forming the subject of the application (if none, enter zero).

Have all of these emission sources been described in an ESDM Report that was previously reviewed as part of an application for an existing Environmental Compliance Approval? ○ Yes ○ No

5.1.3 O. Reg. 419/05 Requirements

Which of the following sections of O. Reg. 419/05 applies to the facility?

☐ s.19 (Schedule 2) ☐ s.20 (Schedule 3) ☐ Does not apply. Please indicate reason:

Has an instrument under O. Reg. 419/05 been issued? ○ Yes ○ No

If yes, what type(s) of instruments (including any notices, orders or approvals) has (have) been issued? (select all that apply)

- ☐ ss. 4(2) Adjacent Properties
- ☐ ss. 7(1) Specified Dispersion Models
- ☐ ss. 8(2) Negligible Sources
- ☐ ss. 10(2) Operating Conditions
- ☐ ss. 11(2) Refined Emission Rates
- ☐ ss. 13.1 Value of Dispersion Modeling Parameters
- ☐ ss. 13(1) Meteorological Data
- ☐ ss. 14(6) Area of Modelling Coverage
- ☐ Other (list all that have been issued):
- ☐ ss. 20(4) Speed-up Request
- ☐ ss. 20(5) Speed-up Order
- ☐ s. 35 Site-specific Standard
- ☐ ss. 35(14) Site-specific Standard Order
- ☐ ss. 39(3) Technical Standard Registration (Industry Standard)
- ☐ ss. 39(4) Technical Standard Registration (Equipment Standard)

Is an instrument under O. Reg. 419/05 being requested as part of this application? ○ Yes ○ No

If yes, what type(s) of notice, order or approval is (are) being requested?

- ☐ ss. 7(1) Specified Dispersion Models
- ☐ ss. 8(2) Negligible Sources
- ☐ ss. 10(2) Operating Conditions
- ☐ ss. 11(2) Refined Emission Rates
- ☐ ss. 13(1) Meteorological Data
- ☐ Other (list all that have been requested):
- ☐ ss. 14(6) Area of Modelling Coverage
- ☐ ss. 20(4) Speed-up Request
- ☐ s. 32 Request for a Site-specific Standard Order
- ☐ ss. 39(1)(a) Application for Technical Standard Registration (Industry Standard)
- ☐ ss. 39(1)(b) Application for Technical Standard Registration (Equipment Standard).

Please attach the form(s) requesting the notice(s) and/or order(s) and any additional supporting information.

Has an s.30 Upper Risk Threshold (Schedule 6) been exceeded? If yes, please include additional supporting information. ○ Yes ○ No

Is the facility located in a multi-tenant building? If yes, additional information may be requested. ○ Yes ○ No

Are all of the contaminants to which the application relates represented in the Ministry of the Environment publication titled "*Summary of Standards and Guidelines to support Ontario Regulation 419: Air Pollution – Local Air Quality*" or have they been screened out based on the publication titled "*Jurisdictional Screening Level (JSL) List, A Screening Tool for Ontario Regulation 419: Air Pollution – Local Air Quality*"? (If no, please attach Supporting Information for a Maximum Ground Level Concentration Acceptability Request for Compounds with no Ministry POI Limit – Supplement to Application for Approval, EPA S.9 (PIBS 4872)). ○ Yes ○ No

5.2 Noise

IF YOUR APPLICATION DOES NOT HAVE NOISE EMISSIONS, PLEASE PROCEED TO SECTION 5.3.

5.2.1 Noise Assessment ?

Have you completed an Acoustic Assessment Report (AAR) or Abbreviated Acoustic Assessment Report (A-AAR)? ○ Yes ○ No

If yes, please indicate the report you have completed:

○ **AAR** Please attach the Acoustic Assessment Report.

Does the AAR show that applicable limits are met? ○ Yes ○ No

If no, please attach the Acoustic Assessment Report including the Noise Abatement Action Plan.

○ **A-AAR** Please attach the Abbreviated Acoustic Assessment Report.

Does the A-AAR show that applicable limits are met? ○ Yes ○ No

Note that certain conditions must be met before using the A-AAR and that the A-AAR must show that the applicable limits are met otherwise an AAR may be required.

If no, is the application eligible for Primary or Secondary Noise Screening? ○ Yes ○ No

Note that if you are not eligible for either of the screenings, you must submit either an AAR or A-AAR.

If yes, is your proposed activity described with one of the NAICS codes that are eligible for the Primary Noise Screening? ○ Yes ○ No

If yes, is the actual separation distance between the facility and the noise sensitive point of reception (POR) greater than the minimum required separation distance calculated from the Primary Noise Screening? ○ Yes ○ No

If yes, please attach the Primary Noise Screening form and supporting documentation.
Note that if the Primary Noise Screening is not successful then you may attempt to proceed with the secondary noise screening.

If no, does the Secondary Noise Screening report show that the applicable sound level limits are met? ○ Yes ○ No

If yes, please attach the Secondary Noise Screening Report and supporting documentation.
Note that if you cannot demonstrate that the applicable sound level limits are met then you must submit either an AAR or A-AAR.

5.2.2 Equipment Subject to Noise Review ?

(√)	Description	Number of Pieces of Equipment
☐	Arc Furnaces	
☐	Asphalt Plants	
☐	Blow-down Devices	
☐	Co-generation Facilities	
☐	Crushing Operations	
☐	Flares	
☐	Gas Turbines	
☐	Pressure Blowers or Large Induced Draft Fans (flow rate > 47m^3/second or static pressure > 1.25 kilopascals)	
☐	Any other equipment not listed above that has not previously been reviewed by the Director in connection with an application for an Environmental Compliance Approval with respect to the facility	
☐	Any other equipment not listed above that is identical to equipment for which a noise assessment was previously reviewed by the Director in connection with an application for an Environmental Compliance Approval with respect to the facility	

☑ 5.3 Sewage Works

IF YOUR APPLICATION DOES NOT CONTAIN SEWAGE WORKS PLEASE PROCEED TO SECTION 5.4

☑ 5.3.1 Facility Type – Sewage Works

Select the type of facility that is the subject of the application (select all that apply).

☐ **Sewage Treatment Plant (STP)**

Further information:

- ☐ Primary
- ☐ Secondary
- ☐ Tertiary
- ☐ Receives septage
- ☐ Constructed/Engineered Wetlands
- ☐ On-site system
- ☐ Lagoons (check all that apply below)
  - ☐ Septage
  - ☐ Municipal
  - ☐ Other (specify):

☐ Municipal or private facility
Category: ○ New ○ 1 ○ 2 ○ 3 ○ 4

Please indicate the maximum design capacity of the municipal or private sewage treatment plant:
○ ≤ 4,550 m^3/day   ○ > 4,550 m^3/day

☐ Facility for the treatment of leachate
Category: ○ New ○ 1 ○ 2 ○ 3 ○ 4

☐ Facility for the treatment of industrial process wastewater
Category: ○ New ○ 1 ○ 2 ○ 3 ○ 4

☐ Facility for the disposal of non-contact cooling water

☐ Subsurface disposal

Please indicate the design capacity of the subsurface disposal:
○ ≤ 15 m^3/day   ○ > 15 m^3/day and < 50 m^3/day   ○ > 50 m^3/day

☒ **Stormwater Management Facility**
Category: ◉ New ○ 1 ○ 2 ○ 3 ○ 4

☐ Wet Pond   ☐ Dry Pond   ☒ Other (specify): Secondary confinement basins for oil filled transformers

For the following, you must complete and attach the relevant sections of the pipe data form:

- ☐ **Storm Sewers**
- ☐ **Combined Sewers**
- ☐ **Sanitary Sewers**
- ☐ **Ditches**
- ☐ **Forcemains**
- ☐ **Pumping Station**

Is a Hydrogeological Assessment required? ○ Yes ◉ No (If yes, please attach the hydrogeological assessment.)

Is a review of effluent criteria assessment for stormwater management, cooling water or soil remediation facilities required? ○ Yes ◉ No
(If yes, please attach the final effluent criteria accepted by the Regional Office of the Ministry.)

Is a review of effluent criteria assessment for municipal or private sewage, industrial process wastewater or leachate treatment plant required? ○ Yes ◉ No
(If yes, please attach the final effluent criteria accepted by the Regional Office of the Ministry.)

☑ 5.3.2 Servicing ?

The works will provide sewage servicing for (select all that apply):

☐ **Residential**
- ☐ Subdivision
- ☐ Condominium
- ☐ Institutional
- ☐ Other (specify):

Is there a Municipal Responsibility Agreement in place? ○ Yes ○ No ○ N/A
If yes, please attach a copy of the Municipal Responsibility Agreement.

☐ **Commercial**
- ☐ Hotel, Motel, Inn
- ☐ Resort
- ☐ Restaurant
- ☐ Campground, Park
- ☐ Shopping Malls
- ☐ Highway Service Station/Gas Bars
- ☐ Rental Cabins
- ☐ Other (specify):

☒ **Industrial**

Describe:

Rainwater drainage of secondary confinement basins

☑ 5.3.3 Sewage Servicing for Waste Disposal/Landfill Sites ?

Does/Will the sewage treatment facility receive waste disposal/landfill site leachate? ○ Yes ◉ No If yes, please identify the site(s) below.

Name of Site Contributing Leachate	Environmental Compliance Approval Number	Volume of leachate (m^3)
1.		
2.		
3.		
4.		
5.		

5.4 Waste Disposal Site

IF YOUR APPLICATION IS NOT FOR A WASTE DISPOSAL OR PROCESSING SITE PLEASE PROCEED TO SECTION 5.5

5.4.1 Facility Description – Waste Disposal Site (information on the nature of the proposed business or activity at this site)

Service Area

Total Area of Site (hectares)

Monitoring (select all that apply)

☐ Groundwater ☐ Surface Water ☐ Landfill Gas ☐ Leachate ☐ None ☐ Other (specify):

Type(s) of waste to be accepted at this site (select all that apply)

Subject:
☐ Hazardous Waste
☐ Liquid Industrial Waste

Non-subject:
☐ Municipal (non-hazardous)
☐ Other Liquid Waste

Municipal waste categories to be accepted at this site (select all that apply)

☐ All Categories ☐ Domestic Sources ☐ IC&I Sources ☐ Source Separated Organics ☐ Tires ☐ Leaf & Yard Waste
☐ Contaminated Soil ☐ Wood Waste ☐ Blue Box Materials ☐ Other (specify):

Other liquid waste categories to be accepted at this site (select all that apply)

☐ Processed Organics ☐ Waste from Food Processing/Preparation Operations ☐ Hauled Sewage ☐ Other (specify):

Hazardous Waste / Liquid Industrial Waste								
Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code

5.4.2 Waste Transfer/Processing/Composting – Complete this information if waste transfer and/or processing and/or composting take(s) place at this facility

Waste Types to be Transferred or Processed	Design Capacity	
☐ Hazardous waste or liquid industrial waste	○ ≤ 100 tonnes per day	○ > 100 tonnes per day
☐ Waste other than hazardous waste and liquid industrial waste	○ ≤ 100 tonnes per day	○ > 100 tonnes per day

Change to Operations

○ No Change Proposed ○ Change does not require fundamental design review ○ Change requires fundamental design review

Liquid Waste

Maximum Storage Capacity (m³)			Maximum Residual for Final Disposal (m³)					
Hazardous	Liquid Industrial	Other Liquid Waste	Hazardous		Liquid Industrial		Other Liquid Waste	
			Daily	Annually	Daily	Annually	Daily	Annually

Solid Waste

Maximum Storage Capacity (tonnes)		Maximum Residual for Final Disposal (tonnes)			
Hazardous	Non-hazardous	Hazardous		Non-hazardous	
		Daily	Annually	Daily	Annually

Maximum Amount of Waste to be Received Daily

Liquid (m³)			Solid (tonnes)	
Hazardous	Liquid Industrial	Other Liquid Waste	Hazardous	Non-hazardous

5.4.3 Thermal Treatment Facility – Complete this information if thermal treatment takes place at this facility

Waste Type for Thermal Treatment	Design Capacity	
☐ Hazardous waste or liquid industrial waste	○ ≤ 100 tonnes per day	○ > 100 tonnes per day
☐ Waste other than hazardous waste and liquid industrial waste	○ ≤ 100 tonnes per day	○ > 100 tonnes per day

Change to Operations		
○ No Change Proposed	○ Change does not require fundamental design review	○ Change requires fundamental design review

Liquid Waste								
Maximum Storage Capacity (m^3)			Maximum Residual for Final Disposal (m^3)					
Hazardous	Liquid Industrial	Other Liquid Waste	Hazardous		Liquid Industrial		Other Liquid Waste	
			Daily	Annually	Daily	Annually	Daily	Annually

Solid Waste						
Maximum Storage Capacity (tonnes)		Maximum Residual for Final Disposal (tonnes)				
Hazardous	Non-hazardous	Hazardous		Non-hazardous		
		Daily	Annually	Daily	Annually	

Maximum Amount of Waste to be Received Daily				
Liquid (m^3)			Solid (tonnes)	
Hazardous	Liquid Industrial	Other Liquid Waste	Hazardous	Non-hazardous

Maximum Daily Feed Rate (tonnes/m^3)			
Hazardous Waste (tonnes)	Non-hazardous Waste (tonnes)	Liquid Industrial Waste (m^3)	Other Liquid Waste (m^3)

5.4.4 Landfill Site – Complete this information if this facility operates as a landfill site

Waste Types to be accepted at the Landfill	Design Capacity		
☐ Hazardous waste or liquid industrial waste	○ ≤ 40,000 m^3	○ > 40,000 m^3 ≤ 3 million m^3	○ > 3 million m^3
☐ Waste is only uncontaminated tree stumps, leaves, branches, concrete and rocks	○ ≤ 40,000 m^3	○ > 40,000 m^3 ≤ 3 million m^3	○ > 3 million m^3
☐ Waste other than hazardous waste and liquid industrial waste, other than uncontaminated tree stumps, leaves, branches, concrete and rocks.	○ ≤ 40,000 m^3	○ > 40,000 m^3 ≤ 3 million m^3	○ > 3 million m^3

Change to Operations		
○ No Change Proposed	○ Change does not require fundamental design review or hydrogeological assessment	○ Change requires fundamental design review or hydrogeological assessment

Maximum Landfilling Capacity (m^3)			
Hazardous Waste	Non-hazardous Waste	Liquid Industrial Waste	Other Liquid Waste

Maximum Amount of Waste to be Received							
Hazardous Waste (tonnes)		Non-hazardous Waste (tonnes)		Liquid Industrial Waste (m^3)		Other Liquid Waste (m^3)	
Daily	Annually	Daily	Annually	Daily	Annually	Daily	Annually

Landfill Information					
Area to be Landfilled (hectares)	Total Site Area including Buffer Area (hectares)	Estimated Date of Closure (yyyy/mm/dd)	Population Served	Control Types (select all that apply)	
				☐ Leachate Collected and Treated Off-site	☐ Leachate Collected and Treated On-site
				☐ Landfill Gas Collected and Flared	☐ Landfill Gas Collected for Energy Generation
				☐ Other (describe):	

5.5 Waste Management Systems (Except Mobile Waste Processing) ?

IF YOUR APPLICATION IS NOT FOR A WASTE MANAGEMENT SYSTEM PLEASE PROCEED TO SECTION 5.7.

5.5.1 Fleet List (all vehicles and equipment to be used in the operation of the Waste Management System) ?

Separate list attached? ○ Yes ○ No

Year	Make	Model	Vehicle Identification Number (VIN)	Licence Plate Number	Province/State

5.5.2 Vehicle Information ?

Are all the vehicles to be used owned by the applicant? ○ Yes ○ No

If no, please include additional information about ownership arrangements for each vehicle not owned by the applicant.

Has a minimum of $1,000,000.00 liability insurance been obtained for all vehicles for which it is required? ○ Yes ○ No

Describe any additional insurances that are held (for example, environmental impairment liability insurance).

Print Form   Clear Form   Save Form

5.5.3 General Waste Management System

Type(s) of Waste to be Transported by the General Waste Management System (select all that apply)

Subject:

- ☐ Hazardous Waste
- ☐ Liquid Industrial Waste

Non-subject:

- ☐ Municipal (non-hazardous)
- ☐ Other Liquid Waste

Non-subject Categories to be Transported by the General Waste Management System (select all that apply)

- ☐ Blue Box Materials
- ☐ Dewatered Catch Basin Clean-out Material
- ☐ Waste from Food Processing/ Preparation Operations
- ☐ Domestic Sources
- ☐ Leaf/Yard Waste
- ☐ Tires
- ☐ Commercial
- ☐ Wood Waste
- ☐ Waste Wash Water
- ☐ Others (specify):
- ☐ Non-Hazardous Solid Industrial
- ☐ Spill Cleanup Material
- ☐ Processed Organics (not for land application)
- ☐ Asbestos Waste in Bulk
- ☐ Contaminated Soil
- ☐ Grease Trap Waste

Subject Waste Categories to be Transported by the General Waste Management System   Separate list attached? ○ Yes ○ No

Hazardous Waste / Liquid Industrial Waste								
Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code

☐ All drivers are/will be trained in accordance with O. Reg. 347 and all pertinent environmental legislation.

☐ Each vehicle used to transport a specific subject waste class is suitable for that waste transportation in order to protect the health and safety of the public and the natural environment.

Note: For transporters of pathological waste and PCBs (waste classes 243 and 312) Operations Manual and Driver Training Manual must also be attached and Financial Assurance must be provided.

General Waste Management System – Disposal Site Information

What is the Final Destination of Waste to be Transported by the General Waste Management System? (select all that apply)

☐ A disposal site in Ontario approved by the Ministry of the Environment

☐ Disposal sites outside of Ontario approved by another regulatory agency

List the destination province(s)/state(s):

5.5.4 Soil Conditioner Waste Management System

(includes non-agricultural source material (NASM) that is waste and processed organic waste (biosolids) destined for land application only)

Has the applicant received recommendation from Biosolids Utilization Committee (BUC) for land application of processed organic waste (biosolids) or NASM?

○ Yes If yes, please provide a copy of the BUC recommendation.

○ No If no, please clarify:

Spreading equipment (land application only) Separate list attached? ○ Yes ○ No

Equipment Type	Make & Model	Description

Method of system operation (land application only) ?

Estimated quantity to be handled on an annual basis (cubic metres/litres/tonnes):

Please describe the loading procedures:

Please describe the spreading methods:

Please describe the storage facilities (tanks, lagoons, etc.):

Soil Conditioner Waste Management System – Land Application Sites

What is the final destination of waste to be transported by the soil conditioner waste management system? (must include for land application only)

☐ Non-agricultural land ☐ Agricultural land ☐ Both agricultural and non-agricultural land

5.5.5 Hauled Sewage (Septage) Waste Management System ?

Type(s) of hauled sewage (septage) to be transported

☐ Portable toilet waste ☐ Septic tank waste ☐ Holding tank waste ☐ Other (specify):

Spreading Equipment (land application only)

Separate list attached? ○ Yes ○ No

Equipment Type	Make & Model	Description

Does this system include in-transit storage? ○ Yes ○ No ?

If yes:

a) What is the duration of storage? Please specify (Maximum period of in-transit storage should not exceed more than two weeks):

b) Is the storage tank a prefabricated tank with the capacity < 100,000 L, designed and constructed in accordance with a Class 5 Sewage System under the Ontario Building Code or CAN/CSA B66-05?

○ Yes ○ No If no, please provide a copy of the design of the storage tank signed and dated by a professional engineer.

Does this system include in-transit processing? ○ Yes ○ No ?

If yes:

a) Location of in-transit processing:

☐ In Vehicle ☐ In-storage Tank

b) Describe the method of in-transit processing:

Does this system use barge/boat to transport hauled sewage (septage)? ○ Yes ○ No ?

If yes,

a) Has a minimum of $1,000,000.00 liability insurance been obtained for the barge/boat for which it is required?

○ Yes ○ No

b) Does the barge/boat have an engine of 10 horsepower (hp) or more, for which a commercial vessel licence is required from Transport Canada?

○ Yes ○ No If yes, please include a copy of the commercial vessel licence.

Note: For in-transit storage or processing the applicant must include with the application the consent of the landowner, if the landowner is different than the applicant. A financial assurance estimate must be provided by applicants using in-transit storage or using in-transit processing where processing is conducted in the in-transit storage tanks.

Hauled Sewage (Septage) Waste Management System – Land Application Sites ☐ N/A ?

List the Environmental Compliance Approval Number(s) of all disposal site(s) approved by the Ministry of the Environment for land application of hauled sewage in association with this waste management system.

Instrument Type	Instrument Number	Approval or Application Date (yyyy/mm/dd)

Instrument Type	Instrument Number	Approval or Application Date (yyyy/mm/dd)

5.6 Waste Management System – Mobile Waste Processing

5.6.1 Mobile Waste Management System Process and Equipment Description

Type(s) of Waste to be Processed (select all that apply)

Subject:
- ☐ Hazardous Waste
- ☐ Liquid Industrial Waste

Non-subject:
- ☐ Municipal (non-hazardous)
- ☐ Other Liquid Waste

Number of Units	Type of Waste to be Processed by the Unit(s)	Financial Assurance (per unit)	Financial Assurance Required
	Non-hazardous Solid Waste	$5,000	
	Hazardous Waste	$20,000	
	Liquid Industrial Waste	$20,000	
	Other Liquid Waste	$20,000	
	Multiple Types of Waste from the Categories Above	$20,000	
		Total Financial Assurance	$0

Municipal (non-hazardous) Waste Categories to be Processed (select all that apply)

☐ Contaminated Soil at Cleanup Site ☐ Wood Waste ☐ Construction & Demolition Waste ☐ Asbestos Waste ☐ Tires

☐ Domestic Waste ☐ Other (specify):

Other Liquid Waste Categories to be Processed (select all that apply)

☐ Hauled Sewage ☐ Waste from Food Processing/Preparation Operations ☐ Processed Organic

☐ Other (specify):

Hazardous/Liquid Industrial Waste Types to be Processed							
Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code	Class Code

5.6.2 Equipment Information – Please attach a separate list if more space is required.

Separate list attached? ○ Yes ○ No

Unit No.	Unit Type	Process Description	Equipment List				
			Equipment Type	Make	Model	Serial Number	Equipment Capacity (including unit of measurement)
Unit 1							
Unit 2							
Unit 3							
Unit 4							

5.7 Cleanup of Contaminated Sites

IF YOUR APPLICATION IS NOT FOR A CLEANUP OF A CONTAMINATED SITE PLEASE PROCEED TO SECTION 6.

Type of cleanup:

- ○ In-situ
- ○ Ex-situ
- ○ Both

Contaminated media to be treated:

- ☐ Groundwater
- ☐ Surface water
- ☐ Sediment
- ☐ Soil

Waste Type:

Subject:	**Non-subject:**
☐ Hazardous Waste	☐ Municipal (non-hazardous)
☐ Liquid Industrial Waste	☐ Other Liquid Waste

Type of discharge:

☐ Air	☐ Surface water
☐ Groundwater	☐ Noise
☐ Storm or sanitary	

☑ 6.1 General — THIS IS A LIST OF SUPPORTING INFORMATION TO THIS APPLICATION AND IS SUBJECT TO THE FIPPA AND EBR.

	Attachment	Attached	If no, provide explanation, (include referenced attachment if more space is required for rationale)	Confidential* (√)
☑	Proof of legal name	◉ Yes ○ No		☑
	Enhanced EBR description	○ Yes ○ No		☐
	Provincial Officer Notice	○ Yes ○ No		☐
	Inspection Report	○ Yes ○ No		☐
☑	Detailed project and process description	◉ Yes ○ No		☐
☑	Pre-application Consultation Record	◉ Yes ○ No		☐
	Legal Survey(s)	○ Yes ○ No		☐
☑	Site Plan(s)	◉ Yes ○ No		☐
☑	Scaled area location plan(s) with geo-referencing points identified	◉ Yes ○ No		☐
	Documentation in support of EBR Exception	○ Yes ○ No		☐
	Proof of Compliance with EAA Requirements	○ Yes ○ No		☐
☑	Proof of Consultation/Notification	◉ Yes ○ No		☐
☑	Financial Assurance Estimate	○ Yes ◉ No	not applicable to this project	☐
	Name, address and consent of land/site owner for the installation and operation of the proposed activity or storage location of equipment or vehicle	○ Yes ○ No		☐
	Name, address and phone number of the Operating Authority	○ Yes ○ No		☐
	Copy of NEPDA Permit	○ Yes ○ No		☐
	Copy/Proof of Municipal Planning Approval (ORMCA, general)	○ Yes ○ No		☐
☑	Municipal Zoning Confirmation Letter	◉ Yes ○ No		☐
☑	Zoning map	◉ Yes ○ No		☐
☑	Conservation Authority Clearance	◉ Yes ○ No		☐
	Director's approval for Policy 2 Deviation	○ Yes ○ No		☐
☑	Application Fee	◉ Yes ○ No		☐

Attachment	Attached	If no, provide explanation, (include referenced attachment if more space is required for rationale)	Confidential* (√)
☑ A copy of this application has been sent to the Ministry Local District Office	◉ Yes ○ No		☐
Explanation for confidentiality	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ 6.2 Air

Emission Summary and Dispersion Modelling (ESDM) Report prepared in accordance with s.22 and of O. Reg. 419/05 (including signed checklist – PIBS 5357e)	○ Yes ○ No		☐
Electronic copy of the Dispersion Modelling input and output files prepared in accordance with s.26 of O. Reg. 419/05	○ Yes ○ No		☐
Supporting Information for a Maximum Ground Level Concentration Acceptability Request for Compounds with no Ministry POI Limit – Supplement to Application for Approval, EPA S.9 (PIBS 4872)	○ Yes ○ No		☐
Copies of forms requesting O. Reg. 419/05 instruments and supporting documentation	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ 6.3 Noise and Vibration

Primary Noise Screening	○ Yes ○ No		☐
Secondary Noise Screening	○ Yes ○ No		☐
Abbreviated Acoustic Assessment Report including signed checklist (A-AAR)	○ Yes ○ No		☐
Acoustic Assessment Report including signed checklist (AAR) (PIBS 5356e)	○ Yes ○ No		☐
Vibration Assessment report	○ Yes ○ No		☐

Attachment	Attached	If no, provide explanation, (include referenced attachment if more space is required for rationale)	Confidential* (√)
Noise Abatement Action Plan	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ 6.4 Sewage

	Signed Municipal Responsibility Agreement	○ Yes ○ No		☐
	Detailed description of the proposed activities/works	○ Yes ○ No		☐
☑	Notice of Completion for the Environmental Study Report (ESR)	○ Yes ◉ No	not applicable to project	☐
☑	Design Brief	◉ Yes ○ No		☐
☑	Preliminary Engineering Report	◉ Yes ○ No		☐
	Final Plans	○ Yes ○ No		☐
☑	Engineering Drawings and Specifications	◉ Yes ○ No		☐
☑	Sewage quantity and quality characteristics	○ Yes ◉ No	not applicable to project	☐
☑	Stormwater Management Report	○ Yes ◉ No	not applicable to project	☐
☑	Stormwater Management Plan	○ Yes ◉ No	not applicable to project	☐
	Hydrogeological Assessment	○ Yes ○ No		☐
☑	Environmental Impact Analysis	○ Yes ◉ No	not applicable to project	☐
	Final effluent criteria accepted by regional office of the Ministry	○ Yes ○ No		☐
	Sewage Works Limited Operational Flexibility Requirements			
	1. Engineer's Report	○ Yes ○ No		☐
	2. Declarations	○ Yes ○ No		☐
	Pipe Design Data Form	○ Yes ○ No		☐
	Other (please describe):	○ Yes ○ No		☐

Attachment	Attached	If no, provide explanation, (include referenced attachment if more space is required for rationale)	Confidential* (√)

☑ **6.5 Waste Disposal Sites**

Attachment	Attached	If no, provide explanation	Confidential* (√)
Design and Operations Report	○ Yes ○ No		☐
☑ Stormwater Management Report	◎ Yes ◎ No		☐
Hydrogeological Assessment	○ Yes ○ No		
☑ Assessment of Physical and Water Use Conditions	◎ Yes ◎ No		☐
Waste Limited Operational Flexibility Requirements			
1. Engineer's Report	○ Yes ○ No		☐
2. Declarations	○ Yes ○ No		☐
Copy of notification to adjacent landowners	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ **6.6 Waste Management Systems**

Attachment	Attached	If no, provide explanation	Confidential* (√)
Proof of vehicle and/or equipment ownerships	○ Yes ○ No		☐
Complete Fleet List (list of all vehicles, trailers and equipment used)	○ Yes ○ No		☐
Copy of the Liability Insurance for all vehicles for which insurance is required	○ Yes ○ No		☐
Copy of BUC recommendation	○ Yes ○ No		☐
Copy of the storage tank design	○ Yes ○ No		☐
Copy of commercial vehicle licence	○ Yes ○ No		☐
☑ Description of the physical location where the vehicles transporting biomwedical waste are being disinfected	◎ Yes ◎ No		☐
☑ Drivers Training Manual (for PCB/Biomedical Waste)	◎ Yes ◎ No		☐
☑ A copy of the applicant's Operation Plan including detailed packaging and biomedical waste handling methods	◎ Yes ◎ No		☐
☑ Contingency and Emergency Procedures Plan (for PCB/ Biomedical Waste/Hauled Sewage (Septage))	◎ Yes ◎ No		☐
Other (please describe):	○ Yes ○ No		☐

Attachment	Attached	If no, provide explanation, (include referenced attachment if more space is required for rationale)	Confidential* (√)

☑ 6.7 Mobile Waste Processing

Design and Operations Report – Mobile Waste Processing of General Waste	○ Yes ○ No		☐
Design and Operations Report – Mobile Waste Processing of Liquid Waste	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ 6.8 Cleanup of Contaminated Sites

Design Report for Cleanup of Contaminated Sites	○ Yes ○ No		☐
Other (please describe):	○ Yes ○ No		☐

☑ 6.9 Other Attachments

Title	Reference	Confidential* (√)
Environmental Response Plan		☐
		☐
		☐
Are you attaching an additional list of attachments? ○ Yes ◉ No	If there is not enough space to list all of the attachments included in this application package, please include an additional listing of these attachments.	

*Please note: The collection of personal information in this application is necessary to administer the Ministry's approvals program, which is authorized pursuant to the Environmental Protection Act and the Ontario Water Resources Act. The personal information collected in this application will be used to administer the program, including for the purposes of the Ministry's compliance and enforcement activities under the aforementioned acts, and for the purposes of making information in respect of Environmental Compliance Approvals available to the public with the exception of payment information. Questions about the collection of the information can be directed to a Client Service Representative, Environmental Approvals Access and Service Integration Branch, 2 St. Clair Avenue West, Floor 12A, Toronto Ontario M4V 1L5; Telephone outside Toronto 1-800-461-6290 or in Toronto 416-314-8001 or Fax 416-314-8452.

This page has been intentionally left blank, please proceed to page 45 for Payment Information.

Payment Information: Application for an Environmental Compliance Approval

Please Note:

1. If you are completing this form by hand, you must complete and attach your fee calculations separately.
   You do not need to include the supplemental fee calculations if you are filling in this form electronically.
2. If you are completing this form electronically, the fees for this application have been calculated based on the information you have provided.
   The Ministry may require additional information during the review of your application that could impact the total fee required.
3. All fees should be paid in Canadian funds, payable to the *Minister of Finance*, except fees for *Transfer of Review*, which are payable to the local municipality.
4. Credit card payments are accepted for payments under $10,000 only.
5. If you are paying by certified cheque or money order, please staple your payment to this page.
6. The information collected in this section of the form is considered confidential and will only be used to process your application fee.

Do not include this page in the copies of your application that are being provided to the Local Ministry District Office.

Amount Enclosed

$

Method of Payment

☐ Certified Cheque ☐ Money Order
☐ VISA ☐ MasterCard ☐ American Express

Credit Card Information (if paying by VISA, MasterCard or American Express)

Name on Card (please print) | Credit Card Number | Expiry Date (mm/yyyy)

Cardholder Signature | Date (yyyy/mm/dd)

If paying by certified cheque or money order, please attach it here.

ontario.ca/environment

Ontario

PIBS: 8551e (10/2011)

Hydro Hawkesbury, 110kv substation refit

Project description

Hydro Hawkesbury is proposing a project for the refit of the 110kV substation situated at 990 Main Street west.

The main refit activities include:

- Station ground grid;
- Cable trenches and trays;
- Steel structures and switchgear;
- Concrete foundations;
- Overhead cables;
- A new power transformer;
- Reinstallation of an existing transformer;
- Secondary spill confinement for the transformers;
- A new access gate;
- A new control building.

The project does not necessitate the enlargement of the yard or terracing. The current surface drainage is conserved, and thus is not addressed in project documents. The only projected drainage works are related to the secondary spill confinement system, as described in the separate design brief.

Pascal Le Sauteur, P. Eng

Hydro Hawkesbury, 110kv substation refit

Design brief: Transformer secondary confinement system

The current design brief is a description of the secondary confinement system projected for the Hydro-Hawkesbury substation situated at 990 Main Street west.

The substation is currently undergoing a refit of its installations, including the replacement of the transformer foundations and the addition of a secondary confinement system below the oil filled transformers.

The secondary confinement system is comprised of the following main components:

Confinement basins: the basins are comprised of geocomposite clay liners to ensure impermeability to water and oil. The basins are filled with fire quenching clear stone with a void ration of at least 45%. This stone reduces combustion of the oil in case of a fire combined with a spill, as the stone reduces access to oxygen. The total confinement capacity of both basins designed to contain 110% of the oil of the largest transformer and a 24 hour, 25 year recurrence rainfall event. During normal conditions, a drainage system allows rainwater to flow out of the basins, avoiding water accumulation. This drainage system directs liquids to the drainage sump chamber that contains the "Imbiberbeads" drain shut off system.

Calculation summary:

Oil Volume of largest transformer X 110% : 24,2 m^3

24 hour/25 year rainfall (Oka) : 85,9mm

Total basin area : 348 m^2

Rainwater volume allowance: 348 m^2 * 85,9 mm = 29,9 m^3

Total required volume : 24,2 m^3 + 29,9 m^3 = 54,1 m^3

As designed confinement volume : 55,5 m^3

"Imbiberbeads" drain shut off system: the drain shutoff system is designed to stop oil flow beyond the secondary confinement system. Oil from minor or slow leaks is absorbed into the "Imbiberbeads" media, allowing only clean water to flow beyond the system. A massive spill will cause the "Imbiberbeads" media to swell and completely block the drain outlet, causing all liquids to be contained within the secondary confinement basins. The "Imbiberbeads" system is contained within a drainage sump chamber that allows easy maintenance and provides a convenient place pump out retained liquids in case of a spill.

Drain outlet: during normal conditions, rainwater from the confinement basins is discharged from the drainage sump chamber towards the road side ditch by a buried PVC pipe. Only clean water is discharged towards the ditch, as oil is absorbed or completely blocked by the "Imbiberbead" drain shutoff system.

The secondary confinement system is therefore designed to allow drainage of rainwater towards the roadside ditch during normal conditions, but intercepts and contains any oil that may leak from the transformers, avoiding discharge into the environment.

Pascal Le Sauteur, P. Eng


990 Main Street west, main entrance
Substation south west corner
Main St W
Google earth
Google earth
pieds
300
mètres
100

SOUTH NATION
CONSERVATION
DE LA NATION SUD

38 rue Victoria Street, Finch, ON K0C 1K0 Tel: 613-984-2948 Fax: 613-984-2872 Toll Free: 1-877-984-2948 www.nation.on.ca

Via Email Transmission (JBolduc@Hawkesbury.ca) 09 April 2015

Jacob Bolduc
Planner / Urbaniste ~ FOTENN Consultants Inc.
Town of / Ville de Hawkesbury

**Re: Environmental Emergency Plan
Hydro Hawkesbury ~ Site 40388A230**

Dear Mr. Bolduc,

On November 5, 2015, South Nation Conservation (SNC) received the above noted Environmental Emergency Response Plan. We were asked by the Town of Hawkesbury to review the Plan and provide comments under our agreement for drinking water Risk Management services relating to Part IV of the *Clean Water Act*, 2006. Our comments were based on the location of the site within the Intake Protection Zone 2 for the Town of Hawkesbury.

On November 13, 2014 SNC provided comments on the Plan to the Town of Hawkesbury. These comments were accepted and incorporated into the Plan in the revised version received December 2, 2014.

If you require any additional information or support, please do not hesitate to contact me.

Sincerely,

Alison McDonald

Alison McDonald, M. Sc.
Lead, Source Protection
amcdonald@nation.on.ca

Corporation de la ville de of the Town of
HAWKESBURY

600, Higginson, Hawkesbury, ON K6A 1H1
T. (613) 632-0106

www.hawkesbury.ca

Cadastre : 0208040002468000000

Le 19 janvier 2015

Hydro Hawkesbury Inc.
850, rue Tupper
Hawkesbury, ON
K6A 3S7

Compétence de: Michel Poulin

Objet: **Station d'Hydro Hawkesbury, 990 rue Main Ouest**
CON 1 BLK F PT LOT 14

Monsieur,

Le 6 janvier 2015, nous avons reçu votre demande pour la rénovation du poste électrique situé à l'adresse ci-haut mentionnée. Les plans et devis suivants ont été revus par les services techniques, d'urbanisme, du bâtiment et d'incendie.

Les plans et devis suivants ont étés examinés :

1. *STATION LAYOUT, STRUCTURE*, plan no. A1-14988-S-001 à 006 daté du 3/06/2013, révisé le 15/12/2015
2. *STATION LAYOUT, STRUCTURE, FOUNDATION FOR ISO ANS SURGE ARRESTER FOUNDATION FOR CT AND ISO SUPPORT*, plan no.. A1-14988-C-001 À 007, daté du 03/06/2013, révisé le 16/12/2015.
3. *Project Description Sheet*, daté du 06/01/2015.
4. *Design Brief: Transformer Secondary Confinement System*, reçu le 6/01/2015.
5. *Environmental Emergency Plan*, Hydro Hawkesbury – Site 40388A230, daté du 8 décembre 2014.

Nonobstant que nous vous avions informé que votre projet était assujetti à une demande d'approbation d'un plan d'implantation conformément à l'article 41 de la Loi sur l'aménagement du territoire et au règlement municipal n° 22-2013 sur les contrôles de plans d'implantation, suite à la révision des plans et devis, nous jugeons que votre projet ne soit pas sujet à une telle demande d'approbation d'un plan d'implantation.

.../2

Notamment, selon notre révision des documents ci-haut énumérés, nous jugeons qu'une approbation d'un plan d'implantation tel que mentionné n'est pas requise puisque vos plans et devis démontrent clairement que votre réfection de la station d'hydro n'occasionne pas d'impact sur l'aménagement existant ainsi que sur le système des eaux de surface existants. De plus, votre Plan d'Urgence explique bien le fonctionnement de vos installations et démontre que la réfection de vos installations améliorera la protection de la source d'eau de la ville.

Conséquemment, la municipalité ne vous exigera aucun permis ni frais, étant donné que vous êtes un service public et une entité de la municipalité. Toutefois, nous exigeons que les rapports d'achèvement des travaux ainsi que le rapport final de vos professionnels retenus pour la révision de la réalisation de votre projet nous soient transmis pour nos dossiers.

Nous apprécions votre bonne collaboration dans ce projet afin d'assurer la santé et sécurité pour notre communauté.

Cordialement,

M Belle-Isle

Manon Belle-Isle, MCIP, RPP
Urbaniste

MBI :mb

c.c. : J. Portelance, Présidente
Comité des services du développement économique et du tourisme

J.C. Miner, Chef du service du bâtiment

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Ontario Corporation Number
Numéro de la compagnie en Ontario

1436779

1.

Ministry of Consumer and Commercial Relations — Ministère de la Consommation et du Commerce
Ontario

CERTIFICATE — CERTIFICAT

This is to certify that these articles are effective on — Ceci certifie que les présents status entrent en vigueur le

OCTOBER 25 OCTOBRE, 2000

Director / Directrice

4

Business Corporations Act / Loi sur les sociétés par actions

Form 1 Business Corporations Act

Formule 1 numéro 1 Loi sur les compagnies

ARTICLES OF INCORPORATION
STATUTS CONSTITUTIFS

1. The name of the corporation is: — *Dénomination sociale de la compagnie:*

HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

2. The address of the registered office is: — *Adresse du siège social:*

850 Tupper Road

(Street & Number, or R.R. Number & if Multi-Office Building give Room No.)
(Rue et numéro, ou numéro de la R.R. et, s'il s'agit édifice à bureaux, numèro du bureau)

Hawkesbury, Ontario — K6A 3S7

(Name of Municipality or Post Office)
(Nom de la municipalité ou du bureau de poste)

(Postal Code/*Code postal)*

3. Number (or minimum and maximum number) of directors is: — *Nombre (ou nombres minimal et maximal) d'administrateurs:*

A minimum of 3 and a maximum of 5

4. The first director(s) is/are: — *Premier(s) administrateur(s):*

First name, initials and surname *Prénom, initiales et nom de famille*	Address for service, giving Street & No. or R.R. No., Municipality and Postal Code *Domicile élu, y compris la rue et le numéro, le numéro de la R.R. ou le nom de la municipalité et le code postal*	Resident Canadian State Yes or No *Résident Canadien Oui/Non*
Normand Beaulieu	630 Thorne St., Hawkesbury, ON, K6A 2N6	YES
Kenneth Ménard	3575 Highway 17, Hawkesbury, ON, K6A 2R2	YES
Martin Bonhomme	3067 rue Daniel, Kirkland, QC, H9J 2H2	YES
Robert R. Bergevin	R.R.#1, Vankleek Hill, ON, K0B 1R0	YES

SG 02/2000

5. Restrictions, if any, on business the corporation may carry on or on powers the corporation may exercise.

Limites, s'il y a lieu, imposées aux activités commerciales ou aux pouvoirs de la compagnie.

None

6. The classes and any maximum number of shares that the corporation is authorized to issue:

Catégories et nombre maximal, s'il y a lieu, d'actions que la compagnie est autorisée à émettre:

The Corporation is authorized to issue an unlimited number of Common Shares.

7. Rights, privileges, restrictions and conditions (if any) attaching to each class of shares and directors authority with respect to any class of shares which may be issued in series:

Droits, privilèges, restrictions et conditions, s'il y a lieu, rattachés à chaque catégorie d'actions et pouvoirs des administrateurs relatifs à chaque catégorie d'actions qui peut être émise en série:

Not Applicable

8. The issue, transfer or ownership of shares is/~~is not~~ restricted and the restrictions (if any) are as follows:

L'émission, le transfert ou la propriété d'actions est/n'est pas restreinte. Les restrictions, s'il y a lieu, sont les suivantes:

Subject to the terms of any share issue or transfer restrictions in a unanimous shareholder agreement as defined in the *Business Corporations Act* (Ontario), the right to transfer shares in the capital stock of the Corporation is restricted and no shares of the Corporation shall be transferred without the consent of the Board of Directors first being obtained.

9. Other provisions, if any, are: *Autres dispositions, s'il y a lieu:*

1. The number of shareholders of the Corporation, exclusive of persons who are in its employment and exclusive of persons who, having been formerly in the employment of the Corporation were, while in that employment, and have continued after termination of that employment to be, shareholders of the Corporation, is limited to not more than fifty, two or more persons who are the joint registered owners of one or more shares being counted as one shareholder.

2. Any invitation to the public to subscribe for securities of the Corporation is prohibited.

3. Subject to the terms of any borrowing power restrictions in a unanimous shareholder agreement, as defined in the Business Corporations Act (Ontario), the Board of Directors may from time to time, in such amounts and on such terms as it deems expedient:

(i) borrow money on the credit of the Corporation;

(ii) issue, reissue, sell or pledge debt obligations (secured or unsecured) of the Corporation;

(iii) give a guarantee on behalf of the Corporation to secure performance of an obligation of any person or body corporate; and

(iv) charge, mortgage, hypothecate, pledge or cede and transfer or otherwise create a security interest in all or any of the currently owned or subsequently acquired real or personal, movable or immovable, property of the Corporation, including book debts, rights, powers, franchises and undertakings, to secure any debt obligations or any money borrowed, or other debt or liability of the Corporation.

4. The Board of Directors may from time to time delegate to such one or more of the directors and officers of the Corporation as may be designated by the board all or any of the power conferred on the board pursuant to the preceding paragraph to such extent and in such manner as the Board of Directors shall determine at the time of each such delegation.

10. The names and addresses of the incorporators are *Nom et adresse des fondateurs* First name, initials and last name or corporate name *Prénom, initiale et nom de famille ou dénomination sociale*	Full address for service or address of registered office or of principal place of business giving street & No. or R.R. No., municipality and postal code *Domicile élu, adresse du siège social ou adresse de l'établissement principal, y compris la rue et le numéro, le numéro de la R.R., le nom de la municipalité et le code postal*
The Corporation of the Town of Hawkesbury	600 Higginson Street Hawkesbury, Ontario K6A 1H1

These articles are signed in duplicate.

Les présents statuts sont signés en double exemplaire.

Signatures of incorporators / *signatures des fondateurs*

The Corporation of the Town of Hawkesbury

Per:

Name: Normand Beaulieu
Position: Clerk

Per:

Name: Lucien Berniquez
Position: Mayor

APPENDIX F

TOWN OF HAWESBURY CORRESPONDENCE

Corporation de la ville de / of the Town of HAWKESBURY
600, Higginson, Hawkesbury, ON K6A 1H1
T. (613) 632-0106
www.hawkesbury.ca

Cadastre : 0208040002468000000

Le 19 janvier 2015

Hydro Hawkesbury Inc.
850, rue Tupper
Hawkesbury, ON
K6A 3S7

Compétence de: Michel Poulin

<u>Objet:</u> **Station d'Hydro Hawkesbury, 990 rue Main Ouest**
CON 1 BLK F PT LOT 14

Monsieur,

Le 6 janvier 2015, nous avons reçu votre demande pour la rénovation du poste électrique situé à l'adresse ci-haut mentionnée. Les plans et devis suivants ont été revus par les services techniques, d'urbanisme, du bâtiment et d'incendie.

Les plans et devis suivants ont étés examinés :

1. *STATION LAYOUT, STRUCTURE*, plan no. A1-14988-S-001 à 006 daté du 3/06/2013, révisé le 15/12/2015
2. *STATION LAYOUT, STRUCTURE, FOUNDATION FOR ISO ANS SURGE ARRESTER FOUNDATION FOR CT AND ISO SUPPORT*, plan no.. A1-14988-C-001 À 007, daté du 03/06/2013, révisé le 16/12/2015.
3. *Project Description Sheet*, daté du 06/01/2015.
4. *Design Brief: Transformer Secondary Confinement System*, reçu le 6/01/2015.
5. *Environmental Emergency Plan*, Hydro Hawkesbury – Site 40388A230, daté du 8 décembre 2014.

Nonobstant que nous vous avions informé que votre projet était assujetti à une demande d'approbation d'un plan d'implantation conformément à l'article 41 de la Loi sur l'aménagement du territoire et au règlement municipal n° 22-2013 sur les contrôles de plans d'implantation, suite à la révision des plans et devis, nous jugeons que votre projet ne soit pas sujet à une telle demande d'approbation d'un plan d'implantation.

…/2

Notamment, selon notre révision des documents ci-haut énumérés, nous jugeons qu'une approbation d'un plan d'implantation tel que mentionné n'est pas requise puisque vos plans et devis démontrent clairement que votre réfection de la station d'hydro n'occasionne pas d'impact sur l'aménagement existant ainsi que sur le système des eaux de surface existants. De plus, votre Plan d'Urgence explique bien le fonctionnement de vos installations et démontre que la réfection de vos installations améliorera la protection de la source d'eau de la ville.

Conséquemment, la municipalité ne vous exigera aucun permis ni frais, étant donné que vous êtes un service public et une entité de la municipalité. Toutefois, nous exigeons que les rapports d'achèvement des travaux ainsi que le rapport final de vos professionnels retenus pour la révision de la réalisation de votre projet nous soient transmis pour nos dossiers.

Nous apprécions votre bonne collaboration dans ce projet afin d'assurer la santé et sécurité pour notre communauté.

Cordialement,

M Belle-Isle

Manon Belle-Isle, MCIP, RPP
Urbaniste

MBI :mb

c.c. : J. Portelance, Présidente
Comité des services du développement économique et du tourisme

J.C. Miner, Chef du service du bâtiment

Corporation de la ville de / of the Town of HAWKESBURY

APPROBATION D'UN PLAN D'AMÉNAGEMENT

AU DEMANDEUR

Les renseignements personnels apparaissant sur cette demande sont recueillis conformément à la *Loi sur l'accès à l'information municipale et la protection de la vie privée* et seront utilises pour donner suite à votre demande. Les questions sur cette collecte devraient être adressées par écrit au coordonnateur de l'accès à l'information et de la protection de la vie privée de la ville de Hawkesbury.

Le processus d'approbation d'un plan d'aménagement est prescrit par l'article 41 de la Loi sur l'aménagement du territoire, le plan directeur de la ville de Hawkesbury et le règlement municipal no 47-2006. Une approbation d'un plan d'aménagement est requise pour tout développement commercial, industriel, institutionnel et résidentiel.

Afin de faciliter le traitement de votre demande, veuillez compléter la demande ci-jointe et soumettre les plans et documents appropriés. Une liste de vérification est également jointe afin de vous assurer que l'information complète est soumise.

Le délai requis pour approuver votre demande varie selon la complexité des plans. Veuillez prévoir un délai d'environ 8 semaines pour l'approbation. Toutes les révisions techniques sont effectuées par une firme professionnelle. Tous les rapports de gestion des eaux pluviales sont révisés par la Conservation de la Nation Sud. Tous les frais professionnels relèvent de la responsabilité du demandeur, tel que stipulé au règlement no 21-2008.

Si de plus amples renseignements s'avèrent nécessaires, veuillez communiquer avec l'urbaniste au (613) 632-0106, poste 2020 ou télécopieur (613) 632-2463.

Dossier ______

DEMANDE POUR APPROBATION D'UN PLAN D'AMÉNAGEMENT

☑ nouvelle demande ☐ amendement à l'entente d'aménagement

Date de la demande 2014-12-16

A) INFORMATION SUR LE DEMANDEUR

1) Nom du propriétaire Hydro-Hawkesbury inc.

Adresse	850 Tupper Street,	Hawkesbury	K6A 3S7
	Numéro et rue	Ville	Code postal

Téléphone: (613) 632-6689 Fax: (613) 632-8603

2) Nom du représentant Michel Poulin

Adresse	850 Tupper Street,	Hawkesbury	K6A 3S7
	Numéro et rue	Ville	Code postal

Téléphone: (613) 632-6689 Fax: (613) 632-8603

3) Nom de l'ingénieur: Pascal Le Sauteur

Adresse:	464, boulevard Saint-Germain Ouest,	Rimouski (Québec)	G5L 3P1
	Numéro et rue	Ville	Code postal

Téléphone: (418) 723-8151 p. 236 Fax: (418) 732-7822

B) INFORMATION SUR LA PROPRIÉTÉ

Adresse municipale: 990 (numéro) Main Street west (nom de la rue)

Description légale Lot 0899 (14 ptie) Conc. Broken Front No de plan Prescott (No. 46)

Façade du lot 58,24 m. Profondeur du lot 71,19 m.

Superficie 3067,5 m^2.

C) INFORMATION SUR L'AMÉNAGEMENT

Désignation au plan directeur Community commercial policy area (CC)

Désignation au règlement de zonage Highway commercial district (CH)

Usage actuel de la popriété et bâtiment(s) Poste électrique

Usage proposé et/ou bâtiment(s) proposé(s) Le site conserve son usage actuel

D) SIGNATAIRES

Veuillez indiquer le nom et titre de la personne autorisée à signer l'entente d'aménagement
Michel Poulin

E) CALCUL DES ESPACES DE STATIONNEMENT

	Bâtiments existants	Bâtiments proposés	Total
Superficie de plancher	____ m^2	____ m^2	____ m^2
No. d'espaces requis selon le règlement de zonage			
No. d'espaces pour handicappés Inclus au total ci-haut			

Non applicable

F) COÛTS ESTIMÉS POUR LES SERVICES MUNICIPAUX

Veuillez indiquer les coûts estimés pour les améliorations du site (excluant les coûts du bâtiment et du terrain). Une lettre de crédit au montant de 50% de ces coûts est requise avant la signature de l'entente d'aménagement.

1.	Semence/tourbe	$
2.	Plantation (arbres et arbustes)	$
3.	Clôture et murs de soutènement	$
4.	Pavage et traçage de lignes	$
5.	Accès au stationnement et aire de chargement	$ –
6.	Bordure	$
7.	Trottoir et rampe	$
8.	Éclairage du site	$
9.	Enclos à déchets	$
10.	Service d'eau et branchement	$
11.	Égout sanitaire et branchement	$
12.	Égout pluvial	$
13.	Élargissement du chemin et coupe d'asphalte	$
14.	Enseignes pour route d'incendie et stationnement pour mobilité réduite	$
15.	Coût d'ingénierie	$
	TOTAL	$

Non applicable

Si applicable, fournir une feuille séparée pour les coûts et l'étendue des travaux sur la propriété municipale (dépôt 100%).

DÉCLARATION:

Je, Michel Poulin déclare que le contenu de cette demande et de l'approbation du plan d'aménagement est véridique et précis au meilleur de ma connaissance

Signature ______________ Date Dec 19, 2014

USAGE INTERNE SEULEMENT	Date de circulation
Administration	
Ingénieur professionnel	
Conservation de la Nation Sud	
Chef du bâtiment	
Chef pompier	
Travaux publics	
Service de l'eau	
Paiement des frais de la demande	$

LISTE DE VÉRIFICATION

Vérifier la liste afin de vous assurer de soumettre toute information requise.

GÉNÉRAL

1.	Formulaire de demande complète avec l'engagement de révision par un professionnel	1. x
2.	Une (1) copie du plan d'arpentage mis à jour ou plan de référence	2. x
3.	Une (1) copie de l'acte enregistré de la propriété	3. x
4a.	Cinq (5) copies papier (pleine grandeur) et cinq (5) copies (grandeur légale) de l'ébauche de plan d'aménagement à l'échelle standard métrique: Élévations, mécanique, services, utilités publiques et aménagement	4a. x
4b.	Trois (3) copies du rapport de calcul – gestion des eaux pluviales	4b. Voir notes
5.	Un dépôt de $1,500.00 payable à la Ville de Hawkesbury pour les frais professionnels	5. x
6a.	Une lettre de crédit au montant de 50% des coûts. Veuillez utiliser le formulaire ci-joint. Lettre requise avant la signature de l'entente	6a. n/a
6b.	Un dépôt de 100% (chèque visé) est requis pour les travaux sur la propriété municipale.	6b. n/a
7.	Un chèque au montant de $1,000.00 payable à la Ville de Hawkesbury pour traiter la demande **ou** un chèque au montant de $600.00 pour un amendement	7. x
8.	Une (1) copie de l'hypothèque enregistrée (si applicable)	8. n/a
9.	Une (1) copie des plans finaux approuvés: plan d'aménagement, élévations, mécanique, services, aménagement et rapport sur la gestion des eaux pluviales	9. Voir notes
10.	Une copie (grandeur légale) des plans finaux approuvés avec une copie digitale en PDF.	10. Voir notes

Notes: 4b - Le rapport de calcul (design brief) est spécifique au système de confinement secondaire.
9 et 10 - Les documents finaux seront soumis à la fin du processus de validation.

DÉTAILS DU PLAN D'AMÉNAGEMENT

(Note: Détails d'ingénierie doivent être estampillés par un ingénieur professionnel de l'Ontario.

1.	Dimension du lot	1. Voir plan cadastre
2.	Superficie	2. Voir plan cadastre
3.	Dimension du bâtiment	3. n/a
4.	Retraits (avant, côté, arrière)	4. n/a
5.	Nombre d'étages	5. n/a
6.	Superficie de plancher pour chaque usage ou occupation	6. n/a
7.	Nombre d'unités résidentielles (i.e. deux (2) unités 2 chambres)	7. n/a
8.	Localisation des entrées au bâtiment	8. n/a
9.	Accès du stationnement et largeur	9. n/a
10.	Nombre d'espaces de stationnement incluant les espaces pour mobilité réduite	10. n/a
11.	Largeur des allées de stationnement et localisation des routes pour service d'incendie	11. n/a
12.	Dimension des espaces de stationnement et des espaces pour mobilité réduite	12. n/a
13.	Aire de chargement et dimension	13. n/a
14.	Enclos à déchets	14. n/a
15.	Localisation et dimension des trottoirs, passages pour piétons et rampes	15. n/a
16.	Bordure de béton incluant détails de construction	16. n/a
17.	Clôture et mur de soutènement	17. x
18.	Localisation des enseignes	18. n/a
19.	Éclairage extérieur et lumières d'urgence	19. n/a
20.	Localisation et dimension de l'aire de jeu pour enfants pour zone (R3)	20. n/a
21.	Angle de visibilité pour les lots de coin	21. n/a
22.	Cour privée et dimension pour zone (R3)	22. n/a

23.	Preuve de disponibilité de stationnement sur le terrain à l'intérieur de 150 m, si applicable	23. n/a
24.	Élévations existantes et proposées des points importants i.e. lot de coin, puisard, lignes de propriété, etc.	24. n/a
25.	Flèches indiquant la direction de l'écoulement des eaux de surface	25. x
26.	Niveau des pentes de sol proposées	26. n/a
27.	Haut proposé des élévations d'empattement	27. n/a
28.	Localisation, dimension, élévations des égouts sanitaires et pluvial, aqueduc et latéraux	28. n/a
29.	Localisation des servitudes d'utilités publiques	29. n/a
30.	Localisation et détails des abaissements, cours d'eau et sorties pour eau de surface	30. x
31.	Localisation de la borne-fontaine la plus rapprochée	31. n/a
32.	Ligne existante du centre de la rue	32. n/a
33.	Phase proposée de construction, si applicable	33. n/a
34.	Plan clé de localisation du site	34. n/a
35.	Flèche pointant le nord, échelle métrique, adresse civique	35. x
36.	Estampe et signature de l'ingénieur professionnel	36. x
37.	Calculs détaillés du design, si applicable	37. x

PLAN D'AMÉNAGEMENT PAYSAGER

1.	Aire ensemencée	1. n/a
2.	Aire tourbée	2. n/a
3.	Arbres, arbustes, haies et espèces proposées	3. n/a
4.	Pourcentage de la superfercie de terrain aménagé	4. n/a
5.	Bande de plantation, si applicable	5. n/a
6.	Localisation des bâtiments, etc.	6. n/a

NOTE: Il n'est pas requis d'avoir le plan d'aménagement paysager estampillé par l'Association des architectes en aménagement paysager de l'Ontario.

Hydro Hawkesbury, 110kv substation refit

Project description

Hydro Hawkesbury is proposing a project for the refit of the 110kV substation situated at 990 Main Street west.

The main refit activities include:

- Station ground grid;
- Cable trenches and trays;
- Steel structures and switchgear;
- Concrete foundations;
- Overhead cables;
- A new power transformer;
- Reinstallation of an existing transformer;
- Secondary spill confinement for the transformers;
- A new access gate;
- A new control building.

The project does not necessitate the enlargement of the yard or terracing. The current surface drainage is conserved, and thus is not addressed in project documents. The only projected drainage works are related to the secondary spill confinement system, as described in the separate design brief.

Pascal Le Sauteur, P. Eng

Hydro Hawkesbury, 110kv substation refit

Design brief: Transformer secondary confinement system

The current design brief is a description of the secondary confinement system projected for the Hydro-Hawkesbury substation situated at 990 Main Street west.

The substation is currently undergoing a refit of its installations, including the replacement of the transformer foundations and the addition of a secondary confinement system below the oil filled transformers.

The secondary confinement system is comprised of the following main components:

Confinement basins: the basins are comprised of geocomposite clay liners to ensure impermeability to water and oil. The basins are filled with fire quenching clear stone with a void ration of at least 45%. This stone reduces combustion of the oil in case of a fire combined with a spill, as the stone reduces access to oxygen. The total confinement capacity of both basins designed to contain 110% of the oil of the largest transformer and a 24 hour, 25 year recurrence rainfall event. During normal conditions, a drainage system allows rainwater to flow out of the basins, avoiding water accumulation. This drainage system directs liquids to the drainage sump chamber that contains the "Imbiberbeads" drain shut off system.

Calculation summary:

Oil Volume of largest transformer X 110% : 24,2 m^3

24 hour/25 year rainfall (Oka) : 85,9mm

Total basin area : 348 m^2

Rainwater volume allowance: 348 m^2 * 85,9 mm = 29,9 m^3

Total required volume : 24,2 m^3 + 29,9 m^3 = 54,1 m^3

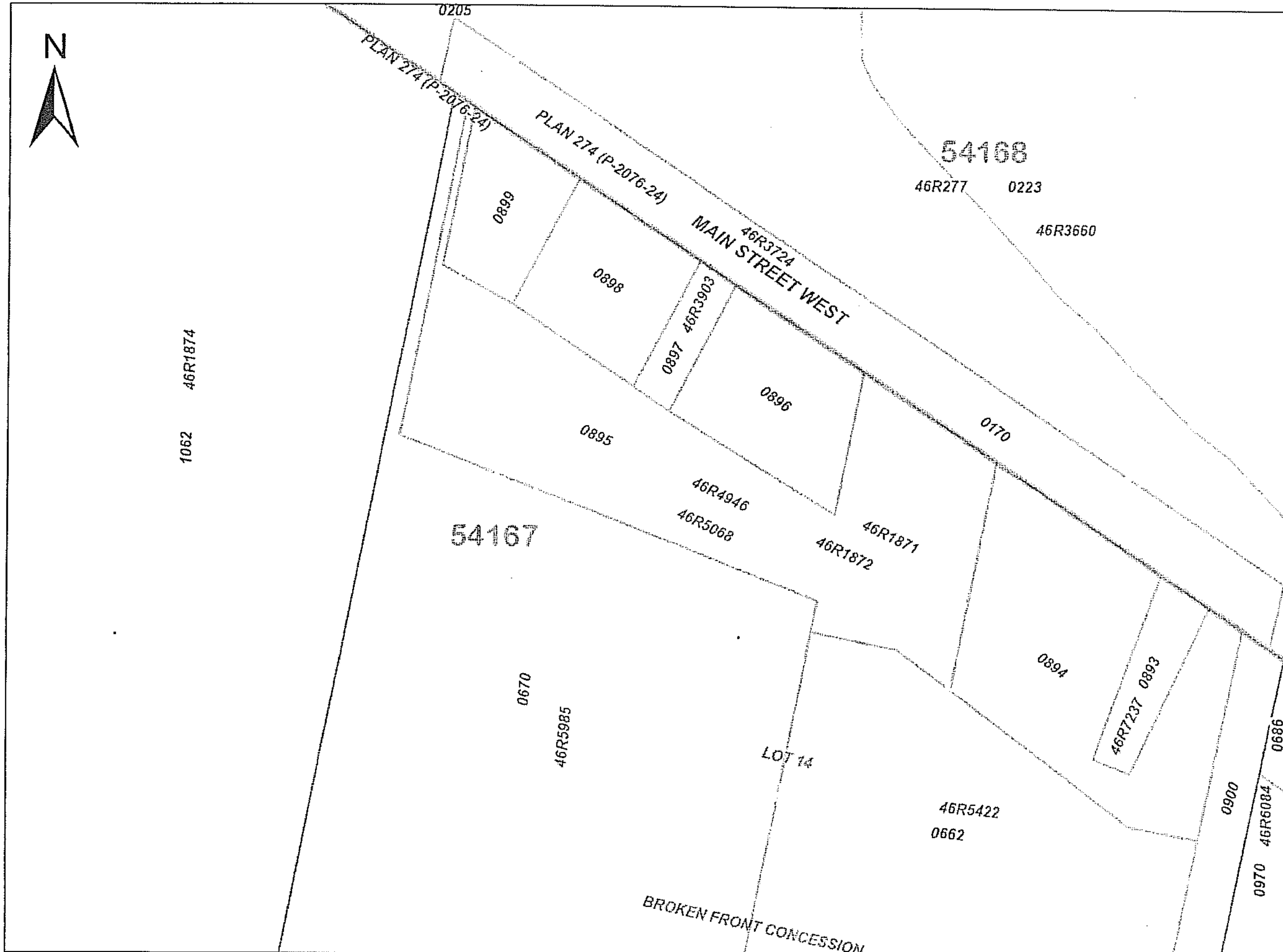
As designed confinement volume : 55,5 m^3

"Imbiberbeads" drain shut off system: the drain shutoff system is designed to stop oil flow beyond the secondary confinement system. Oil from minor or slow leaks is absorbed into the "Imbiberbeads" media, allowing only clean water to flow beyond the system. A massive spill will cause the "Imbiberbeads" media to swell and completely block the drain outlet, causing all liquids to be contained within the secondary confinement basins. The "Imbiberbeads" system is contained within a drainage sump chamber that allows easy maintenance and provides a convenient place pump out retained liquids in case of a spill.

Drain outlet: during normal conditions, rainwater from the confinement basins is discharged from the drainage sump chamber towards the road side ditch by a buried PVC pipe. Only clean water is discharged towards the ditch, as oil is absorbed or completely blocked by the "Imbiberbead" drain shutoff system.

The secondary confinement system is therefore designed to allow drainage of rainwater towards the roadside ditch during normal conditions, but intercepts and contains any oil that may leak from the transformers, avoiding discharge into the environment.

Pascal Le Sauteur, P. Eng



ServiceOntario

PRINTED ON 19 NOV, 2014 AT 14:14:40
FOR LOUISE

SCALE

0 30 60 90 meters

PROPERTY INDEX MAP

PRESCOTT(No. 46)

LEGEND

FREEHOLD PROPERTY
LEASEHOLD PROPERTY
LIMITED INTEREST PROPERTY
CONDOMINIUM PROPERTY
RETIRED PIN (MAP UPDATE PENDING)
PROPERTY NUMBER 0449
BLOCK NUMBER 08050
GEOGRAPHIC FABRIC
EASEMENT

THIS IS NOT A PLAN OF SURVEY

NOTES

REVIEW THE TITLE RECORDS FOR COMPLETE PROPERTY INFORMATION AS THIS MAP MAY NOT REFLECT RECENT REGISTRATIONS

THIS MAP WAS COMPILED FROM PLANS AND DOCUMENTS RECORDED IN THE LAND REGISTRATION SYSTEM AND HAS BEEN PREPARED FOR PROPERTY INDEXING PURPOSES ONLY

FOR DIMENSIONS OF PROPERTIES BOUNDARIES SEE RECORDED PLANS AND DOCUMENTS

ONLY MAJOR EASEMENTS ARE SHOWN

REFERENCE PLANS UNDERLYING MORE RECENT REFERENCE PLANS ARE NOT ILLUSTRATED

Ontario

Ontario ServiceOntario

LAND REGISTRY OFFICE #46

PARCEL REGISTER (ABBREVIATED) FOR PROPERTY IDENTIFIER

54167-0899 (LT)

PREPARED FOR LOUISE
ON 2014/11/19 AT 14:15:03

* CERTIFIED IN ACCORDANCE WITH THE LAND TITLES ACT * SUBJECT TO RESERVATIONS IN CROWN GRANT *

PROPERTY DESCRIPTION: PT LT 14 CON BROKEN FRONT WEST HAWKESBURY AS IN R106750; HAWKESBURY

PROPERTY REMARKS:

ESTATE/QUALIFIER:
FEE SIMPLE
LT CONVERSION QUALIFIED

RECENTLY:
FIRST CONVERSION FROM BOOK

PIN CREATION DATE:
2006/05/23

OWNERS' NAMES
HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

CAPACITY SHARE
ROWN

REG. NUM.	DATE	INSTRUMENT TYPE	AMOUNT	PARTIES FROM	PARTIES TO	CERT/ CHKD
** PRINTOUT INCLUDES ALL DOCUMENT TYPES (DELETED INSTRUMENTS NOT INCLUDED) **						
**SUBJECT, ON FIRST REGISTRATION UNDER THE LAND TITLES ACT, TO:						
**	SUBSECTION 44(1) OF THE LAND TITLES ACT, EXCEPT PARAGRAPH 11, PARAGRAPH 14, PROVINCIAL SUCCESSION DUTIES *					
**	AND ESCHEATS OR FORFEITURE TO THE CROWN.					
**	THE RIGHTS OF ANY PERSON WHO WOULD, BUT FOR THE LAND TITLES ACT, BE ENTITLED TO THE LAND OR ANY PART OF					
**	IT THROUGH LENGTH OF ADVERSE POSSESSION, PRESCRIPTION, MISDESCRIPTION OR BOUNDARIES SETTLED BY					
**	CONVENTION.					
**	ANY LEASE TO WHICH THE SUBSECTION 70(2) OF THE REGISTRY ACT APPLIES.					
**DATE OF CONVERSION TO LAND TITLES: 2006/05/23 **						
R106750	2001/03/16	TRANSFER	$5		HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.	C
CORRECTIONS: 'TRANSFEREE' CHANGED FROM 'HYDRO HAWKESBURY INC.' TO 'HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.' ON 2006/10/30 BY LAND REGISTRAR #99. 'TRANSFEREE: HAWKESBURY HYDRO INC.' DELETED ON 2006/10/30 BY LAND REGISTRAR #99.						
PT978	2006/10/30	LR'S ORDER		LAND REGISTRAR		C
REMARKS: AMENDS OWNER'S NAME						

NOTE: ADJOINING PROPERTIES SHOULD BE INVESTIGATED TO ASCERTAIN DESCRIPTIVE INCONSISTENCIES, IF ANY, WITH DESCRIPTION REPRESENTED FOR THIS PROPERTY.
NOTE: ENSURE THAT YOUR PRINTOUT STATES THE TOTAL NUMBER OF PAGES AND THAT YOU HAVE PICKED THEM ALL UP.

Province of Ontario

Transfer/Deed of Land

Form 1 — Land Registration Reform Act

SoftDocs® 4.1 Wordprocessor Interface

A

FOR OFFICE USE ONLY

1 0 6 7 5 0

CERTIFICATE OF REGISTRATION
CERTIFICAT D'ENREGISTREMENT
PRESCOTT (46)

'01 MAR 16 AM 11 31

Cathy Vallee

LAND REGISTRAR / REGISTRATEUR

New Property Identifiers — Additional: See Schedule ☐

Executions — Additional: See Schedule ☐

(1) Registry ☒ Land Titles ☐

(2) Page 1 of 3 pages CW

(3) Property Identifier(s) Block Property — Additional: See Schedule ☐

(4) Consideration
Five -- 00/100 Dollars $5.00

(5) Description This is a: Property Division ☐ Property Consolidation ☐

Part of Lot 14, Broken Front Concession, in the Township of West Hawkesbury, now in the Town of Hawkesbury, County of Prescott, more particularly described on schedule attached.

(6) This Document Contains (a) Redescription New Easement Plan/Sketch ☐ (b) Schedule for: Description ☒ Additional Parties ☐ Other ☐

(7) Interest/Estate Transferred
Fee Simple

(8) Transferor(s) The transferor hereby transfers the land to the transferee ~~and certifies that the transferor is at least eighteen years old and that~~

Name(s)
HYDRO ONE NETWORKS INC.

Signature(s) Greg Wall
GREG WALL
Senior Real Estate Administrator
I have authority to bind the Corporation

Date of Signature Y M D
2001 03 13

(9) Spouse(s) of Transferor(s) I hereby consent to this transaction.
Name(s) Signature(s) Date of Signature Y M D

(10) Transferor(s) Address for Service 483 Bay Street, Toronto, Ontario. M5G 2P5

(11) Transferee(s) Date of Birth Y M D

HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

(12) Transferee(s) Address for Service 850 Tupper Street, Hawkesbury, Ontario. K6A 3S7

Planning Act — OPTIONAL

(13) Transferor(s) The transferor verifies that to the best of the transferor's knowledge and belief, this transfer does not contravene section 50 of the Planning Act.
Date of Signature Y M D — Signature — Date of Signature Y M D
Signature

Solicitor for Transferor(s) I have explained the effect of section 50 of the Planning Act to the transferor and I have made inquiries of the transferor to determine that this transfer does not contravene that section and based on the information supplied by the transferor, to the best of my knowledge and belief, this transfer does not contravene that section. I am an Ontario solicitor in good standing.
Name and Address of Solicitor — Signature — Date of Signature Y M D

Affix Statement by Solicitor for Transferee(s) here if necessary

(14) Solicitor for Transferee(s) I have investigated the title to this land and to abutting land where relevant and I am satisfied that the title records reveal no contravention as set out in subclause 50(22)(c)(ii) of the Planning Act and that to the best of my knowledge and belief this transfer does not contravene section 50 of the Planning Act. I act independently of the solicitor for the transferor(s) and I am an Ontario solicitor in good standing.
Name and Address of Solicitor — Signature — Date of Signature Y M D

(15) Assessment Roll Number of Property

Cty.	Mun.	Map	Sub.	Par.
02	08	040	002	46800

(16) Municipal Address of Property
Not assigned

(17) Document Prepared by:
JM: 634-501 Hawkesubury (GW)
Hydro One Networks Inc.
7676 Woodbine Avenue, Suite 300
Markham, Ontario
L3R 2N2

FOR OFFICE USE ONLY

Fees and Tax	
Registration Fee	60.00
Land Transfer Tax	
Total	60.00

Additional Property Identifier(s) and/or Other Information

6(b)Other

The name of The Hydro-Electric Commission of Ontario was changed to Ontario Hydro by virtue of The Power Commission Amendment Act, 1973, proclaimed in force March 4, 1974.

Ontario Hydro Networks Company Inc., now Hydro One Networks Inc., is a party to the Form 1 under the Land Registration Reform Act to which this schedule is attached, is a person referred to in section 124 of the Electricity Act, 1998 and is a person from which no consent was required in respect of the transfer in the transfer order, as amended, pursuant to subsection 116(5) of the Electricity Act, 1998.

The interest described in Box (7) in the lands described in Box (5) in the Form 1 under the Land Registration Reform Act to which this schedule is attached was transferred unconditionally to the transferor from Ontario Hydro by or pursuant to a transfer order, as amended, made under the Electricity Act, 1998, which transfer has taken effect.

There were no conditions or other provisions in the transfer order, as amended, that restrict the power or right of the transferor to transfer to the transferee the interest described in Box 7 in the lands described in Box 5 in the Form 1 under the Land Registration Reform Act to which this schedule is attached.

The foregoing statements are statements made pursuant to Section 124 of the Electricity Act, 1998.

The name of Ontario Hydro Networks Company Inc. was changed to Hydro One Networks Inc. as evidenced by Articles of Amendment registered as Instrument Number 106678

(6)(b) Schedule for Description

All that portion of Lot 14, Broken Front Concession, in the Township of West Hawkesbury, now in the Town of Hawkesbury, County of Prescott, in the Province of Ontario, having an area of 0.758 acre, more or less, and shown on the print of Plan 203-10122 attached to Instrument Number 7616-C, more particularly described as follows:

BEARINGS herein are referred to the Southern limit of the King's Highway in Lot 14, Broken Front Concession, Township of West Hawkesbury, now Town of Hawkesbury, shown as North 48 degrees, 39 minutes and 30 seconds West on Department of Highways, Ontario Plan P-2076, deposited as 113;

COMMENCING at a point in the said Southern limit of the King's Highway where it is intersected by the line of a wire fence distant 25.42 feet measured South 48 degrees, 39 minutes and 30 seconds East along said Southern limit from its intersection with the Western limit of said Lot 14;

THENCE South 48 degrees, 39 minutes and 30 seconds East along said Southern limit 191.09 feet;

THJENCE South 34 degrees, 08 minutes and 30 seconds West to and along the line of a wire fence 200.49 feet;

THENCE North 55 degrees, 51 minutes and 30 seconds West at right angles to the last mentioned course 124.85 feet to the line of a wire fence;

THENCE North 18 degrees and 03 minutes East along said line of fence 233.56 feet, more or less, to the point of commencement.

BEING ALL OF THE LANDS IN INSTRUMENT NUMBER 7616-C.

FOR OFFICE USE ONLY

Do Process Software Ltd. • (416) 322-6111   34052-1   3

Affidavit of Residence and of Value of the Consideration
Form 1 – Land Transfer Tax Act

Refer to all instructions on reverse side.

IN THE MATTER OF THE CONVEYANCE OF *(insert brief description of land)* Part of Lot 14, Broken Front Concession, in the Township of West Hawkesbury, now in theTown of Hawkesbury, County of Prescott.

BY *(print names of all transferors in full)* HYDRO ONE NETWORKS INC.

TO *(see instruction 1 and print names of all transferees in full)* HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

I, *(see instruction 2 and print name(s) in full)* YVES J. MENARD

MAKE OATH AND SAY THAT:

1. I am *(place a clear mark within the square opposite that one of the following paragraphs that describes the capacity of the deponent(s)):* *(see instruction 2)*
   - ☐ (a) A person in trust for whom the land conveyed in the above-described conveyance is being conveyed;
   - ☐ (b) A trustee named in the above-described conveyance to whom the land is being conveyed;
   - ☐ (c) A transferee named in the above-described conveyance;
   - ☒ (d) The authorized agent or solicitor acting in this transaction for *(insert name(s) of principal(s))* HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC. described in paragraph(s) ~~(a)~~, ~~(b)~~, (c) above; *(strike out references to inapplicable paragraphs)*
   - ☐ (e) The President, Vice-President, Manager, Secretary, Director or Treasurer authorized to act for *(insert name(s) of corporation(s))* ______ described in paragraph(s) (a), (b), (c) above; *(strike out references to inapplicable paragraphs)*
   - ☐ (f) A transferee described in paragraph ( ) *(insert only one of paragraph (a), (b) or (c) above, as applicable)* and am making this affidavit on my own behalf and on behalf of *(insert name of spouse)* ______ who is my spouse described in paragraph ( ) *(insert only one of paragraph (a), (b) or (c) above, as applicable)* and as such, I have personal knowledge of the facts herein deposed to.
2. *(To be completed where the value of the consideration for the conveyance exceeds $400,000).*
   I have read and considered the definition of "single family residence" set out in clause 1(1)(ja) of the Act. The land conveyed in the above-described conveyance
   - ☐ contains at least one and not more than two single family residences.
   - ☐ does not contain a single family residence.
   - ☐ contains more than two single family residences. *(see instruction 3)*

   Note: Clause 2(1)(d) imposes an additional tax at the rate of one-half of one per cent upon the value of consideration in excess of $400,000 where the conveyance contains at least one and not more than two single family residences.
3. I have read and considered the definitions of "non-resident corporation" and "non-resident person" set out respectively in clauses 1(1)(f) and (g) of the Act and each of the following persons to whom or in trust for whom the land is being conveyed in the above-described conveyance is a "non-resident corporation" or a "non-resident person" as set out in the Act. *(see instructions 4 and 5)*
4. THE TOTAL CONSIDERATION FOR THIS TRANSACTION IS ALLOCATED AS FOLLOWS:

(a) Monies paid or to be paid in cash	$ 5.00	
(b) Mortgages (i) Assumed *(show principal and interest to be credited against purchase price)*	$ Nil	
(ii) Given back to vendor	$ Nil	
(c) Property transferred in exchange *(detail below)*	$ Nil	
(d) Securities transferred to the value of *(detail below)*	$ Nil	
(e) Liens, legacies, annuities and maintenance charges to which transfer is subject	$ Nil	
(f) Other valuable consideration subject to land transfer tax *(detail below)*	$ Nil	
(g) VALUE OF LAND, BUILDING, FIXTURES AND GOODWILL SUBJECT TO LAND TRANSFER TAX *(Total of (a) to (f))*	$ 5.00	$ 5.00
(h) VALUE OF ALL CHATTELS – items of tangible personal property *(Retail Sales Tax is payable on the value of all chattels unless exempt under the provisions of the "Retail Sales Tax Act", R.S.O. 1980, c.454, as amended)*		$ Nil
(i) Other consideration for transaction not included in (g) or (h) above		$ Nil
(j) TOTAL CONSIDERATION		$ 5.00

All Blanks Must Be Filled In. Insert "Nil" Where Applicable

5. If consideration is nominal, describe relationship between transferor and transferee and state purpose of conveyance. *(see instruction 6)*
6. If the consideration is nominal, is the land subject to any encumbrance?
7. Other remarks and explanations, if necessary. Transfer of utility pursuant to Section 159 of the Electricity Act.

Sworn before me at the City of Ottawa in the Province of Ontario this 15 day of March 2001

Anne Elisabeth Weppler, a Commissioner, etc., Regional Municipality of Ottawa-Carleton, for Borden Ladner Gervais LLP, Barristers and Solicitors. Expires April 15, 2000.

A Commissioner for taking Affidavits, etc.

Yves J. Menard
signature(s)

Property Information Record

A. Describe nature of instrument: Conveyance in fee simple

B. (i) Address of property being conveyed *(if available)* Not assigned

(ii) Assessment Roll No. *(if available)* 02 08 040 002 46800

C. Mailing address(es) for future Notices of Assessment under the Assessment Act for property being conveyed *(see instruction 7)* 850 Tupper Street, Hawkesbury, Ontario K6A 3S7

D. (i) Registration number for last conveyance of property being conveyed *(if available)* unknown

(ii) Legal description of property conveyed: Same as in D.(i) above. Yes ☐ No ☐ Not known ☒

E. Name(s) and address(es) of each transferee's solicitor
Borden Ladner Gervais LLP
#1000 - 60 Queen Street, Ottawa, Ontario, K1P 5Y7

For Land Registry Office Use Only	
Registration No. 3	
Registration Date	Land Registry Office No.

School Tax Support (Voluntary Election) See reverse for explanation

(a) Are all individual transferees Roman Catholic ? Yes ☐ No ☐

(b) If Yes, do all individual transferees wish to be Roman Catholic Separate School Supporters ? Yes ☐ No ☐

(c) Do all individual transferees have French Language Education Rights ? Yes ☐ No ☐

(d) If Yes, do all individual transferees wish to support the French Language School Board (where established) ? Yes ☐ No ☐

NOTE: As to (c) and (d) the land being transferred will be assigned to the French Public School Board or Sector unless otherwise directed in (a) and (b).

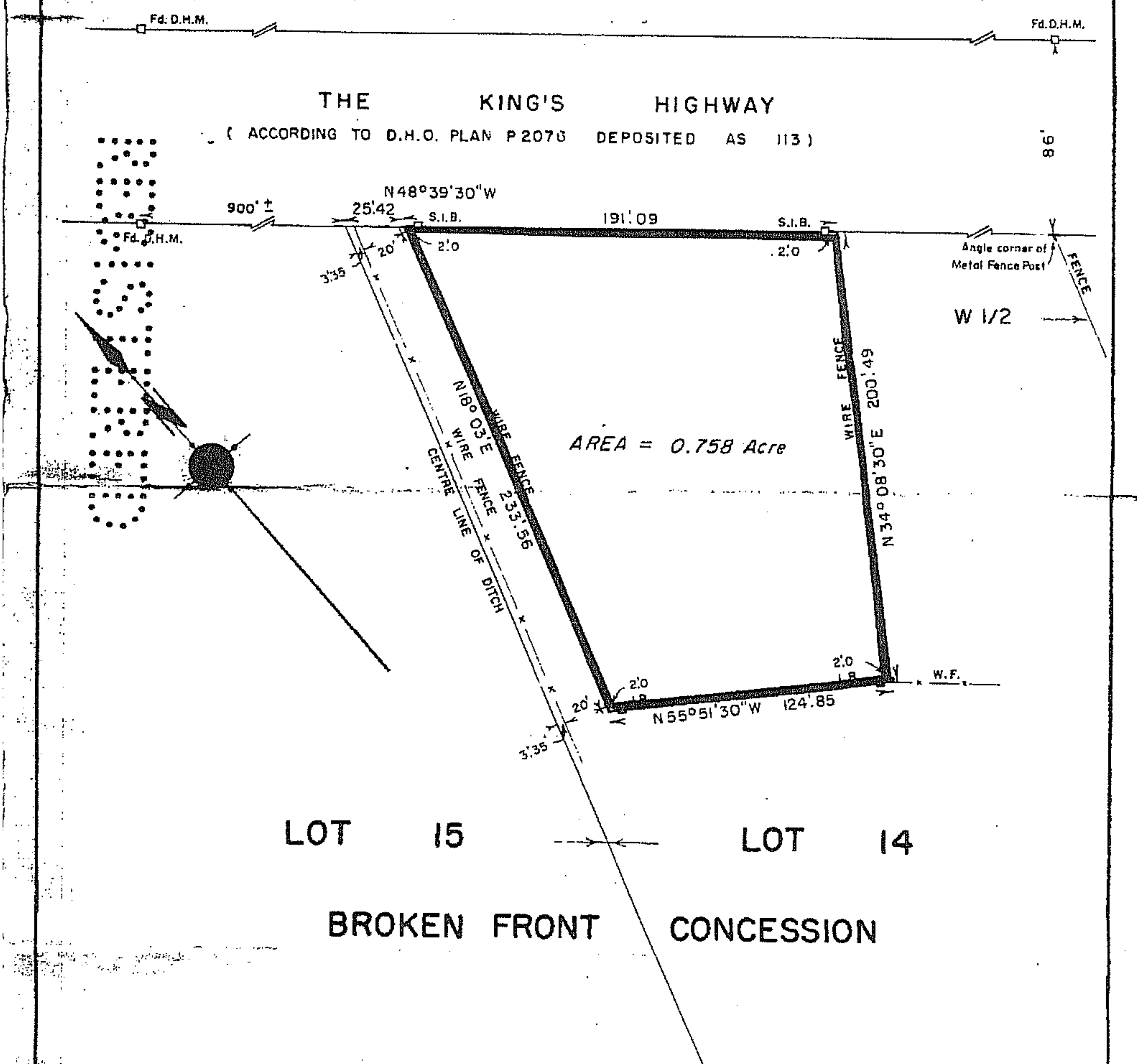
0449D (90-09)

THE HYDRO-ELECTRIC POWER COMMISSION OF ONTARIO

SURVEY DEPARTMENT

TOWNSHIP OF WEST HAWKESBURY

COUNTY OF PRESCOTT



Bearings are referred to the Southern limit of the King's Highway, in Lot 14 Broken Front Concession Township of West Hawkesbury shown as N48°39'30"W on D.H.O. Plan P 2076, Deposited as 113.

O.L.S.

For W. H. WILLIAMS O.L.S.
CHIEF SURVEYOR

HAWKESBURY D. S Q 55	DR. W. F.	SCALE 1 Inch = 60 Feet	203-10122
PLAN SHOWING PART OF LOT 14 BROKEN FRONT CON.	CHD.	DATE March 13, 1964	

H 44-16 837-1801-912

Corporation de la ville de of the Town of HAWKESBURY
600, Higginson, Hawkesbury, ON K6A 1H1
T. (613) 632-0106
www.hawkesbury.ca

Cadastre : 0208040002468000000

Le 9 avril 2014

Hydro Hawkesbury Inc.
850, rue Tupper
Hawkesbury, ON K6A 3S7

Compétence de: Michel Poulin

Objet: **Station d'Hydro Hawkesbury, 990 rue Main Ouest**
CON 1 BLK F PT LOT 14

Monsieur,

Nous accusons réception de la série de plans soumis le 7 avril 2014. Ces plans soumis pour commentaires nous démontrent, entre autres, qu'il est proposé la construction d'un système de confinement secondaire sous les transformateurs et qu'il y a une station de pompage pour le drainage et que le drainage sera pompé dans le fossé municipal. Il est important de noter que cette station d'hydro est située dans la zone 2 de protection de notre source d'eau municipale. Conséquemment, des mesures de protection sont nécessaires lors de ce réaménagement.

Veuillez noter que votre projet est assujetti à une demande d'approbation d'un plan d'implantation conformément à l'article 41 de la Loi sur l'aménagement du territoire et au règlement municipal n° 22-2013 sur les contrôles de plans d'implantation.

Conséquemment, nous vous demandons de remplir ledit formulaire de demande d'approbation d'un plan d'implantation et parmi la liste des plans et devis requis, vous devez nous soumettre un plan de gestion des eaux de surface, un plan de gestion des risques et d'autant plus, vous êtes assujettis à une autorisation environnementale pour la gestion des eaux.

Pour votre information, nous pouvons tenir une réunion de pré-consultation avec vos ingénieurs conseils, le jeudi 17 avril 2014 à 10h30.

Cordialement,

Manon Belle-Isle, MCIP, RPP
Urbaniste

c.c. : G. Ouellette, ing., BPR
J.C. Miner, Chef du service du bâtiment

APPENDIX G
BUILDING PERMIT

Corporation de la ville de / of the Town of HAWKESBURY

600, rue Higginson Street, Hawkesbury, ON K6A 1H1

BUILDING PERMIT

Roll No.: 040 00246800.0000	Application Date: Jan 13, 2014	
Permit #: 2014-005	Issue Date: Jan 14, 2014	
Permit Type: UTILITY BUILDING		Permit Fee: $ 892.00

Pursuant to the bylaws applicable to the Corporation of the Town of Hawkesbury, I, being the owner or acting with the consent of the owner, hereby make application.

OWNER:	Name: HYDRO HAWKESBURY INC			
	Address: 850 TUPPER ST			
	Town: HAWKESBURY	Province: ON	Postal Code: K6A 3S7	Telephone: (613) 632-6689

PROJECT ADDRESS / LOCATION:	Unit:	Street #: 990	Street Name: MAIN W
	Legal Description: CON 1 BLK F PT LOT 14		

DESCRIPTION OF WORK:	Type of Work: Installation of pre-fab building		Estimated Value: $ 66000.00
	Work Proposed: NOUVELLE BASE DE BÉTON ET ÉRIGER BÂTIMENT POUR POSTE DE DISTRIBUTION 110 KV		
	Area (square meters): 16.5	Zoning: 1	No. of Units: 1

CONTRACTOR:	Name: IMI MANUFACTURING INC.			
	Address: 2056 CTY RD 4			
	Town: L'ORIGNAL	Province: ON	Postal Code: K0B 1K0	Telephone: 613-678-8978

CONDITIONS:	ALL DEBRIS, IF ANY, MUST BE TRANSPORTED TO A CERTIFIED DISPOSAL SITE. ALL ELECTRICAL WIRING MUST BE INSPECTED BY THE ELECTRICAL SAFETY AUTHORITY. SEPARATE INSPECTION APPLICATIONS (PERMITS) MUST BE FILED. FOR MORE INFORMATION PLEASE CONTACT THE ELECTRICAL SAFETY AUTHORITY / CUSTOMER SERVICE CENTRE AT TELEPHONE 1-877-372-7233 OR FAX 1-800-667-4278 OR WWW.ESASAFE.COM.

The person to whom this permit has been issued shall notify the officials(s) in advance of the stages of construction specified in the attached schedule.

▶ 24 HOUR NOTICE REQUIRED FOR ANY INSPECTION - TELEPHONE (613) 632-0106 EXT. 2020◀

The personal information on this permit was collected pursuant to the *Building Code Act, 1992* and forms part of a public record open to inspection by any person upon request at the office of the clerk during normal office hours.

Permission is not included to dig, tunnel or bore into or under any part of a street, nor to occupy or obstruct any street sidewalk or other municipal property. To obtain permission to occupy the street or sidewalk during construction, present this permit at the office of the clerk of the municipality. The owner or owner's agent is responsible for the proper setting of grades for the structure, and may request assistance from the inspector. Unless otherwise specifically so provided for and approved in writing by the appropriate inspector, full compliance is required with all the provisions of the Building Code made under the *Building Code Act, 1992*; the Electrical Safety Code adopted by regulation under the *Electricity Act, 1998*; and of any by-law or resolution of the principal authority, which in whole or in part regulates structural requirements, erection, alteration, location, use, etc. of buildings. This permit is subject to revocation in accordance with the above-cited authorities.

If the municipality gives notice of intention to designate a property as property of cultural heritage value or interest under section 29 of the *Ontario Heritage Act*, any permit that allowed for the alteration or demolition of the property and that was issued by the municipality under any Act, before the day the notice was served on the owner of the property and on the Ontario Heritage Trust and published in a newspaper is void as of the day the notice of intention is given in accordance with subsection 29 (3) of that Act.

Chief Building Official: **JEAN-CLAUDE MINER** Telephone: (613) 632-0106 ext. 2020

JC Miner
Signature of Chief Building Official

Jan 15/14
Date

Signature of applicant

Jan 16/14
Date

THIS CARD SHALL BE POSTED AT ALL TIMES DURING CONSTRUCTION IN A CONSPICUOUS PLACE ON THE PROPERTY.

Permit no.: 2014-005

Roll no.: 04-02-468

THE CORPORATION OF THE TOWN OF HAWKESBURY

Schedule "D" to Building By-Law No. 13-2006

AGREEMENT RE USE OF ADMINISTRATION PERFORMANCE DEPOSIT

I, Hydro Hawkesbury, the applicant for a building permit to building for control panel on 990 Main West (civic address) Lot Pt Lot 14 Plan Con 1, hereby agree that as a condition precedent to the validity of any permit issued to me by the Corporation of the Town of Hawkesbury for the said work, and in consideration of the issuance of a Permit to me, hereby deposit with the Corporation of the Town of Hawkesbury the sum of $ 500.00 as a Administration Performance Deposit for the completion of all work as authorized and/or required by the said permit and the repair of any damages to municipal property and payment for cleaning of municipal street as provided in the By-laws of the Corporation of the Town of Hawkesbury or otherwise, within such time limit as is provided in this and other said By-Laws or, if not specifically provided in the By-Laws, within such time as the Chief Building Official may, in his discretion consider adequate (to which exercise of discretion I hereby irrevocable submit) and in the event of my failure to so perform,

I hereby consent to the adoption of such procedures as may be necessary by the Corporation Chief Building Official or by any person appointed by him and /or them for such purpose, including unrestricted entry upon my property, to complete the said work and/or repair any damage and/or repay the Corporation for cleaning of municipal streets all as et out in the said By-Laws, with payment for such procedures to be deducted from the said performance deposit and the balance, if any, to be refunded to me and for so doing this shall irrevocably constitute his food and sufficient authority.

I further understand and agree that, if my final inspection has not been carried out and approved, within the specifications of Schedule "B" – note 2, from the date of my issuance of my building permit that I will forfeit my performance deposit of $ 500.00 and that the amount would become part of the general revenues of the Corporation of the Town of Hawkesbury, for their own use absolutely.

I HERBY completely release the Corporation and its agents, employees and workmen from any and all claims for damages or otherwise which may arise as a result of the procedures herein authorized and taken by them, except for such claims as may arise as a result of negligence on the part of such agents, employees, or workmen.

DATED at the Corporation of the Town of Hawkesbury this ____________ day of ______________________, 20_____.

______________________ Witness

______________________ Applicant

12-26-2727

Corporation de la ville de of the Town of
HAWKESBURY
600, Higginson, Hawkesbury, ON K6A 1H1
T. (613) 632-0106
www.hawkesbury.ca

Cadastre : 04-02-468
Permis: 2013-226

Le 25 novembre 2013

CÉDULE "A"

Hydro Hawkesbury Inc.
850, rue Tupper
Hawkesbury, ON
K6A 3S7

Attention: M. Michel Poulin

Objet: Nouvelle base de béton et bâtiment pour poste de distribution 110 KV – 990 Main Ouest.

Monsieur,

La présente est pour faire suite à la révision des documents soumis pour le projet ci-haut mentionné. L'information suivante est requise afin de continuer la révision du projet :

1. La demande de permis doit être signée par le propriétaire (Michel Poulin).

2. Le formulaire « Commitment to General Reviews by Architect and Engineers » doit être complété par le propriétaire et signé par ce dernier (Hydro Hawkesbury).

3. Le formulaire « Commitment to General Reviews by Architect and Engineers » doit être signé par chaque ingénieur retenu pour ce projet, soit Tetra Tech pour la dalle de béton et L.A. Fancy pour le bâtiment.

Une fois l'information reçue, nous pourrons compléter la révision du projet.

Jean-Claude Miner, CBCO, CRBO
Chief Building Official
Office 613-632-0106, ext. 2221
Fax 613-632-2463
E-mail: jcminer@hawkesbury.ca

APPENDIX H
COST ESTIMATE

TETRA TECH

Wednesday, April 15th, 2015

Mr. Michel Poulin
Manager
Hydro Hawkesbury Inc.
850 Tupper St
Hawkesbury (Ontario)
K6A 3S7

OBJECT : Construction Cost Estimate Summary

Introduction

This document presents the cost estimate for the engineering, procurement and construction activities for the retrofit of the 115 kV substation, which is the property of Hydro Hawkesbury Inc. The estimate has been performed to confirm the construction cost presented to Infrastructure Ontario.

Assumptions

The following assumptions have been taken into account to build the estimate:

- Estimate class 2 (± 10%)
- Estimate is presented in Canadian dollars (CDN)
- The contingency of the concept is not included
- The equipment purchase cost is based on tenders or database
- Work will be performed in regular time and overtime, 10 hours a day, 6 days a week
- The "MEANS" is used as an estimate basis for electrical equipment installation man hours
- The estimate applies a productivity similar to other public utility works
- The productivity used for works is 70%
- Contractor's site mobilization and demobilization costs are included in each discipline hourly rates
- Hourly labor rate (rates similar to those in the construction industry)
- Room and board are included in man hours
- Import duties, permits, asbestos removal are excluded
- Contaminated soil treatments are included as a risk contingency ($99,470)
- Engineering and service fees were provided by the client through invoice and proposal
- There are a minimum of 3 bidders for the major components and the general contractor

Results

The estimate contained two types of cost, direct and indirect. The direct cost includes the electrical equipment, concrete, granular material, the installation, etc. The indirect cost includes all services, such as engineering, utility fees, commissioning, geotech lab, etc. The total of both costs is $2,830 300, including the owner's and risk contingencies.

If we look at the summary table of the cost estimate we can see that the direct cost with risk contingency is $2,090,920. We have $607,030 for civil and structural works and $1,384,420 for electrical works, including electrical components. In the costs, there is a risk contingency for decontamination. At this stage, we do not anticipate contaminated soil but with experience, it would not be surprising to find contaminated soils, even though there never was any major oil spills. The existing transformers have been in services for approximately 55 years. It would be normal through the years that oil would have trickled.

The indirect cost represents $529,337. As mentioned, these costs include the engineering (completed) and the required services for the substation commissioning, as well as the fees for interconnection studies (Hydro One and IESO are included) and the Geotechnical laboratory fees.

Explanation of differences

The first estimate was presented at a preliminary stage, which means that they was no cost for components other than major equipment as the detailed engineering was not begun. The first estimate was done without any detailed engineering. This was a Rough Order of Magnitude (ROM Estimate). According to the literature, a common variance for this type of estimate could be - 25% to + 75%. The ROM estimate had provided a total cost of $1,598,848.05, and with the variance, it would give a total cost ranging from $1,199,136 (- 25%) to $2,787,984 (+ 75%).

The last estimate performed is a class 2 with a variance of +/- 10%. The total estimated cost is $2,830,300 when the variance is applied, the total cost will be between $2,547,270 (- 10%) and $3,113,330 (+ 10%).

When looking at these estimates, we can see that differences are not only on total costs, but also on the items included. Attached is the table 1 where the major differences between the preliminary and the latest estimate are shown.

Also, some items were not included in the preliminary estimate. Following is a list of these items with the associated costs:

- New control building including protection and control system ($184,815)
- 145 kV, 3,000 A load break switches ($73,238)
- The ground grid, as there was no drawing of the actual ground grid, we had to design a new one (Difference of $84,793)
- Shed demolition, at the beginning it was planned to keep the same shed and to add the new control and protection system ($14,900)
- Risk contingency for contaminated soil ($99,740)
- Replacement of the 1,200 A disconnect switches ($7,448)

Conclusion

The main factor explaining the difference between the two estimates is due to the engineering progress at the time the first estimate has been performed. The precision of an estimate is closely bounded to the progress of the engineering. Prior to obtaining approvals from authorities, modifications were made to the design which had a significant effect on construction costs. The latest estimate was performed based on the detailed engineering with an approved design by the authorities. According to detailed engineering, invoices and the proposals received, the construction cost, including the engineering for the rehabilitation is evaluated at $2,830,300 with a precision of +/- 10%.

Hoping our cost estimate meets your expectations,

Sincerely,

Gabriel Ouellette

Gabriel Ouellette, P. Eng.
Project Manager

Attachements

Table 1

Hydro Hawkesbury	First Estimate (ROM Estimate)	Class 2 Estimate +/- 10 %	Comments
Description			
Hydro One			
Hydro One Review (PO to HONI)	$ 25 000.00	$ 60 000.00	
Hydro One Capital Work (Dead End Structure, etc)	$ 100 000.00	$ 100 000.00	Estimated only
Major Equipment			
New Transformers (2) 110kV-12.4kV - 7.5/10/20MVA			
New Transformer (1) 110kV-12.4kV - 15/20/25MVA	$ 738 630.00	$ 586 256.00	
New Circuit Switchers c/w Steel Structure & P&C	$ 131 000.00	$ 136 000.00	Circuit switchers only, no structure and protection and control included
Other Equipment (Switches?)	$ 10 000.00		
New 110kV Structures			
New Structure 110kV c/w assembly	$ 10 360.00	$ 111 180.00	
New insulators	$ 9 382.00	$ 8 190.00	
New 110kV Cables	$ 8 636.00	$ 7 065.00	
110kV Structure & Circuit Switcher Grounding	$ 3 600.00	$ 72 403.00	Includes all works and components for the ground grid
New 12.4kV Structure			
New Structure 15kV c/w assembly	$ 5 180.00	$ 76 318.00	Includes excavation and structure for Insulators
Cable tray for control cables	$ 1 204.00	$ 12 292.00	Includes concrete sleepers
Conduits for control cables	$ 2 792.00	N/A	
New control cables	$ 2 000.00	$ 55 599.00	Includes Identification
new 12.47kV Cables	$ 8 636.00	$ 34 266.00	Includes Bus bar with accessories
12.47kv Structure Grounding	$ 2 450.00		Includes in Circuit switcher grounding.
Metering			
Move Metering	$ 20 000.00	$ 22 496.00	
Construction			
Base Transformers	$ 18 296.00	$ 70 383.00	Including excavation works and excluding Oil containement system
Oil Containment (Sorbweb System)	$ 85 000.00	$ 58 200.00	
Concrete for Oil Containment	$ 18 712.00		Included in Base Transformer
Base Circuit Switchers	$ 10 000.00	$ 155 960.00	Including excavation works and excluding structure
Fence Modification and new gate entrance	$ 6 824.00	$ 7 344.00	
Other Civil (Move Shed etc)	$ 5 000.00	$ 41 920.00	Includes demolition of the old shed, installation of the new control building with it's concrete base
Move Old Power Transformers to new base	$ 15 000.00	$ 14 408.00	
Connection transformers	$ 27 067.50		This item is covered in class two estimate in the item "services"
Power Transformer Grounding	$ 2 252.00		Included in "110kV Structure & Circuit Switcher Grounding" activity
Program P&C and tests	$ 7 500.00	$ 94 445.00	Included pre operational test and commissioning
Contractor Markup (10%, excluding cost transformers)	$ 15 781.15		
Detailled Engineering			
Engineering	$ 100 000.00	$ 273 000.00	Includes preliminary engineering
Sub Total	*$ 1 390 302.65*	*$ 1 997 725.00*	
Contingency (15%)	$ 208 545.40	$ 210 000.00	
TOTAL	**$ 1 598 848.05**	**$ 2 207 725.00**	

PROJECT INFORMATION AND DESCRIPTION

Template S170-EST-F001-E-R0F

TETRA TECH

OWNER : Hydro Hakesbury Inc.	**Project No : 14988TTE**
PROJECT : Detailed Engineering and Project Cost Estimate	**DC :**
	Date : 2015-04-09
Owner Project No: N/A	**Revision : 0**

OWNER : Hydro Hakesbury
ADDRESS : 850 Tupper st,
Hakesbury, Ontario, K2A 3S7
TYPE OF PROJECT : Engineering

- ☐ Order of Magnitude
- ☐ Conceptual
- ☐ Budgetary
- ☑ Definitive
- ☐ Control

PROJECT TEAM :

Project manager (Client):	Michel Poulin	Ph. :	613-632-6689	ext. :	
Lead manager (Tetra Tech QE) :		Ph. :		ext. :	
Civil & structural engineer :	Ali Wardani	Ph. :	514-257-2427	ext. :	3949
Mech. engineer (building) :	n/a	Ph. :		ext. :	
Mechanical engineer :	n/a	Ph. :		ext. :	
Process engineer :	n/a	Ph. :		ext. :	
Electrical engineer :	Gabriel Ouellette	Ph. :	819-562-7266	ext. :	8010
Instrumentation engineer :		Ph. :		ext. :	
Other:		Ph. :		ext. :	
Other:		Ph. :		ext. :	
Lead estimator:	Jean-Pierre Levasseur, PQS	Ph. :	418-843-1956	ext. :	5303
Cost controller :	Michel Tremblay, CEC	Ph. :	418-548-5522	ext. :	449

ESTIMATE BASIS :

Request received : 2015/03/23
Request date : 2015-04-07
Work start date:
Work end date:

Prepared by

Civil & Struc.: Michel Tremblay
Mech. & Piping: N/A
Heating & ventil.:N/A
Elect. & Instr.: Jean-Pierre Levasseur

PROJECT DESCRIPTION SUMMARY :

ESTIMATE BASED ON THE FOLLOWING DOCUMENTS OR HYPOTHESIS :

- Estimate class 2 (± 10 %)
- Estimate is presented in Canadian dollars (CDN).
- The contingency of the concept is not included.
- The purchase cost of equipment is based on tenders or databases.
- Work will be performed in regular time and overtime, 10 hours a day, 6 days a week.
- The "MEANS" is used as an estimate basis for electrical equipment installation manhours.
- The estimate applies a productivity similar to other public utilities works.
- The productivity used for works is 70%.
- Contractor's site mobilization and demobilization costs are included in each discipline hourly rates.
- Hourly labor rate (rate in the construction industry).
- Room and board is included manhours.
- Import duties, permits, asbestos removal are excluded.
- Treatment of contaminated soils are included as a risk contengency ($ 99,470),

COST ESTIMATE SUMMARY

TETRA TECH

OWNER :	Hydro Hakesbury Inc.	☐ Magnitude	Project no : 14988TTE
PROJECT :	Detailed Engineering and Project Cost Estimate	☐ Conceptual	Lot :
		☐ Budgetary	
		☑ Definitive	Date : 2015-04-09
Project No. :	14988TTE	☐ Control	Revision : 0

	DESCRIPTION	OWNER				CONTRACTOR				Total
		Equipment E1	Material M1	Labor L1		Equipment E2	Material M2	Labor L2		
		Amount	Amount	Amount	M.-H./Total	Amount	Amount	Amount	M.-H./Total	
DIRECT CONSTRUCTION COSTS :										
	Civil & Structural	$ -	$ -	$ -	-	$ 94,910	$ 279,070	$ 233,050	1,710	$ 607,030
	Electrical	$ -	$ -	$ -	-	$ 997,840	$ 151,100	$ 235,480	1,600	$ 1,384,420
	Decontamination (if required)	$ 99,470	$ -	$ -	-	$ -	$ -	$ -	-	$ 99,470
	Direct Costs Subtotal :	**$ 99,470**	**$ -**	**$ -**	**0 hrs**	**$ 1,092,750**	**$ 430,170**	**$ 468,530**	**3,310 hrs**	**$ 2,090,920**
INDIRECT COSTS:										
8000	**PROFESSIONAL SERVICES & SITE COSTS**	**% TIC cost**	**% Direct costs**							
8100	Indirects costs including :	18.7%	25.3%							$ 529,337
8200	Engineering and services ($ 371,023 + $ 2,419)									$ -
8300	Hydro One fees ($ 60,000)									$ -
8400	IESO ($ 1,450)									$ -
8500	Pre-op - Commissionning ($ 94,445)									$ -
8600										$ -
8700										$ -
8800										$ -
	Subtotal Prof. Services & Sites Costs:	**18.7%**	**25.3%**							**$ 529,337**
9000	**OWNER'S COSTS**	**% TIC cost**	**% Direct costs**							
9100	Project Team - Owner's Costs									$ -
9200	Project Team - External Costs									$ -
9300	Technology & Management System									$ -
9400	Operation Readiness									$ -
9500	Commissioning									$ -
9600	Start-Up Costs									$ -
9700	Working Capital									$ -
9800	Operation Inefficiencies									$ -
9900	Financial Costs									$ -
	Subtotal Owner Costs :	**0.0%**	**0.0%**							**$ -**
	Subtotal Indirect Costs :	**18.7%**	**25.3%**							**$ 529,337**
Project Subtotal (Before contingencies and escalation) :										**$ 2,620,257**
8900	**ESCALATION & CONTINGENCY**	**% TIC cost**	**% Project ST**							
8910	Owner's contingencies (10 %)									$ 210,000
8920	Escalation									$ -
	Subtotal Indirect Costs Escalation & Contingency :	**7.4%**	**8.0%**							**$ 210,000**
PROJECT TOTAL (to hundred dollars) :										**$ 2,830,300**

SIGNING :

Prepared by : Michel Tremblay, Jean-Pierre Levasseur

Signed by : Michel Tremblay, Jean-Pierre Levasseur **Date : 2015-04-09**

Reviewed by : Gabriel Ouellet **Date : 2015-04-09**

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	Labor-Hour Cost Crew / Discipline	Project No:	14988TTE
Project : Detailed Engineering and Project Cost Estimate		Addendum :	
		Date :	2015-04-09
Project No.: 14988TTE		Revision :	0
Discipline: Civil & structural	CONTRACTOR		

CODE		DESCRIPTION	Qty	Un.	Equipment E2		Material M2		Labor L2				TOTAL
Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
						$ -		$ -		$ -	-	-	$ -
		Demolition				$ -		$ -		$ -	-	-	$ -
		Demolition of a transfomer's foundations (2)	1	lot	$ 5,000	$ 5,000		$ -	$ 5,400	$ 5,400	-	40.0	$ 10,400
		Demolition of the existing control building	1	lot	$ 9,500	$ 9,500		$ -	$ 5,400	$ 5,400	-	40.0	$ 14,900
		Subtotal Demolition:				**$ 14,500**		**$ -**		**$ 10,800**		**80.0**	**$ 25,300**
						$ -		$ -		$ -	-	-	$ -
		Electrical Building (civil works)				$ -		$ -		$ -	-	-	$ -
		Reception and installation	1	lot	$ 4,800	$ 4,800		$ -	$ 4,320	$ 4,320	-	29.4	$ 9,120
		Excavation and backfill	1	lot	$ 1,500	$ 1,500	$ 1,000	$ 1,000	$ 1,500	$ 1,500	-	11.1	$ 4,000
		Concrete slab	1	lot	$ 1,500	$ 1,500	$ 7,000	$ 7,000	$ 5,400	$ 5,400	-	40.0	$ 13,900
		Subtotal Electrical Building (civil				**$ 7,800**		**$ 8,000**		**$ 11,220**		**80.5**	**$ 27,020**
						$ -		$ -		$ -	-	-	$ -
		Foundation for dead and circuit Switcher support (2 un)				$ -		$ -		$ -	-	-	$ -
		Ref:A1-14988-C-002				$ -		$ -		$ -	-	-	$ -
		Excavation	706	m³	$ 12	$ 8,472		$ -	$ 10	$ 7,060	-	52.3	$ 15,532
		MG-112 backfill (granular B)	492	m³	$ 12	$ 5,904	$ 12	$ 5,904	$ 20	$ 9,840	-	72.9	$ 21,648
		MG-20 backfill (granular A)	64	m³	$ 12	$ 768	$ 20	$ 1,280	$ 20	$ 1,280	-	9.5	$ 3,328
		Insulation HI-60	207	m²		$ -	$ 16	$ 3,315	$ 12	$ 2,486	-	18.4	$ 5,802
		Reinforced concrete slab	150	m³	$ 11	$ 1,650	$ 420	$ 63,000	$ 300	$ 45,000	-	333.3	$ 109,650
		Structural steel (ref S-002-1 et S-002-2)	17,000	kg	$ 0	$ 4,080	$ 5.50	$ 93,500	$ 1	$ 13,600	-	92.5	$ 111,180
		Subtotal Foundation for dead and circuit Switcher support (2 un):				**$ 20,874**		**$ 166,999**		**$ 79,266**		**578.9**	**$ 267,140**
						$ -		$ -		$ -	-	-	$ -
		Foundation for ISO post type 1 (2 un)				$ -		$ -		$ -	-	-	$ -
		Réf:A1-14988-C-002				$ -		$ -		$ -	-	-	$ -
		Excavation	60	m³	$ 12	$ 720		$ -	$ 10	$ 600	-	4.4	$ 1,320
		MG-112 backfill (granular B)	24	m³	$ 12	$ 288	$ 12	$ 288	$ 20	$ 480	-	3.6	$ 1,056
		MG-20 backfill (Granular A)	6	m³	$ 12	$ 72	$ 20	$ 120	$ 20	$ 120	-	0.9	$ 312
		Insolation HI-60	30	m²		$ -	$ 16	$ 487	$ 12	$ 365	-	2.7	$ 852
		Concrete base	5.0	m³	$ 11	$ 55	$ 420	$ 2,100	$ 350	$ 1,750	-	13.0	$ 3,905
		Structural steel (2) ref S-003	646	kg	$ 2.50	$ 1,615	$ 5.50	$ 3,553	$ 3	$ 2,132	-	14.5	$ 7,300
		Subtotal Foundation for ISO post type 1 (2 un):				**$ 2,750**		**$ 6,548**		**$ 5,447**		**39.1**	**$ 14,745**
						$ -		$ -		$ -	-	-	$ -
		Foundation 55T3 Transformer pad (2 un)				$ -		$ -		$ -	-	-	$ -
		Ref:A1-14988-C-003A, C-003B				$ -		$ -		$ -	-	-	$ -
		Excavation	406	m³	$ 12	$ 4,872		$ -	$ 10	$ 4,060	-	30.1	$ 8,932
		MG-112 backfill (granular B)	80	m³	$ 12	$ 960	$ 12	$ 960	$ 20	$ 1,600	-	11.9	$ 3,520
		MG-20 backfill (granular A)	54	m³	$ 12	$ 648	$ 20	$ 1,080	$ 20	$ 1,080	-	8.0	$ 2,808
		40-20mm fire stone	160	m³	$ 10	$ 1,600	$ 40	$ 6,400	$ 10	$ 1,600	-	11.9	$ 9,600
		Waterproof GCL membrane	384	m²	$ 11	$ 4,224	$ 17	$ 6,528	$ 15	$ 5,760	-	42.7	$ 16,512
		Drainage	112	m	$ 10	$ 1,120	$ 35	$ 3,920	$ 25	$ 2,800	-	20.7	$ 7,840
		Insulation HI-60	360	m²		$ -	$ 16	$ 5,760	$ 12	$ 4,320	-	32.0	$ 10,080
		Concrete base	63.0	m³	$ 11	$ 693		$ -	$ 570	$ 35,910	-	266.0	$ 36,603
		Subtotal Foundation 55T3 Transformer pad (2 un):				**$ 14,117**		**$ 24,648**		**$ 57,130**		**423.2**	**$ 95,895**
						$ -		$ -		$ -	-	-	$ -
		Foundation for ISO post type 1A & 2				$ -		$ -		$ -	-	-	$ -

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	Labor-Hour Cost Crew / Discipline	Project No: 14988TTE
Project : Detailed Engineering and Project Cost Estimate		Addendum :
		Date : 2015-04-09
Project No.: 14988TTE		Revision : 0

CODE Facility	Item	DESCRIPTION	Qty	Un.	Equipment E2 Unit. Price	Equipment E2 Amount	Material M2 Unit. Price	Material M2 Amount	Labor L2 Unit. Price	Labor L2 Amount	M-H/Un.	M-H/Total	TOTAL
Discipline: Civil & structural					CONTRACTOR								
		Ref:A1-14988-C-005				$ -		$ -		$ -		-	$ -
		Excavation	83	m³	$ 12	$ 996		$ -	$ 10	$ 830	-	6.1	$ 1,826
		MG-112 backfill (granular B)	75	m³	$ 12	$ 900	$ 12	$ 900	$ 20	$ 1,500	-	11.1	$ 3,300
		MG-20 backfill (granular A)	3	m³	$ 12	$ 36	$ 20	$ 60	$ 20	$ 60	-	0.4	$ 156
		Concrete base	5.0	m³	$ 11	$ 55	$ 420	$ 2,100	$ 1,025	$ 5,125	-	38.0	$ 7,280
		Structural steel type 2 (Ref S-006)	412	kg	$ 3	$ 1,030	$ 5.50	$ 2,266	$ 3	$ 1,360	-	9.2	$ 4,656
		Structural steel type 1a (Ref S-003)	330	kg	$ 3	$ 825	$ 5.50	$ 1,815	$ 3	$ 1,089	-	7.4	$ 3,729
		Subtotal Foundation for ISO post type 1A & 2 :				**$ 3,842**		**$ 7,141**		**$ 9,964**		**72.3**	**$ 20,947**
						$ -		$ -		$ -	-	-	$ -
		Foundation for ISO & CT				$ -		$ -		$ -	-	-	$ -
		Ref:A1-14988-C-001				$ -		$ -		$ -	-	-	$ -
		Excavation	83	m³	$ 12	$ 996		$ -	$ 10	$ 830	-	6.1	$ 1,826
		MG-112 backfill (granular B)	75	m³	$ 12	$ 900	$ 12	$ 900	$ 20	$ 1,500	-	11.1	$ 3,300
		MG-20 backfill (granular A)	3	m³	$ 12	$ 36	$ 20	$ 60	$ 20	$ 60	-	0.4	$ 156
		Concrete base	6.0	m³	$ 11	$ 66	$ 420	$ 2,520	$ 350	$ 2,100	-	15.6	$ 4,686
		Structural steel type 1 (Ref S-003)	330	kg	$ 3	$ 825	$ 5.50	$ 1,815	$ 3	$ 1,089	-	7.4	$ 3,729
		Structural steel ISO and SURGE (Ref S-005)	760	kg	$ 3	$ 1,900	$ 5.50	$ 4,180	$ 3	$ 2,508	-	17.1	$ 8,588
		Subtotal Foundation for ISO & CT:				**$ 4,723**		**$ 9,475**		**$ 8,087**		**57.7**	**$ 22,285**
						$ -		$ -		$ -	-	-	$ -
		Foundation for ISO & SA				$ -		$ -		$ -	-	-	$ -
		Ref:A1-14988-C-005				$ -		$ -		$ -	-	-	$ -
		Excavation	83	m³	$ 12	$ 996		$ -	$ 10	$ 830	-	6.1	$ 1,826
		MG-112 backfill (granular B)	75	m³	$ 12	$ 900	$ 12	$ 900	$ 20	$ 1,500	-	11.1	$ 3,300
		MG-20 backfill (granular A)	3	m³	$ 12	$ 36	$ 20	$ 60	$ 20	$ 60	-	0.4	$ 156
		Concrete base	6.0	m³	$ 11	$ 66	$ 420	$ 2,520	$ 350	$ 2,100	-	15.6	$ 4,686
		Structura steel type 1 (Ref S-003)	330	kg	$ 3	$ 825	$ 5.50	$ 1,815	$ 3	$ 1,089	-	7.4	$ 3,729
		Structural steel ISO and SURGE (Ref S-006)	411	kg	$ 3	$ 1,028	$ 5.50	$ 2,261	$ 3	$ 1,356	-	9.2	$ 4,644
		Subtotal Foundation for ISO & SA:				**$ 3,851**		**$ 7,556**		**$ 6,935**		**49.9**	**$ 18,341**
						$ -		$ -		$ -	-	-	$ -
		Site works				$ -		$ -		$ -	-	-	$ -
		Sewing pump chamber	1	ea	$ 1,250	$ 1,250	$ 14,000	$ 14,000	$ 2,160	$ 2,160	-	16.0	$ 17,410
		Protective bollard	2	ea	$ 500	$ 1,000	$ 1,000	$ 2,000	$ 1,000	$ 2,000	-	14.8	$ 5,000
		Storm outfall	32	m	$ 47	$ 1,504	$ 100	$ 3,200	$ 125	$ 4,000	-	29.6	$ 8,704
		Fence	8	m	$ 500	$ 4,000	$ 63	$ 500	$ 168	$ 1,344	-	10.0	$ 5,844
		Double chain fence	1	ea	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	-	3.7	$ 1,500
		Pavement structure - Reparation	200	m²	$ 20	$ 4,000	$ 30	$ 6,000	$ 15	$ 3,000	-	22.2	$ 13,000
		Crushed stone	420	m²	$ 10	$ 4,200	$ 25	$ 10,500	$ 10	$ 4,200	-	31.1	$ 18,900
		Trenches for grounding (based onr 60 m./day)	600	m	$ 10	$ 6,000	$ 20	$ 12,000	$ 45	$ 27,000	-	200.0	$ 45,000
		Subtotal Site works:				**$ 22,454**		**$ 48,700**		**$ 44,204**		**327.4**	**$ 115,358**
			TOTAL :			**$ 94,910**		**$ 279,070**		**$ 233,050**		**1710 hrs**	**$ 607,030**

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc. | **Labor-Hour Cost Crew / Discipline** | **Project No: 14988TTE**

Project : Detailed Engineering and Project Cost Estimate | **Addendum :**

Date : 2015-04-09

Project No.: 14988TTE | **Revision : 0**

Discipline: Electrical

CODE		DESCRIPTION	Qty	Un.	CONTRACTOR								TOTAL
					Equipment E2		Material M2		Labor L2				
Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
						$ -		$ -		$ -	-	-	$ -
		Electrical equipments				$ -		$ -		$ -	-	-	$ -
		New 110kV Dead-end wood structure (by others)				$ -		$ -		$ -	-	-	$ -
		New 110kV Dead-end wood structure (by others)	1	ea		$ -	$ -	$ -		$ -	-	-	$ -
		52T3-LBS : 3000A 145kV - Load Break switch				$ -		$ -		$ -	-	-	$ -
	5	Motorized 3-pole Vertical Break Disconnect Switch 138 kV Nom., 650 kV BIL, 3000	1	ea	$ 26,875	$ 26,875	$ 2,688	$ 2,688		$ 7,056	48.0	48.0	$ 36,619
		52T3-L/52T3-I : 1200A 145kV 38KA				$ -		$ -		$ -	-	-	$ -
	4	3-pole Circuit Switcher Siemens, SF6 type, 1200 A, 31,5 kA, 121 kV max., 550 KV BIL	1	ea	$ 63,383	$ 63,383	$ 6,338	$ 6,338		$ 4,704	32.0	32.0	$ 74,425
		52T2-L/52T2-I : 1200A 145kV 38KA				$ -		$ -		$ -	-	-	$ -
	4	3-pole Circuit Switcher Siemens, SF6 type, 1200 A, 31,5 kA, 121 kV max., 550 KV BIL	1	ea	$ 63,383	$ 63,383	$ 6,338	$ 6,338		$ 4,704	32.0	32.0	$ 74,425
		Metering Cabinet				$ -		$ -		$ -	-	-	$ -
		Metering Cabinet	1	ea	$ 22,496	$ 22,496	$ 2,250	$ 2,250		$ 4,704	32.0	32.0	$ 29,450
		55T3 : Transformer 15/20/25 MVA				$ -		$ -		$ -	-	-	$ -
	3	New 3Ø Transformer 110 kV / 12,48 kV, 15/20/25 MVA	1	ea	$ 586,256	$ 586,256	$ 58,626	$ 58,626		$ 9,408	64.0	64.0	$ 654,290
		55T3B : Switch 2000A 12.5kV				$ -		$ -		$ -	-	-	$ -
		55T3B : Switch 2000A 12.5kV	3	ea	$ 1,200	$ 3,600	$ 120	$ 360		$ 3,528	8.0	24.0	$ 7,488
		52T2-LBS : 3000A 145kV - Load Break switch				$ -		$ -		$ -	-	-	$ -
	5	Motorized 3-pole Vertical Break Disconnect Switch 138 kV Nom., 650 kV BIL, 3000	1	ea	$ 26,875	$ 26,875	$ 2,688	$ 2,688		$ 9,408	64.0	64.0	$ 38,971
		CT-2.1 : Current transformer 600:5A				$ -		$ -		$ -	-	-	$ -
	2	Current Transformer, bushing type, Meramec, model T.B.D.	3	ea	$ 2,052	$ 6,156	$ 205	$ 616		$ 3,528	8.0	24.0	$ 10,300
		55T2 : Transformer 7.5/10/12.5 MVA - EXISTING				$ -		$ -		$ -	-	-	$ -
	1	Existing Transformer to be remove for relocation	1	ea	$ 2,500	$ 2,500	$ -	$ -		$ 4,704	32.0	32.0	$ 7,204
	1	Existing Transformer to be relocated on new base in oil containment	1	ea	$ 2,500	$ 2,500	$ -	$ -		$ 4,704	32.0	32.0	$ 7,204
		LA2-T2 : Station class 12.7kV MCOV				$ -		$ -		$ -	-	-	$ -
	7	Substation Surge Arrester, polymer intermediate type PVI-LP, 12,7 kV MCOV, rated 15 kV, 4-hole NEMA pad line terminal Hubbell cat. #300813	3	ea	$ -	$ -	$ 480	$ 1,440		$ 1,764	4.0	12.0	$ 3,204
		CT-2.4 : Current transformer 2000:5A				$ -		$ -		$ -	-	-	$ -
	6	Outdoor cast epoxy resin insulated Current Transformer 15 kV, current ratio 1200/2000:5 A, Ritz cat. #GIFD25-03	3	ea	$ -	$ -	$ 500	$ 1,500		$ 3,528	8.0	24.0	$ 5,028
		Subtotal Electrical equipments:				**$ 804,024**		**$ 82,842**		**$ 61,740**		**420.0**	**$ 948,606**
						$ -		$ -		$ -	-	-	$ -
		Cable tray including grounding				$ -		$ -		$ -	-	-	$ -
		300mm Steel Cable tray	30	m		$ -	$ 100	$ 3,000		$ 5,292	1.2	36.0	$ 8,292

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc. | **Labor-Hour Cost Crew / Discipline** | **Project No: 14988TTE**

Project : Detailed Engineering and Project Cost Estimate | **Addendum :**

Date : 2015-04-09

Project No.: 14988TTE | **Revision : 0**

Discipline: Electrical

CODE		DESCRIPTION	Qty	Un.	CONTRACTOR								TOTAL
					Equipment E2		Material M2		Labor L2				
Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
		Concrete support for cable tray	10	ea	$ 400	$ 4,000		$ -		$ -	-	-	$ 4,000
		2/0 Copper conductor (grounding)	30	m		$ -	$ 10	$ 300		$ 441	0.1	3.0	$ 741
		Bolted ground connection to tray	12	ea		$ -	$ 35	$ 420		$ 1,764	1.0	12.0	$ 2,184
		Subtotal Cable tray including				**$ 4,000**		**$ 3,720**		**$ 7,497**		**51.0**	**$ 15,217**
						$ -		$ -		$ -	-	-	$ -
						$ -		$ -		$ -	-	-	$ -
		Control Building				$ -		$ -		$ -	-	-	$ -
		Building including electrical components, protection and control panel	1	lot	$ 184,815	$ 184,815	$ -	$ -		$ -	-	-	$ 184,815
		Subtotal Control Building:				**$ 184,815**		**$ -**		**$ -**		**-**	**$ 184,815**
						$ -		$ -		$ -	-	-	$ -
						$ -		$ -		$ -	-	-	$ -
		Aerial bus pipe and conductors				$ -		$ -		$ -	-	-	$ -
		Aluminium Bus Pipe				$ -		$ -		$ -	-	-	$ -
	8	ALUMINIUM BUS PIPE, 15 kV 6063-T6 ALLOY 53% IACS ASA SCH. 80 - 2 IN. O.D.: 2,375 IN. (60,3mm) WALL THICKNESS: 0,218 IN. (5,54mm)	90	m	$ -	$ -	$ 30	$ 2,700		$ 13,230	1.0	90.0	$ 15,930
		Aluminium conductor (ACSR)				$ -		$ -		$ -	-	-	$ -
	9	2 AWG, CODE "SPARATE" Nominal DIAM. 8,24mm	225	m	$ -	$ -	$ 2	$ 450		$ 6,615	0.2	45.0	$ 7,065
		Subtotal Aerial bus pipe and conductors:				**$ -**		**$ 3,150**		**$ 19,845**		**135.0**	**$ 22,995**
						$ -		$ -		$ -	-	-	$ -
		Accessories for aerial feeders				$ -		$ -		$ -	-	-	$ -
	10	Porcelaine Suspension Insulator Clevis type, ANSI Class 52-4	120	ea	$ -	$ -	$ 28	$ 3,360		$ 4,410	0.3	30.0	$ 7,770
	10	Porcelaine Suspension Insulator Clevis type, ANSI Class 52-4 (for spare)	15	ea	$ -	$ -	$ 28	$ 420		$ -	-	-	$ 420
	11	Station type post Insulator, 110 kV BIL each 30 3 spare Cantilever strenght 17,9 kN, 127 mm B.C. Ø NGK cat.# PH01110	30	ea	$ -	$ -	$ 168	$ 5,040		$ 4,410	1.0	30.0	$ 9,450
	12	Eye nut, bolt Ø 5/8 IN, galvanized steel.	6	ea		$ -	$ 5	$ 30		$ -	-	-	$ 30
	13	Turnbuckle 5/8 x 6 IN, Clevis-Clevis type, galvanized steel	6	ea	$ -	$ -	$ 70	$ 420		$ -	-	-	$ 420
	14	Turnbuckle 5/8 x 6 IN, Clevis-Eye type, galvanized steel	6	ea	$ -	$ -	$ 70	$ 420		$ -	-	-	$ 420
	15	Triangle Dead End Clamp, aluminium, Clevis type 5/8 IN pin Ø, for ACSR 2 AWG conductor, Hubbell Power System cat.# SD57C	6	ea		$ -	$ 120	$ 720		$ 882	1.0	6.0	$ 1,602
	16	Dead End Clamp, aluminium, Clevis type 5/8 IN pin Ø, for ACSR 2 AWG each 6 conductor Burndy cat.# CUW26RE-1	6	ea		$ -	$ 20	$ 120		$ 882	1.0	6.0	$ 1,002

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	Labor-Hour Cost Crew / Discipline	Project No: 14988TTE
Project : Detailed Engineering and Project Cost Estimate		Addendum :
		Date : 2015-04-09
Project No.: 14988TTE		Revision : 0

Discipline: Electrical

CODE			DESCRIPTION	Qty	Un.	CONTRACTOR Equipment E2 Unit Price	Equipment E2 Amount	Material M2 Unit Price	Material M2 Amount	Labor L2 Unit Price	Labor L2 Amount	Labor L2 M-H/Un.	Labor L2 M-H/Total	TOTAL
	Facility	Item												
		17	Anchor shackle, body and hardware Ø 5/8 IN. Hubbell Power System cat.# AS25	6	ea		$ -	$ 19	$ 114		$ -	-	-	$ 114
		18	Alu. Straight Cable to flat Terminal Connector, 145 kV, 2000A ACSR 2 AWG "SPARATE" to NEMA 4-hole pad Anderson (Hubbell Power System) cat.# ACF-6-C	36	ea		$ -	$ 48	$ 1,728		$ 2,646	0.5	18.0	$ 4,374
		19	Alu. Flat terminal to Stud Connector, 145 kV, 2000A NEMA 4-hole pad to Stud 1-1/2 IN. 12UNF Anderson (Hubbell Power System) cat.# ADSF141C3812	6	ea		$ -	$ 118	$ 708		$ 441	0.5	3.0	$ 1,149
		20	Alu. Cable to Flat terminal «T» Connector, 145 kV, 2000A Main: ALU. CONDUCTOR (ACSR) 2 AWG, CODE "SPARATE" Tap: NEMA 4-hole pad parallel to conductor Anderson (Hubbell Power System) cat.# ATCF-630-1	3	ea		$ -	$ 62	$ 186		$ 441	1.0	3.0	$ 627
		21	Alu. Straight Bus Pipe to Stud connector, 145 kV, 2000A ASA SCH. 80 - 2 IN. Alu. Bus Pipe to Stud 1-1/2 IN. 12UNF Anderson (Hubbell Power System) cat.# ADST142-12	6	ea		$ -	$ 145	$ 870		$ 882	1.0	6.0	$ 1,752
		22	Alu. Bus pipe to Cable «T» Connector, 145 kV, 2000A Main: ASA SCH. 80 - 2 IN. Alu. Bus Pipe Tap: Alu. Conductor (ACSR) 2 AWG, CODE "SPARATE" Anderson (Hubbell Power System) cat.# ATTC-206	6	ea		$ -	$ 102	$ 612		$ 882	1.0	6.0	$ 1,494
		23	Alu. Bus Clamp rigig-sliding type ASA SCH. 80 - 2 IN. Alu. Bus Pipe to Insulator 5 IN. B. C. Anderson (Hubbell Power System) cat.# AUR-20-5	21	ea		$ -	$ 131	$ 2,751		$ 3,087	1.0	21.0	$ 5,838
		24	Alu. Bus Clamp expansion type ASA SCH. 80 - 2 IN. Alu. Bus Pipe to Insulator 5 IN. B. C. Anderson (Hubbell Power System) cat.# AURF-20-5	6	ea		$ -	$ 852	$ 5,112		$ 882	1.0	6.0	$ 5,994
			Subtotal Accessories for aerial feeders:				**$ -**		**$ 22,611**		**$ 19,845**		**135.0**	**$ 42,456**
							$ -		$ -		$ -	-	-	$ -
							$ -		$ -		$ -	-	-	$ -
			Interconnection cables				$ -		$ -		$ -	-	-	$ -
			001A Cable TECK90 2C #12 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. AC DISTRIB. PANEL	53	m		$ -	$ 4	$ 212		$ 935	0.1	6.4	$ 1,147
			001B Cable TECK90 2C #12 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. AC DISTRIB. PANEL	35	m		$ -	$ 4	$ 140		$ 617	0.1	4.2	$ 757
			002A Cable TECK90 2C #12 AWG from 52T2-L CIRCUIT SWITCHER to CRTL BLDG. DC DISTRIB. PANEL	53	m		$ -	$ 4	$ 212		$ 935	0.1	6.4	$ 1,147

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	Labor-Hour Cost Crew / Discipline	Project No: 14988TTE
Project : Detailed Engineering and Project Cost Estimate		Addendum :
		Date : 2015-04-09
Project No.: 14988TTE		Revision : 0
Discipline: Electrical	CONTRACTOR	

CODE		DESCRIPTION	Qty	Un.	Equipment E2		Material M2		Labor L2				TOTAL
Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
		002B Cable TECK90 2C #12 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. DC DISTRIB. PANEL	35	m		$ -	$ 4	$ 140		$ 617	0.1	4.2	$ 757
		003A Cable TECK90 2C #10 AWG from 52T2-L CIRCUIT SWITCHER to CRTL BLDG. DC DISTRIB. PANEL	53	m		$ -	$ 5	$ 265		$ 1,091	0.1	7.4	$ 1,356
		003B Cable TECK90 2C #10 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. DC DISTRIB. PANEL	35	m		$ -	$ 5	$ 175		$ 720	0.1	4.9	$ 895
		004A Cable TECK90 20C #14 AWG from 52T2-L CIRCUIT SWITCHER to CRTL BLDG. CNTL & PROT. PANEL	53	m		$ -	$ 12	$ 636		$ 2,065	0.3	14.0	$ 2,701
		004B Cable TECK90 20C #14 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. CNTL & PROT. PANEL	35	m		$ -	$ 12	$ 420		$ 1,363	0.3	9.3	$ 1,783
		005A Cable TECK90 20C #14 AWG from 52T2-L CIRCUIT SWITCHER to CRTL BLDG. CNTL & PROT. PANEL	53	m		$ -	$ 12	$ 636		$ 2,065	0.3	14.0	$ 2,701
		005B Cable TECK90 20C #14 AWG from 52T3-L CIRCUIT SWITCHER to CRTL BLDG. CNTL & PROT. PANEL	35	m		$ -	$ 12	$ 420		$ 1,363	0.3	9.3	$ 1,783
		006A Cable TECK90 25C #14 AWG from 55T3 POWER TRANSFORMER to CRTL BLDG. CNTL & PROT. PANEL	40	m		$ -	$ 16	$ 640		$ 1,605	0.3	10.9	$ 2,245
		006B Cable TECK90 25C #14 AWG from 55T2 POWER TRANSFORMER to CRTL BLDG. CNTL & PROT. PANEL	63	m		$ -	$ 16	$ 1,008		$ 2,528	0.3	17.2	$ 3,536
		007A Cable TECK90 4C #10 AWG from 55T3, CT3.1 to CRTL BLDG. CNTL & PROT. PANEL	40	m		$ -	$ 7	$ 280		$ 1,176	0.2	8.0	$ 1,456
		007B Cable TECK90 4C #10 AWG from 55T2, CT2.1 to CRTL BLDG. CNTL & PROT. PANEL	63	m		$ -	$ 7	$ 441		$ 1,852	0.2	12.6	$ 2,293
		008A Cable TECK90 4C #10 AWG from 55T3, CT3.2 to CRTL BLDG. CNTL & PROT. PANEL	40	m		$ -	$ 7	$ 280		$ 1,176	0.2	8.0	$ 1,456
		008B Cable TECK90 4C #10 AWG from 55T2, CT2.4 to CRTL BLDG. CNTL & PROT. PANEL	65	m		$ -	$ 7	$ 455		$ 1,911	0.2	13.0	$ 2,366
		010A Cable TECK90 3C #10 AWG from 55T3 POWER TRANSFORMER to CRTL BLDG. AC DISTRIB. PANEL	40	m		$ -	$ 6	$ 240		$ 1,176	0.2	8.0	$ 1,416
		011A Cable TECK90 2C #12 AWG from 55T3 POWER TRANSFORMER to CRTL BLDG. DC DISTRIB. PANEL	40	m		$ -	$ 4	$ 160		$ 706	0.1	4.8	$ 866
		012A Cable TECK90 25C #14 AWG from 55T3 POWER TRANSFORMER to CRTL BLDG. CNTL & PROT. PANEL	40	m		$ -	$ 16	$ 640		$ 1,605	0.3	10.9	$ 2,245
		Teck connectors "ST" for 2C # 12 Teck cable	10	ea		$ -	$ 15	$ 150		$ 2,205	1.5	15.0	$ 2,355
		Teck connectors "ST" 2C # 10 Teck cable	4	ea		$ -	$ 15	$ 60		$ 529	0.9	3.6	$ 589
		Teck connectors "ST" for 3C # 10 Teck cable	2	ea		$ -	$ 20	$ 40		$ 323	1.1	2.2	$ 363
		Teck connectors "ST" for 4C # 10 Teck cable	6	ea		$ -	$ 20	$ 120		$ 970	1.1	6.6	$ 1,090
		Teck connectors "ST" 20C # 14 Teck cable	8	ea		$ -	$ 25	$ 200		$ 1,764	1.5	12.0	$ 1,964
		Teck connectors "ST" for 25C # 14 Teck cable	6	ea		$ -	$ 25	$ 150		$ 1,323	1.5	9.0	$ 1,473
		Identification, tests, connection of ctrl cables	420	ea		$ -	$ 2	$ 840		$ 15,435	0.3	105.0	$ 16,275
		Subtotal Interconnection cables:				**$ -**		**$ 8,960**		**$ 48,057**		**326.9**	**$ 57,017**
						$ -		$ -		$ -	-	-	$ -

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	Labor-Hour Cost Crew / Discipline
Project : Detailed Engineering and Project Cost Estimate	
Project No.: 14988TTE	
Discipline: Electrical	

Project No:	14988TTE
Addendum :	
Date :	2015-04-09
Revision :	0

CODE		DESCRIPTION	Qty	Un.	CONTRACTOR								TOTAL
					Equipment E2		Material M2		Labor L2				
Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
						$ -		$ -		$ -	-	-	$ -
		Grounding (E-005 @ E-008)				$ -		$ -		$ -	-	-	$ -
		Main underground conductor				$ -		$ -		$ -	-	-	$ -
		4/0 Copper conductor (buried)	650	m		$ -	$ 15	$ 9,750		$ 4,778	0.1	32.5	$ 14,528
		Copper ground rod	8	ea		$ -	$ 35	$ 280		$ 1,764	1.5	12.0	$ 2,044
		Inspection box	8	ea		$ -	$ 75	$ 600		$ 1,176	1.0	8.0	$ 1,776
		Ground mat	1	ea		$ -	$ 585	$ 585		$ 588	4.0	4.0	$ 1,173
		2/0 ground conductor from 4/0 to equipment/structure				$ -		$ -		$ -	-	-	$ -
		2/0 Copper conductor	800	m		$ -	$ 10	$ 8,000		$ 5,880	0.1	40.0	$ 13,880
		Compression connector 4/0 to 2/0	60	ea		$ -	$ 35	$ 2,100		$ 8,820	1.0	60.0	$ 10,920
		2 holes compression connector	120	ea		$ -	$ 35	$ 4,200		$ 17,640	1.0	120.0	$ 21,840
		2/0 ground cable from 4/0 to existing fence				$ -		$ -		$ -	-	-	$ -
		2/0 Copper conductor	150	m		$ -	$ 10	$ 1,500		$ 1,103	0.1	7.5	$ 2,603
		Compression connector 4/0 to 2/0	20	ea		$ -	$ 35	$ 700		$ 2,940	1.0	20.0	$ 3,640
		Split bolt connecteur KS Burndy	140	ea		$ -	$ 15	$ 2,100		$ 10,290	0.5	70.0	$ 12,390
		Subtotal Grounding (E-005 @ E-008):				$ -		**$ 29,815**		**$ 54,978**		**374.0**	**$ 84,793**
						$ -		$ -		$ -	-	-	$ -
						$ -		$ -		$ -	-	-	$ -
		Equipment dismantling				$ -		$ -		$ -	-	-	$ -
		Dismanlling equipment	1	lot	$ 5,000	$ 5,000		$ -		$ 23,520	160.0	160.0	$ 28,520
		Subtotal Equipment dismantling :				**$ 5,000**		**$ -**		**$ 23,520**		**160.0**	**$ 28,520**
						$ -		$ -		$ -	-	-	$ -
				TOTAL :		**$ 997,840**		**$ 151,100**		**$ 235,480**		**1600 hrs**	**$ 1,384,420**

DETAILED COST ESTIMATE

TETRA TECH

Owner : Hydro Hakesbury Inc.	☐ Magnitude	**Labor-Hour Cost Crew / Discipline**	**Project No: 14988TTE**
Project : Detailed Engineering and Project Cost Estimate	☐ Conceptual ☐ Budgetary ☑ Definitive		**Addendum :** **Date :** 2015-04-09
Project No.: 14988TTE	☐ Control		**Revision : 0**

Discipline: Civil (decontamination)

CODE			DESCRIPTION	Qty	Un.	OWNER / CONTRACTOR: Equipment E1		Material M2		Labor L2				TOTAL
	Facility	Item				Unit. Price	Amount	Unit. Price	Amount	Unit. Price	Amount	M-H/Un.	M-H/Total	
							$ -		$ -		$ -	-	-	$ -
							$ -		$ -		$ -	-	-	$ -
			Basis of estimate for decontamination: Total excavation = 1411 cubic meter at 50% of total volume = 711 cubic meter x 2.0 metric tons / cubic meter =1, 422 t m @ 70 $/ metric ton =	711	m.cu.	$ 140	$ 99,470		$ -		$ -	-	-	$ 99,470
							$ -		$ -		$ -	-	-	$ -
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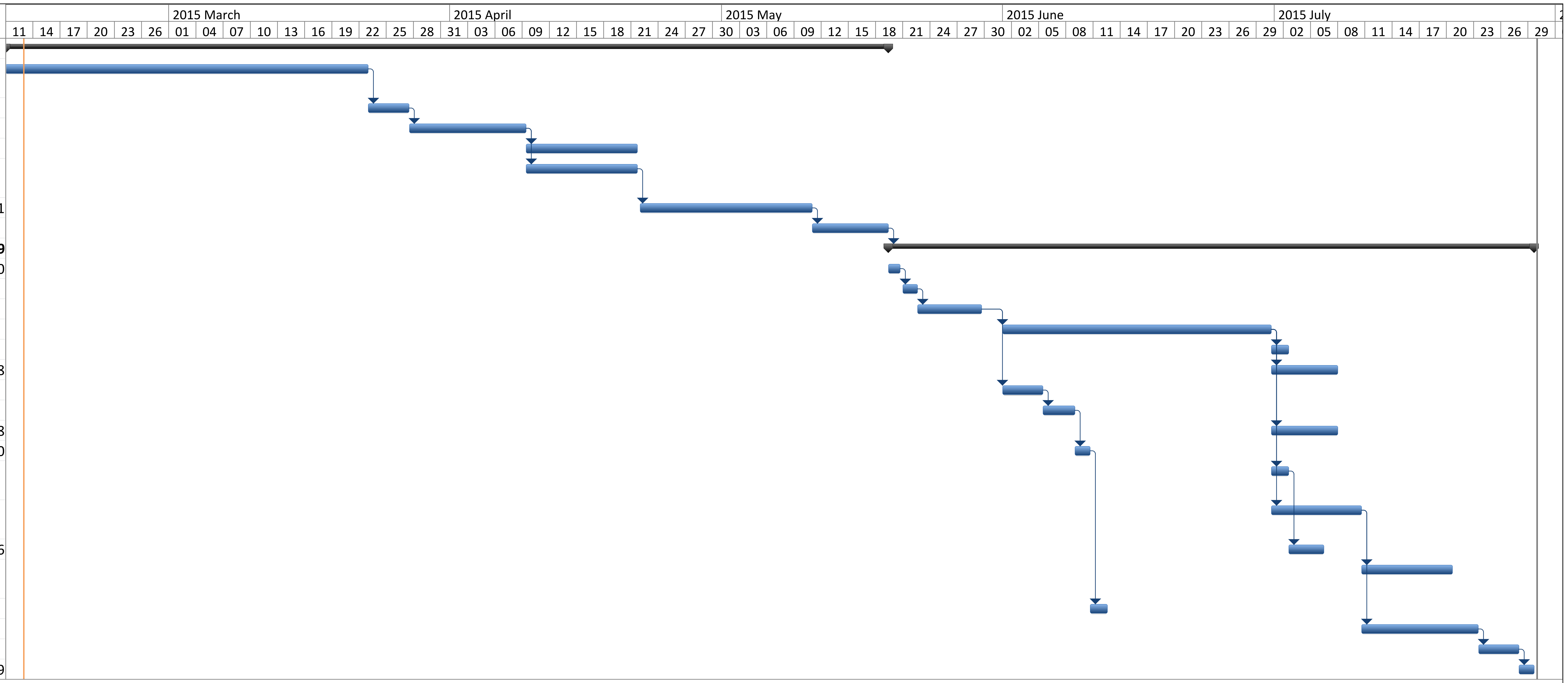
				TOTAL :			**$ 99,470**		**$ -**		**$ -**		**0 hrs**	**$ 99,470**

APPENDIX I

CONSTRUCTION SCHEDULE

ID	Task Mode	Task Name	Duration	Start	Finish
1		**110 KV Station Retrofit engineering phase**	**79 days**	**Wed 15-02-11**	**Tue 15-05-19**
2		Detailed engineering package for comments	32 days	Wed 15-02-11	Mon 15-03-23
3		Project cost estimate	1 wk	Mon 15-03-23	Fri 15-03-27
4		Issued for Comments package review	2 wks	Fri 15-03-27	Thu 15-04-09
5		Drawings corrections (if required)	2 wks	Thu 15-04-09	Tue 15-04-21
6		Issued for Tender package (including LBS spec)	2 wks	Thu 15-04-09	Tue 15-04-21
7		Tendering process	3 wks	Wed 15-04-22	Mon 15-05-11
8		Issued for construction package	7 days	Mon 15-05-11	Tue 15-05-19
9		**110 KV Station Retrofit Construction phase**	**59 days**	**Tue 15-05-19**	**Wed 15-07-29**
10		Mobilizing on site	2 days	Tue 15-05-19	Wed 15-05-20
11		Existing transformers removal	2 days	Thu 15-05-21	Fri 15-05-22
12		Civil work for soil preparation	6 days	Fri 15-05-22	Fri 15-05-29
13		Equipment foundations construction	25 days	Mon 15-06-01	Tue 15-06-30
14		Drainage	2 days	Tue 15-06-30	Thu 15-07-02
15		Below ground grounding	6 days	Tue 15-06-30	Wed 15-07-08
16		Imbiber bead system installation	5 days	Mon 15-06-01	Fri 15-06-05
17		Site granular backfill	2 days	Fri 15-06-05	Tue 15-06-09
18		Steel Structures Installation	6 days	Tue 15-06-30	Wed 15-07-08
19		Chain link fence replacement	2 days	Tue 15-06-09	Wed 15-06-10
20		Power transformer Installation on it's base(new)	2 days	Tue 15-06-30	Thu 15-07-02
21		Circuit Switchers and load break switches Installation	9 days	Tue 15-06-30	Fri 15-07-10
22		Existing Power transformer relocation	2 days	Thu 15-07-02	Mon 15-07-06
23		Bus bar installation including CT and Surge Arrestors	7 days	Fri 15-07-10	Mon 15-07-20
24		Equipment Fence Grounding	2 days	Wed 15-06-10	Fri 15-06-12
25		All conductor and cables	10 days	Fri 15-07-10	Thu 15-07-23
26		Testing and commissionning	3 days	Thu 15-07-23	Tue 15-07-28
27		Demobilizing	2 days	Tue 15-07-28	Wed 15-07-29



Project: 14988TTE-Station Retrofi
Date: Fri 15-02-13

Task	Summary	External Milestone	Inactive Summary	Manual Summary Rollup	Finish-only
Split	Project Summary	Inactive Task	Manual Task	Manual Summary	Deadline
Milestone	External Tasks	Inactive Milestone	Duration-only	Start-only	Progress

APPENDIX J
GROUND GRID STUDY

HYDRO HAWKESBURY

GROUND GRID STUDY
MAIN STREET WEST SUBSTATION

Tetra Tech's project no. : 14988

October 14th, 2014

Hydro Hawkesbury

Ground Grid Study
Main Street West Substation

Tetra Tech's project no.: 14988

Tetra Tech QE inc.
5100, Sherbrooke Street East, Suite 900
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Prepared by:

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LICENSED PROFESSIONAL ENGINEER
14/10/2014
G. OUELLETTE
100194289
PROVINCE OF ONTARIO

October 2014
Revision #0

TETRA TECH

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Tetra Tech inc. has been mandated by Hydro Hawkesbury to conduct a ground grid study at the substation located on Main Street West. The objective of this study is to define the design parameters and to prepare the construction drawings for a new ground grid designed to limit the step and touch voltages to the maximum allowable per IEEE standard no. 80-2000. The existing ground grid is not considered in this study.

To achieve this objective, resistivity measurements were conducted on site to determine a two-layer soil model, which was used to establish the safety assessments and simulate surface potential inside the station under fault conditions. The resistivity of the soil was found to be relatively low as the upper layer is estimated at 21Ohms-m and the lower layer is 253 Ohms-m. A superficial surface layer composed of 150 mm of crushed rock was also considered. Based on these soil parameters, the planned ground grid would have a calculated resistance to ground of 0.60 Ohms.

The maximum symmetrical line to ground fault current is 1.761kA with X/R=3.83 without considering the contribution of incoming line from the HONI station and distribution lines.

The safety assessment is made using a human body mass of 50 kg and a fault clearing time of 1 sec. Based on these parameters, the permissible voltage values are determined:

- Maximum permissible step voltage = 2440 Volts
- Maximum permissible touch voltage =733 Volts
- Ground potential rise = 1063 Volts

Simulations made using CYMGRD 6.5 Rev1 software showed that the maximum step and touch voltages found on the planned ground grid are lower than the above permissible values.

Tetra Tech recommends to proceed with the construction of the planned ground grid according to drawing No.A1-14988-E-005 as this design meets applicable safety requirements.

GROUND GRID STUDY

1 INTRODUCTION

Tetra Tech has been mandated by Hydro Hawkesbury to conduct a ground grid study at the substation located on Main Street West. The purpose of this study is to design the substation ground grid. The ground grid design must follow the applicable standard.

The software CYMGRD and the following documents were used to determine the various parameters that are necessary for this study, such as the soil model, safety assessment, the maximum grid current and the step and touch voltages:

- Standard IEEE 80-2000 - Guide for Safety in AC Substation Grounding
- Standard IEEE 81-1993 - Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System
- Canadian Electrical Code

2 PARAMETERS

To achieve these objectives, resistivity measurements were conducted on site to determine a two-layer soil model, which was used to establish the safety assessments and simulate surface potential inside the station under fault conditions. The resistivity of the soil is estimated at 21 Ohms-m for the first 13.5 m layer and 253 Ohms-m for second layer. See Appendix A for the soil resistivity report.

The simulations of the grid are based on the following parameters:

- A superficial surface layer of 150 mm of clear stone was considered evaluated at 3000 Ohms-m. Based on these soil parameters, the planned ground grid would have a calculated resistance to ground of 0.60 Ohm.
- The maximum symmetrical line to ground fault current is 1.761kA with X/R=3.83 without considering the contribution of incoming line from the HONI station and distribution lines. See Appendix B for the fault levels.
- The safety assessments were made using a human body mass of 50 kg and a fault clearing time of 0.5 second.

3 RESULTS

The ground grid layout 2D and 3D modeled in CYMGRD are presented in figure 1 and 2.

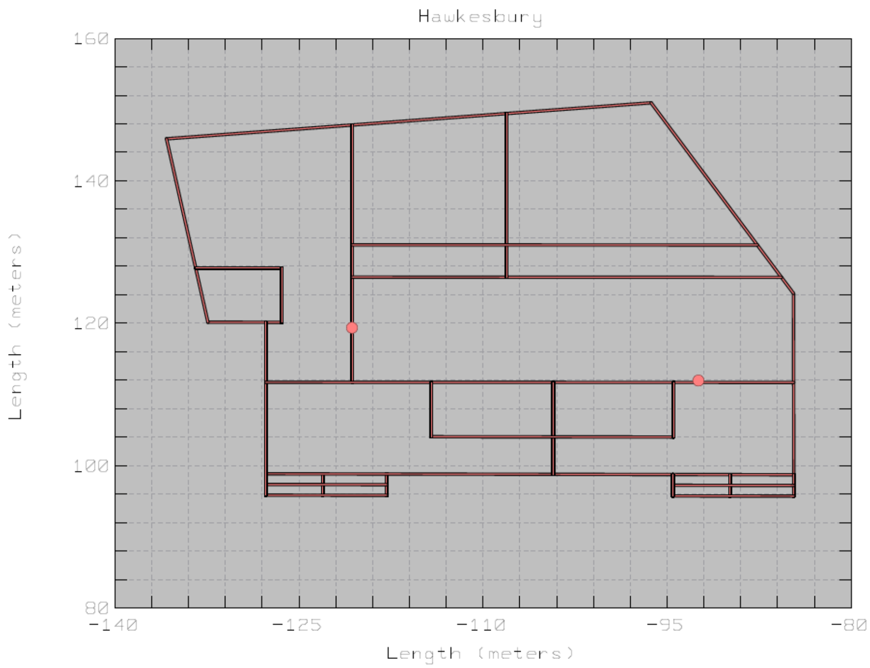


Figure 1 – Ground Grid Layout

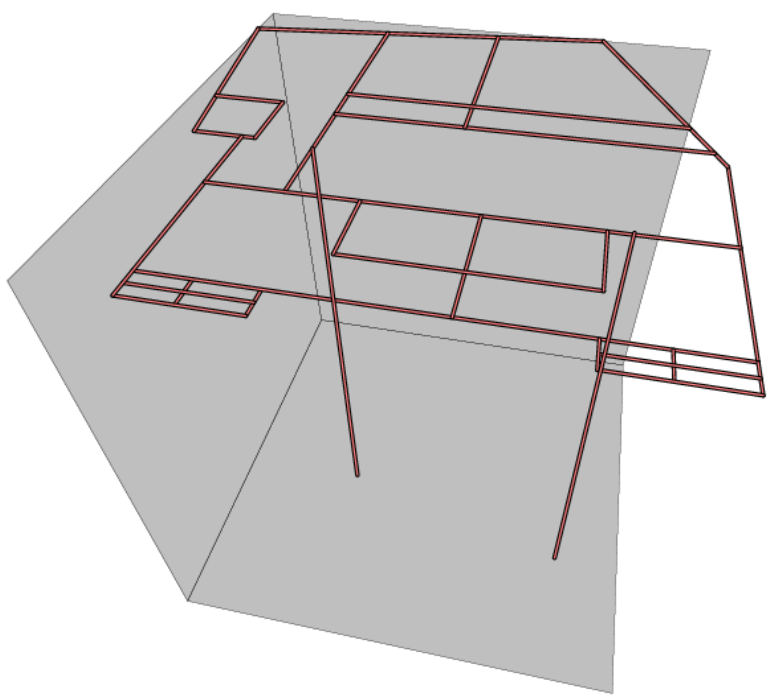


Figure 2 – Ground Grid Layout 3D

CYMGRD is used to calculate the step and touch potentials for the substation and to calculate also the maximum ground potential rise (GPR) and the maximum permissible step and touch potential values. These limits are presented in the table 1.

Table 1 – Safety criteria

	Step potential [Volts]	**Touch potential [Volts]**	**Ground potential rise [Volts]**
Potential thresholds	2440	733	1063
Maximum calculated potential	31	176	1012

The maximum step and touch voltages and ground potential rise are lower than the maximum permissible values.

Two potential contour plots have also been prepared that give an overall view of the ground grid touch potential. Figures 3 and 4 show the calculation results from CYMGRD and Figure 5 shows the legend associated with the potential contour.

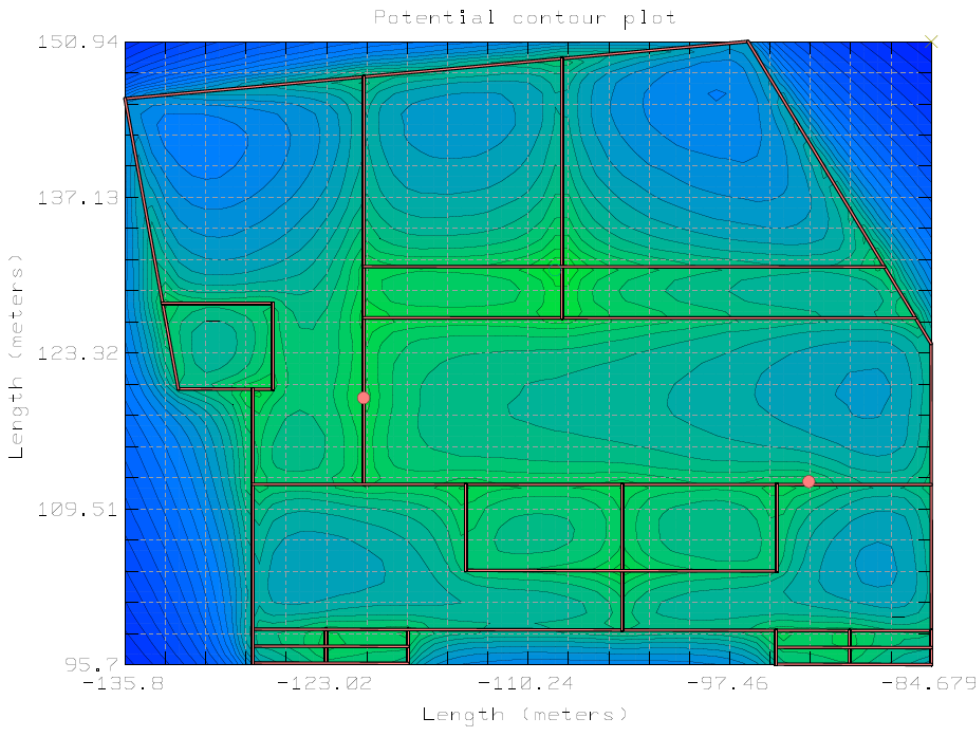


Figure 3 – Potential contour plot

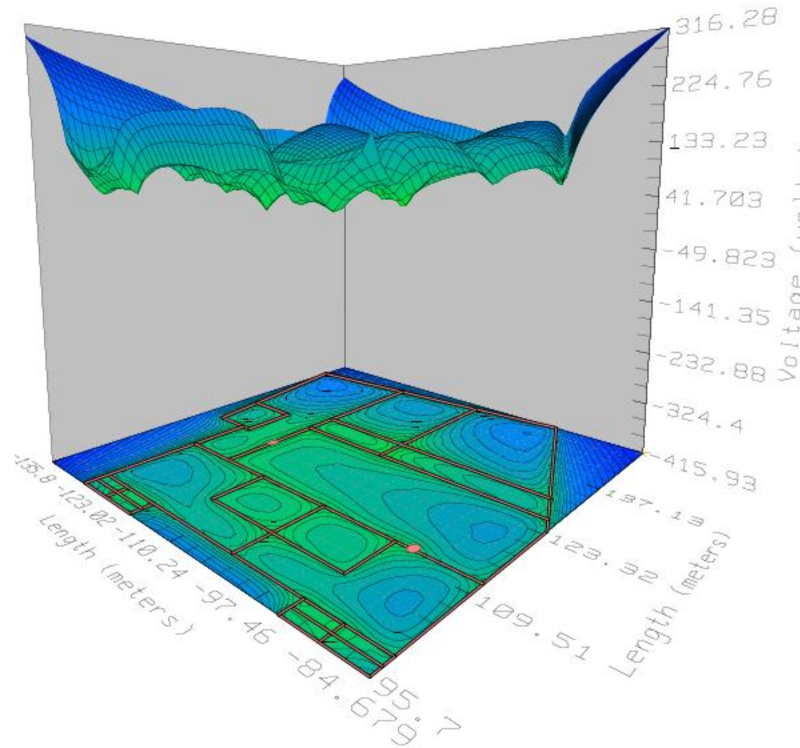


Figure 4 – Potential contour plot 3D

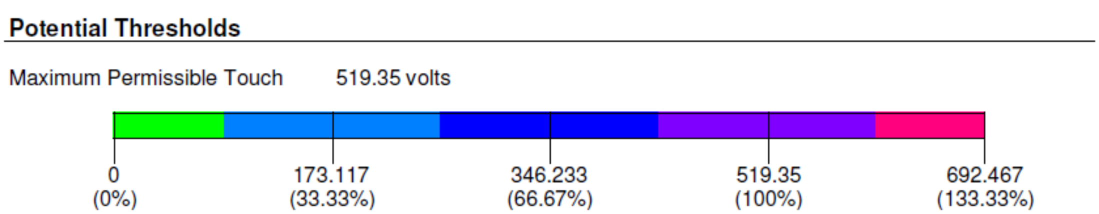


Figure 5 – Potential contour legend

Analysis of a potential profile is also performed on the ground grid. The plot for this profile is shown in Figure 6.

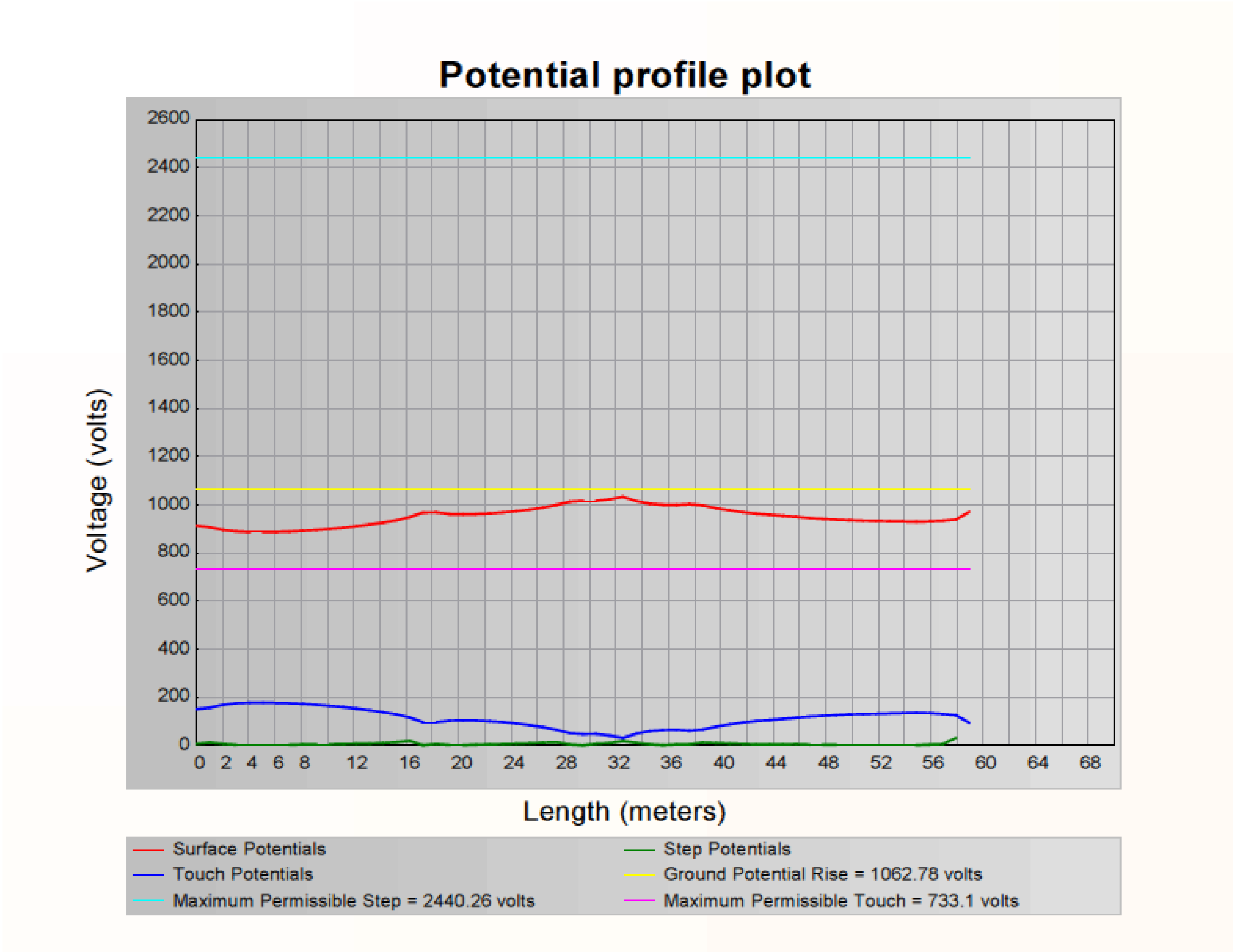


Figure 6 – Potential Profile plot

The grid analysis report is presented below.

Grid analysis report

mercredi, juillet 31, 2013, 16:55:49

Station Name	Hawkesbury
Project	HH_Ground Grid
Study	HawksburyGroundGrid

Parameters

Equivalent Parallel Z Spec.	Infinite Z
Nominal Frequency	60 hz
Bus ID	OHL-373
LG Fault Current	1761 amps
Remote Contribution	100 %
Upper Layer Thickness	13.5 meters
Upper Layer Resistivity	21 ohm-m
Lower Layer Resistivity	253 ohm-m

Output Results

Ground Potential Rise	1062.78 volts
Calculated Ground Resistance	0.597503 ohms
Equivalent Impedance	0.597468 ohms

Primary Electrode Elements

X1	Y1	Z1	X2	Y2	Z2	Length	Radius	Current	Electrode
			(meters)				(mm)	(amps)	(#)
-132.4189	120.1411	0.45	-126.4209	120.1087	0.45	5.9981	6.7	16.7551	Asy 1
-135.8	145.8833	0.45	-96.3096	150.9437	0.45	39.8133	6.7	237.7349	Asy 2
-135.8	145.8833	0.45	-132.4189	120.1411	0.45	25.9633	6.7	147.5592	Asy 3
-120.6583	111.6813	0.45	-120.6583	147.8236	0.45	36.1423	6.7	99.0737	Asy 4
-123.0562	98.8116	0.45	-123.0562	95.8171	0.45	2.9945	6.7	5.6585	Asy 5
-117.8653	98.8037	0.45	-117.8653	95.8037	0.45	3	6.7	8.8528	Asy 6
-84.6794	98.7	0.45	-84.6974	124.1661	0.45	25.4661	6.7	130.4339	Asy 7
-127.7062	98.8345	0.45	-84.6794	98.7	0.45	43.027	6.7	153.4048	Asy 8
-127.6984	97.3344	0.45	-117.8653	97.3037	0.45	9.8331	6.7	28.8358	Asy 9
-127.7062	95.8345	0.45	-117.8653	95.8037	0.45	9.8409	6.7	45.6056	Asy 10
-96.3096	150.9437	0.45	-84.6974	124.1661	0.45	29.1871	6.7	160.2025	Asy 11
-127.7062	95.8345	0.45	-127.7062	120.1156	0.45	24.2812	6.7	102.7476	Asy 12
-89.8703	98.7079	0.45	-89.8703	95.7134	0.45	2.9945	6.7	5.672	Asy 13
-84.6794	98.7	0.45	-84.6794	95.7	0.45	3	6.7	16.3715	Asy 14
-94.5254	97.2308	0.45	-84.6794	97.2	0.45	9.8461	6.7	29.1366	Asy 15
-94.5202	95.7308	0.45	-84.6794	95.7	0.45	9.8409	6.7	46.4799	Asy 16
-94.5254	98.7225	0.45	-94.5254	95.728	0.45	2.9945	6.7	8.8919	Asy 17
-127.7062	111.686	0.45	-84.6885	111.6572	0.45	43.0177	6.7	105.3133	Asy 18
-133.4157	127.7298	0.45	-126.4209	127.7251	0.45	6.9948	6.7	22.0998	Asy 19
-120.6583	126.4498	0.45	-85.6775	126.4263	0.45	34.9808	6.7	83.7184	Asy 20
-108.0891	126.4413	0.45	-108.0882	149.4344	0.45	22.9931	6.7	67.5852	Asy 21
-126.4209	120.1087	0.45	-126.4209	127.7251	0.45	7.6165	6.7	19.9437	Asy 22
-104.2811	98.7608	0.45	-104.2811	111.6702	0.45	12.9094	6.7	27.1012	Asy 23
-114.1946	104.0507	0.45	-94.4787	103.9891	0.45	19.7161	6.7	51.1569	Asy 24
-94.4787	103.9891	0.45	-94.4787	111.6702	0.45	7.6811	6.7	21.2529	Asy 25
-114.1946	104.0507	0.45	-114.1946	111.6769	0.45	7.6263	6.7	18.0084	Asy 26
-120.6583	130.9814	0.45	-87.6398	130.9593	0.45	33.0185	6.7	79.8402	Asy 27

Total Length Of Primary Conductors 480.777 meters

-92.45	111.93	0.45	-92.45	111.93	3.45	3	9.5	13.0576	Asy 1
-120.68	119.35	0.45	-120.68	119.35	3.45	3	9.5	8.4011	Asy 2

Total Length Of Primary Rods 6 meters

Total Number Of Elements 29

4 RECOMMENDATION

Tetra Tech recommends proceeding with the construction of the planned ground grid to meet the applicable safety requirements (see Appendix C for drawing No. A1-14988-E-005).

TETRA TECH

SOIL RESISTIVITY REPORT

A

MAIN STREET WEST SUBSTATION
GROUND RESISTIVITY TESTING

Presented to

BPR Energy
5,100 Sherbrooke East
Montreal, QC H1V 3R9

AUGUST 2012 **C12843**

SIGMA GEOPHYSICS INC.

1400 Marie-Victorin, suite 200
ST-BRUNO QC J3V 6B9
Téléphone: (450) 441-4600
Fax: (514) 227-5378
Email: info@geosigma.com
www.Geosigma.com

TABLE OF CONTENT

APPENDIX

1 INTRODUCTION

In July 2012, **SIGMA GEOPHYSICS INC**. has been mandated by **BPR Energy** for the execution of a resistivity survey on the site of a substation owned by **Hawkesbury Hydro** located on Main Street west. The present report deals mainly with the results obtained as well as their analysis. Other topics such as field methods, site characteristics, equipment and personnel are also briefly discussed herein.

2 GENERAL REMARKS

2.1 Survey location and positioning

The localization map on the next page shows the position of the resistivity soundings. The positions were determined on site using a differential GPS with a precision of around 2 metres.

2.2 Work schedule, crew and equipment

The field work was executed on August 2^{sd} 2012. Table 1 and table 2 describe the crew and equipment associated with the data acquisition, the administration and the report.

TABLE 1 – LIST OF PERSONNEL	
NAME	**TASK**
Claude Provost, Engineer	Report, interpretation
Jean-Philippe Demers, Tech.	Data acquisition

TABLE 2 – LIST OF EQUIPMENT			
QTY	**DESCRIPTION**	**MODEL**	**MAKER**
1	Resistivity meter	Syscal R1+	Iris Instrument
28	Stainless steel electrode		
1	Differential GPS (Garmin 60 in WAAS 3D mode)		

Client: BPR ENERGY
Date: AUG 2012
Contract: C12843

Hydro Hawkesbury

MAIN STREET WEST SUBSTATION
RESISTIVITY SOUNDINGS LOCATION

SIGMA GÉOPHYSIQUE SIGMA INC.

SCALE 1:2,000

3 METHODOLOGY

3.1 Resistivity survey

As recommended by the standards **IEEE STD 81-1983** (*IEEE Guide For Measuring Earth Resistivity*) and **IEEE STD-80-2000** (*IEEE Guide for safety in AC Substation Grounding*), soundings with multiple spacing have been carried out, to obtain the resistivity values of every layers that form the overburden (and the rock, if it is the case).

The electrodes array used was a *Schlumberger array with multiple partitions*, including **Wenner** configuration. The advantage of this array is the possibility to measure the lateral variations in resistivity, giving of a more accurate value of the true resistivity.

The spacing between the 2 current injection electrodes starts at 1 metre, with a logarithmic increment of 4 steps per decade (1 m, 1.8 m, 3.2 m, 5.6 m, 10 m, etc…) with a maximum of 100 metres on this site. The current was injected on the form of continuous current with a polarity inversion, using a 2 sec cycle (pos. 1 sec and neg. 1 sec). From the measurements, a modelisation of the data has been carried out to obtain the true resistivity value of each layer forming the soil. The results of the modelisation for the 7 soundings are presented on the "Interpretation and modelisation" graphs located in appendix. The modelisation has been executed with the assumption that the layers are parallel. In this case, we can obtain by mathematic inversion a geoelectric representation of each site. As more than one resistivity-thickness combination can theoretically give the same result, the use of geotechnical data, such as nature and thickness of the soil, allows for a better estimation of the true thickness and resistivity of each layer. Data coming from a geotechnical study have been used for the switchyard site (**Houle Chevrier Engineering Ltd.** Geotechnical Investigation August 2012, project 12-321).

4 RESULTS

4.1 Soil resistivity

The following table summarizes the results of the modelization for each sounding, consisting in the **thickness (T)** in m, the **resistivity (ρ)** in ohm-m and the probable **stratigraphic interpretation (Stra)** for each layer with the following code:

SD	Superficial deposit
CB	Silty clay (brown)
CG	Silty clay (grey)
TR	Till and rock probable

MAIN STREET WEST SUBSTATION - SUMMARY OF RESULTS												
	LAYER 1			LAYER 2			LAYER 3			LAYER 4		
No	T m	ρ ohm-m	Stra	T m	ρ ohm-m	Stra	T m	ρ ohm-m	Stra	T m	ρ ohm-m	Stra
1	0.3	29	SD	3.2	16	CB	12.9	30	CG	∞	229	TR
2	0.1	359	SD	2.9	18	CB	12.4	24	CG	∞	297	TR
3	0.5	25	SD	1	13	CB	14.3	28	CG	∞	233	TR

∞=infinite depth

The soil around the site of the substations presents few variations. The following model has been produced using the overburden thickness measured with the boreholes and by using the average resistivities measured will all the electrical soundings. The superficial layer has been ignored.

MAIN STREET WEST SUBSTATION 3 LAYERS MODEL		
THICKNESS (m)	RESISTIVITY (Ohm-m)	DESCRIPTION
2	16	Silty clay (brown)
11.5	27	Silty clay (grey)
∞	253	Till and rock probable

∞ = infinite depth

This model could be reduced to an approximate simple 2 layers model by combining the first 2 layers:

MAIN STREET WEST SUBSTATION **SIMPLIFIED APPROXIMATE 2 LAYERS MODEL**		
THICKNESS (m)	**RESISTIVITY (Ohm-m)**	**DESCRIPTION**
13.5	21	Silty clay
∞	253	Till and rock probable

During winter, the resistivity of the first layer could be considerably higher, up to a depth of 1.5 m.

This model does not take into account the resistivity of the surface granular material that could be present at the surface of the substation.

The interpretation and the report have been executed by Mr Claude Provost, Eng.

Claude Provost, Eng.

Geophysicist

APPENDIX

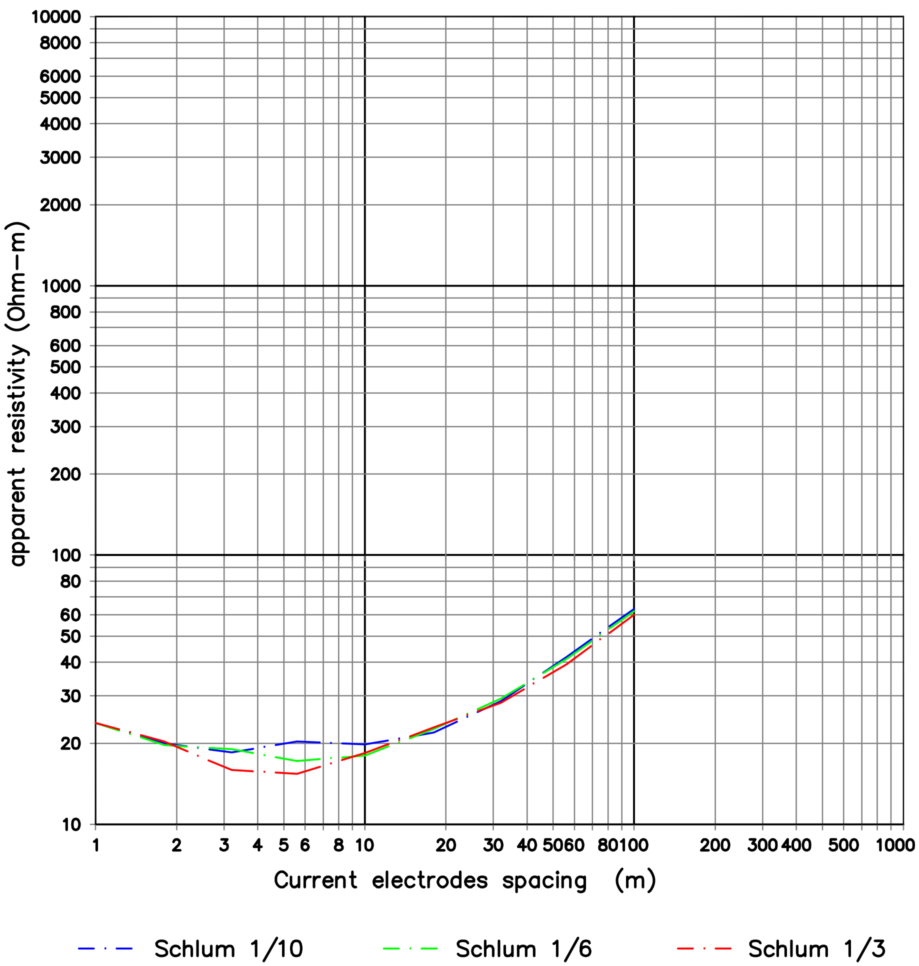
RESISTIVITY MEASUREMENTS

Survey Date: Aug 2 2012
Temp: 22 C, sunny
Sounding direction:NE-SW
Sounding location: See map

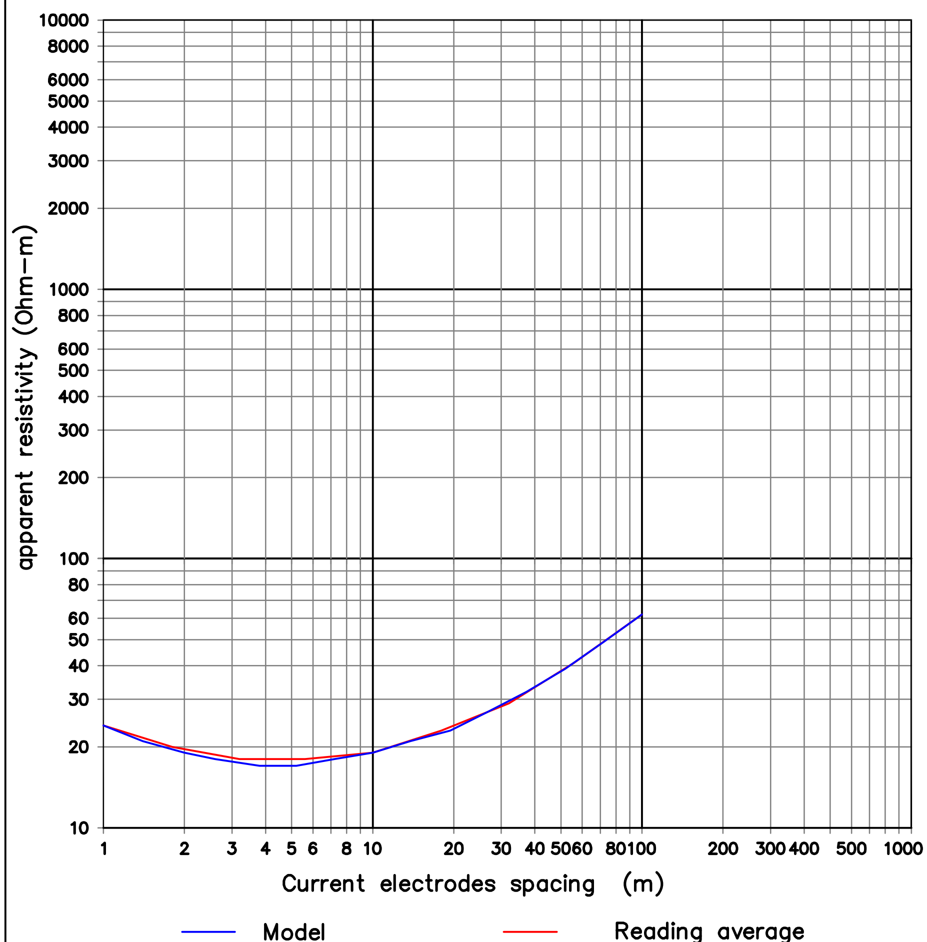
Equipment used:
IRIS SYSCAL R1+

HYDRO HAWKESBURY
SOUNDING SE- 1

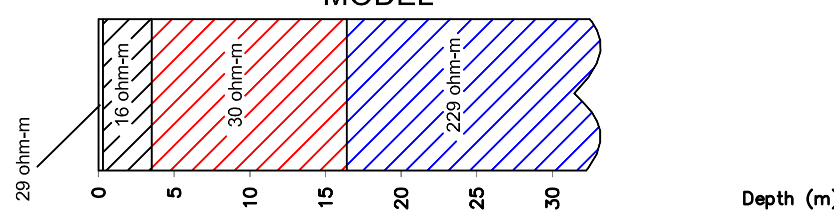
RESISTIVITY MEASUREMENT



INTERPRETATION AND MODELIZATION



MODEL



SIGMA

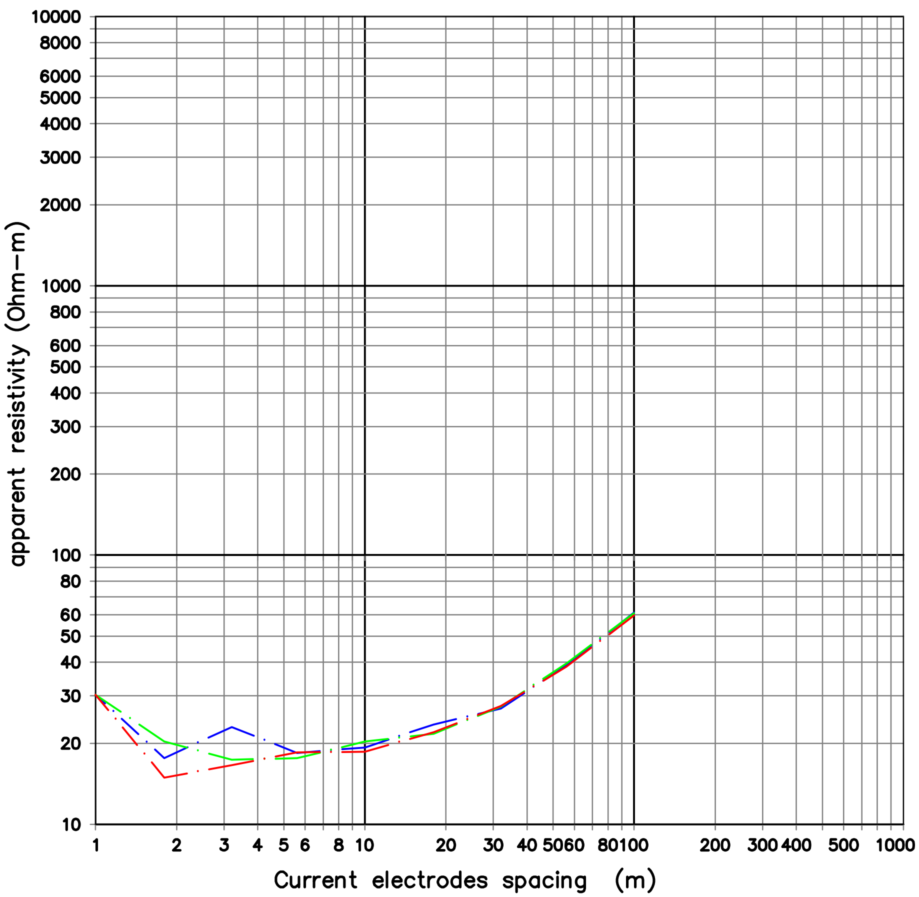
Sigma Geophysics inc.

Survey Date: Aug 2 2012
Temp: 22 C, sunny
Sounding direction:NW-SE
Sounding location: See map

Equipment used:
IRIS SYSCAL R1+

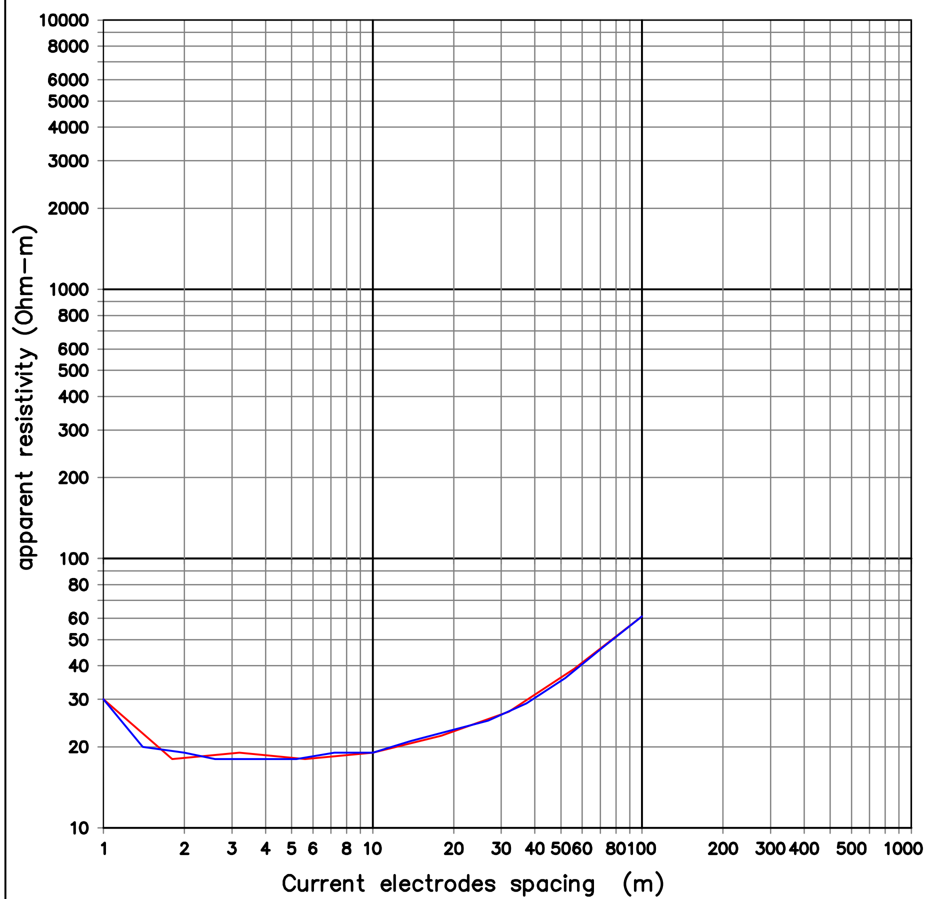
HYDRO HAWKESBURY
SOUNDING SE- 2

RESISTIVITY MEASUREMENT



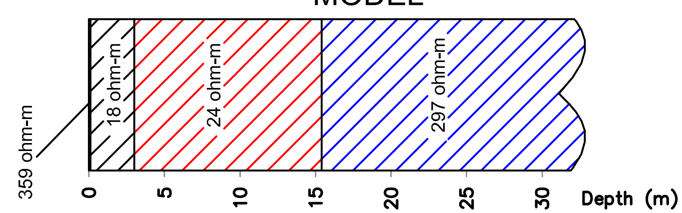
Schlum 1/10 Schlum 1/6 Schlum 1/3

INTERPRETATION AND MODELIZATION



Model Reading average

MODEL



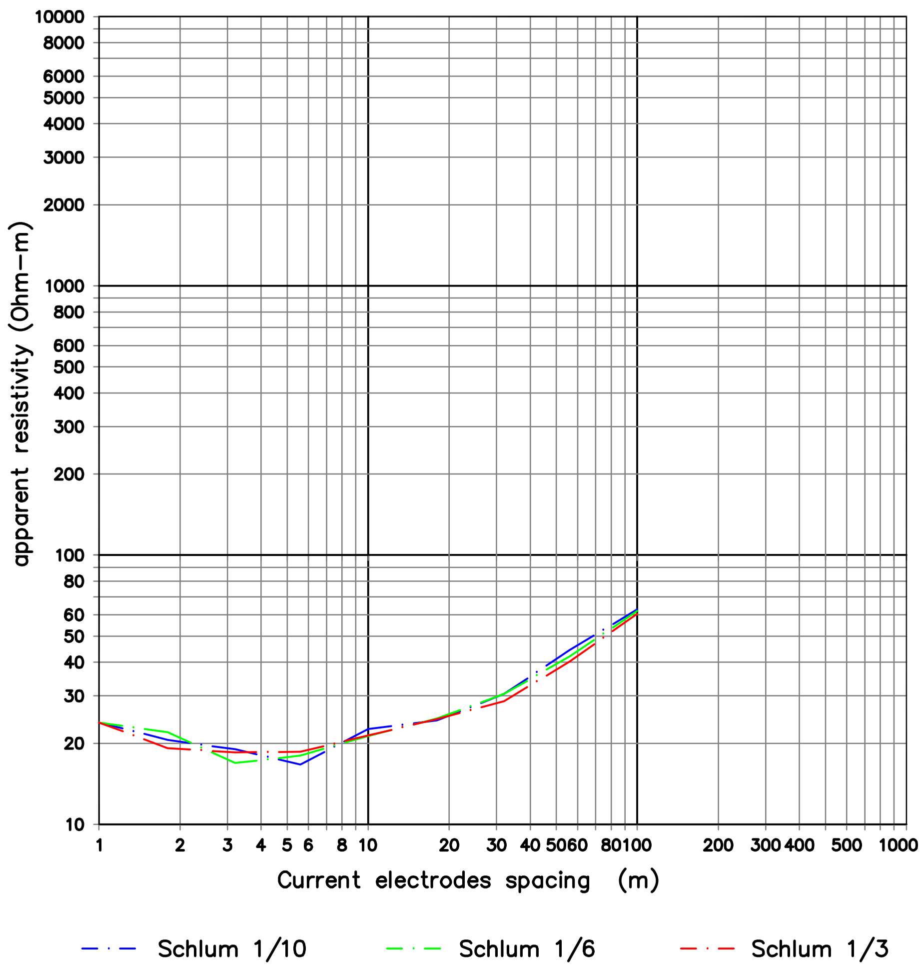
Sigma
Geophysics inc.

Survey Date: Aug 2 2012
Temp: 22 C, sunny
Sounding direction:N-S
Sounding location: See map

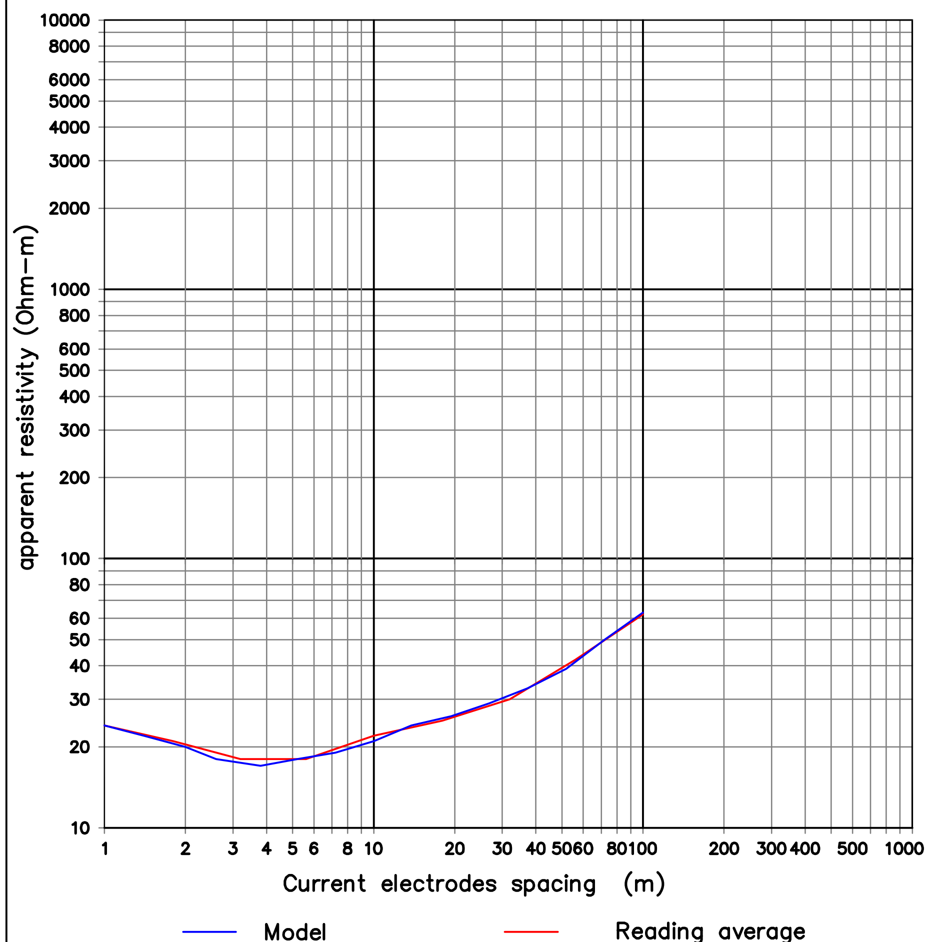
Equipment used:
IRIS SYSCAL R1+

HYDRO HAWKESBURY
SOUNDING SE- 3

RESISTIVITY MEASUREMENT



INTERPRETATION AND MODELIZATION



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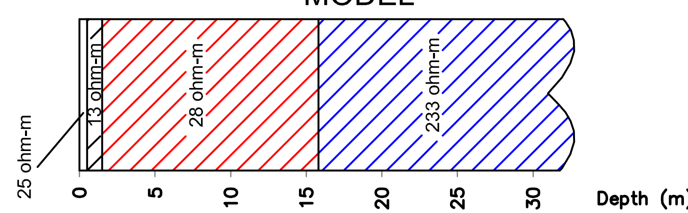


Sigma
Geophysics inc.

FAULT DATA

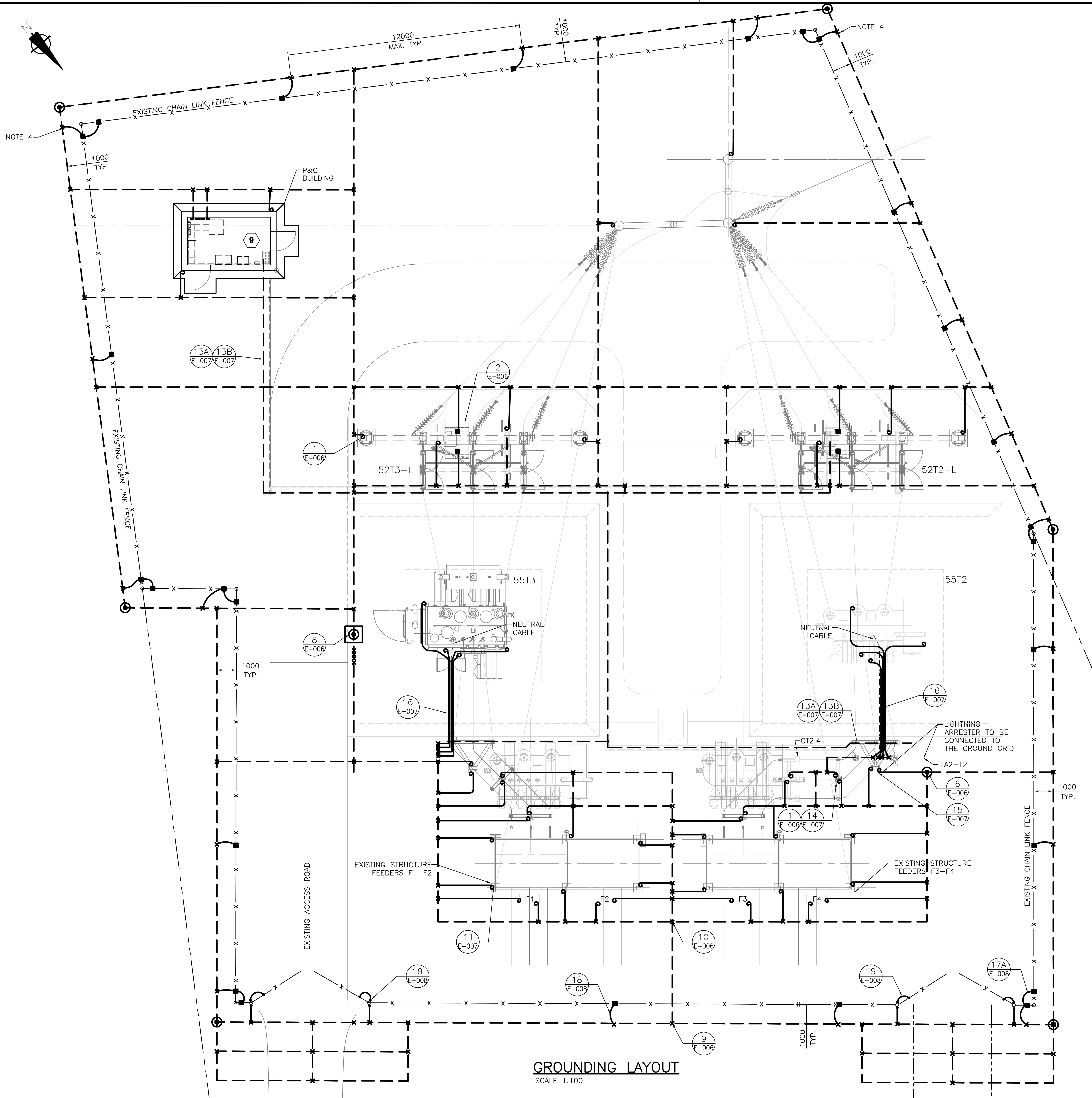
B

```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, JUN 07 2012  10:37
  SHORT CIRCUIT MODEL FOR HYDRO ONE NETWORK SYSTEM
  3P/1P HV Max Bus Faults.

                                 BRKER X------- THREE PHASE FAULT --------X X-- LINE TO GROUND FAULT --X
X- LLG SYMM I -X
   BUS# X-- NAME --X BASKV MAX V  TIME  FLTMVA  SYMM I ASYMM I   X/R FACTOR  SYMM I ASYMM I   X/R FACTOR
PHASE   3IA0    RPOS    XPOS    RZERO   XZERO
    373 HAWKESBU    118.05 1.076 0.033   436.5   1.984   1.997   4.05 1.006   1.109   1.115   3.83 1.005
1.761   0.770  0.0655  0.2652  0.2411  0.8929
```

GROUND GRID LAYOUT DRAWING

C



GROUNDING LAYOUT

SCALE 1:100

SYMBOLS/ LEGEND

- NEW UNDERGROUND COPPER CONDUCTOR 4/0 BURIED AT 450mm ±10mm FROM FINISHED GRADE
- GROUND ROD (SEE DETAIL NO. 4 OR NO. 6 DWG A1-14988-E-006)
- CONNECTION TO THE GROUND NETWORK (SEE DETAIL NO. 5, 9 OR 10 DWG. A1-14988-E-006)
- GROUND ROD WITH INSPECTION BOX (SEE DETAIL NO. 8 DWG. A1-14988-E-006)
- 2/0 AWG BARE COPPER CONDUCTOR
- BOLTED GROUND CONNECTION WITH COMPRESSION LUG TYPE HYLUG (BURNDY).
- SPLIT BOLT CONNECTION (CHAIN LINK FENCE AND FENCE POST).
- GROUNDING MAT 1200mm x 1830mm HOT-DIP GALVANIZED STEEL.

NOT TO USE FOR CONSTRUCTION

NOTES:

1. INSPECTION AND APPROVAL IS REQUIRED BEFORE BACKFILLING THE GROUND GRID.
2. LEAVE ENOUGH EXTRA COPPER CONDUCTOR FOR ELECTRICAL EQUIPMENT CONNECTIONS TO THE GROUND GRID.
3. SURFACE LAYER OF 150mm OF CLEAR CRUSHED STONES (20mmØ) WITH A RESISTIVITY OF 3000 OHMS-METERS
4. FENCE TO BE GROUNDED TO THE STATION GROUND GRID AT EACH CORNER POST AND GATE POST, AND AT INTERMEDIATE POSTS AT INTERVALS NOT EXCEEDING 12m.
5. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED.
6. GROUNDING DETAILS ON DWG A1-14988-E-006, E-007 & E-008.
7. THE CONTRACTOR SHALL LEAVE EXTRA LENGTH OF CONDUCTOR TO BOND SOME OF THE PILES. EXACT LOCATION AND QUANTITY TO BE DETERMINED AT SITE ALONG WITH CLIENT'S REPRESENTATIVE.

REFERENCE DRAWINGS:

A1-14988-E-002
A1-14988-E-006
A1-14988-E-007
A1-14988-E-008

REV.	TECH.	DATE	DESCRIPTION
3	G.O.	2014/10/02	ISSUED FOR ESA APPROVAL
2	G.O.	2014/03/17	ISSUED FOR COMMENTS
1	G.O.	2013/09/18	ISSUED FOR CONSTRUCTION
0	G.O.	2013/08/30	ISSUED FOR TENDER

ENGINEER STAMP

TETRA TECH
5100, Sherbrooke Street East
Suite 900
Montreal QC H1V 3R9
Tel.: 514 257-0707
Fax: 514 257-2418

CUSTOMER

Hydro Hawkesbury
850 Tupper St.
Hawkesbury, Ontario
K6A 3S7
Tel. 613-632-6689

PROJECT
110kV STATION REFURBISHMENT

TITLE
STATION LAYOUT
GROUNDING LAYOUT

Date	Designed by	Drawn by	Approved by
2013.06.19	H.Ouquelle Eng.	L.Propetto	G.Ouellette P.Eng
Scale	Consultant number		Customer number
1:100	14988		
Drawing number			Revision
A1-14988-E-005			3

A1 metric size 841x594.5

APPENDIX K
GEOTECHNICAL REPORT

APPENDIX L

HYDRO ONE APPROVAL

Hydro One Networks Inc.
125 C Line
Orangeville, ON
L9W 3V2
www.HydroOne.com

Mr. Michel Poulin

Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury, ON
K6A 3S7

May 26, 2016

RE: Hydro Hawkesbury, Final Design For Hydro One Approval

Mr. Michel Poulin,

In response to your email seeking approval to proceed with the next phases of the project ("upgrading the transformer at Hawkesbury MTS #1"), based on the revised design that incorporated a load break switch in series with the circuit switcher to alleviate the need for teleprotection back to the Hydro One substation. Hydro Hawkesbury Inc. submitted a complete drawing and protection report package for approval which addresses all comments previously received from Hydro One. The design review in regards to the EWDs and relay logics has been reviewed and found acceptable by Hydro One's Protection & Control Specialist. The revised design is approved to commence the next phases of the project.

Hydro Hawkesbury Inc. also required the load forecast for future grid growth. The 2016 system and 2021 system will be sent as an attachment in an email.

Please contact me if you have further questions, or require additional information.

Regards,

Stacey Pasztor

Account Executive
Key Accounts Management
416.953.4738
519.317.3892
stacey.pasztor@hydroone.com

APPENDIX M
SUMMARY OF ASSETS BEING FINANCED

Appendix M – Summary of Assets Being Financed:

Asset	Estimated Initial Cost	Estimated Life Span
Control Building	$77,000	60 years
Transformer 110kV-12.4kV 15/50/25MVA	$600,000	50 years
Circuit Switchers (2)	$137,000	50 years
Loadbreak Switches (2)	$72,000	50 years
Oil Containment System	$85,000	50 years
Protection, Metering and Auxiliary Systems	$195,000	50 years
Grounding, Ground Grid	$65,000	50 years
Structures, Foundations, Fencing, etc.	$350,000	60 years