Greater Sudbury Hydro
du Grand Sudbury

Greater Sudbury Hydro Inc.

Interrogatory Submission

March 10, 2020

Ontario Energy Board Staff

EB-2019-0037

empowering communities
le pouvoir aux communautés

A GSU company

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1-Staff-1 Updated RRWF and Models

Question:

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses.

Response:

GSHi submits the following updated models as part of these interrogatory responses:

1) GSHI_IRR_2020_Rev_Reqt_Work_Form_20200310

   a. See the following table, which provides a corrected Gross Revenue Deficiency figure (corrected for tax credits in "Approved Rates" year, and ensures equal "Distribution Revenue" figures in both Current and Proposed columns). This Gross Revenue Deficiency reconciles to tab "14. Tracking_Sheet" of the RRWF:

Description	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		3,232,969
Distribution Revenue	23,198,586	23,198,586
Other Operating Revenue Offsets - net	1,519,787	1,519,787
Total Revenue	**24,718,373**	**27,951,342**
Operating Expenses	22,033,642	22,033,642
Deemed Interest Expense	1,998,550	1,998,550
Total Cost and Expenses	**24,032,192**	**24,032,192**
Utility Income Before Income Taxes	686,181	3,919,150
Tax Adjustments to Accounting Income	- 2,723,150	- 2,723,150
Taxable Income/(Loss)	**- 2,036,969**	**1,196,000**
Income Tax Rate	26.5%	26.5%
Income Tax on Taxable Income	-	316,940
Income Tax Credits	- 539,797	-
Utility Net Income/(Loss)	**1,225,977**	**3,602,210**
Utility Rate Base	105,698,648	105,698,648
Deemed Equity Portion of Rate Base	42,279,459	42,279,459
Income/(Equity Portion of Rate Base)	2.90%	8.52%
Target Return - Equity on Rate Base	8.52%	8.52%
Deficiency/Sufficiency in Reutrn on Equity	**-5.62%**	**0.00%**
Indicated Rate of Return	2.54%	5.30%
Requested Rate of Return on Rate Base	5.30%	5.30%
Deficiency/Sufficiency in Rate of Return	**-2.76%**	**0.00%**
Target Return on Equity	3,602,210	3,602,210
Revenue Deficiency/(Sufficiency)	2,376,233	-
Gross Revenue Deficiency/(Sufficiency)	3,232,969	

2) GSHI_IRR_2020_Filing_Requirements_Chapter2_Appendices_20200310 – only the following tabs updated:
    a. App. 2-AA_Capital Projects
    b. App. 2-BA_Fixed Asset Cont
    c. App. 2-EA_Account 1575 (2015)
    d. App. 2-H_Other_Oper_Rev
    e. App. 2-IB_Load_Forecast_Analysis
    f. App. 2-JA_OM&A_Summary_Analys
    g. App. 2-JB_OM&A_Cost_Drivers
    h. App. 2-JC_OMA Programs
    i. App. 2-K_Employee Costs
    j. App. 2-L_OM&A_per_Cost_FTE
    k. App. 2-N_Corp_Cost_Allocation
    l. App. 2-OA Capital Structure
    m. App. 2-OB_Debt Instruments
    n. App. 2-R_Loss Factors
3) GSHI_IRR_2020_DVA_Continuity_Schedule_CoS_20200310
    a. Attachment 1 to this interrogatory response is “Tab "3. Appendix A" 1508 Reconciliation”, which reconciles the sum of account 1508 variances on tab "3. Appendix A" of the DVA Continuity Schedule.
4) GSHi_IRR_2020_ACM_ICM_Model_20200310
5) GSHI_IRR_2020_Cost_Allocation_Model_v3.7_20200310
6) GSHI_IRR_2020_Load_Forecast_Model_20200310
7) GSHI_IRR_2020_LRAMVA_Workform_20200310
8) GSHI_IRR_2020_RTSR_Workform_20200310
9) GSHI_IRR_2020_Test_Year_Income_Tax_PILs_20200310
10) GSHI_IRR_Cost_of_Power_20200310
11) GSHI_IRR_Update_of_Demand_Data_20200310

Attachment 1 (of 1):

1-Staff-1 Attachment 1: DVA Continuity Appendix A Reconciliation

GSHI_IRR_2020_DVA_Continuity_Schedule_CoS_20200310
Tab "3. Appendix A" 1508 Reconciliation

Purpose: To reconcile the sum of account 1508 variances on tab "3. Appendix A" of the DVA Continuity Schedule

	Other Adjustment	2019 Principal	2020 Principal (Projected)	Grand Total	Description
Pole Attachment Revenue Variance		$ (507,989)	$ (174,699)	**$ (682,688)**	Pole rental revenue deferred in 2019, plus projection for 2020., as discussed in interrogatory 9-Staff-87.
Other Regulatory Assets - Sub-Account - Energy East Pipeline	$ (8,837)			**$ (8,837)**	Write off of Energy East Pipeline as per interrogatory 9-Staff-86.
Smart Grid Capital Deferral Account - (OEB Account 1534)	$ 172,015			**$ 172,015**	Principal portion of total claim amount for 1534, see discussion in 9-Staff-88.
Smart Grid OM&A Deferral Account - (OEB Account 1535)	$ 264,227			**$ 264,227**	Principal portion of total claim amount for 1535, see discussion in 9-Staff-88.
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		$ 42,788	$ 14,808	**$ 57,596**	Principal portion of OEB cost assessments for 2019 and first 4 months of 2020, projected and proposed for final disposition.
Smart Grid Capital Deferral Account - (OEB Account 1534) - Interest	$ 5,779			**$ 5,779**	Interest portion of total claim amount for 1534, see discussion in 9-Staff-88.
Smart Grid OM&A Deferral Account - (OEB Account 1535) - Interest	$ 19,287			**$ 19,287**	Interest ortion of total claim amount for 1535, see discussion in 9-Staff-88.
Other Regulatory Assets - Sub-Account - Energy East Pipeline - Interest	$ (419)			**$ (419)**	
	$ 452,052	$ (465,201)	$ (159,891)	**$ (173,040)**	

1-Staff-2 Letters of Comment

Question:

Following publication of the Notice of Application, the OEB received two letters of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

Please see the responses to the two letters of comment, included as Tab 1, Interrogatory 2, Attachment 1 and also filed as a separate document on RESS with this interrogatory submission. As of the date of filing interrogatory responses, GSHi has not received any additional letters of comment.

Attachment 1 (of 1):

1-Staff-2 Attachment 1: Response to Letters of Comment

-----Original Message-----
From: Webmaster <Webmaster@oeb.ca>
Sent: Saturday, December 21, 2019 8:30 AM
To: registrar <registrar@oeb.ca>
Subject: Letter of Comment - [redacted]

The Ontario Energy Board

-- Comment date --
2019-12-21

-- Case Number --
EB-2019-0037

-- Name --
Whitney Muzyka

-- Phone --
[redacted]

[redacted] Company --
[redacted]

-- Address --
[redacted]

-- Comments --
I would like to comment, although not elderly, but responsible for an elderly family member who lives independently on a very limited budget, that I feel the elderly in the Sudbury area will suffer with increases to their utility bills. I realize it is impossible to break this down elderly vs non, and I realize the costs of our hydro utilities are also going up, but I am concerned with the ability for the elderly to both pay their bills as well as stay in their homes with increasing costs of taxes, utilities and food. I do not know the percentage who would be affected by this increase in our community, I just wanted the human aspect considered in the application.

Thank you, Whitney Muzyka

-- Attachment --

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February 12, 2020

VIA RESS

Dear Ms. Muzyka:

Thank you very much for expressing your concerns to the Ontario Energy Board regarding our 2020 rate application. Your participation in this rate-setting process is truly appreciated.

Every action taken and decision made at Greater Sudbury Hydro is viewed through the lens of our corporate values. Central to these values is our commitment to always *doing the right thing* to serve our customers' best interests while also ensuring the integrity and longevity of our distribution system infrastructure. It's a balancing act that requires reflection and a careful weighing of customer needs and priorities alongside the recommendations of our expert staff. It's not always easy to do.

The portion of your bill we control and that is impacted by the rate increase we are requesting is called the distribution charge (it represents about 17% of the total charges seen on customer bills). This is the money we collect to maintain and upgrade our infrastructure to make sure we can provide a consistent supply of electricity to our customers.

If we do not increase our distribution rates, then the total amount of revenue we'll collect from our customers to operate the distribution system will not have increased in over a decade. We've always worked hard to deliver consistent value to our customers while minimizing the financial impact on their bills; however, given the current need to upgrade our equipment to ensure public safety and reliability of service while also keeping pace with evolving industry standards, maintaining status quo with our distribution rates just isn't sustainable. Deferring our plans to help keep costs neutral would be irresponsible. It would not be the right thing to do.

We know that the rate increase we are proposing is needed, but we also know that more money required for service means less in our customers' pockets. We hear your concerns and acknowledge the challenges accepting these new rates may pose for you and for others, particularly those in more precarious financial circumstances. There are a number of provincial resources available that should be explored by those who qualify for assistance in reducing their monthly bills, and we would gladly provide you with guidance on how to access them. If you'd like

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to learn more please reach out to our Director of Communications, Wendy Watson, by calling our office at 705-675-7536.

Thank you again for your letter. We want to assure you that we have always considered impact on customers—what you rightly call the *human aspect*—when making our decisions. I promise you that we will continue to do so.

Respectfully,

Original Signed By

Frank Kallonen
CEO, Greater Sudbury Hydro Inc.

From: Webmaster <Webmaster@oeb.ca>
Sent: Friday, December 20, 2019 6:34 PM
To: registrar <registrar@oeb.ca>
Subject: Letter of Comment - [redacted]

The Ontario Energy Board

-- Comment date --
2019-12-20

-- Case Number --
EB-2019-0037

-- Name --
Justin Nykilchuk

-- Phone --
[redacted]

-- Company --

-- Address --
[redacted]

-- Comments --
This increase is significant, I currently use less than 10$ of electricity and pay over 20$ for delivery. My total hydro bill will increase by approximately 20% with the increase in delivery charges. This is a significant increase for those of us who are low income students, and are conscious to conserve energy for budgetary reasons. I feel my efforts are hopeless as prices for delivery continue to increase without any regard for usage charges.

-- Attachment --

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February 12, 2020

VIA RESS

Dear Mr. Nykilchuk:

Thank you very much for expressing your concerns to the Ontario Energy Board regarding our 2020 rate application. Your participation in this rate-setting process is truly appreciated.

Every action taken and decision made at Greater Sudbury Hydro is viewed through the lens of our corporate values. Central to these values is our commitment to always *doing the right thing* to serve our customers' best interests while also ensuring the integrity and longevity of our distribution system infrastructure. It's a balancing act that requires reflection and a careful weighing of customer needs and priorities alongside the recommendations of our expert staff. It's not always easy to do.

The portion of your bill we control and that is impacted by the rate increase we are requesting is called the distribution charge (it represents about 17% of the total charges seen on customer bills). This is the money we collect to maintain and upgrade our infrastructure to make sure we can provide a consistent supply of electricity to our customers.

If we do not increase our distribution rates, then the total amount of revenue we'll collect from our customers to operate the distribution system will not have increased in over a decade. We've always worked hard to deliver consistent value to our customers while minimizing the financial impact on their bills; however, given the current need to upgrade our equipment to ensure public safety and reliability of service while also keeping pace with evolving industry standards, maintaining status quo with our distribution rates just isn't sustainable. Deferring our plans to help keep costs neutral would be irresponsible. It would not be the right thing to do.

We know that the rate increase we are proposing is needed, but we also know that more money required for service means less in our customers' pockets. As a student who is working hard to conserve energy, we hear your concerns and we acknowledge the challenges accepting these new rates may pose for you and for others in precarious financial circumstances. There are a number of provincial resources available that should be explored by those who qualify for assistance in reducing their monthly bills, and we would gladly provide you with guidance on how to access

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them. If you'd like to learn more please reach out to our Director of Communications, Wendy Watson, by calling our office at 705-675-7536.

Thank you again for your letter. We want to assure you that we have always considered impact on customers when making our decisions. I promise you that we will continue to do so.

Respectfully,

Original Signed By

Frank Kallonen
CEO, Greater Sudbury Hydro Inc.

1-Staff-3 Customer Engagement

Question:

Ref 1: Exhibit 1 – Tab 6 – Schedule 1

The results of Sudbury Hydro's customer engagement showed that a majority of both residential and business customers wanted a balance between rates and outages.

a) Would Sudbury Hydro agree that this could be interpreted as keeping reliability status quo, with the minimal amount of cost?
b) If not, how does Sudbury Hydro interpret the results of its customer engagement?
c) If possible, please quantify Sudbury Hydro's interpretation in b)

Response:

a) Yes, GSHi would agree that the results of the customer engagement activities undertaken show that customers have generally been pleased with the level of reliability in the service that GSHi provides, and they would prefer to maintain status quo with the minimal amount of costs.

   However, while customers have not expressed strong dissatisfaction with the current levels of service they receive, a review of GSHi's outage data has shown that the frequency and duration of Cause 5 outages (that is, outages stemming from defective equipment) have been increasing (Exhibit 1, Tab 7, Schedule 1, Pages 8-13). GSHi believes that without needed investments in system renewal this trend will continue.

   Leaving things as they are with respect to capital spending is not acceptable, as aging equipment will continue to degrade, compromising reliability. GSHi must establish a new normal—a status quo of sustained reliability well into the future. Doing so will require an increase to customer rates in order to fund needed capital investments.

GSHi must move forward with its plans for system renewal activities to better serve its customers.

b) Not applicable

c) Not applicable

1-Staff-4 Performance Measurement

Question:

Ref 1: Exhibit 1 – Tab 7 – Schedule 1, p. 9

Sudbury Hydro stated that adverse weather outages is a "result of high winds that cause trees and/or branches, to snap, causing them to fall into live conductors and triggering protection equipment to trip and isolate the faulted circuit, which in turn results in a service interruption necessitating a truck roll to fix the problem."

a) Has Sudbury Hydro considered inspecting high-risk trees, in addition to fast growth areas, and focus vegetation management in those areas?

Sudbury Hydro also stated that it designs and builds pole lines that exceed Canadian Standards Association (CSA) standards to ensure that the lines are storm-hardened.

b) Please provide an estimate on, a per kilometer basis, the incremental cost of the storm-hardened design and the CSA standard design.

Response:

a) As part of its four-year vegetation management cycle, GSHi asks contractors to include specific pricing terms for high-risk (danger) tree removal when submitting responses to RFQs from the utility.

   Concurrently, the utility fulfills its mandatory Distribution System Code obligation to inspect its distribution system assets at least once in a three period. Depending on these results, as well as other data such as outage type/frequency, the utility may determine that a reasonable course of action to avoid undesired outcomes could include, for example, focusing additional resources towards vegetation management in some areas of its service territory as compared with other areas that do not demonstrate a similar need for additional resources.

b) GSHI, as part of its standard engineering practices and Construction Verification Program, continues to build and design pole lines to meet or exceed the latest revision of CSA C22.3 No.1. Overhead Systems which ensures that new distribution system expansions, extensions and replacements are storm-hardened to a level appropriate with the regional climate. In the Standard, there are four deterministic load conditions: Severe, Heavy, Medium Loading A and Medium Loading B. Throughout the communities serviced by GSHI, conformance with the Standard requires the utility to build to Medium Loading B, at a minimum. By meeting the CSA standard, we are storm-hardening our distribution system to a level appropriate for the local climate.

1-Staff-5 Leases

Question:

Ref 1: Exhibit 1 – Tab 8 – Schedule 1 – Attachment 4, 2018 Audited Statements

Note 2 part o indicates that Sudbury Hydro intends to adopt IFRS 16 Leases beginning January 1, 2019. It has assessed that there will be no significant impact from IFRS 16.

a) Please indicate the total amount of finance leases as at the 2018 year-end.
b) Please quantify and discuss the impact of adopting IFRS 16 effective January 1, 2019.
c) Please explain Sudbury Hydro's treatment of finance leases in the current application
d) Please indicate the total amount of finance leases included in rate base in 2020 and where it is included in Appendix 2-BA.

Response:

a) GSHi has one finance lease as at the 2018 year-end. GSHi entered into a financing agreement with TD Equipment Finance Canada Inc. in 2015 in the amount of $971,607. The finance term was for 10 years at a fixed interest rate of 4.33% and is secured by the underlying specified assets under financing.

   Please see Exhibit 5, Tab 1, Schedule 2, Attachment 3 for a copy of the finance lease between GSHi and TD Equipment Finance Canada Inc.

b) GSHi is currently finalizing its 2019 fiscal year-end and has not yet quantified the impact of adopting IFRS 16 for the 2019 fiscal year. GSHi is unable to quantify the impact at this time.

c) GSHi has included its one finance lease in Appendix 2-OB, Debt Instruments. The finance lease is impacting GSHi's long-term debt rate.

d) In 2015, as per Appendix 2-BA, GSHi capitalized $1,320,994 to building. In the same year, GSHi entered into a financing agreement with assets added in the year provided as collateral in the financing agreement. The financing agreement was in the amount of $971,607 and is included as Exhibit 5, Tab 1, Schedule 2, Attachment 3. The amount capitalized in 2015 to building exceeded the amount financed. GSHi summarizes in the below table the amount of building financed and remaining in rate base in the 2020 Test Year of $777,286. This amount is included in the Net Book Value of "Buildings" in Appendix 2-BA in 2020.

	2015	2016	2017	2018	2019	2020
Gross capital, building (HVAC Equipment)	$971,607	$971,607	$971,607	$ 971,607	$ 971,607	$ 971,607
Accum Amort	$ (19,432)	$ (58,296)	$ (97,161)	$(136,025)	$(174,889)	$(213,754)
Net book value, capital assets	$952,175	$913,311	$874,446	$ 835,582	$ 796,718	$ 757,853
Amortization Expense (25 years)	$ (19,432)	$ (38,864)	$ (38,864)	$ (38,864)	$ (38,864)	$ (38,864)
		Average Net Book Value, 2019-2020				**$ 777,286**

2-Staff-6 Gross AssetVariance Analysis

Question:

Ref 1: Exhibit 2 – Tab 1 – Schedule 2, pp. 2-27

Sudbury Hydro provided gross asset variance amounts for contributions/deferred revenue in the reference above.

a) Please provide the variance analysis for the contributions/deferred revenue account.

Response:

The variance analysis for the contributions/deferred revenue account is below. Please note that 2019 has been updated for 2019 year end unaudited actuals.

Table 1 – 2013 Board Approved vs. 2013 Actual Gross Assets by Account

Contributions				
1995	Contributions & Grants	- 16,012,875	- 16,556,417	- 543,542
2440	Deferred Revenue[5]	-	-	-
Subtotal - Contributions		**- 16,012,875**	**- 16,556,417**	**- 543,542**

Contributions and Grants

GSHi experienced higher contributions than expected in 2013:

- An unbudgeted contribution of $223,009 was received in relation to work requiring the relocation of GSHi plant to accommodate a City of Sudbury road construction project;
- Contributions from Subdivision-related work were $92,148 higher than forecast; and,
- Contributions from Commercial-related work were $146,803 higher than forecast.
- The remaining $81,582 is due to other immaterial projects.

Table 2 – 2014 Actual vs. 2013 Actual Gross Assets by Account

Contributions					
1995	Contributions & Grants	- 16,556,417	-	16,556,417	-
2440	Deferred Revenue[5]	-	- 898,557		- 898,557
Subtotal - Contributions		**- 16,556,417**	**- 898,557**	**16,556,417**	**- 898,557**

Deferred Revenue variance of 898,557

The variance relates to the following:

- $390,593 for thirteen commercial developments
- $149,135 for city roadwork
- $145,355 for four subdivision developments
- $213,474 for a number of small contributions (overhead/underground services/system betterments)

Table 3 – 2015 Actual vs. 2014 Actual Gross Assets by Account

Contributions					
1995	Contributions & Grants	-	-		-
2440	Deferred Revenue[5]	- 898,557	- 2,225,598		- 1,327,041
Subtotal - Contributions		**- 898,557**	**- 2,225,598**	**-**	**- 1,327,041**

<u>Deferred revenue variance $1,327,041</u>

The variance relates to the following:

- $707,456 for sixteen commercial developments
- $373,028 for four subdivision developments
- $145,184 for two line relocations
- $101,373 several small contributions (overhead/underground services/system betterments)

Table 4 – 2016 Actual vs. 2015 Actual Gross Assets by Account

Contributions				
1995	Contributions & Grants	-	-	-
2440	Deferred Revenue[5]	- 2,225,598	- 3,141,356	- 915,758
Subtotal - Contributions		**- 2,225,598**	**- 3,141,356**	**- 915,758**

Deferred revenue variance $915,758

The variance relates to the following:

- $421,227 for twenty-one commercial developments
- $143,808 for city roadwork
- $239,810 for four subdivision developments
- $110,913 several small contributions (overhead/underground services/system betterments)

Table 5 – 2017 Actual vs. 2016 Actual Gross Assets by Account

Contributions				
1995	Contributions & Grants	-	-	-
2440	Deferred Revenue[5]	- 3,141,356	- 3,848,574	- 707,219
Subtotal - Contributions		**- 3,141,356**	**- 3,848,574**	**- 707,219**

Deferred revenue variance $707,219

The variance relates to the following:

- $251,666 for twenty-two commercial developments
- $157,403 for city roadwork
- $115,403 for three subdivision developments
- $71,677 system betterments
- $111,366 several small contributions (overhead/underground services/system betterments)

Table 6 – 2018 Actual vs. 2017 Actual Gross Assets by Account

Contributions				
1995	Contributions & Grants	-	-	-
2440	Deferred Revenue[5]	- 3,848,574	- 5,062,611	- 1,214,036
Subtotal - Contributions		**- 3,848,574**	**- 5,062,611**	**- 1,214,036**

Deferred revenue variance $1,214,036

The variance relates to the following:

- $811,379 for twenty-eight commercial developments
- $266,075 for city roadwork

- $66,602 for eight subdivision developments
- $69,980 several small contributions (overhead/underground services/system betterments)

Table 7 – 2019 Bridge Year Projected vs. 2018 Actual Gross Assets by Account

Contributions					
1995	Contributions & Grants		-	-	-
2440	Deferred Revenue[5]		- 5,062,611	- 6,761,089	- 1,698,479
Subtotal - Contributions			**- 5,062,611**	**- 6,761,089**	**- 1,698,479**

Deferred revenue variance $1,698,479

The variance relates to the following:

- $593,292 for twenty commercial developments
- $294,008 for emergency plant replacements
- $328,093 for city roadwork
- $42,828 for five subdivision developments
- 405,000 for the Science North storage battery project
- $35,258 several small contributions (overhead/underground services/system betterments)

Table 8 – 2020 Test Year vs. 2019 Bridge Year Projection Gross Assets by Account

Contributions					
1995	Contributions & Grants		-	-	-
2440	Deferred Revenue[5]		- 6,761,089	- 7,843,189	- 1,082,100
Subtotal - Contributions			**- 6,761,089**	**- 7,843,189**	**- 1,082,100**

Deferred revenue variance $1,082,100

The variance relates to the following:

- $500,000 for commercial developments (based on history)
- $275,000 for city roadwork (based on history)
- $225,000 for subdivision developments (based on history)
- $82,100 several small contributions (overhead/underground services/system betterments) (based on history)

2-Staff-7 Fixed Asset Continuity

Question:

Ref 1: Chapter 2 Appendices – 2 – BA

Ref 2: Chapter 2 Appendices – 2 – AA

In 2019 and 2020, Sudbury Hydro showed the exact same amount for disposals in the fixed asset continuity schedule.

a) Please confirm that the disposal amounts are correct.

Sudbury Hydro has shown building costs under General Plant in reference 2 but there is only building costs recorded in Account 1808, which is under the Distribution Plant category.

b) Please confirm if there are building costs other than Sudbury Hydro's office building in Account 1808. If so, please explain why Sudbury Hydro has not used Account 1908 for general plant building costs to be consistent with how capital expenditures are reported in reference 2.

Response:

a) The disposal amounts are correct. GSHi has updated 2019 disposals for 2019 actuals. GSHi used historical experiences to project 2020 disposals.

b) GSHi confirms that there are building costs other than Sudbury Hydro's office building in Account 1808. GSHi has not historically separated general plant building from distribution system buildings and have therefore used Account 1808 for all building assets. However, since transitioning to IFRS GSHi has the details needed to classify general plant building into Account 1908. As a result of this interrogatory, GSHi has now reclassified general plant building assets in Account 1908. GSHi has adjusted the 2019 Opening Balances in Account 1808 and 1908 for the Bridge Year, and has followed this through to the 2020 Test Year. Please see Attachment 1 to this response. This adjustment has also been reflected in the Chapter 2 Appendices Live Model included with this submission.

Attachment 1 (of 1):

2-Staff-7 Attachment 1: Fixed Asset Continuity Schedule

File Number:	EB-2019-0037
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2019**

			Cost				Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Smart Grid Adj**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Smart Grid Adj**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 3,218,379	$ -			$ 3,218,379	-$ 3,172,319	-$ 30,490			-$ 3,202,810	$ 15,569
CEC	1612	Land Rights (Formally known as Account 1906)	$ 58,790	$ 6,524			$ 65,314	$ -				$ -	$ 65,314
N/A	1805	Land	$ 940,079	$ -			$ 940,079	$ -				$ -	$ 940,079
47	1808	Buildings	$ 2,954,574	$ 33,068			$ 2,987,642	-$ 1,719,546	-$ 62,057			-$ 1,781,603	$ 1,206,039
47	1820	Distribution Station Equipment <50 kV	$ 20,781,600	$ 1,988,015	-$ 354,980		$ 22,414,635	-$ 12,108,882	-$ 430,251	$ 345,190		-$ 12,193,943	$ 10,220,692
47	1825	Storage Battery Equipment	$ -			$ 881,028	$ 881,028	$ -	-$ 44,051		-$ 65,937	-$ 109,988	$ 771,040
47	1830	Poles, Towers & Fixtures	$ 27,215,982	$ 2,134,988	-$ 394,635		$ 28,956,335	-$ 10,530,145	-$ 574,888	$ 223,042		-$ 10,881,991	$ 18,074,344
47	1835	Overhead Conductors & Devices	$ 40,769,583	$ 944,617	-$ 854,127		$ 40,860,073	-$ 27,485,809	-$ 537,970	$ 799,779		-$ 27,224,001	$ 13,636,071
47	1840	Underground Conduit	$ 24,457,747	$ 433,360	-$ 12,461		$ 24,878,646	-$ 13,670,387	-$ 306,024	$ 9,811		-$ 13,966,600	$ 10,912,046
47	1845	Underground Conductors & Devices	$ 16,711,738	$ 677,149	-$ 93,442		$ 17,295,444	-$ 10,603,462	-$ 276,078	$ 61,501		-$ 10,818,039	$ 6,477,405
47	1850	Line Transformers	$ 30,251,814	$ 1,742,133	-$ 871,628	$ 48,224	$ 31,170,543	-$ 15,894,266	-$ 514,767	$ 585,212	-$ 5,425	-$ 15,829,246	$ 15,341,297
47	1855	Services (Overhead & Underground)	$ 16,347,433	$ 399,878	-$ 98,216		$ 16,649,096	-$ 7,573,633	-$ 310,715	$ 56,239		-$ 7,828,109	$ 8,820,987
47	1860	Meters	$ 9,026,088	$ 148,145			$ 9,174,233	-$ 4,956,054	-$ 517,651			-$ 5,473,705	$ 3,700,528
47	1908	Buildings & Fixtures	$ 11,731,379	$ 242,329			$ 11,973,707	-$ 4,955,683	-$ 347,134			-$ 5,302,818	$ 6,670,890
8	1915	Office Furniture & Equipment (10 years)	$ 90,616				$ 90,616	-$ 63,602	-$ 4,630			-$ 68,232	$ 22,384
10	1920	Computer Equipment - Hardware	$ 762,482				$ 762,482	-$ 744,499	-$ 10,733			-$ 755,233	$ 7,250
10	1930	Transportation Equipment	$ 6,649,937	$ 144,362	-$ 181,016		$ 6,613,283	-$ 4,398,462	-$ 433,925	$ 181,016		-$ 4,651,370	$ 1,961,913
8	1940	Tools, Shop & Garage Equipment	$ 2,535,629	$ 81,475			$ 2,617,104	-$ 2,045,113	-$ 96,629			-$ 2,141,742	$ 475,362
8	1955	Communications Equipment	$ 2,407,599	$ -			$ 2,407,599	-$ 1,821,128	-$ 91,012			-$ 1,912,140	$ 495,460
47	1980	System Supervisor Equipment	$ 2,305,222	$ 264,515		$ 29,720	$ 2,599,457	-$ 1,511,404	-$ 63,370		-$ 2,122	-$ 1,576,896	$ 1,022,561
47	1985	Miscellaneous Fixed Assets	$ 45,835	$ 1,833			$ 47,668	-$ 42,303	-$ 463			-$ 42,766	$ 4,902
47	2440	Deferred Revenue[5]	-$ 5,062,611	-$ 1,698,479			-$ 6,761,089	$ 331,231	$ 198,360			$ 529,591	-$ 6,231,498
	1330	WIP - Capital Inventory	$ 1,316,431	$ 89,473			$ 1,405,904	$ -				$ -	$ 1,405,904
	2055	Work in Process	$ 911,100	$ 567,671	-$ 793,279		$ 685,492	$ -				$ -	$ 685,492
		Sub-Total	**$ 216,427,426**	**$ 8,201,056**	**-$ 3,653,785**	**$ 958,972**	**$ 221,933,670**	-$ 122,965,465	-$ 4,454,481	$ 2,261,790	-$ 73,485	**-$ 125,231,641**	**$ 96,702,029**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	(129,739.00)				-$ 129,739	$ 129,739				$ 129,739	$ -
		Total PP&E	**$ 216,297,687**	**$ 8,201,056**	**-$ 3,653,785**	**$ 958,972**	**$ 221,803,931**	**-$ 122,835,726**	**-$ 4,454,481**	**$ 2,261,790**	**-$ 73,485**	**-$ 125,101,902**	**$ 96,702,029**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**-$ 4,454,481**				
		Net of WIP and Cap Inv 1330 and 2055	**$ 214,070,156**	**$ 7,543,913**			**$ 219,712,535**						**$ 94,610,633**

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 433,925
8		Stores Equipment	Stores Equipment	-$ 96,629
	2440	Less Deferred Revenue included in 4245 Other Revenue		$ 198,360
			Net Depreciation	-$ 4,122,287

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Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: MIFRS
Year: 2020

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 3,218,379	$ 580,000		$ 3,798,379	-$ 3,202,810	-$ 72,135		-$ 3,274,945	$ 523,434
CEC	1612	Land Rights (Formally known as Account 1906)	$ 65,314			$ 65,314	$ -			$ -	$ 65,314
N/A	1805	Land	$ 940,079			$ 940,079	$ -			$ -	$ 940,079
47	1808	Buildings	$ 2,987,642			$ 2,987,642	-$ 1,781,603	-$ 62,718		-$ 1,844,320	$ 1,143,321
47	1820	Distribution Station Equipment <50 kV	$ 22,414,635	$ 2,783,837	-$ 330,867	$ 24,867,605	-$ 12,193,943	-$ 469,779	$ 269,017	-$ 12,394,705	$ 12,472,900
47	1825	Storage Battery Equipment	$ 881,028			$ 881,028	-$ 109,988	-$ 44,051		-$ 154,040	$ 726,988
47	1830	Poles, Towers & Fixtures	$ 28,956,335	$ 1,525,594	-$ 501,865	$ 29,980,064	-$ 10,881,991	-$ 620,695	$ 408,055	-$ 11,094,632	$ 18,885,433
47	1835	Overhead Conductors & Devices	$ 40,860,073	$ 1,550,337	-$ 888,305	$ 41,522,105	-$ 27,224,001	-$ 578,973	$ 722,255	-$ 27,080,719	$ 14,441,386
47	1840	Underground Conduit	$ 24,878,646	$ 778,584	-$ 28,476	$ 25,628,754	-$ 13,966,600	-$ 318,129	$ 23,156	-$ 14,261,573	$ 11,367,181
47	1845	Underground Conductors & Devices	$ 17,295,444	$ 754,468	-$ 186,313	$ 17,863,599	-$ 10,818,039	-$ 283,988	$ 151,483	-$ 10,950,543	$ 6,913,055
47	1850	Line Transformers	$ 31,170,543	$ 998,783	-$ 935,407	$ 31,233,920	-$ 15,829,246	-$ 548,065	$ 760,557	-$ 15,616,754	$ 15,617,166
47	1855	Services (Overhead & Underground)	$ 16,649,096	$ 547,642	-$ 149,699	$ 17,047,038	-$ 7,828,109	-$ 322,507	$ 121,719	-$ 8,028,897	$ 9,018,142
47	1860	Meters	$ 9,174,233	$ 174,862		$ 9,349,095	-$ 5,473,705	-$ 523,884		-$ 5,997,589	$ 3,351,506
47	1908	Buildings & Fixtures	$ 11,973,707	$ 500,000		$ 12,473,707	-$ 5,302,818	-$ 361,981		-$ 5,664,799	$ 6,808,909
8	1915	Office Furniture & Equipment (10 years)	$ 90,616			$ 90,616	-$ 68,232	-$ 4,630		-$ 72,862	$ 17,754
10	1920	Computer Equipment - Hardware	$ 762,482			$ 762,482	-$ 755,233	-$ 4,833		-$ 760,066	$ 2,416
10	1930	Transportation Equipment	$ 6,613,283	$ 450,000	-$ 375,000	$ 6,688,283	-$ 4,651,370	-$ 400,461	$ 375,000	-$ 4,676,831	$ 2,011,452
8	1940	Tools, Shop & Garage Equipment	$ 2,617,104	$ 85,000		$ 2,702,104	-$ 2,141,742	-$ 95,297		-$ 2,237,039	$ 465,065
8	1955	Communications Equipment	$ 2,407,599			$ 2,407,599	-$ 1,912,140	-$ 90,021		-$ 2,002,161	$ 405,439
47	1980	System Supervisor Equipment	$ 2,599,457	$ 18,000		$ 2,617,457	-$ 1,576,896	-$ 68,938		-$ 1,645,835	$ 971,623
47	1985	Miscellaneous Fixed Assets	$ 47,668			$ 47,668	-$ 42,766	-$ 555		-$ 43,321	$ 4,347
47	2440	Deferred Revenue[5]	-$ 6,761,089	-$ 1,082,100		-$ 7,843,189	$ 529,591	$ 207,802		$ 737,393	-$ 7,105,796
	1330	WIP - Capital Inventory	$ 1,405,904			$ 1,405,904	$ -			$ -	$ 1,405,904
	2055	Work in Process	$ 685,492	$ 564,000	-$ 554,817	$ 694,675	$ -			$ -	$ 694,675
		Sub-Total	**$ 221,933,670**	**$ 10,229,007**	**-$ 3,950,749**	**$ 228,211,928**	**-$ 125,231,641**	**-$ 4,663,838**	**$ 2,831,242**	**-$ 127,064,237**	**$ 101,147,690**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	(129,739.00)			-$ 129,739	$ 129,739			$ 129,739	$ -
		Total PP&E	**$ 221,803,931**	**$ 10,229,007**	**-$ 3,950,749**	**$ 228,082,189**	**-$ 125,101,902**	**-$ 4,663,838**	**$ 2,831,242**	**-$ 126,934,498**	**$ 101,147,690**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,663,838**			
		Net of WIP and Cap Inv 1330 and 2055	**$ 219,712,535**	**$ 9,665,007**	**-$ 3,395,932**	**$ 225,981,610**					**$ 99,047,112**

CCA Class	OEB Account	Description	Less: *Fully Allocated Depreciation*	Amount
10		Transportation	Transportation	-$ 400,461
8		Stores Equipment	Stores Equipment	-$ 95,297
	2440	Less Deferred Revenue included in 4245 Other Revenue		$ 207,802
			Net Depreciation	-$ 4,375,882

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Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Notes:

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

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

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

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

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

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

2-Staff-8 Cost of Power

Question:

Ref 1: Exhibit 2 – Tab 1 – Schedule 3

Ref 2: Regulated Price Plan (RPP) Report – November 1, 2019 to October 31, 2020, October 22, 2019

To calculate the cost of power, Sudbury Hydro has used the commodity prices from the OEB's RPP Report for May 1, 2019 to April 30, 2020, issued April 17, 2019. The OEB has since issued the RPP Report for November 1, 2019 to October 31, 2020, issued October 22, 2019.

a) Please complete the attached cost of power model with the updated RPP Report.

Response:

a) The cost of power model has been updated to reflect the RPP Report issued on October 22, 2019 and has been uploaded in RESS as part of the IR response filing.

2-Staff-9 Capital Expenditures

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: Chapter 2 Appendices – 2-AB

In the two references above, Sudbury Hydro broke down the capital expenditures into the four categories: system access, system renewal, system service, and general plant.

a) Please reconcile appendices 2-AB to 2-AA by breaking down capital contributions to the same four categories.
b) Please confirm if the 2019 actual capital expenditures represents the actual incurred capital spending at the time of filing the application or is the forecasted spend for 2019 incorporating actuals at the time of filing the application. If it is the actual incurred capital spending, please provide the time-period that it represents.
c) In reference 2, Sudbury Hydro's actual net capital expenditure was on average 17.6% below the planned net capital expenditure from 2013-2019. Please explain how Sudbury Hydro has changed its capital expenditure planning since its last cost of service to provide a higher confidence level in its estimations.

Response:

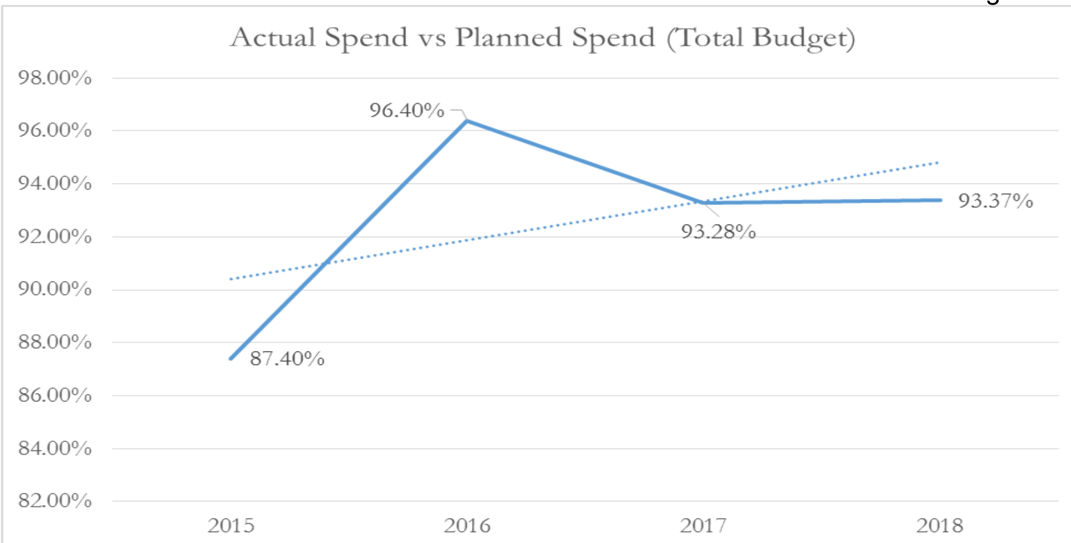
a) Please see Table 1 below for the adjustments that allocate capital contributions in 2-AB to each of the investment categories, thus reconciling to 2-AA.

Table 1 - Contributions in the four categories reported in 2-AA and 2-AB								
	Contributions							
	2013	2014	2015	2016	2017	2018	2019	2020
System Access	(1,108)	(779)	(1,208)	(856)	(691)	(1,196)	(990)	(1,082)
System Renewal	(129)	(68)	(25)	(13)	(31)	(22)	(299)	
System Service	(9)	(32)	(23)	(13)	(35)	(18)	(410)	
General Plant	(1)							
Total	(1,247)	(878)	(1,256)	(883)	(757)	(1,236)	(1,698)	(1,082)

Any remaining difference relates to the allocation of Miscelaneous projects shown in aggregate in Appendix 2-AA.

a) The 2019 actual capital expenditures represent the actual incurred capital spending at the time of filing the application. The time period that it represents are costs from January 1, 2019 through September 30, 2019.

b) GSHi acknowledges that its actual net capital expenditures were on average below the planned expenditure from 2013-2019. However, since its last Cost of Service (COS), GSHi has continued to work on its capital expenditure planning to improve the confidence level in its estimations. As an illustration of this improvement, the figure below shows the Actual Spend vs the Planned Spend (Total Budget) over the historical period 2015-2018 of the DSP:



During the historical period, 'Actual Spend' as compared to 'Planned Spend' has trended upward at an average of approximately 92% per year, which exceeds the corporate target (± 10% of Total Budget).

Prior to the commencement of the yearly construction cycle, the Engineering department meets with Operations, Stores and the Control Room to map the various capital projects to the projected internal staffing capabilities using its Scheduling Tool.

Further, since the last COS, staff in both the Engineering and Operations departments have continued to enhance inter-departmental communication during project design and estimation. Guided by GSHI's ISO Management System, a vital component of prospective investment estimation involves a formal 'Design and Development' review between the responsible Project Coordinator (Engineering Technologist) and an Operations Supervisor. The Project Coordinator will produce a design using the appropriate USF distribution standards and/or GSHi-approved standards. These standards are digitized inside the corporate Superion financial system which facilitates the correct selection of materials for a given design. Design verification is subsequently accomplished by the Supervisor, Engineering's review of design outputs. Finally, the prospective work order (complete with approved standards) is reviewed and approved prior to the formal 'Pre-Construction Review' meeting with the pertinent Operations department staff. This review occurs for all jobs over $50,000 to review the scope of the job prior to the release of the work order package.

Implementation of the above capital expenditure planning process(es) have contributed to the recent improvement in GSHi's ability to produce higher confidence project estimates. As a matter of course, the organization will continue to seek continuous improvement and continue to further refine the capital expenditure planning process as appropriate.

2-Staff-10 Capital Expenditures

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2 Material investments

Please answer the following interrogatories for each capital program below.

- System Access – Meter Installation
- System Access – Overhead/Underground Services
- System Renewal – Emergency Plant Replacements
- System Renewal – Major Substation Repairs
- General Plant – Tools and Equipment

a) For each of the capital programs above, there are discrepancies between the historical amounts provided in reference 1 and the associated investment document provided in reference 2; or there are no capital spending in particular historical years in reference 1. Please reconcile the amounts in reference 1 and 2 and confirm whether or not there was capital spending in reference 1.

b) For each of the capital programs above please provide the forecasting method used to forecast the test year amounts.

Response:

a)

- System Access – Meter Installation

In this capital program, with respect to Reference 1, the 2017 cost of $63,282 – a cost which is beneath GSHi’s materiality threshold of $115,000 - was rolled up into the ‘Miscellaneous’ line located beneath the calculated sub-total for the year 2017 in Appendix 2-AA.

- System Access – Overhead/Underground Services

In this capital program, with respect to Reference 1, the 2015 cost of $105,773 and the 2018 cost of $96,081 in the area of **Underground Services** - each of which are beneath GSHi's materiality threshold of $115,000 - have been rolled up into the 'Miscellaneous' line located beneath the calculated sub-total for their respective years in Appendix 2-AA.

- System Renewal – Emergency Plant Replacements

In this capital program, with respect to Reference 1, the 2015 cost of $34,677 – a cost which is beneath GSHi's materiality threshold of $115,000 - was rolled up into the 'Miscellaneous' line located beneath the calculated sub-total for the year 2015 in Appendix 2-AA.

- System Renewal – Major Substation Repairs

In this capital program, with respect to Reference 1, the 2017 cost of $33,197 and the 2018 cost of $112,098 - each of which are beneath GSHi's materiality threshold of $115,000 - have been rolled up into the 'Miscellaneous' line located beneath the calculated sub-total for their respective years in Appendix 2-AA.

- General Plant – Tools and Equipment

In this capital program, with respect to Reference 1, the 2015 cost of $69,666, the 2017 cost of $107,409 and the 2018 cost of $101,718 - each of which are beneath GSHi's materiality threshold of $115,000 - have been rolled up into the 'Miscellaneous' line located beneath the calculated sub-total for their respective years in Appendix 2-AA.

b)

- System Access – Meter Installation

These mandatory connection or upgrade projects are customer demand-driven and must be connected within a timeline prescribed by the OEB. GSHi must adhere to DSC requirements, including providing an *Offer to Connect* and a supply connection as described in Section 7.2 *Connection of New Services* in the DSC.

To forecast a 'Test Year' program cost under "Meter Installation", Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2019 inclusive are as follows:

2013 - $103,867

2014 – $117,775

2015 - $152,796

2016 – $176,067

2017– $63,282

2018 – $120,024

2019 – $147,711

Per the customer growth forecast, an appropriately-sized spending envelope is crafted to ensure sufficient funds are available to connect prospective load/REG customers expediently. The forecast cost for the 2020 capital program of $174,862 seeks to strike a balance between the average value of this grouping, which is $125,931 and the variability in program costs, where in 2016 the incurred costs were as high as $176,067 yet in 2017 incurred costs were as low as $63,282.

- System Access – Overhead/Underground Services

These mandatory connection or upgrade projects are customer demand-driven and must be connected within a timeline prescribed by the OEB. GSHi must adhere to DSC requirements, including providing an *Offer to Connect* and a supply connection as described in Section 7.2 *Connection of New Services* in the DSC.

To forecast a 'Test Year' program cost under "Overhead/Underground Services", Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2019 inclusive are as follows:

2013 – Overhead Services: $112,732; Underground Services: $90,863

2014 – Overhead Services: $138,646; Underground Services: $119,099

2015 – Overhead Services: $129,537; Underground Services: $105,773

2016 – Overhead Services: $170,919; Underground Services: $146,179

2017 – Overhead Services: $133,409; Underground Services: $117,965

2018 – Overhead Services: $140,168; Underground Services: $96,081

2019 – Overhead Services: $181,239; Underground Services: $115,584

Projected spending is dependent on new customer load/REG connections requests. Lower (or negative) growth than forecast will result in less spending required to connect prospective customers to the distribution system. Similarly, higher growth than expected will require increased spending in excess of the budgeted amount.

The 2020 capital program forecast cost of $150,500 in Overhead Services and $122,400 in Underground Services are both in line with the average historical value of these groupings, which are $143,807 for Overhead Services and $113,077 for Underground Services.

- System Renewal – Emergency Plant Replacements

Replacing defective distribution assets is almost always required the moment a failure occurs. Occasionally, it may be possible to feed the same customers by closing existing bus-breaks and supplying electricity from an adjacent feeder. Otherwise, the defective asset(s) must be replaced. This service restoration work is a top priority.

To forecast a ‘Test Year’ program cost under “Emergency Plant Replacements”, Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2019 inclusive are as follows:

2013 - $23,965

2014 – $279,054

2015 - $34,677

2016 – $234,114

2017– $509,595

2018 – $577,726
2019 – $46,633

This prospective investment will help to ensure that there are sufficient funds available to procure needed equipment to enact important repairs to failed distribution system assets (not including transformers). Customers have repeatedly demonstrated that they expect high service reliability and are not tolerant of longer duration outages. By ensuring high availability of construction materials, crews can quickly make repairs to get customers back on in the event of an unplanned service disruption.

The forecast cost for the 2020 capital program of $326,547 seeks to strike a balance between the average value of this grouping, which is $243,680 and the large variability in program costs, where in 2018 the incurred costs were as high as $577,726 yet in 2015 incurred costs were as low as $34,677.

- System Renewal – Major Substation Repairs

To forecast a ‘Test Year’ program cost under “Major Substation Repairs”, Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2019 inclusive are as follows:

2013 - $332,236

2014 – $211,887

2015 - $302,638

2016 – $116,135

2017– $33,197

2018 – $112,098

2019 – $131,077

The forecast cost for the 2020 capital program of $180,000 is in line with the average value of this grouping, which is $177,038.

- General Plant – Tools and Equipment

Tool and equipment expenditures are prioritized and paced on an as-needed basis based on input from GSHi employees. Significant input is received from the Garage Mechanics, P&C Dept, Engineering Dept and line personnel, among other field staff. Failure to procure suitable new and/or refurbished tools may hinder GSHi's ability to continue to provide excellent electricity service delivery to its customers.

To forecast a 'Test Year' program cost under "Tools and Equipment", Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2019 inclusive are as follows:

2013 - $77,762

2014 – $85,032

2015 - $69,666

2016 – $116,135

2017– $107,409

2018 – $101,718

2019 – $81,475

The forecast cost for the 2020 capital program of $85,000 is in line with the average historical value of this grouping, which is $91,313.

2-Staff-11 System Access - Road Authority Work

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.4 System Access – Road Authority Work

Sudbury Hydro provided historical road authority work expenditures in reference 1 and 2.

a) Please confirm whether reference 1 or reference 2 is correct for the 2015 actual capital expenditure for road authority work.
b) Please provide the historical contributions from the road authority for each year between 2013 and 2019.
c) Sudbury Hydro stated in reference 2 that it meets with road authorities at least once a year. Please provide the latest list of relocations discussed at the last meeting. The list should include the project name, the year of the project, the number of kilometers of line to be relocated, the number of circuits on the line, and voltage level.
d) Please provide a list of historical relocation project between 2013 and 2019. The list should include the project name, the number of kilometers of line relocated, the number of circuits on the line, and voltage level.
e) Sudbury Hydro stated in reference 2 that if the City of Greater Sudbury requests the relocation work, the costs are shared evenly between the City of Greater Sudbury and Sudbury Hydro. Does this mean that Sudbury Hydro has a written agreement with the city? If so, please provide the agreement.

Response:

a) Reference 2 is correct for the 2015 actual capital expenditure for road authority work. As the cost that year was $81,302, it is not displayed in reference 1. Rather, it is rolled up in the “Miscellaneous” line located beneath the calculated sub-total for the year 2015.

b) The historical contributions from the road authority between 2013 and 2019 are as follows:

2013: $226,581
2014: $149,135
2015: $8,986
2016: $143,808
2017: $170,959
2018: $266,075
2019: $215,734

c) The table below provides the latest list of relocations discussed at the last meeting:

2019

NAME	KMS	# OF CIRCUITS	VOLTAGE
Maley / Lansing Pole Replacement	NONE	2	12,470V 120/240V
Allan Street – Coniston	NONE	2	2,400V 120/240v
William Street – Coniston	0.25	1	120/240V
Kelly Lake @ Lorne	NONE	4	44,000V 12,470V 4,160V 120/240V
Allan Street Bridge Installation	NONE	2	2,400V 120/240v

d) The tables below include historical relocation projects between 2013 and 2018. The information for 2019 is provided in response to part c).

2018

NAME	KMS	# OF CIRCUITS	VOLTAGE
Maley / Frood Pole Relocation	0.18	2	44,000V 2,400V
Elm and Big Nickel Road	0.03	2	7,200V 120/240V
Leslie Street	0.165	1	120/240V
Avalon Road	0.03	2	7,200V 120/240V
Lorne / Martindale	.07	3	12,470V 4,160V 120/240V
Maley Drive @ Falconbridge	0.355	2	12,470V 120/240V
1280 Kingsway	NONE	4	2 X 12,470V 347/600V 120/240V
William and Walter Avenue	0.08	1	4,160V
Maley Drive @ Lasalle	0.12	1	12,470v
Maley Drive @ Barrydowne	1.259	2	12,470V 7,200V

2017

NAME	KMS	# OF CIRCUITS	VOLTAGE
Kingsway Line Relocation	0.715	4	2 X 12,470V 347/600V 120/240V
Notre Dame (Maley Project)	0.07	1	120/240v
Kingsway Line Relocation	NONE	5	2 X 12,470V 347/600V 120/208V 120/240V
Kelly Lake Road Pole Relocation	NONE	3	44,000V 12,470V 120/240V
Second Avenue City Road Relocation	0.1	2	2 X 7200V

2016

NAME	KMS	# OF CIRCUITS	VOLTAGE
Keast Drive Pole Relocation	NONE	2	7,200V 120/240V
Lorne Street – City Road Widening	0.1	1	2,400V
319 Moonlight Avenue	NONE	1	120/240V
Balsam Street	0.66	2	4,160V 120/240V
Lorne Street Road Widening	0.63	4	12,470V 4,160V 120/208V 120/240V
Queen Street West Nipissing	NONE	1	12,470V
Long Lake Road	NONE	3	3 X 12,470V
Lorne Street	0.46	4	44,000V 12,470V 4,160V 120/240V

2015

NAME	KMS	# OF CIRCUITS	VOLTAGE
NONE			

2014

NAME	KMS	# OF CIRCUITS	VOLTAGE
Madison Culvert	0.393	3	3 x 12,470V
Barrydowne / Shoppers Drugmart	NONE	4	44,000V 2 X 12,470V 120/240V
Second Avenue Road Widening	0.718	4	2 X 12,470V 7200V 347/600V 120/240V
Barrydowne @ Lasalle Road Widening	0.847	3	44,000V

			12,470V 7200V 124/240V

2013

NAME	KMS	# OF CIRCUITS	VOLTAGE
Bouchard @ Marcel	NONE	0	NONE (STUB POLE)
Regent Street Road Widening	0.618	3	12,470V 7,200V 120/240V

e) Sudbury Hydro does not have a formal, written cost-sharing agreement between itself and the City of Greater Sudbury. The arrangement between ourselves and our shareholder is informal and is based on mutual trust and a strong working relationship.

2-Staff-12 System Renewal - Failed Transformers

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.6 System Renewal – Failed Transformers

Sudbury Hydro stated in reference 2 that distribution transformers are replaced on a reactive basis.

a) Please provide the number of transformers replaced each year between 2013 and 2019.

b) Please provide the forecasting methodology Sudbury Hydro used for the 2019 and 2020 forecast.

Response:

a) The table below provides data on the number of transformers replaced each year beginning in 2013 and continuing through 2019 under the "Failed Transformers" program.

YEAR	TOTAL FAILED TRANSFORMERS REMOVED FROM SERVICE
2013	39
2014	37
2015	70
2016	60
2017	39
2018	79
2019	39

b) To forecast both a 2019 and 2020 program cost under “Failed Transformers”, Sudbury Hydro looked back at its historical costs dating to 2013. The program costs for the years 2013 through 2018 inclusive are as follows:

2013 - $207,884

2014 – $173,492

2015 - $552,325

2016 – $438,522

2017– $230,949

2018 – $533,204

The forecast cost for the 2019 and 2020 capital program of $350,000 is in line with the average value of this grouping, which is $355,729.

2-Staff-13 System Renewal - Battery Bank Replacement

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.8 System Renewal – Battery Bank Replacement

Sudbury Hydro stated that the Battery Bank Replacement expenditures were previously embedded in major substation repairs.

a) Please provide the historical spending on Battery Bank Replacement for the years 2013 to 2019.
b) Please provide the asset condition assessment of battery banks.

Response:

a) Historical spending on battery bank replacements for the years 2013 to 2019 is as follows:

   2013: $0
   2014: $0
   2015: $0
   2016: $0
   2017: $0
   2018: $91,119
   2019: $55,295

b) There is no formal, documented condition assessment for substation battery banks. Replacements are driven by battery load bank testing, age, visual inspections and the ability to provide adequate, reliable power in the event of a loss of supply at the substation.

   Major Station Maintenance activities are scheduled on a four-year cycle. During maintenance, crews will test and assess the ability of the battery bank(s) to provide backup power in the event they are needed to provide power to micro-processor-based protection relays. Depending on these test results, a decision to defer replacement of the battery bank until the next cycle can occur.

2-Staff-14 System Betterment

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.9 System Betterment

Ref 3: Chapter 2 Appendices – 2-JA

Sudbury Hydro stated in reference 2 that implementation of this investment will reduce future OM&A costs. However, in reference 3, Sudbury Hydro is asking for a 15.8% increase in OM&A from last year.

a) Please provide the quantitative analysis of OM&A savings by the continuation of this program.
b) Please provide the forecasting methodology Sudbury Hydro used for the 2019 and 2020 forecast.

Response:

a) It is not possible to quantitatively determine the impact of capital investments on future O&M expenditures; however, qualitatively, investments into *System Renewal* in particular are generally expected to result in a decrease in future O&M expenditure, at a rate lower than it would otherwise trend, because paced, continuous replacement of older-vintage assets with new assets will help to reduce upward pressure on O&M expenditures as there will be fewer equipment failures and reduced expenditures as it relates to unplanned emergency repairs.

b) To forecast a yearly 2019 and 2020 program cost under "*System Betterment*", Sudbury Hydro considered its historical costs dating to 2013. The program costs for the years 2013 through 2018 inclusive are as follows:

2013 - $452,844

2014 – $252,883

2015 - $756,753

2016 – $531,897

2017– $978,438

2018 – $474,468

The forecast cost for the 2019 and 2020 capital programs of $574,555 per year seeks to strike a balance between the average value of this grouping, which is $574,547 and the large variability in program costs, where in 2017 the incurred costs were as high as $978,438 yet in 2013 incurred costs were as low as $252,883.

2-Staff-15 General Plant - Vehicles

Question:

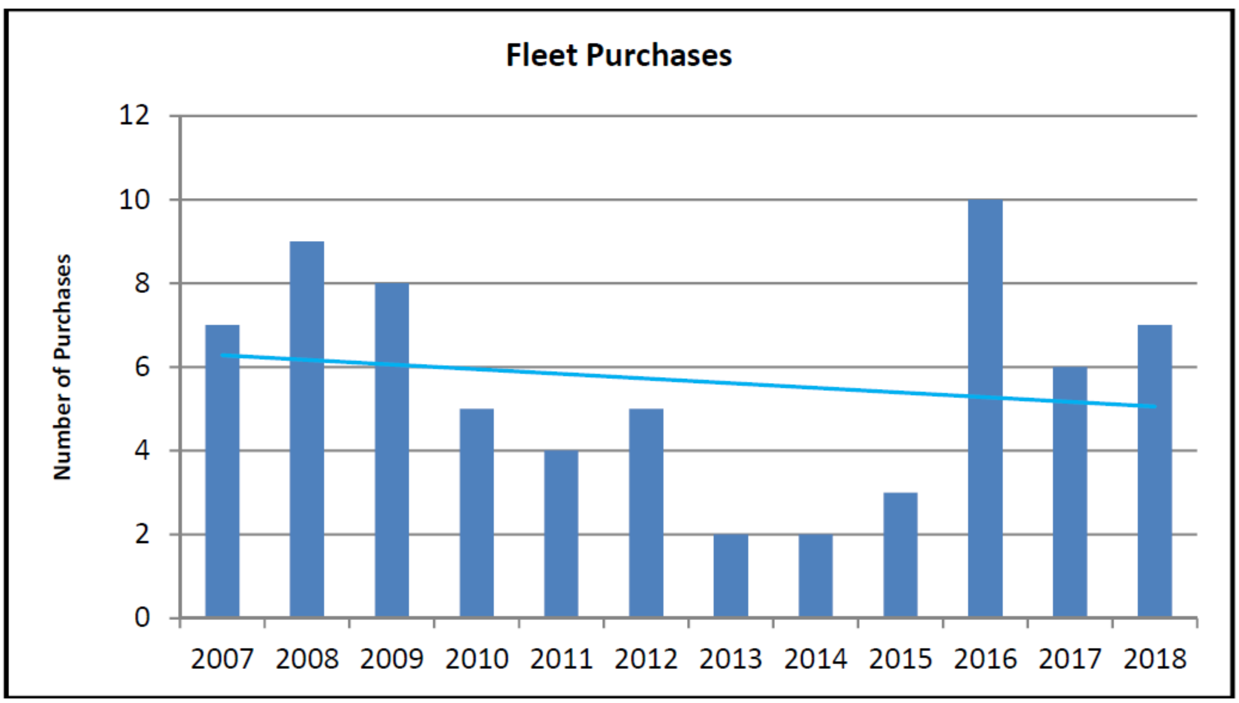
Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.10 General Plant - Vehicles

a) Please provide the type and number of vehicles purchased each historical year between 2013 and 2019.
b) Has Sudbury Hydro compared the cost of leasing a vehicle to purchasing? If so, please provide the comparison. If not, why not?
c) What would be the typical monthly leasing cost and terms of the vehicles proposed in this application?
d) How does Sudbury Hydro dispose of the old vehicles?

Response:

a) The figure below shows the number of vehicles purchased between 2007 and 2018. In 2019, four vehicles were purchased.



For each historical year between 2013 and 2019, the type of vehicle purchased is as follows:

	Type of Vehicle Purchased
2013	International 7400 Double Bucket Truck (x1) Ford Explorer (x1)
2014	Freightliner Step Van (x1) Ford F150 Pickup Truck (x1)
2015	Trailer (x1) Ford F250 Pickup Truck (x1) Ford Explorer (x1)
2016	Trailer (x2) Dodge Ram Pickup Truck (x2) Freightliner FM2 (x2) Dodge Journey Ford F150 Pickup Truck (x2) Ford Bucket Truck
2017	Chevy Silverado Pickup Truck (x4) Freightliner FM2 (x1) Skylift Backyard Machine
2018	Trailer (x2) Chevy 1500 Pickup Truck (x2) Toyota Carolla (x1) Chevy Silverado Pickup Truck (x2)
2019	Chevy Silverado Pickup Truck (x2) GMC Sierra Pickup Truck (x2)

b) For many of the smaller vehicles in the Sudbury Hydro-owned fleet, leasing is not a viable option. The heavy use of these vehicles in various construction-related field activities is such that it would be extremely difficult to return these vehicles to the vendor in an acceptable physical condition. Further, Sudbury Hydro normally undertakes various customizations to its vehicles to outfit them with, for example, radios/communications systems, signaling beacons, etc that would be expensive and tedious to re-do if the fleet vehicles continuously “turned-over” based on leasing terms.

For its larger fleet assets, such as bucket trucks, Sudbury Hydro has recently begun to explore the business case for leasing versus outright purchase and will incorporate its findings into its procurement process moving forward.

c) The typical monthly leasing cost and terms of the vehicles proposed in this application are shown in the table below:

Vehicle Description	Flagged for Action Year	Estimated Leasing Cost ($) based on a 5 yr term 5% OAC
#38 1996 Int. Telelect RBD	2020	447,537.57
#66 2011 Freightliner FM2	2021	349,270.80
#26 1989 IHC Bucket Truck 65'	2022	540,806.40
#61 2003 Freightliner SB	2023	495,739.20
#45 2007 Freightliner FM2	2024	495,739.20
#85 2012 Freightliner FM2	2025	495,739.20
#77 2011 Freightliner FM2	2026	366,171.00
#29 Toyota Forklift	2026	135,201.60

d) Depending on the make, vehicles are disposed of in different ways at Sudbury Hydro. Smaller vehicles, like a Chevy Silverado or a Ford F150, are auctioned off internally to the highest bidder. If an internal bid is not received, the vehicle is sold at the monthly Northern Auto Auction in Sudbury. For larger vehicles, such as double bucket trucks, Sudbury Hydro works with manufacturer's representatives to establish a fair market value for the vehicle being disposed of. Once a fair market value has been established, the vehicle is typically sold to private buyers.

2-Staff-16 General Plant - Buildings

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Ref 2: 5.4.3.2.6.11 General Plant – Buildings

Sudbury Hydro stated that its facility is over 50 years old and requires investments in the interior bathrooms and the parking lot.

a) Please confirm whether reference 1 or reference 2 is correct for the 2017 and 2018 actual capital expenditure for building costs.
b) Please provide the specific scope of work and costs planned for each year between 2020-2024 for building refurbishment.
c) Please provide the forecasting methodology Sudbury Hydro used for the 2019 and 2020 forecast.

Response:

a) Reference 2 is correct for the 2017 and 2018 actual capital expenditure for building costs.

With respect to Reference 1, the 2017 cost of $101,852 and the 2018 cost of $21,465 - each of which are beneath GSHi's materiality threshold of $115,000 - have been rolled up into the 'Miscellaneous' line located beneath the calculated sub-total for their respective years in Appendix 2-AA.

b) Given the age of the facility at over 50 years old, GSHi needs investment to refurbish its interior bathrooms, which among other things have experienced repeated flooding episodes over the years. Walls will be repainted and worn tile replaced for a revitalized and consistent look throughout the facility. Additionally, the main staff parking lot requires extensive work to properly grade and resurface the travelled area. Health and Safety hazards have been identified as a result of the current state of this parking area and this investment is required to alleviate the identified deficiencies and make it safe for everybody to use.

Proposed investment under '*Buildings'* is a smaller, albeit important part of the capital expenditure plan, where at this time a yearly specific scope of work is not defined. Every year, spending is required to refurbish GSHi's main office building while staying in compliance with prescribed *Standards* and *Regulations.* Other sources of spending arise as safety and/or employee productivity issues are brought to the fore and must be addressed expediently. The capital costs which GSHi anticipates to incur from the years 2020 through 2024 are shown in the table below:

Year	Budget
2020	300,000
2021	306,000
2022	312,120
2023	318,362
2024	324,730

c) To forecast a yearly 2019 and 2020 program cost under "*Buildings*", Sudbury Hydro considered its historical costs dating to 2013. The program costs for the years 2013 through 2018 inclusive are as follows:

2013 - $176,906

2014 – $1,364,323

2015 - $1,312,438

2016 – $1,342,565

2017– $101,852

2018 – $21,465

Yearly investment requirements are partially based on historical needs and seek to incorporate building requirements as prescribed through codes, standards and regulations. Any codes, standards or regulations that may emerge and that require GSHi to incur costs to meet the requirements will be considered at the appropriate time. Other planned investment(s) in the yearly capital expenditure plan may need to be deferred accordingly.

The years 2014 through 2016 saw GSHi incurring significant costs, especially in comparison to 2013, 2017 and 2018, as projects related to major building energy retrofits and compliance with the *Accessibility for Ontarians with Disabilities Act, 2005* were completed. With these projects completed, future costs relating to *'Buildings'* are expected to be reduced significantly.

The capital forecast cost of $465,000 (2019) and $300,000 (2020) seeks to strike a balance between the average value of this grouping, which is $719,924 and the large variability in program costs, where in 2014 the incurred costs were as high as $1,364,323 yet in 2018 incurred costs were as low as $21,465.

2-Staff-17 Gemmell MS 11

Question:

Ref 1: 5.4.3.2.1.1 System Renewal – Gemmell MS11

Ref 2: Greater Sudbury Hydro 2019 Asset Condition Assessment, p. 45

Ref 3: 5.4.3.2.1.5 System Service – Gemmell MS11

Sudbury Hydro stated that this investment is to allow load to shift from the T2 transformer to the T1 Transformer. Gemmell MS is one for four stations that feed the Kingsway Corridor, which is an important commercial area. Gemmell MS currently has a station rating of 15/21.7MVA and a station peak load of 17.85MVA. From the asset condition assessment (ACA), Gemmell MS also has a risk index of 9.2% which is considered very low risk (0% being the least risk and 100% being the most risk).

a) Please provide the feeder designations and configuration for the four stations that supply the Kingsway Corridor (ie. Which station feeders are connected with each other and how?)
b) Please provide the latest public municipal plans for the Kingsway Corridor, the geographical location (ie. What street is it on and from where to where?), and updates on any Local Planning Appeal Tribunal decisions.
c) Please provide the oil natural air forced rating of Gemmell T2 and confirm that in the event that T1 fails now the station peak load exceeds Gemmell T2's ratings.
d) The risk based asset condition assessment shows that Gemmell T1 is ranked 10th and all higher ranked assets have a risk index of at least 57.4%. Please explain why Sudbury Hydro has chosen to replace Gemmell T1 first.
e) Please provide the costs Sudbury Hydro has incurred to date and the costs Sudbury Hydro has an obligation to meet (eg. transformer delivery).
f) Please provide the number and duration of outages for this station in the past five years.
g) Does this station have capabilities to connect a mobile unit substation?

Sudbury Hydro also stated that the construction of the double feeder egress from the upgraded Gemmell MS11 will provide additional capacity for the Kingsway Corridor. Sudbury Hydro also stated that the poles for this project are owned by Bell Canada. Sudbury Hydro further stated that the regional road authority is expected to be performing road construction work in 2020.

h) Please provide the total length of the new feeders.
i) Please provide the joint use agreement between Sudbury Hydro and Bell Canada, or the agreement on cost sharing.
j) Please provide the cost sharing calculation between Sudbury Hydro, Bell Canada, and the road authority.
k) Sudbury Hydro stated that it will be seeking consent and participation from Bell Canada. Has Bell Canada committed to this project? Who will be doing the construction of the line?

Response:

a) The four stations having an impact on the service of the Kingsway Corridor, and their feeder designations, are as follows:

Station	Station Designation	Feeder Designation
Gemmell	11T1	11F1
		11F2
		11F3
	11T2	11F5
		11F6
		11F7
		11F8
		11F9
Moonlight	18T1	18F1
		18F2
		18F3
Levert	6T1	6F1
		6F2
		6F3
		6F4

Barrydowne	16T1	16F3
		16F4
		16F5
		16F6

Of the stations and feeders listed above, the Kingsway Corridor is directly supplied by 4 radial feeders (11F7, 11F8, 18F2, 18F3) that are electrically connected via normally open switches. The 18F2 and 11F7 are separated by means of a gang operated switch, as are the 18F3 and 11F8 feeders. In the event that changes to the normal system configuration are required, the following additional feeder transfers are possible:

Adjacent Feeder Load Transfers			
Feeder A	**Transfer**	**Feeder B**	**Switching Device**
11F7	To	6F2	Pad Mounted Switchgear
11F7	To	11F1	Pole Mounted, Gang Operated Switch
11F8	To	6F4	Pole Mounted, Gang Operated Switch
11F8	To	11F5	Pole Mounted, Gang Operated Switch
11F8	To	11F6	Pole Mounted, Gang Operated Switch
18F2	To	18F1	Pole Mounted, Gang Operated Switch
18F2	To	18F3	Pole Mounted, Gang Operated Switch
18F3	To	6F3	Pad Mounted Junction Enclosure
18F3	To	18F2	Pole Mounted, Gang Operated Switch
Extended Load Transfers			
11F1	To	16F3	Pole Mounted, Gang Operated Switch
18F1	To	6F3	Pole Mounted, Gang Operated Switch

b) The ‘Kingsway Corridor’ referred to in the *Distribution System Plan* is the portion of Municipal Road #55 that stretches roughly from Lloyd St to the Highway 17 By-Pass, located in Sudbury.
The magnitude of the projected load growth along the Kingsway corridor is contingent on decisions from the Local Planning Appeal Tribunal (LPAT) of Ontario, a topic which is presently the subject of considerable debate within the community. Sudbury Hydro is not aware of any new information stemming from Local Planning Appeal Tribunal decisions since the initial filing of the *Distribution System Plan*.

c) The ONAF rating of Gemmell T2 is 13.33MVA. GSHi confirms that in the event that the Gemmell T1 fails, that the station peak load exceeds Gemmell T2’s ratings.

d) During the formulation of the 2020-2024 capital expenditure plan, Sudbury Hydro considered a number of factors to arrive at a prospective list of investments that the utility felt fairly balanced both costs and risks.
Internal capabilities of staff to execute these prospective investments is an important consideration and is a factor in determining the optimum timing for a prospective investment.
In the DSP, there are two central themes, from a capital expenditures perspective. The first theme involves the utility’s ongoing voltage conversion efforts. These conversions are intended to improve existing customer reliability levels while standardizing on 12.47kV inventory levels and reducing Stores overhead. With these investments, the utility will be proactively improving the *Health Index* scores for a number of its most important asset categories. In addition to the renewal of assets whose end of useful service life has arrived, these investments will benefit customers by enhancing the utility’s ability to provide adequate supply capacity from both a load and REG connection request perspective to the affected conversion zones. Meanwhile, from an operational perspective, GSHi is mindful that pushing forward too aggressively with the conversion may present challenges to the Control Room in ensuring acceptable levels of flexibility in the event that the system is required to be reconfigured in response to an outage event. As a result of the foregoing, the <u>earliest</u> that GSHi could reasonably forecast to set a construction date to renew the assets located at municipal substation Cressey MS3 after it had completed the mandatory make-ready work was 2021.

The second central theme in the DSP involved the utility's focus on making available adequate supply capacity to the "Kingsway Corridor" commercial area. Several proposed investments are discussed in the DSP with respect to this important growth area. Although concrete growth requirements are not yet known, GSHi desires to be in a position to respond quickly to prospective connection requests from these and other new loads that could serve as important drivers of economic activity for the region. To accomplish the goal of ensuring sufficient supply capacity exists, Gemmell MS11 was chosen to be renewed prior to Moonlight MS18. By scheduling the renewal of Moonlight MS18 to occur in 2022, the utility expects to be better-positioned to implement the optimum design considerations relevant to the eventual renewal of the substation in light of new information emerging from the LPAT process that resolves investment uncertainty for all parties involved.

With both central themes of the DSP addressed by the renewal of each of MS3, MS11 and MS18, the utility will then be well-positioned to turn its attention toward prospective renewal of the triumvirate of municipal substations MS8, MS13 and MS10. At this point, the prospective investment to replace the 8T1 at Marttila MS8 would be the most important priority project for 2023 and would not be deferrable. However, these plans may have to be re-visited/re-evaluated and are contingent on the outcome of ongoing condition monitoring of municipal substation Paris MS13.

e) As of March 4, 2020, GSHi has incurred $130,621 in costs related to this project.

To date, encumbrances/commitments made on the part of GSHi toward this project for items including the power transformer, electrical engineering and primary high-voltage switchgear are $580,475.

f) For the past five years (2019 – 2015 inclusive), the table below provides outage data specific to municipal substation Gemmell MS11, including: the number of interruptions, the number of customers interrupted and the number of customer-hours of interruption:

Station Name	Outage Cause	# of Interruptions	# of Customers Interrupted	# of Customer-Hours of Interruption
Gemmell	0	2	2,629	2,204
	1	0	0	0
	2	0	0	0
	3	0	0	0
	4	0	0	0
	5	0	0	0
	6	0	0	0
	7	0	0	0
	8	0	0	0
	9	0	0	0
	10	0	0	0

g) Unfortunately, there is insufficient space to connect a mobile unit substation on the existing property.

h) The total length of the new feeders will be approximately 1.06km.

i) Sudbury Hydro contacted Bell Canada via email on February 24, 2020 in response to this interrogatory to seek their permission to provide the joint use agreement between the two companies. On February 25, 2020, Bell Canada replied via email that "…We have been asked this by other LDC's and our response is that it not be shared as it is a confidential agreement." In consideration of Bell Canada's response, Sudbury Hydro cannot supply the requested joint use agreement in response to this interrogatory.

j) As per the response to part i) Sudbury Hydro cannot share the cost-sharing calculation between itself and Bell Canada.

k) Bell Canada has not yet committed to this project.

GSHi will be seeking Bell Canada's consent and participation in the rebuilding of the existing 12kV pole line along Gemmell St. Bell Canada owns the poles on which GSHI is currently a tenant. The expectation is that Bell Canada will insist on placing the poles after which GSHi will attend the site to transfer/install its own plant. Further, the work will need to be coordinated with the regional Road Authority, which is expected to be performing road construction work of its own in 2020.

2-Staff-18 System Renewal - Kathleen Station MS2 and Capreol MS 32

Question:

Ref 1: Chapter 2 Appendices – 2-AA

Sudbury Hydro rebuilt Kathleen Station in 2018 for $3,324,676 and Capreol Station in 2019 for $1,723,622.

a) Please provide the asset condition of each of the stations prior to the rebuild.
b) Please provide the scope of work for each of the station rebuilds.
c) Please provide the historical outages experienced at the Kathleen and Capreol stations.

Response:

a) For information regarding the asset condition of each station, please see **Attachment #1** and **Attachment #2**.

b) <u>Kathleen MS2</u> - Scope of Work

The rebuilt station has an installed capacity of 15/20 MVA and has two (2) - 44kV ingress feeders and six (6) - 12.47kV feeders egressing the station.

It contains two (2) pad-mounted 44kV load break switches with fuses and motor controller (2T1-L & 2T2-L), two (2) x 7.5/10 MVA ONAF power transformers with on-load tap changers (2T1, 2T2) and a lineup of six (6) feeders housed in arc-resistant switchgear, including incoming cells (2B1, 2B2) with breakers and a tie cell (2B1B2). The 15kV switchgear, protective relays and SCADA equipment are located inside the existing building.

Work Completed in the rebuild:

- Preliminary engineering completed by GSHi. Consulting services acquired for detailed electrical and civil design;
- Existing end-of-life equipment was removed;

- Tower in substation yard was dismantled;
- GHSi removed the existing foundations and structures. The substation yard was excavated and old material was removed;
- Disposed of existing station transformers;
- Disposal of 5kV switchgear lineup;
- Drain and dispose 5kV oil breakers;
- Excavate and demolish existing duct banks;
- New backfill and subgrade;
- New 44kV feeder ingress located in concrete-encased duct banks;
- New 44kV switchgear concrete foundations, with new S&C Electric 46kV outdoor metal clad load-break switches, with fuses and motor operators for remote control;
- New transformer foundations with oil containment pit and fire/noise barrier wall;
- Installed new 44kV to 12.47kV, 7.5/10MVA power transformers with on-load tap changers;
- Completed building restorations (including new doors), structural support, concrete treatment and maintenance;
- New leveling pad for 15kV switchgear;
- New Powell 15kV switchgear, 11 cells and station service. Switchgear incorporates a 'Main-tie-Main' configuration;
- Five (5) new 15kV distribution feeders located in concrete-encased duct banks;
- New risers and riser poles, with switches. New tie switches for operational flexibility;
- New SCADA control cabinet and equipment; and
- Two (2) new 125V DC, 75 ampere-hour batteries and charger.

<u>Capreol MS32</u> - Scope of Work

The existing 4.16kV substation was rebuilt with both 4.16kV and 12.47kV capabilities. The existing control building and property perimeter fence was re-utilized for the new station, while the interior station fence and equipment was replaced.

The electrical engineering portion of the project was completed by GSHi. GSHi procured both civil engineering and consulting services as part of the project.

The station contains a substation yard and a small portable building set on pillars. Both were utilized as part of the design of the new MS32 substation.

The new station has an installed capacity of 5/ 6.667 MVA and has one (1) - 44kV ingress feeder and three (3) - 4.16kV feeders egressing the station.

It contains one (1) pole-mounted 44kV load break switch (LBS) with fuses, one (1) x 5/6.667 MVA ONAF transformer with off-load tap changers and dual voltage secondary. A lineup of three (3) feeders housed in metal-enclosed 15kV switchgear, including an incoming cell, a metering cell and a station service transformer cell, are used for isolation. The station also contains three (3) pad mounted reclosers. The three new SEL 651R protective relays and SCADA equipment is located inside the existing control building.

Work completed in the rebuild:

- GSHi performed detailed electrical design and electrical construction on this station;
- Consulting services were procured for the civil design. A General Contractor was hired to complete the civil construction;
- Existing end-of-life equipment was removed;
- Tower in substation yard was dismantled;
- Disposed of existing station transformer;
- Disposal of 5kV switchgear lineup;
- GHSi removed the existing foundations and structures. The substation yard was excavated and old material was removed;
- Excavate and demolish existing duct banks;
- New backfill and subgrade;
- New 44kV feeder ingress located in concrete-encased duct banks;
- New 44kV pole-mounted load-break switch, with fuses;
- New transformer foundations;
- Installed a new 44kV to 4.16/12.47kV, 5/6.67MVA ONAN/ONAF power transformer;
- New pad for 15kV switchgear, as well as pre-fabricated pits for reclosers;
- New five (5) cell lineup of 15kV S&C electric switchgear with load break switches. Gear is operated at 4.16kV;

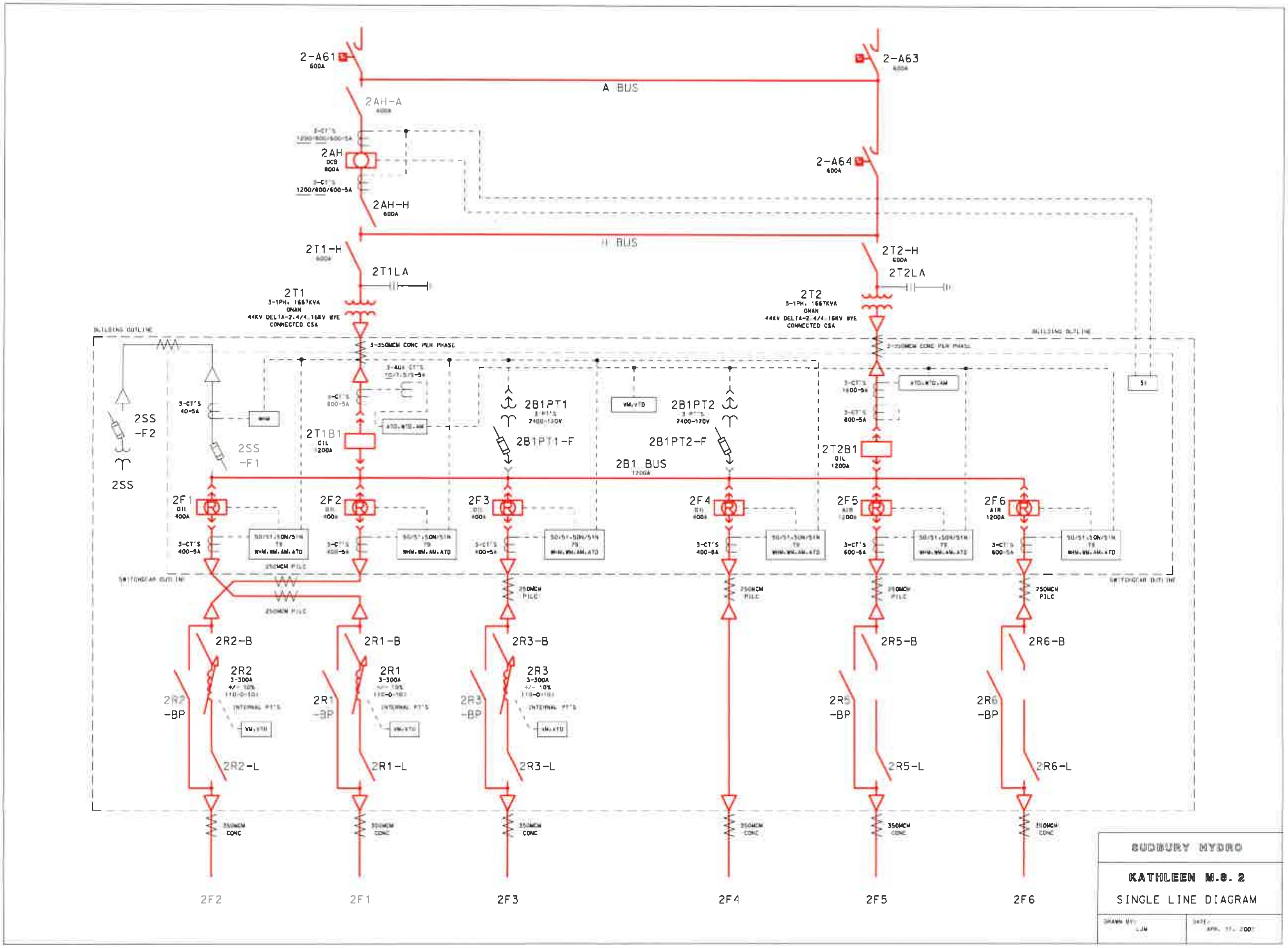
- Three (3) new G&W 15kV pad-mounted Viper reclosers with SEL 651 Relays;
- Three (3) new 15kV distribution feeders located in concrete-encased duct banks;
- New SCADA control cabinet and equipment, including DC supply; and
- New risers and riser poles, with switches.

c) Historical outages experienced at both Kathleen and Capreol substation are shown in the table below:

Station Name	Outage Cause	# of Interruptions	# of Customers Interrupted	# of Customer-Hours of Interruption
Capreol	0	0	0	0
	1	3	4,531	21,531
	2	14	21,014	25,299
	3	0	0	0
	4	0	0	0
	5	0	0	0
	6	1	1,515	3,712
	7	0	0	0
	8	0	0	0
	9	0	0	0
	10	0	0	0
Kathleen	0	1	628	126
	1	0	0	0
	2	4	1,688	2,549
	3	0	0	0
	4	2	1,551	2,042
	5	0	0	0
	6	0	0	0
	7	0	0	0
	8	0	0	0
	9	0	0	0
	10	0	0	0

Attachment 1 (of 2):

2-Staff-18 Attachment 1: Kathleen MS2



2-A61
600A
2-A63
600A
A BUS
2AH-A
2AH
2AH-H
2-A64
600A
H BUS
2T1-H
2T1LA
2T1
3-1PH, 1667KVA
ONAN
44KV DELTA-2.4/4.16KV WYE
CONNECTED CSA
2T2-H
2T2LA
2T2
3-1PH, 1667KVA
ONAN
44KV DELTA-2.4/4.16KV WYE
CONNECTED CSA
2SS
-F2
2SS
-F1
2SS
2T1B1
OIL
1200A
2B1PT1
2B1PT1-F
2B1PT2
2B1PT2-F
2B1 BUS
1200A
2T2B1
OIL
1200A
2F1
2F2
2F3
2F4
2F5
2F6
2R2-B
2R2
2R2
-BP
2R2-L
2R1-B
2R1
2R1
-BP
2R1-L
2R3-B
2R3
2R3
-BP
2R3-L
2R5-B
2R5
-BP
2R5-L
2R6-B
2R6
-BP
2R6-L
2F2
2F1
2F3
2F4
2F5
2F6
SUDBURY HYDRO
KATHLEEN M.S. 2
SINGLE LINE DIAGRAM

Costello Associates MS Inspection Sheet

Utility: Sudbury Hydro Inspected by: S Costello

Station: MS-2 Kathleen Date: June 13/08

Transformer Make: Packard Size: 3x 1667 kVA 2 Banks Imp.: 5.7 Pri. Volt: 44 Sec Volt: 2.4

S/N: 6 units OLTC: NO Manufactured: 1952

Vector Diagram

Yard

	OK	Concern	
Fence Security	✓		
Fence Grounding	✓		
Fence Foundations	✓		
Fence Attachments		✓	City
Warning Signs	✓		
Barbed Wire		✓	1 corner
Ground grid	✓		
Lighting	✓		
Locks	✓		
Crushed Stone:	✓		
Snow	✓		
Trees	✓		
Vegitation/Weeds	✓		
House Keeping	✓		

Transformer

	OK	Concern	
Conservator Oil Level			See
LTC Oil Level			Bank
Gas Detector Relay			Sheet.
Winding Temperature			
Oil Temperature			
Silica Gel			
Bushing Oil Level			
Paint Condition			
Grounding			
OLTC Padlock			
Bushing Condition			
Explosion Diaphram			
Neutral Connection			
Oil Leaks/Sweating			
PCB Free Sticker			

Building

	OK	Concern	
Grounding	✓		
Paint	✓		
Roof		✓	Leak
Windows		✓	Very old 1-pane
Doors	✓		
Structure			
Warning Signs	✓		
Security	✓		
Station Power			
Sump Pump			
Eye Wash	✓		
Lights	✓		
Building Temperature	✓		

Switchgear/Structures

	OK	Concern	
Grounding	✓		
Structure	✓		
Height Clearances		✓	
Porcelain Arrestors	✓		
Pin-type Insulators	✓		
Load Break Switches	✓		
Gradient Control Mats		✓	In progress
Station Service Tx	✓		
Recloser Op Counters			na
Recloser Target Reset			
Switchgear Pilot Lights	✓		

Comments: City fence coupled to station fence. Radial 44kV Feed. Lights over open 4kV bus work. Low clearances inside building. Mini-oil circuit breakers in 5kV gear. Very old 5kV equipment.

Utility: Sudbury Hydro Inspected by: S. Costello

Station: MS-2 Kathleen Date: June 13/08

Power Transformers / Regulators

	Bank 1			Bank 2			Spare
Check if there is a concern	**TX 1**	**TX 2**	**TX 3**	**TX 1**	**TX 2**	**TX 3**	
Identify the transformer ->	R	W	B	R	W	B	
Grounding	☐	☐	☐	☐	☐	☐	☐
Age	☑	☑	☑	☑	☑	☑	☐
Clearances	☐	☐	☐	☐	☐	☐	☐
Condensation in explosion glass	☐	☐	☐	☐	☐	☐	☐
Containment	☐	☐	☐	☐	☐	☐	☐
Rust	☐	☐	☐	☐	☐	☐	☐
Oil leakage / sweating	☑	☑	☑	☑	☐	☐	☐
Cracked bushings	☐	☑	☐	☐	☐	☐	☐
Arrestors	☐	☐	☐	☐	☐	☐	☐
Bushings	☑	☑	☑	☑	☑	☑	☐
Temperature devices	☐	☐	☐	☐	☐	☐	☐
Tap changers	☐	☐	☐	☐	☐	☐	☐
PCB > 50 ppm historically	☐	☐	☐	☐	☐	☐	☐
PCB last reading							
Year installed	–	1952	–	–	1952	–	
Engineer Life Expectancy Report							
Number of faults since 1986							

Explanation of hazardous situations and solutions:

No breathers. Poor paint condition. No shutoff valves on Rads.
Seppage on bushings.
Low interfacial tension on all transformers. Gas accumulation consistent with age.

Costello Associates

Substation Risk Assessment Form

Station MS- 2 Kathleen Year Built 1952

Section 1: Public Safety – conditions that impact public safety at the station:

Area of Concern	Check		
	1	2	3
Perimeter Security	✓		
Fence Grounding and Bonding	✓		
Station Yard	✓		
Station Building	✓		
Station Setting – Proximity		✓	
Station Setting - Encroachments	✓		
Overall public safety condition	✓		

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

School

Overall Public Safety Risk Rating	Blue	Purple	Yellow	Orange	Red
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
		✓			

Section 2: Worker Safety – conditions that impact worker safety at the station:

Area of Concern	Check		
	1	2	3
Grounding and Bonding	✓		
Safe limits of approach		✓	
Working clearances			✓
Switching access difficult	✓		
Multiple sources of voltage	✓		
Porcelain		✓	
Operational Issues			✓
Maintenance Issues		✓	
Overall worker safety condition			✓

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

Maintenance issues that can be quickly rectified may be eliminated from risk assessment.

Overall Worker Safety Risk Rating	Blue	Purple	Yellow	Orange	Red
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

Inspected by: SC Date: June 13/08

Costello Associates

Substation Risk Assessment Form

Section 3: Risks of Major Equipment Failure

A. Condition of Equipment

Area of Concern	Check		
	1	2	3
Power Transformers			✓
High-side switchgear			✓
Distribution-side switchgear			✓
Protection and Control Equipment			✓
Underground cables	✓		
Structures		✓	
Overall equipment condition			✓

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

B. Factors that may impact the consequences of major equipment failure

Concern	Impact of Consequence		
	L	M	H
Station setting – proximity	More than 100m	Between 100m and 10m	10m or less
Station setting – watercourses	None	Storm sewers/drains	Open water
Lack of backup supply	≤2 hours switching	Between 2 – 24h outage	No backup
Critical loads (hospitals etc)	None	With generators	No generators
Grounding and bonding	Today's code	Some deficiencies	Poor
Oil containment	Yes	Partial	None
Explosion barriers	Yes	Partial	None
Fire fighting capability	Hydrants	Storage Tanks	None
Presence of PCB's	None	Storage Only	In-service
Overall equipment condition	**L**	**M**	**H**

C. Based on the equipment condition and consequences, state the risk rating for a major equipment failure:

Overall Failure Risk Rating	Blue	Purple	Yellow	Orange	Red
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

Section 4: Overall Substation Risk Assessment

Station Risk Assessment	Blue	Purple	Yellow	Orange	Red
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

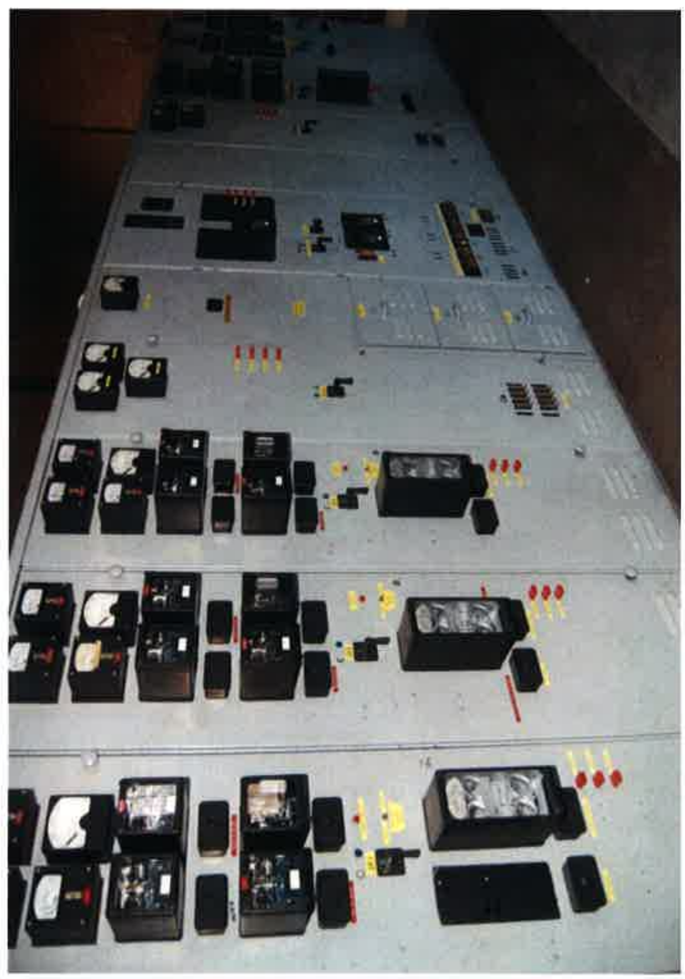
Comments: Age of transformers, switchgear, + relays. Mini-OCB's indoors are concern for injury, fire in case of violent failure.

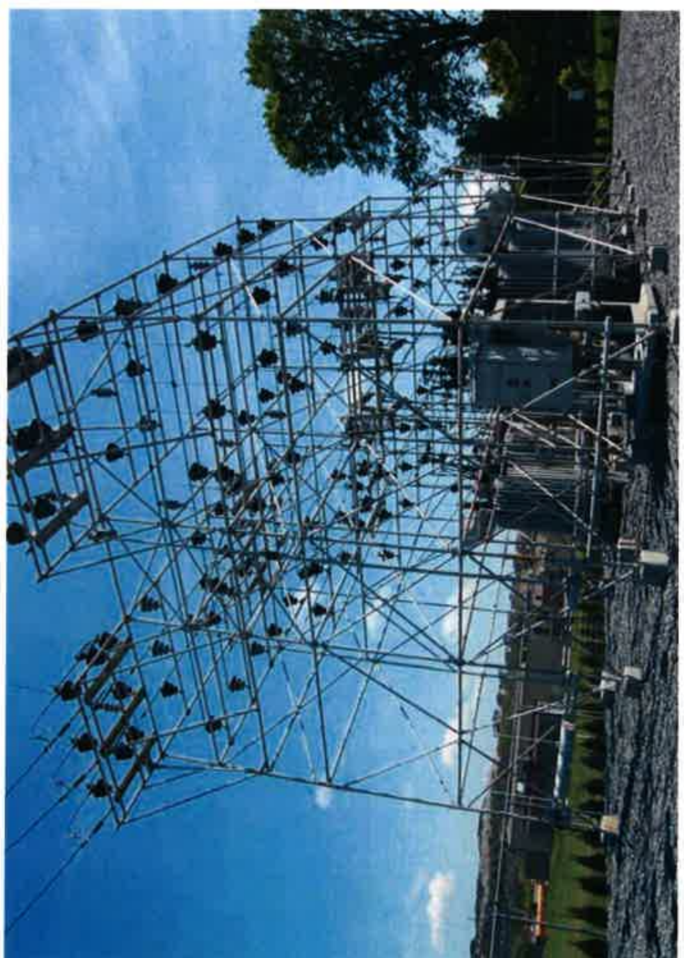
Inspected by: S Costello

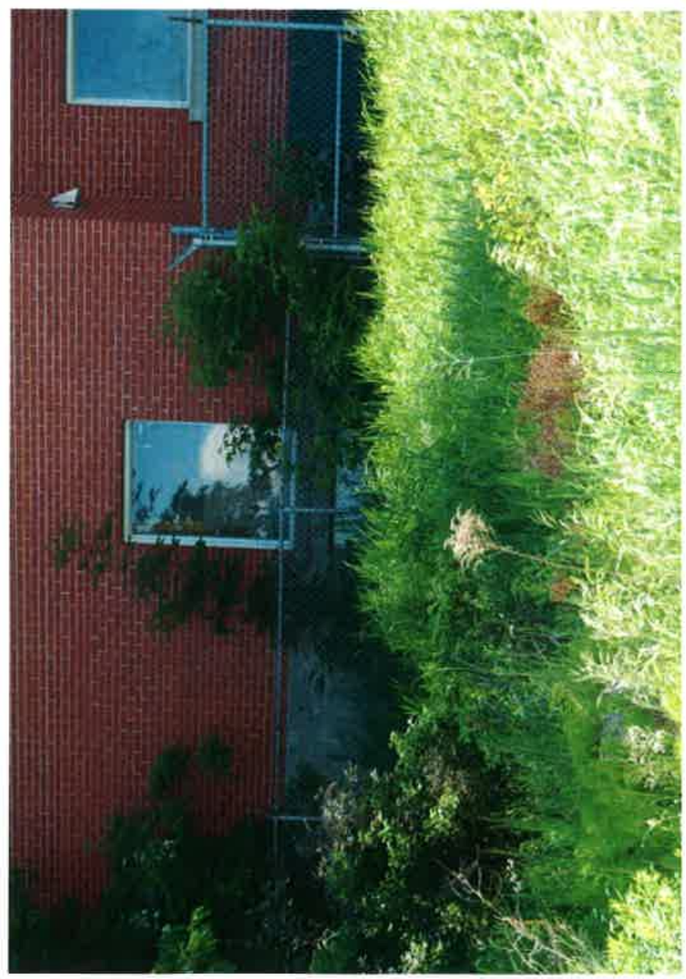
Date: June 13/08


2-F2


2-F-1

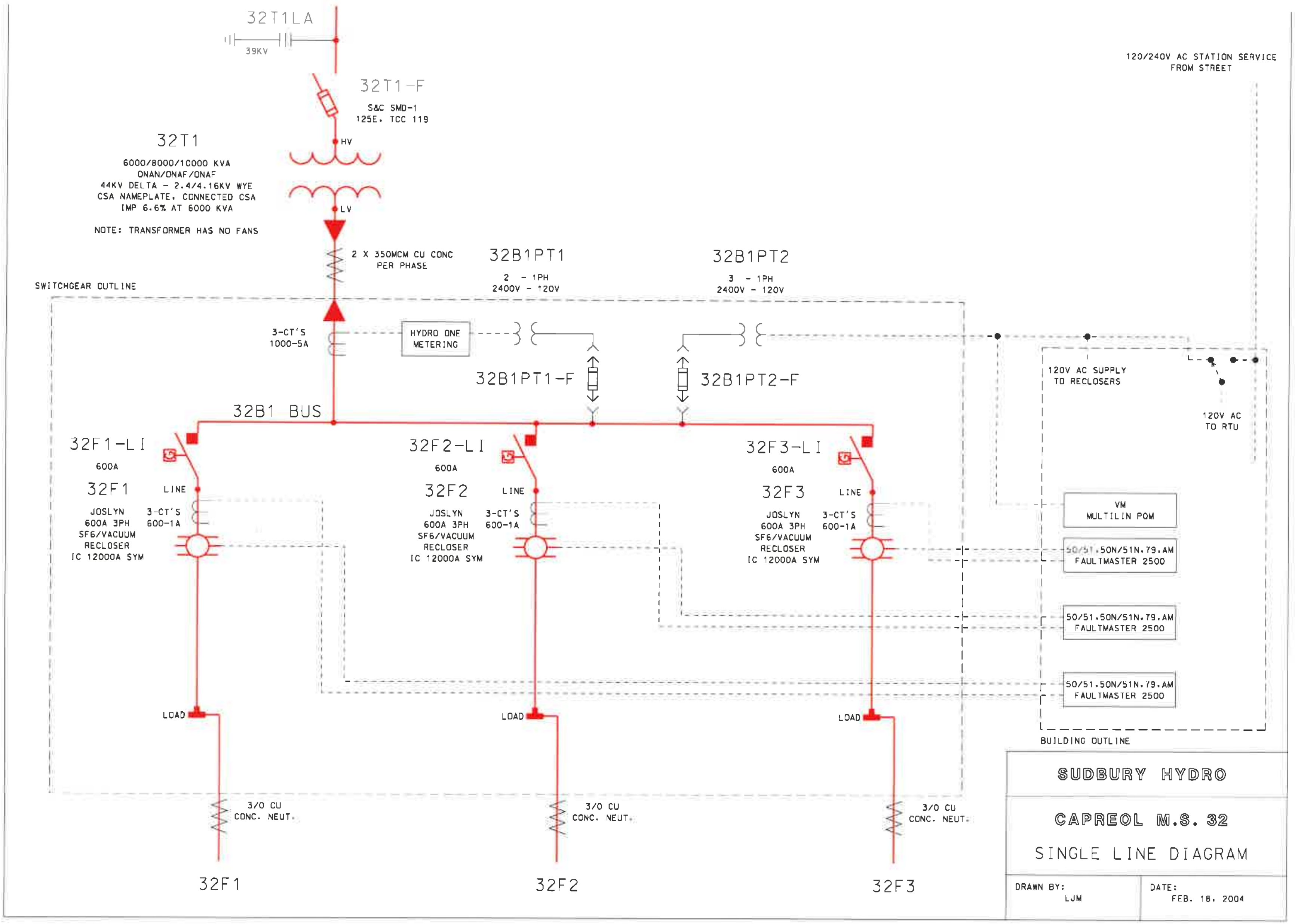






Attachment 2 (of 2):

2-Staff-18 Attachment 2: Capreol MS32



SUDBURY HYDRO

CAPREOL M.S. 32

SINGLE LINE DIAGRAM

DRAWN BY: LJM	DATE: FEB. 16, 2004

Costello Associates MS Inspection Sheet

Utility: Sudbury Hydro Inspected by: S. Costello

Station: MS-32 Capreol Date: June 19/08

Transformer Make: CGE Size: 6MVA Imp.: 6.62 Pri. Volt: 44 Sec Volt: 4160/2[illegible]

S/N: 390-4349 1957 OLTC: ±5% Primary Fuses: 125E

Vector Diagram Δ Y

Yard

Yard	OK	Concern	
Fence Security	✓	○	
Fence Grounding	○	✓	
Fence Foundations	✓	○	
Warning Signs	✓	○	
Barbed Wire	✓	○	
Locks	✓	○	
Crushed Stone:	✓	○	
Snow	✓	○	
Trees	✓	○	
Vegitation/Weeds	✓	○	

Building

Building	OK	Concern	
Grounding	○	✓	Communications Shack. (1)
Paint	✓	○	
Roof	✓	○	
Windows	○	○	na
Doors	✓	○	
Structure	○	○	
Warning Signs	○	○	na
Security	✓	○	
Station Power	✓	○	
Sump Pump	○	○	
Eye Wash	○	✓	none.
Lights	✓	○	
Building Temperature	✓	○	

Transformer

Transformer	OK	Concern	
Conservator Oil Level	○	○	Sealed
Winding Temperature	✓	○	45/65
Oil Temperature	✓	○	35/55
Silica Gel	○	○	na.
~~LTC Oil Level~~	~~○~~	~~○~~	
~~LTC Operations Ctr~~			
~~LTC Min~~			
~~LTC Max~~			
~~LTC Reset~~	~~○~~	~~○~~	
Bushing Oil Level	○	○	na
Paint Condition	✓	○	
Grounding	✓	○	
OLTC Padlock	✓	○	
Bushing Condition	✓	○	
Explosion Diaphram	○	○	none.
Neutral Connection	✓	○	

Switchgear/Structures

Switchgear/Structures	OK	Concern	
Grounding	✓	○	
Structure	✓	○	
Height Clearances	✓	○	
Porcelain Arrestors	✓	○	
Pin-type Insulators	✓	○	
Load Break Switches	○	✓	Grounding
Gradient Control Mats	✓	○	
Station Service Tx	○	○	
Recloser Op Counters	○	○	
Recloser Target Reset	○	○	

Comments: Station appears to be in good shape.
- Main sub fence not properly grounded. Fabric not grounded. Rails not bonded. Improper welding.
- Boundary fence not grounded - which may be OK, except communication shack is grounded to main grid. Transfers GPR outside + could create hazard.

Costello Associates

Substation Risk Assessment Form

Station MJ-32 Capreol   Year Built 1957

Section 1: Public Safety – conditions that impact public safety at the station:

Area of Concern	Check 1	Check 2	Check 3
Perimeter Security	✓		
Fence Grounding and Bonding		✓	
Station Yard		✓	
Station Building	✓		
Station Setting – Proximity	✓		
Station Setting - Encroachments	✓		
Overall public safety condition		✓	

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

Overall Public Safety Risk Rating	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

Section 2: Worker Safety – conditions that impact worker safety at the station:

Area of Concern	Check 1	Check 2	Check 3
Grounding and Bonding		✓	
Safe limits of approach	✓		
Working clearances	✓		
Switching access difficult	✓		
Multiple sources of voltage	✓		
Porcelain	✓		
Operational Issues		✓	
Maintenance Issues	✓		
Overall worker safety condition		✓	

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

Maintenance issues that can be quickly rectified may be eliminated from risk assessment.

Overall Worker Safety Risk Rating	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

Inspected by: S. Costello   Date: June 19/08

Costello Associates
Substation Risk Assessment Form

Section 3: Risks of Major Equipment Failure

A. Condition of Equipment

Area of Concern	Check 1	Check 2	Check 3	
Power Transformers		✓		age
High-side switchgear	✓			
Distribution-side switchgear	✓			
Protection and Control Equipment	✓			
Underground cables	✓			
Structures	✓			
Overall equipment condition		✓		

1 = Acceptable

2 = Some deficiencies

3 = Needs attention soon

B. Factors that may impact the consequences of major equipment failure

Concern	Impact of Consequence: L	M	H
Station setting – proximity	More than 100m	Between 100m and 10m	10m or less
Station setting – watercourses	None	Storm sewers/drains	Open water
Lack of backup supply	<2 hours switching	Between 2 – 24h outage	No backup
Critical loads (hospitals etc)	None	With generators	No generators
Grounding and bonding	Today's code	Some deficiencies	Poor
Oil containment	Yes	Partial	None
Explosion barriers	Yes	Partial	None
Fire fighting capability	Hydrants	Storage Tanks	None
Presence of PCB's	None	Storage Only	In-service
Overall equipment condition	**L**	**M**	**H**

C. Based on the equipment condition and consequences, state the risk rating for a major equipment failure:

Overall Failure Risk Rating	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
			✓		

Section 4: Overall Substation Risk Assessment

Station Risk Assessment	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
	20+ Years	11-20 years	4-10 years	2-3 years	1 year
				✓	

Comments: Fence grounding issues - public exposure. Further engineering required.

Inspected by: Costello

Date: June 19/08.


DANGER
PAS D'ADMISSION
NO ADMITTANCE

2-Staff-19 System Renewal - Pole Rebuilds

Question:

Ref 1: 5.4.3.2.1.2 System Renewal – Pole Rebuilds

Sudbury Hydro proposed three investments for pole rebuilds, CKSO Road, South Bay Road, and Miscellaneous Site Restorations. Sudbury Hydro also stated that the ACA recommended that Sudbury Hydro have an annual program to address a certain percentage of poles every year as to not create a backlog of assets needing attention.

a) Please breakdown the total investment cost to each of the three investments, the number of poles, and the length of each feeder planned for replacement.
b) Please confirm that this investment is to meet the recommendation of the ACA.
c) Please explain why there is only budgeted amounts for 2020 if this program is intended to proactively replace poles on a paced basis.
d) In the comparative project section, Sudbury Hydro provided the Croatia Road rebuild project, which replaced 16 poles, transformers, overhead conductor. Does that mean the investment for CKSO Road and South Bay Road will also have other asset replacements such as transformers and overhead conductor? If so, please provide the number of transformers and kilometer of conductors replaced.

Response:

a) The prospective *2020 System Renewal – Pole Rebuilds* investment of $494,292 tabled in the DSP can be broken out as follows:

CKSO Rd – Estimated Cost: **$167,625**
- 3 X 40’ CL3 wood poles
- 1 x 45’CL3 wood pole
- 20 x 50’ CL2 wood poles
- 5 X 55’ CL2 wood poles

The approximate length of the portion of the feeder slotted for replacement is 1.5km

South Bay Rd – Estimated Cost **$176,667**

- 7 X 40’ CL3 wood poles
- 12 x 50’ CL2 wood poles

The approximate length of the portion of the feeder slotted for replacement is 1.4km

Misc. Site Restorations – Estimated Cost **$150,000**

The actual number of poles addressed by this prospective investment will depend on the ability of the existing joint use tenants to transfer their plant off of the old GSHi-owned pole(s). The average number of poles removed from service from 2015 through 2019 is 369.

b) GSHi confirms that this investment is to meet the recommendation of the ACA.

c) Budgeted program amounts for the years 2021 through 2024 inclusive can be found in the Distribution System Plan in the following location(s).

5.4.3.2.2.1 System Renewal – Lines pgs. 262-267 **(2021)**
5.4.3.2.3.2 System Renewal – Lines pgs. 280-285 **(2022)**
5.4.3.2.4.2 System Renewal – Lines pgs. 294-300 **(2023)**
5.4.3.2.5.2 System Renewal – Lines pgs. 310-316 **(2024)**

d) Both of the prospective investments for CKSO Road and South Bay Road will involve the replacement of conductors and transformers.

The list of transformer and conductor assets being replaced for CKSO Road is as follows:

- Three x 50kVA Dual Voltage/120/240V overhead transformers
- 2,300m of 3 x 336 mcm al. 12kV primary overhead conductor
- 60m of 1 x #2 ACSR al. 12kV primary overhead conductor
- 1,710m of 1 x 3/0 AACSR neutral messenger c/w 266 mcm al. secondary

The list of transformer and conductor assets being replaced for South Bay Road is as follows:

- Three x 50kVA 7,200/120/240V overhead transformers
- One x 37.5kVA 7,200/120/240V overhead transformer
- 900m of 1 x #4sldcu 12kV primary overhead conductor
- 770m of 1 x #2str cu. open wire 120/240V secondary conductor

2-Staff-20 System Renewal - West Nipissing Voltage Conversion

Question:

Ref 1: 5.4.3.2.1.3 System Renewal - West Nippissing Voltage Conversion

Sudbury Hydro has planned to convert the existing 4.16kV system to 12.47kV in the Town of Sturgeon Falls. This will eventually result in the retirement of the municipal station MS38.

a) Sudbury Hydro stated that it plans to approach Hydro One to fund at least a portion of the construction activities. Please provide the joint use agreement between Hydro One and Sudbury Hydro.
b) Please provide the total number of kilometers of line that need to be converted to remove MS38.
c) In reference 1, the planned investment amounts vary significantly over the next five years for the complete conversion of MS38. Please provide the scope of work anticipated over the next five years and reasons why it is not equally paced.
d) Since Hydro One is the owner of these poles, has Hydro One committed to this project and confirmed that they have the resources to complete the work in 2020?

Response:

a) The joint use agreement between Hydro One and Sudbury Hydro is provided as Attachment #1.

b) Feeders to be converted as part of the West Nipissing Voltage Conversion Project are as follows:
36F1 = 2,059m
36F2 = 1,006 m
36F3 = 2,793 m
37F1 = 6,191m
37F2 = 203m
37F4 = 95m
38F1 = 2,676m
38F2 = 5,697m

38F3 = 2,848m

Total: 23.6 kilometers

c) This investment is part of a larger project that will convert a total of 1,500 customers from the existing 4.16kV distribution system to a 12.47kV distribution system at locations throughout GSHi's contiguous service territory in the Town of Sturgeon Falls. The existing 4.16kV system is over 45 years old in most areas. The distribution system has reached the end of its useful life and the availability of spare parts is an issue.

In the Town of Sturgeon Falls voltage conversion area, the project involves the installation of:

- 226 – 4.16kV Overhead distribution transformers
- 2 – 4.16kV Pad-mounted distribution transformers
- 11 – 4.16kV Mini-pad distribution transformers
- 19 poles (owned by Hydro One)
- Ensuring that appropriate clearances are present on the existing 4kV system in the West Nipissing Conversion are for eventual energization of the supply conductors to 12.47kV.

The capital costs which GSHi anticipates it will incur over the forecast period 2020-2024 are shown in the table below:

Year	Budget
2020	89,177
2021	250,000
2022	200,000
2023	675,000
2024	375,000
Totals	$1,589,177

As much as possible, GSHi strives to pace its yearly prospective capital expenditures. As it pertains to this particular investment need, there exist a few notable exceptions. In 2020, the budgetary cost of $89,177 is necessarily lower so as to provide funding to other prospective investments in the capital expenditure plan which are expected to have a large impact on operational risk (i.e. investments related to the renewal of

Gemmell MS11 and Cressey MS3). In 2023, the budgetary cost of $675,000 is largely due to the proposed re-construction of the existing Hydro One-owned 44kV pole line along Nipissing St to permit appropriate clearances for a GSHi-owned 12kV primary voltage underbuild.

d) Hydro One has not yet committed to this project.

With respect to project A11 that is expected to occur in 2023, GSHI will be seeking Hydro One's consent and participation in the rebuilding of the existing 44kV pole line along Nipissing St (from Ethel to Railway). Hydro One owns the 19 poles on which GSHi is currently a tenant. The expectation is that Hydro One will insist on placing the poles and stringing their own sub-transmission circuit after which GSHi will attend the site to transfer/install its own plant.

GSHi will be approaching Hydro One to fund at least a portion of the construction activities. As the pole owner, it is Hydro One's responsibility to ensure that its poles are maintained in good condition. The condition of some of the poles along Nipissing St have deteriorated to the point where GSHi believes Hydro One would agree that replacement of the pole(s) would be warranted. The cost(s) to replace these poles would be borne by the owner, whereas the joint use attachers (in this case GSHi), would be responsible for their own transfer costs. An agreement to provide any partial funding of this project by Hydro One would contribute to a reduction in the overall budgetary costs that form part of this prospective investment.

Attachment 1 (of 1):

2-Staff-20 Attachment 1: 2006 01 01 5 YR Term Automatic Annual Renewal SUDBURY HYDRO ONE

Greater Sudbury Hydro Inc./
Hydro du Grand Sudbury Inc.

500 Regent Street / rue Regent, PO Box 250 / CP 250, Sudbury, ON P3E 4P1
Telephone (705)675-7536 Fax (705)671-1413

March 31, 2006

Hydro One Networks Inc.
185 Clegg Rd.
Markham ON L6G 1B7

Attention: Mr. Steve Vance
Manager – Process Management
Business Integration - Hydro One Networks

Dear Mr. Vance:

Re: Agreement Governing Licensed Occupancy of Power Utility Distribution Poles

Please find enclosed three (3) signed copies of the Agreement Governing Licensed Occupancy of Power Utility Distribution Poles.

Please ensure the appropriate person in your company reviews and signs the agreements and returns one (1) copy attention: Mr. Brian McMillan, P. Eng.

Thank you for your cooperation and attention to this matter. If you have any questions or concerns do not hesitate to call.

Yours truly,

B.A. (Brian) McMillan, P. Eng.
Vice President - Distribution Electrical Systems

lf

Enc.

AGREEMENT FOR

LICENCED OCCUPANCY OF POWER UTILITY DISTRIBUTION POLES

THIS AGREEMENT FOR LICENSED OCCUPANCY OF POWER UTILITY DISTRIBUTION POLES made in duplicate this 1st day of January, 2006 (the "**Effective Date**").

BETWEEN:

GREATER SUDBURY HYDRO INC. **OF THE FIRST PART,**

-AND-

HYDRO ONE NETWORKS INC.

OF THE SECOND PART.

WHEREAS the Parties hereto desire to establish Joint Use of their respective poles when and where Joint Use is of mutual advantage, in accordance with the principles and values outlined in Schedule "A" attached hereto;

AND WHEREAS the conditions determining the desirability of Joint Use depend in each case upon the respective requirements of each of the Parties for safety, service, and economy, and each Party is to be the sole judge as to whether these requirements are best met by Joint Use in respect of its own poles.

NOW THEREFORE in consideration of the mutual covenants, agreements, terms and conditions herein and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the Parties agree as follows:

ARTICLE 1 - TERRITORY AND SCOPE OF AGREEMENT

1.1 This Agreement shall cover all such poles and Attachments for the purpose of overhead power distribution of each Party now existing or hereafter erected as may be brought under this Agreement in accordance with the Joint Use procedures hereinafter provided which are the subject of this Agreement.

ARTICLE 2 - DEFINITIONS

For the purposes of this Agreement, the following terms, when used herein, unless the context indicates otherwise, shall have the following meanings:

2.1 "Agreement" means this Agreement for Licensed Occupancy of Power Utility Distribution Poles between the Parties and shall include Schedules "A" and "B" attached hereto and any amendments to the body of this Agreement or to the Schedules.

2.2 "Anchorage" means all the physical components and their association, one with the other, used for anchoring the Joint Use Pole.

2.3 "Attach(ing)" means the placing of Attachments directly on or supported by the Joint Use Poles.

2.4 "Attachment" means any Electrical Equipment, but for greater certainty does not include Telecommunications Attachments.

2.5 "Contract Administration Guide" ("CAG") means the administrative and operating practices and processes outlined in Schedule "B" attached hereto.

2.6 "CPI" means the Consumer Price Index for August for Ontario in a given year as determined by Statistics Canada, for use commencing January 1 of the following year.

2.7 "Customer" shall mean a Person to which a Party distributes electricity.

2.8 "Electrical Equipment" shall have the meaning ascribed to it in the Ontario *Electrical Safety Code,* as amended.

2.9 "Emergency " means a situation in which there is an imminent or existing interruption of electrical service, the condition of the Joint Use Poles and/or Attachments on the Joint Use Poles pose an imminent danger or threat to the safety, property, security or welfare of an individual or the public or the environment, and/or a situation declared as such by a public safety government authority.

2.10 "Governing Body" means a government authority having jurisdiction over highways or other public places, including municipalities, acting under legislative authority to carry out duties in maintaining and improving public highways or other public places.

2.11 "Hazardous Condition" means a structural/mechanical or electrical condition that has the potential to cause harm or injury to persons or property and which requires specific work methods to be carried out for the condition to be removed.

2.12 "Joint Anchorage" means a common anchoring system to which guy wires of either Party are attached, each guy wire providing guying for one Party's conductors and related equipment including Attachments on a Joint Use Pole.

2.13 "Joint Use" means the use or intended use for support on a Joint Use Pole that is owned by either Party of the Attachments of both Parties.

2.14 "Joint Use Pole" means a pole which supports, or is intended to support, the Attachments of both Parties.

2.15 "Licensee" means the Party making or applying for permission to make, Joint Use of the Owner's pole.

2.16 "Line Clearing" means the provision of adequate clearance from all vegetation for all Attachments carried on or supported by Joint Use Poles and includes items such as underbrush control, tree removals, cabling or guying of trees, pruning or trimming, treatment of cuts and disposal of debris.

2.17 "Make Ready Work" means (i) work that is necessary and required solely for the purpose of accommodating the Licensee's Attachments that the Licensee wishes to attach to the Owner's poles and includes, but is not limited to, initial Line Clearing, any changes or additions to or Rearrangement of the Owner's poles or the Owner's Attachments and (ii) work on the Owner's poles or Attachments which the Owner decides to carry out in advance of the Owner's schedule to carry out such work as a result of the Licensee's desire to place its Attachments on the Owner's poles and "Make Ready" shall have the corresponding meaning. Without restricting the generality of the foregoing, Make Ready Work does not include the costs of repairing any pole such that it meets the Standard prior to permitting the Licensee to place its Attachments on the said Joint Use Pole.

2.18 "Normal Pole" has the meaning ascribed to it in Schedule "B", Exhibit 2, Clause 1.1.

2.19 "Owner" means the Party having sole ownership of a pole in respect of which application for Joint Use is made by the other Party.

2.20 "Party and Parties" means and includes, respectively, only a Party or Parties to this Agreement.

2.21 "Permit" means the approved Request for Licensed Occupancy of Poles form as evidenced by the signature of a duly authorized employee or designate of the Owner.

2.22 "Permit Fee" means the annual fee paid by the Licensee for the privileges granted by the Owner in accordance with the terms and conditions of this Agreement.

2.23 "Person" means a natural person, corporation, firm, partnership, limited liability company, joint venture or other form of association or entity.

2.24 "Pole Line Location" means a line of poles generally paralleling a roadway or laneway, and the location of said line shall comprise the space between the centre line of the road and the limit of the road allowance as it may exist now or at any time in the future.

2.25 "Primary Conductor" means a conductor operating in excess of 750 volts.

2.26 "Qualified Contractor" means a worker who is competent and has the requisite certification, licensing, training, education, experience and familiarity with the safety rules, procedures and hazards associated with high voltage electrical systems.

2.27 "Rearrange(ing)" means the removal of Attachments from one position on a Joint Use Pole and the placing of the same Attachments in another position on the same Joint Use Pole.

2.28 "Request for Licensed Occupancy of Poles" means the written application in the form attached hereto as Exhibit 1 to Schedule "B", the format of which may be revised from time to time and in the sole and absolute discretion of the Owner, to be completed and submitted to the Owner by the Licensee in order to obtain permission to place its Attachments onto the Owner's poles.

2.29 "Residual Value" means the monetary value ascribed to a pole at the time it is removed, as determined by Table 1, of Exhibit 4 of Schedule "B" attached to this Agreement.

2.30 "Secondary Conductor" means a conductor operating at 750 volts or less.

2.31 "Standard" means the Canadian Standards Association (CSA) Standard CAN/CSA - C22.3 No. 1, "Overhead Systems".

2.32 "Telecommunications Attachments" means any material, apparatus, equipment or facility used for the purpose of providing Telecommunications Service.

2.33 "Telecommunications Service" has the meaning ascribed to it in the *Telecommunications Act* (Canada).

2.34 "Third Party" means a Person who is not a party to this Agreement.

2.35 "Transferring" means the removal of Attachments from one Joint Use Pole and the placing of the same Attachments on another Joint Use Pole.

ARTICLE 3 - ESTABLISHING JOINT USE OF POLES

3.1 Whenever the Licensee desires to place or alter the number, size or nature of its Attachments on poles, it shall make application to the Owner in accordance with Schedule "B" attached hereto and the Owner shall reply to such application in the manner specified in Schedule "B" attached hereto within 30 days after receipt of said application.

3.2 The Licensee may, due to Emergency situations and without prior application to the Owner, place or Rearrange its Attachments on the poles of the Owner. When said Attachment(s) is on a non-Joint Use Pole, application for Joint Use shall be made within 30 days after the placing or Rearranging of said Attachments, subject to the terms of this Agreement.

ARTICLE 4 – STANDARDS

4.1 The Licensee represents and warrants that on the Effective Date the Attachments which form the subject of Existing Permits (as defined in clause 16.2 below) comply with the Standard and all other applicable laws, statutes, regulations, by-laws, standards, and codes, including, without limitation, Ontario Regulation 22/04 passed under the *Electricity Act*, 1998, as amended and that the Attachments which form the subject of Permits that are not Existing Permits shall, at the time the Joint Use is established for said Attachments, comply with the then current Standard or the Owner's then current Distribution Standards, whichever is more stringent, as well as all other applicable laws, statutes, regulations, by-laws, standards and codes, including, without limitation, Ontario Regulation 22/04 passed under the *Electricity Act*, 1998, as amended. Subject to the foregoing, the Licensee represents and warrants and covenants that at the Licensee's sole risk and expense, during the Term of this Agreement, the Attachments which form the subject of Existing Permits (as defined in clause 16.2 below) shall comply with the Standard and all other applicable laws, statutes, regulations, by-laws, standards and codes, including, without limitation, Ontario Regulation 22/04 passed under the *Electricity Act*, 1998, as they may be amended from time to time and the Attachments which form the subject of Permits that are not Existing Permits shall comply with the Standard then current Standard or the Owner's then current Distribution Standards, whichever is more stringent, as well as all other applicable laws, statutes, regulations, by-laws, standards and codes, including, without limitation, Ontario Regulation 22/04 passed under the *Electricity Act*, 1998, as they may be amended from time to time.

ARTICLE 5- RIGHT OF WAY FOR LICENSEE'S ATTACHMENTS

5.1 The Licensee shall be responsible for obtaining any and all easements, rights of way, licenses, privileges, authorizations, permissions, or other land rights from Third Parties, including but not limited to, authorization or permission to locate on municipal or provincial road allowances or any other applicable authorization or permission required from any municipal, provincial or federal government or any agency, body or board thereof having jurisdiction, as may be necessary for the placement, operation, maintenance, Line Clearing and removal of its Attachments upon and along the Joint Use Poles provided for in a Permit (individually "Right of Way", collectively "Rights of Way") and if the Licensee fails to comply with the provisions of this clause, subject to clause 18.2 below, it shall indemnify the Owner from and against any and all claims or demands or other liability resulting from such failure.

5.2 The Owner gives no warranty of permission from property owners, municipalities or others for the use of the Owner's poles by the Licensee, and if objection is made thereto and the Licensee is unable to remedy the matter satisfactorily within thirty (30) days, the Owner may then, by notice in writing at any time, require the Licensee to remove its Attachments from the Joint Use Poles involved, and the Licensee shall, at its own expense, remove its Attachments from such Joint Use Poles within ninety days (90) days after receipt of said notice unless the Licensee is legally required to remove its Attachments by a shorter time period in which case the Licensee shall remove its Attachments from such Joint Use Poles during such shorter period of time.

5.3 Nothing in this Article shall be deemed to confer on the Licensee any authority to maintain its Attachments on the Owner's poles for the said period of ninety (90) days, or any portion thereof, or otherwise to infringe upon any legal rights of such property owners, municipalities or Third Parties.

5.4 If both Parties agree, one Party may obtain any required Right of Way for both Parties. Upon such agreement, each Party shall share equally the cost of obtaining the Right of Way, including reasonable compensation paid to the property owner.

ARTICLE 6 - MAINTENANCE OF JOINT USE POLES AND ATTACHMENTS

6.1 Each Party shall maintain its Joint Use Poles and its Attachments on Joint Use Poles in a safe and serviceable condition, in accordance with the placement and safety practices and specifications set out in the CAG, all applicable laws, statutes, regulations, by-laws, guidelines and codes of every governmental authority which may be applicable including, without limitation, the Work Protection Code and good work practices.

6.2 Each Party will be responsible for installing and maintaining its own separate anchoring system. Where mutually agreeable, Joint Anchorages may be considered but such installations should not be construed as the normal practice.

6.3 Subject to clause 6.5 below, the Owner shall replace any of its Joint Use Poles that it deems defective and the costs of any such replacements shall not be considered as Make Ready costs for new Joint Use. The Licensee shall replace its Attachments on Joint Use Poles as soon as they deteriorate or become defective or unsafe.

6.4 In the event that the Owner determines that there is a Hazardous Condition posed by its Joint Use Poles or its Attachments thereon, which includes, but is not limited to, deteriorated or defective Joint Use Poles, the Owner shall (i) notify the Licensee in writing of the potential safety risk and the nature of the Hazardous Condition as soon as reasonably possible, (ii) mark or band the Joint Use Poles where the Hazardous Condition exists in accordance with the CAG and (iii) correct the Hazardous Condition as soon as possible after discovering the Hazardous Condition, but in any event not later than 30 days after discovering the Hazardous Condition. Until such time that the Owner has remedied the Hazardous Condition, the Owner shall offer protection to the Licensee, its employees and contractors and its equipment at no cost.

6.5 Both Parties acknowledge and agree that if the Licensee proceeds to work on its Attachments located on the applicable Joint Use Pole(s) where a Hazardous Condition exists after receiving such notification by the Owner pursuant to clause 6.4 and prior to the Owner having rectified, replaced or provided adequate protection from the said Hazardous Condition, the Licensee shall do so at its own risk and shall assume all risk of damage, loss or injury to its Attachments, to the Owner's Attachments and to Attachments of Third Parties and to its employees, servants, agents, representatives, contractors and other persons acting on its behalf in performing the work and to any other Person.

6.6 In the event that the Licensee determines that there is a Hazardous Condition posed by any Joint Use Poles or by its Attachments on the Joint Use Poles, the Licensee shall (i) notify the Owner in writing of the potential safety risk and the nature of the Hazardous Condition as soon as reasonably possible, (ii) mark or band the Joint Use Poles where the Hazardous Condition exists in accordance with Section 9.0 of the CAG and (iii) if the Hazardous Condition relates to the Licensee's Attachments, correct the Hazardous Condition as soon as possible after discovering the Hazardous Condition, but in any event not later than 30 days after discovering the Hazardous Condition. If the Hazardous Condition relating to the Licensee's Attachments is not so corrected by the Licensee, the Owner may remove the Licensee's Attachments at the Licensee's sole expense and risk of damage to the Licensee's Attachments and the Owner shall be reimbursed by the Licensee for the said costs of removal within thirty (30) days of issuance of an invoice by the Owner. Until such time that the Licensee has remedied the Hazardous Condition relating to the Licensee's Attachments, the Licensee shall offer protection to the Owner, its employees and contractors and its equipment at no cost.

6.7 In the event that either the Owner or the Licensee suspects a problem with any Joint Use Poles or any Attachments thereon, such Party shall notify the other of said problem. If the Owner is of the opinion that said problem does not constitute a potential or actual Hazardous Condition, it shall so notify the Licensee, following which any remedial work associated with the said suspected problem that the Licensee wishes the Owner to provide to the Licensee for purposes of the Licensee working on its Attachments on any said Joint Use Pole shall be at the sole cost and risk of the Licensee except as otherwise specified in any applicable law.

ARTICLE 7 - PLANNED REMOVAL OF ATTACHMENTS – TERMINATION OF THE JOINT USE OF POLES

7.1 Nothing in this Agreement shall be considered as a restriction upon the right of either Party to remove at any time any of its Attachments, except Joint Anchorages, from Joint Use Poles. Such Joint Anchorages shall automatically become the property of the Owner of the Joint Use Poles when said Attachments have been removed.

7.2 If the Owner desires, or is required, to discontinue the use of a Joint Use Pole, the Owner shall give the Licensee notice in writing of the cancellation of the Joint Use. Provided that the Owner would not be in breach of a provision in a prior agreement with a Third Party, the Owner shall give the Licensee an option to either purchase the said Joint Use Pole in accordance with the Residual Value Table 1 of Exhibit 4 of Schedule "B" or remove the Licensee's Attachments within 90 days after receipt of notification of the removal or abandonment unless the Parties agree to such other time. In the case where the Licensee decides to purchase the said Joint Use Pole, existing rights of Third Parties will continue to be respected per Article 11.

7.3 The Licensee may at any time abandon the use of a Joint Use Pole by removing therefrom all its Attachments, except Joint Anchorages or common neutrals, and by giving due notice thereof in writing to the Owner. The Licensee shall in such case pay to the Owner the full Permit Fee for each Attachment on said Joint Use Pole for the then current year ending on the last day of December of the said year.

7.4 When either Party has discontinued or abandoned the use of a Joint Use Pole(s), the Permit for occupation of the said Joint Use Pole(s) shall be cancelled, in accordance with the procedure set out in Section 4 of Schedule "B".

ARTICLE 8 – LINE CLEARING

8.1 Subject to the provisions of this Article 8 and Exhibit 3 of Schedule "B" and provided the Licensee complies with its obligations in clause 5.1 above, the Owner is responsible for carrying out Line Clearing (whether Make Ready Line Clearing or maintenance Line Clearing) on its Joint Use Poles.

8.2 In performing Line Clearing, the Owner shall:

a) provide vegetation clearances for both Parties where new Joint Use Pole lines are constructed; and

b) provide that clearances are maintained around the Attachments of both Parties in accordance with the Standard.

8.3 Where the Licensee wishes to establish new Joint Use and the Owner is agreeable to such new Joint Use, the Owner shall determine if any Make Ready Line Clearing is required pursuant to clause 1.1 of Exhibit 3 to Schedule "B" and if so, the Owner shall notify the Licensee of the required Make Ready Line Clearing and the costs thereof. The Licensee shall pay for the costs of such required Make Ready Line Clearing before the Owner is obligated to provide the Make Ready Line Clearing.

8.4 Emergency Line Clearing required due to storm damage or unforeseen trees falling onto either Party's Attachments shall be the responsibility of each Party and shall be at that Party's sole risk and expense.

ARTICLE 9 - ANNUAL PERMIT FEES AND RATES

9.1 The Licensee shall, during the Term of this Agreement, pay to the Owner, the applicable Permit Fee per Licensee Attachment on each Joint Use Pole in accordance with the terms and conditions herein.

9.2 During the first quarter of each year, an invoice shall be prepared by the Owner to the Licensee indicating the amounts payable for the calendar year immediately preceding, in accordance with Schedule "B", Clause 3.1.

9.3 Any Attachment that has been placed on or removed from any Joint Use Pole during the course of the year shall be charged the full Permit Fee for the full year.

9.4 In October of each year, the Owner will calculate the amounts for the forthcoming calendar year using the formula set forth in Clause 9.5 below.

9.5 Subject to clause 9.6 below, the following formula shall be used by the Owner in each year of the Term of this Agreement to determine the Permit Fee payable by the Licensee for the following calendar year:

$$R_t = R_{t-1} \cdot 1 + \left[\frac{CPI_{t-1} - CPI_{t-2}}{CPI_{t-2}} \right]$$

Where:

R_t is the Permit Fee for the next year
R_{t-1} is the Permit Fee for the current year
CPI_{t-1} is the Consumer Price Index for Ontario for August of the current year
CPI_{t-2} is the Consumer Price Index for Ontario for August of the previous year

Notes:
1. CPI is based on "all items for Ontario".

9.6 The formula specified in clause 9.5 shall apply for purposes of determining the Permit Fees payable after 2005 only. The Parties agree that the applicable Permit Fee payable by the Licensee for the year 2005 is $28.61 unless the OEB mandates a different rate or rate methodology, such mandated rate or rate methodology shall automatically apply as soon as it has been implemented by the OEB without any need for an amendment to this Agreement.

9.7 If the Owner, acting reasonably, determines that the Licensee has not had a previous satisfactory business relationship with the Owner, the Owner may, in its sole and absolute discretion, require that the Licensee deposit with the Owner, security in an amount and in a form satisfactory to the Owner, securing the due performance of the obligations of the Licensee as provided for in this Agreement. The security shall be maintained in good standing by the Licensee for a period of three years from the date that it is first placed with the Owner; provided, however, that it shall be maintained for a longer period if the Owner, acting reasonably, determines that the business relationship with the Licensee requires the continuation of the security.

ARTICLE 10 - INVOICES AND PAYMENT FOR WORK

10.1 Upon completion of work performed by one Party, the expense of which is to be borne wholly or in part by the other Party as specified in this Agreement, the Party performing such work shall, after its completion, render to the other Party an itemized invoice for labour, materials and other expenses in accordance with Exhibit 4 of Schedule "B". Payment of such invoices shall be made by the Party owing same within thirty (30) days after the invoice has been rendered.

10.2 Whenever under this Agreement it is considered advisable by both Parties, in the interest of economy, to use unit charges as representing the cost of certain operations, nothing in the foregoing terms of this Article shall preclude the practice of so doing.

10.3 All Third Party requests for moving, removing, or altering a Joint Use Pole or for the Transferring or Rearranging of Attachments thereon are to be governed by Exhibit 2, Schedule "B". Notwithstanding the provision of Clause 2.0 of Exhibit 2, Schedule "B" to this Agreement, whenever a Third Party requires the moving, removing or altering of a Joint Use Pole, or the Transferring or Rearranging of Attachments thereon, and the said Third Party is to bear all or any part of the expenses incurred as a result thereof, each of the Parties shall conclude its own arrangements with the Third Party in regard to payment for the alterations involving its Joint Use Pole or Attachments. Reconstruction or Rearrangements shall not proceed without concurrence of both Parties.

10.4 Except where expressly provided in this Agreement, both Parties acknowledge and agree that the costs involved in erecting, placing, maintaining and otherwise dealing with the Joint Use Poles and Attachments in specified circumstances shall be borne by each Party or divided between the Parties respectively as outlined in Exhibit 2 of Schedule "B" attached hereto.

10.5 In the event that the Licensee fails to pay any amount payable hereunder when due, such unpaid amount shall bear interest from the payment due date until the date the Owner receives such payment at a rate of 1.5% per month compounded monthly (19.56 per cent per year).

ARTICLE 11 - RIGHTS OF THIRD PARTIES

11.1 If the Owner has granted rights or privileges to a Third Party to use poles not covered by this Agreement, then nothing herein contained shall be construed as affecting such rights or privileges, if and when this Agreement is made applicable to such poles. The Owner shall have the right to continue and extend such existing rights or privileges, it being expressly understood, however, that for the purpose of this Agreement, the Attachments of any such Third Party shall be treated as Attachments of the Owner.

11.2 Nothing in this Agreement shall prevent or limit the Owner of any Joint Use Pole from permitting the affixing of Third Party Attachments to such Joint Use Poles.

11.3 Where the Licensee acquires ownership of Joint Use Poles, it shall also assume those existing obligations of the Owner under this Agreement vis-à-vis Third Parties.

ARTICLE 12 - ASSIGNMENT OF RIGHTS

12.1 Except as otherwise provided in this Agreement, the Licensee shall not assign this Agreement, or any of its rights, obligations or interests hereunder to any Person without the prior written consent of the Owner. Notwithstanding the foregoing, nothing herein contained shall prevent or limit the right of either Party to make a general mortgage or any sale of any or all of its property, rights, privileges and franchises or to enter into any merger or consolidation, and, in the case of the foreclosure of such mortgage or sale under power of sale contained therein, or in the case of such lease, transfer, assignment, merger or consolidation, the Party shall cause its rights and obligations hereunder to pass to and be acquired and assumed by the mortgagee on foreclosure or the purchaser at such sale, or the transferee, lessee, assignee or the merged or consolidated company, as the case may be. Subject to the foregoing, this Agreement shall extend to, be binding upon and to the benefit of the Parties hereto and their respective successors and permitted assigns.

ARTICLE 13 - WAIVER OF TERMS AND PROVISIONS

13.1 The failure of either Party hereto to enforce at any time any of the provisions of this Agreement or to exercise any right, power or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of this Agreement or any part hereof or the right of either Party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of this Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed as or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the Party which expressly waives a right, power or option under this Agreement.

ARTICLE 14 – CONTRACTORS

14.1 Only Qualified Contractors may be used by the Parties to do any work in connection with their respective Attachments on the Joint Use Poles. Each Party is responsible for retaining its own Qualified Contractors and for ensuring compliance by the Qualified Contractors with the terms and conditions set out in this Agreement, including the CAG.

14.2 Each Party shall ensure that its employees, agents, representatives, contractors, Qualified Contractors or subcontractors in the performance of the said Party's obligations and the exercise of the said Party's rights under this Agreement:

a) comply with the Standard and all applicable laws, statutes, regulations, by-laws, guidelines and codes of every governmental authority which may be applicable and as well as the requirements of the Electrical Safety Authority;
b) comply with the placement, safety practices and specifications set out in the CAG;
c) are competent and qualified to deal with electrical hazards in accordance with the requirements of the *Occupational Health & Safety Act* (Ontario) as amended and all applicable regulations thereunder including, without limitation, Construction Projects – O. Reg. 213/91 or Part 11 of the Canada Labour Code, R.S.C. 1985, c. L.2, as amended and all applicable regulations thereunder, whichever is more stringent.

14.3 Neither Party shall direct or supervise the employees, agents, representatives, contractors, Qualified Contractors or subcontractors of the other Party. Notice of violation or non-compliance given to a contractor, subcontractor or Qualified Contractor shall also be provided at the same time or as soon as possible thereafter to an authorized representative of the Party responsible for the contractor, subcontractor or Qualified Contractor, as the case may be.

14.4 The Owner may request the Licensee to provide, and within 30 days after receipt of such request, the Licensee shall provide, to the Owner, documentation in respect of processes and procedures that the Licensee and its Qualified Contractors, contractors and subcontractors have in place to ensure that work on the Joint Use Poles is completed in a competent and safe manner.

14.5 The Party engaging a contractor or Qualified Contractor is entirely responsible for ensuring, and if necessary, for providing to the contractor or Qualified Contractor, as the case may be, electrical hazards awareness training necessary to demonstrate the appropriate level of skill and competence to work in proximity to an electrical environment.

ARTICLE 15 - SERVICE OF NOTICES

15.1 Any notice or other writing required or permitted to be given under this Agreement or for the purpose of it shall be in writing and shall be deemed to have been properly given on the date of actual delivery if delivered by hand, five business days after dispatch by registered or certified mail, one day after dispatch by facsimile transmission, addressed to the Party to whom it was sent at the address, or facsimile number, of such Party set forth below or at such other address or facsimile number as the Party shall subsequently designate to the other Party by notice given in accordance with this paragraph.

To: Greater Sudbury Hydro Inc.
500 Regent St, PO Box 250
Sudbury ON P3E 4P1
Attn: VP- Distribution Electrical Systems
Fax: 705- 675- 0529

To: Hydro One Networks Inc.
185 Clegg Road,
Markham Ontario. L6G 1B7
Attention: Joint Use Manager
Fax: (905) 946-6215

ARTICLE 16 – TERM

16.1 Subject to the provisions of Article 20 hereof and the termination rights in this clause 16.1, this Agreement shall be of full force and effect for an initial period of five (5) years from January 1, 2005 (the "Initial Term") and shall thereafter be automatically renewed for successive periods of one (1) year each (the Initial Term and renewal periods collectively referred to as the "Term"); provided, however that either Party may terminate this Agreement effective at any time after the expiration of the Initial Term by providing the other Party with six (6) months' prior written notice.

16.2 The Parties acknowledge and agree that any permits or authorizations that were previously in force prior to the Effective Date and which authorize Joint Use, whether in the form of a Permit or otherwise, including without limitation, verbal authorizations or permissions (collectively, "Existing Permits"), shall, except for purposes of clause 4.1, be deemed to be Permits under the terms and conditions of this Agreement.

ARTICLE 17 - RESOLUTION PROCESS

17.1 Any controversy, dispute, difference, question or claim arising between the Parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said Parties (collectively "Dispute") shall be settled in accordance with this clause. The aggrieved Party shall send the other Party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Clause. The Presidents of the Parties shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the Parties may submit the Dispute to mediation. If the Parties submit the Dispute to mediation and are unable to resolve the said Dispute through mediation, the Parties may pursue any other remedies available to them at law.

ARTICLE 18 - LIABILITY AND INDEMNIFICATION AND INSURANCE

A. Liability and Indemnification

18.1 The Licensee hereby assumes all risk of damage to or loss of its Attachments howsoever caused, and does for itself and its successors and assigns hereby release and forever discharge the Owner of the Joint Use Poles on which the Licensee's Attachments are placed, its successors and assigns, its employees and agents from all claims and demands with respect thereto, except to the extent that such loss and damage are caused by the Owner's negligence. The Licensee hereby agrees to fully release, indemnify and save harmless the Owner, its successors and assigns, its employees and agents, of, from and against all damage, loss or injury to persons or property which may be suffered or which may hereafter be sustained or incurred by reason of, or in any way relating to, arising from, or based upon the exercise by the Licensee of the rights and other permissions herein granted and/or the performance of or purported performance of or non-performance of the Licensee of any of its obligations or covenants in this Agreement, and all manner of claims, charges, expenses, liabilities, obligations and demands in connection therewith, including, but not limited to, claims from the Licensee or from Third Parties, arising out of power outages or fluctuations that would not have occurred but for the presence of the Licensee's Attachments on the Joint Use Poles, except to the extent that any of the foregoing are caused by the Owner's negligence.

18.2 Notwithstanding anything else in this Agreement,

(a) the Owner shall not be liable to the Licensee for any claims or demands that may be made against the Licensee by a Third Party insofar as the said claims or demands are for losses and damages that the Licensee, because of section 2.2.2 of Ontario's *Distribution System Code*, is not liable to pay to the said Third Party; and

(b) where no claim is made against the Licensee by a Third Party but the Licensee suffers damages to its assets or business under circumstances in which the Owner would, because of clause 18.1 of this Agreement, be liable to the Licensee, the Owner shall not be liable to the Licensee for any of the categories of losses and damages that are enumerated in section 2.2.2 of Ontario's *Distribution System Code*.

18.3 The Parties acknowledge and agree that this Article 18 (A) shall survive termination or expiry of this Agreement.

B. Insurance

18.4 The Licensee shall, during the Term of this Agreement, procure and maintain in full force and effect with financially responsible insurance carriers, insurance policies in which the Owner is named as an additional insured in the amount of Five Million Dollars ($5,000,000.00) against liability due to damage to the Owner's property or property of any other person or persons and against liability due to injury to or death of any person or persons in any one instance. Such policies of insurance shall:

a) contain a severability of interest clause and cross liability clause between the Licensee and the Owner;
b) be non-contributing with, and shall apply only as primary and not excess to any other insurance available to the Owner;
c) provide that it shall not be cancelled or amended so as to reduce or restrict coverage except upon thirty (30) days' prior notice (by registered mail) to the Owner.

18.5 The Licensee shall, upon the Owner's request, provide the Owner with a certificate of insurance completed by a duly authorized representative of the Licensee's insurer certifying that coverages required pursuant to clause 18.4 above are in effect.

18.6 The Licensee agrees that the insurance described in clause 18.4 herein does not in any way limit the Licensee's liability pursuant to the indemnity provisions of this Agreement.

ARTICLE 19 - FORCE MAJEURE

19.1 Except for the payment of any monies required hereunder, neither Party shall be deemed to be in default of this Agreement where the failure to perform or the delay in performing any obligation is due wholly or in part to a cause beyond its reasonable control, including but not limited to an act of God, act of any federal, provincial, municipal or government authority, civil commotion, strikes, lockouts and other labour disputes, fires, flood, sabotage, earthquake, storm, epidemic, and an inability due to causes beyond the control of the Party. The Party subject to such an event of force majeure shall promptly notify the other Party of its inability to perform or of any delay in performing due to an event of force majeure and shall provide an estimate as soon as practicable when the obligation will be performed. The time for performing the obligation shall be extended for a period equal to the time during which the Party was subject to the event of force majeure. Both Parties shall explore all reasonable avenues available to avoid or resolve events of force majeure in the shortest possible time, but this requirement shall not oblige the Party suffering a strike, lockout or labour dispute to compromise its position in such strike, lockout or labour dispute.

ARTICLE 20 - SUSPENSION OR TERMINATION FOR DEFAULT

20.1 The permission granted by any Permit may be terminated by the Owner: (i) if the Joint Use Pole(s) designated by such Permit is abandoned by the Owner; or (ii) if the Owner desires or must discontinue the use of the Joint Use Pole(s), and in either case the Licensee does not wish to purchase the said Joint Use Pole in accordance with clause 7.2 above and in either case of termination, the Owner shall provide the Licensee with at least ninety (90) days prior written notice thereof. If the Joint Use Pole(s) designated by such Permit(s) is sold, the Owner may not transfer any Joint Use Pole unless as a condition of transfer the purchaser agrees to continue to allow the Licensee's Attachment(s) thereon for the remainder of the Term.

20.2 If the Licensee defaults at any time in the payment of the Permit Fee or fails to or neglects at any time to fully perform, observe and comply with all the terms, conditions and covenants herein, then the Owner shall as soon as practicable after becoming aware of the default, notify the Licensee in writing of such default and the Licensee shall correct such default to the Owner's satisfaction within thirty (30) days of the issuance of such notice or within a longer time period if agreeable to the Owner, failing which the Owner may forthwith terminate this Agreement and the privileges herein granted in respect of the Permits affected by the default.

20.3 The Owner shall be entitled, at its option, to terminate this Agreement immediately upon written notice to the Licensee upon the Licensee becoming bankrupt or insolvent or upon the Licensee ceasing to carry on business.

20.4 The termination of a Permit approved pursuant to this Agreement shall not be deemed to be termination of this Agreement unless such Permit is the last remaining or only Permit approved pursuant to this Agreement in which case the termination of the Permit shall be deemed to be termination of this Agreement.

20.5 Upon the termination of this Agreement or of a Permit approved pursuant to this Agreement, the Licensee shall at its sole expense and at the request of the Owner, remove from the Joint Use Poles its Attachment(s) covered by this Agreement or by the terminated Permit respectively within ninety (90) days after receipt of notice thereof or within a shorter period of time in case of an Emergency as may be determined by the Owner, failing which the Owner may, at the Licensee's risk of damage to the Licensee's Attachment(s) and at the expense of the Licensee, remove such Attachment(s). Upon the removal of such Attachment(s) by the Owner, the Owner shall have the right to retain the Attachment(s) so removed until the Licensee pays the cost of removal thereof and if the Licensee fails to pay such costs within thirty (30) days of invoicing then the Owner shall have the further right to sell the Attachment(s) so removed and apply the amount so received against the costs of removing the Attachment(s).

ARTICLE 21 - MISCELLANEOUS

21.1 This Agreement, together with the Schedules attached hereto, constitutes the entire agreement between the Parties with respect to the matter herein and supersedes all prior oral or written representations and agreements concerning the subject matter of this agreement.

21.2 This Agreement shall be construed and enforced in accordance with, and the rights of the Parties shall be governed by, the laws of the Province of Ontario and the federal laws of Canada applicable therein, and the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of this Agreement.

21.3 Article headings are not to be considered part of this Agreement and are included solely for convenience of reference only. They are not intended to be a full or accurate description of the content thereof.

21.4 Schedules "A" and "B" attached hereto are to be read with and form a part of this Agreement.

21.5 Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the Parties. The Parties agree that they are and will at all times remain independent and are not and shall not represent themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either Party which could establish any apparent relationship of agency, employment, joint venture or partnership and no Party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other Party to any other person nor with respect to any other action of the other Party.

21.6 If any provision of this Agreement is declared invalid or unenforceable by any competent authority such provision shall be deemed severed and shall not affect the validity or enforceability of the remaining provisions of this Agreement, unless such invalidity or unenforceability renders the operation of this Agreement impossible.

21.7 This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

21.8 No amendment, modification or supplement to this Agreement shall be valid or binding unless set out in writing and executed by the Parties with the same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed, as of the date first written above, by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

____

Name:
Title:
I have the authority to bind the corporation.

GREATER SUDBURY HYDRO INC.

____

Name: Brian McMillan
Title: VP - Distribution Electrical Systems
I have the authority to bind the corporation.

SCHEDULE "A"

PRINCIPLES AND VALUES

This Agreement is based on the mutual desire by both Parties to work together to their respective benefit, and to ensure that Joint Use is planned and implemented where appropriate because it is the right thing to do for each Party's Customers that it serves, its employees and stakeholders.

This Agreement has been put in place to encourage communication between both Parties and to formalize their respective obligations related to Joint Use.

Recognizing that all situations cannot be covered in detail, the following set of Principles and Values has been created to facilitate the creation of new procedures and problem resolution. These Principles and Values are the fundamental framework for the Joint Use relationship and form an essential part of this Agreement, or any modification that may be required from time to time.

Trust

Trust is the most critical success factor in achieving our joint mission. We must be competent, open and trustworthy in our dealings with each other.

Safety and Standards

Our actions and decisions will be based upon a respect for each other's safety and technical standards.

Win/Win

The Joint Use relationship requires understanding of each other's perspective and subsequently choosing actions of mutual benefit.

Reciprocity

Reciprocity is an important consideration in the development and application of this Agreement recognizing that each and every transaction will not necessarily be mutually beneficial.

Value Added

We will emphasize doing the "right things right" and eliminate processes that do not add value to our respective business and the community we serve.

Pride in Partnership

As both Parties are committed to excellence, we take pride in the way we work together and share our resources for the benefit of the communities we serve.

Customer Focus

Our actions and decisions will be driven by the needs of the communities and respective Customers that we both serve.

Environmental Responsibility

Our actions and decisions will be based on respect for each Party's environmental initiatives and concerns.

Empowered Teams

Our agreement will enable frontline teams to make operational decisions consistent with these principles and values.

Continuous Improvement

We will continuously strive to improve all aspects of our working relationships.

SCHEDULE "B"

CONTRACT ADMINISTRATION GUIDE

1.0 GENERAL

1.1 For purposes of this CAG, capitalized words or expressions, unless otherwise defined in this CAG, shall have the meaning given to them in the Agreement for Licensed Occupancy of Power Utility Distribution Poles to which this CAG is attached and of which this CAG forms a part ("the Agreement").

1.2 The procedures and forms detailed herein have been prepared to outline, in general, the requirements for authorizing Joint Use under the Agreement.

1.3 Each of the Parties have authorized the respective designated representative identified in Clause 15.1 of the Agreement to sign Permits on its behalf. Each Party may change their respective designated representative, or add other designated representatives, by notice in writing to the other Party.

1.4 Where practical, field visits shall be made jointly by the Parties to determine the most practical and economical solution for both Parties. However, the Licensee subject to clause 3.2 of the Agreement, shall not place any Attachments onto the Owner's poles without first obtaining approval in the form of a signed Permit.

2.0 APPLICATION BY THE LICENSEE FOR JOINT USE OF THE OWNER'S POLES

2.1 Whenever the Licensee wishes to place its attachments, or alter the number, size or nature of its Attachments, on the Owner's poles, it shall complete and submit a Request for Licenced Occupancy of Poles form and the Owner shall reply to such form in the manner specified herein. In addition, as part of its application, the Licensee shall submit such other information or material required by the Owner for purposes of the Owner assessing the feasibility of the Licensee placing, affixing or attaching its attachments onto the Owner's poles, including the ability of the Owner to comply with all applicable laws, statutes, regulations, by-laws, standards, and codes in respect of its poles.

2.2 Where the Owner deems it necessary, the Owner's representative shall arrange for a joint field visit. At this time, the Owner's representative shall form an opinion as to the feasibility and desirability of the proposed Joint Use.

2.3 Notwithstanding any provision herein or in the body of the Agreement, the Owner may in its sole and absolute discretion refuse to grant the permission requested. In such an instance, the Owner will state in writing its reasons for refusing to grant the permission requested. If the Licensee can satisfy the Owner's concerns, then the Licensee may make a new application and resubmit for approval by the Owner.

2.4 If the proposed Joint Use is acceptable to both Parties, the Owner's representative will, if necessary, prepare an estimate of Make Ready costs stipulating the cost to be paid by the Licensee should Make Ready Work be required to accommodate the proposed Joint Use. The signed original estimate and one signed copy will be forwarded to the Licensee's representative.

2.5 After receipt of the Owner's estimate and provided the Licensee finds the estimate acceptable, the Licensee's representative will arrange for signing in accordance with the Licensee's authorization practices after which the original estimate shall be signed and returned to the Owner's representative and the copy shall be signed and retained by the Licensee for its records.

2.6 After the signed cost estimate form has been returned to the Owner, the Request for Licensed Occupancy of Poles form attached as Exhibit 1 hereto, shall be prepared by the Licensee's representative and signed by the Licensee's representative. The Licensee is required to specify the location, size, number and nature of the proposed Attachments. Two copies shall be prepared and signed by the Licensee's representative and both copies shall be forwarded to the Owner's representative for approval.

2.7 If satisfactory, the Owner's representative will sign both copies of the Request for Licensed Occupancy of Poles form and return the original to the Licensee's representative, thus authorizing the Joint Use.

2.8 The Owner will then proceed with the Make Ready Work necessary to accommodate the proposed Joint Use and forward the invoice to the Licensee for the costs of the said Make Ready Work.

2.9 The Owner shall, at its sole cost, ensure that its poles and Attachments meet the Standard prior to permitting the Licensee to place any of its Attachments onto the said poles.

3.0 <u>ANNUAL INVOICING AND AUDITS</u>

3.1 During the first quarter (1/4) of each year, each Owner shall prepare a summary invoice indicating the total number of Licensee Attachments on each Joint Use Pole and amount owing including the applicable taxes, in accordance with the provisions of Article 9 of the Agreement.

3.2 (a) In order to ensure the accuracy and completeness of existing Joint Use Permits, a joint field inspection shall be made at least once every six years during the Term of the Agreement (the six-year period commencing on the year of the Effective Date) at a time and day to be mutually agreed upon. Audit costs shall be equally borne by both Parties. If the Parties cannot agree on a time and day with a minimum of 3 months' advance notice for an audit, then the Owner shall conduct the audit and the audit costs shall be equally borne by both Parties. If the Parties agree to a time and day for an audit and one of the Parties cannot or does not attend, then the other Party can carry out the audit and the audit costs shall be equally borne by both Parties. Any discrepancies will be corrected and new Permits cancelling or superseding the previous Permits shall be signed by both Parties within 30 days after the relevant Joint Use inspection to reflect the actual Joint Use pole count. If at any time during the Term of the Agreement an Attachment(s) is attached to any of the Owner's poles or Joint Use Poles without a Permit(s) being approved by or on behalf of the Owner for such Attachment(s), the Licensee shall remove the said unauthorized Attachment(s) as requested by the Owner. In the event the Licensee fails to remove the said unauthorized Attachment(s), the Owner shall have the right to forthwith remove any and all unauthorized Attachment(s) placed on its poles or Joint Use Poles and to charge the Licensee for all costs incurred by the Owner as a result of the removal of such unauthorized Attachment(s). Where it is determined by the Owner, in its sole and absolute discretion, to be feasible to do so, the Licensee may submit a revised or new Request for Licensed Occupancy of Poles form to reflect the Attachment(s). In the event the revised or new Request for Licensed Occupancy of Poles form is approved by the Owner, the said Attachment(s) become(s) authorized and may remain on the poles or Joint Use Poles subject to the terms and conditions of this Agreement.

b) In addition to the Permit Fees and other applicable fees payable for authorized Attachment(s) and the costs identified in clause 3.2(a) above, the Licensee agrees to pay to the Owner the total Permit Fees for any unauthorized Attachment(s) for the years during which the unauthorized Attachment(s) are placed on the poles or Joint Use Poles or for a period of five years, whichever amount is less, or (ii) for a period of five years where the date upon which the unauthorized Attachment(s) are placed on the poles or Joint Use Poles cannot be established, the total Permit Fees being calculated by using the Permit fee for the current year in which the calculation is being made. The Parties agree that the total Permit Fees herein provided shall be deemed to be fair and just in the circumstances and shall be treated as liquidated damages and not as a penalty. Should the number of unauthorized Attachment(s) exceed 2% of the number of Attachments for which Permits have been granted, the Licensee will also pay to the Owner its labour costs associated with the audit inspection wherein the Owner discovered the unauthorized Attachment(s).

4.0 REVISION AND CANCELLATION OF PERMITS

4.1 For changes in the number or nature of a Licensee Attachment(s) already on the Owner's Joint Use Pole, a "Superseding" Permit is required to be approved by the Owner before the change can be made. A revised Permit shall be prepared by the Licensee in a manner similar to that for "New" Joint Use as outlined in Section 2 above and the Licensee shall ensure that the existing Permit number that is being "Superseded" is shown in the appropriate block and that the new number of Joint Use Poles is shown in the "Rental Poles" block.

4.2 For the termination or cancellation of any Permits, a new Permit number is not required. The word "Cancellation" or "Termination" will be typed in the space normally used for the Permit number and the Permit number to be "Cancelled" shall be shown in the "Location" block noting the reason for cancellation.

5.0 PURCHASE/SALE OF EXISTING JOINT USE POLES

5.1 a) When the Owner discontinues the use of a Joint Use Pole(s) and the Licensee has agreed to purchase the said pole(s), as per Article 7, Clause 7.2 of the Agreement, the sale/purchase price for each Joint Use Pole shall be calculated as follows:

$$P = R - C$$

Where:

P = Sale/Purchase Price

R = Residual Value from Exhibit 4 hereto, Table 1
C = Cost of Pole Removal from Exhibit 4 hereto, Table 2 For the individual Joint Use Pole to be sold, where the cost of removal exceeds the Residual Value of the said Joint Use Pole, a nominal price of $1.00 will apply.

b) The act of purchasing installed Joint Use Poles does not transfer a Right of Way, therefore, it will be the responsibility of the new Owner to ensure that any required Rights of Way are first obtained pursuant to Article 5 of the Agreement in order for the purchase of poles to be effective.

6.0 NOTIFICATION OF NEW LINES

6.1 Whenever either Party is intending to reconstruct its existing Joint Use Poles, extend its services in the vicinity of existing Joint Use Poles or in such other situations where the other Party might reasonably be affected, notice shall be provided to the other Party stating the location of such new work. The other Party shall reply within 14 days as to whether or not Joint Use will be desirable. Should the Licensee desire space on the new poles, a new Request for Licensed Occupancy of Poles form must be submitted by the Licensee to the Owner for approval pursuant to Section 2.0 of this CAG.

7.0 REBUILD, REPLACEMENT OR RELOCATION OF POLES

7.1 If, at any time, the Owner deems it necessary to remove, replace or change the location of any Joint Use Pole designated by a Permit as supporting Attachments of the Licensee, the Owner shall notify the Licensee in writing, including conceptual pole plans, as far in advance of the start of work as is possible but in any event not less than 90 days in advance of the start of work by the Owner. Once the Owner's work is completed, the Licensee shall be informed of the requirement to remove or relocate its Attachments within a further 60 days. If, due to the complexity or timing of the Licensee's work, the 60 day period cannot reasonably be met, a mutually agreed to completion time period will be negotiated and confirmed in writing by both Parties. In both cases, the Licensee's completion period shall commence from the date written notification from the Owner to the Licensee is given. Within this time, the Licensee shall, at its sole risk and expense, remove its Attachments from the relevant Joint Use Pole and, except when the notice specifies to the contrary, may transfer the Attachments to the Joint Use Pole in the new location or to the new pole, as the case may be. In either case, the terms and conditions of the Agreement shall continue to apply to the Attachments so transferred.

7.2 The Licensee agrees to Rearrange (or remove) temporarily and at its sole risk and expense any of its Attachments placed on Joint Use Poles of the Owner, whenever notified to do so by the Owner for purposes of the Owner carrying out work on its Joint Use Poles within a time limit to be determined mutually by the two Parties, failing which by no later than 60 days after the date of the notice from the Owner.

7.3 In case of Emergency, the Owner may give such shorter notice as the Owner deems expedient regarding removal, rearrangement, replacement or transfer of the Licensee's Attachments, and the notice may be given orally or by fax.

7.4 In instances where plant adjustments are initiated as a result of work being done by a municipality or other Governing Body in Ontario pursuant to the *Public Service Works on Highways Act*, as amended, all conditions of notification and scheduling of work indicated in clause 7.1, and 7.2 above shall be superseded and dictated by the requirements of the Municipality or Governing Body in Ontario, where such requirements exist.

7.5 a) If the Licensee fails to comply with a notice given pursuant to any of clauses 7.1, 7.2, or 7.3 above, then the Owner, unless agreement is reached with the Licensee with regard to an alternative method of compliance, shall be entitled to a delayed removal charge of $100 per Joint Use Pole per month commencing on the month during which the Licensee was to comply with the Owner's notice, until such time as the Licensee has fully complied with the Owner's notice.

b) If the Owner fails to comply with the notification periods or mutually agreed to completion periods, as the case may be, pursuant to any of the clauses 7.1, 7.2 or 7.3 above, the Owner shall not be entitled to a delayed removal charge until notification according to paragraph 7.1 is executed.

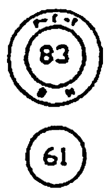
c) The Owner and the Licensee will consider opportunities to perform work operations for each other to minimize delays and costs associated with the rebuild, replacement and relocation of Joint Use Poles. The Licensee will initiate discussion regarding alternatives at the initial time of notification.

8.0 POLE LINE LOCATIONS

8.1 Neither Party shall place a pole in a Pole Line Location already occupied by a pole or pole line of the other Party, regardless of whether the existing pole or pole line is Joint Use or not, without the written consent of the owner of the existing pole or pole line.

8.2 Neither Party shall add, remove or replace a pole in a pole line belonging to the other party without the written consent of the other Party. Any such pole so placed shall become the property of the other Party. All costs incurred by the other party associated with a pole so placed or replaced by the first Party will be the responsibility of the first Party.

8.3 Pole markings s[redacted] be placed on all of the Owner's Joint Use Po[redacted] to clearly indicate ownership, placement year, and pole test and treatment date as shown in the diagram below or some other mutually acceptable practice. The Joint Use Poles may also be marked with pole tag insignia to denote pole number, switch number, transformer location and other information. Any additional markings desired by the Licensee must be first approved by the Owner. It should be noted the dating nails are installed at or near the brand height. For Joint Use Poles 55 ft (16.8M) or less, the brands is 10ft (3M) from the butt. For Joint Use Poles over 55 ft, the brand is 14 ft (4 M) from the butt.



Note: Top diagram depicts nail with treatment year. Bottom diagram depicts nail with installation year.

9.0 MARKING AND CORRECTION OF HAZARDOUS CONDITIONS

9.1 When either Party discovers a Hazardous Condition on a Joint Use Pole, it shall notify the other Party and shall mark the Joint Use Pole as follows:

a) Electrical hazards: Red belted tag holder with tag
b) Structural hazards: 2 Yellow bands for emergency or where the pole will be changed within 6 months;

2 yellow bands mean any one or more of the following:

- **½ inch or less shell** remaining of sound wood at each of the test drill locations.
- The **shell rot** at ground-line is greater than **1 1/4 inch average** all around the pole.
- Within the first 6 feet above ground, a "chunk" greater than **30%** of the cross section is missing. (This would normally be the result of an impact from a snow plow or farm equipment.)
- The pole is in a condition considered to be a severe and immediate risk to public safety. (Example, a broken pole, or a pole leaning severely with a transformer attached to it.)

A single yellow band if pole change will be done in subsequent planned work releases)

1 yellow band indicates any one or more of the following:

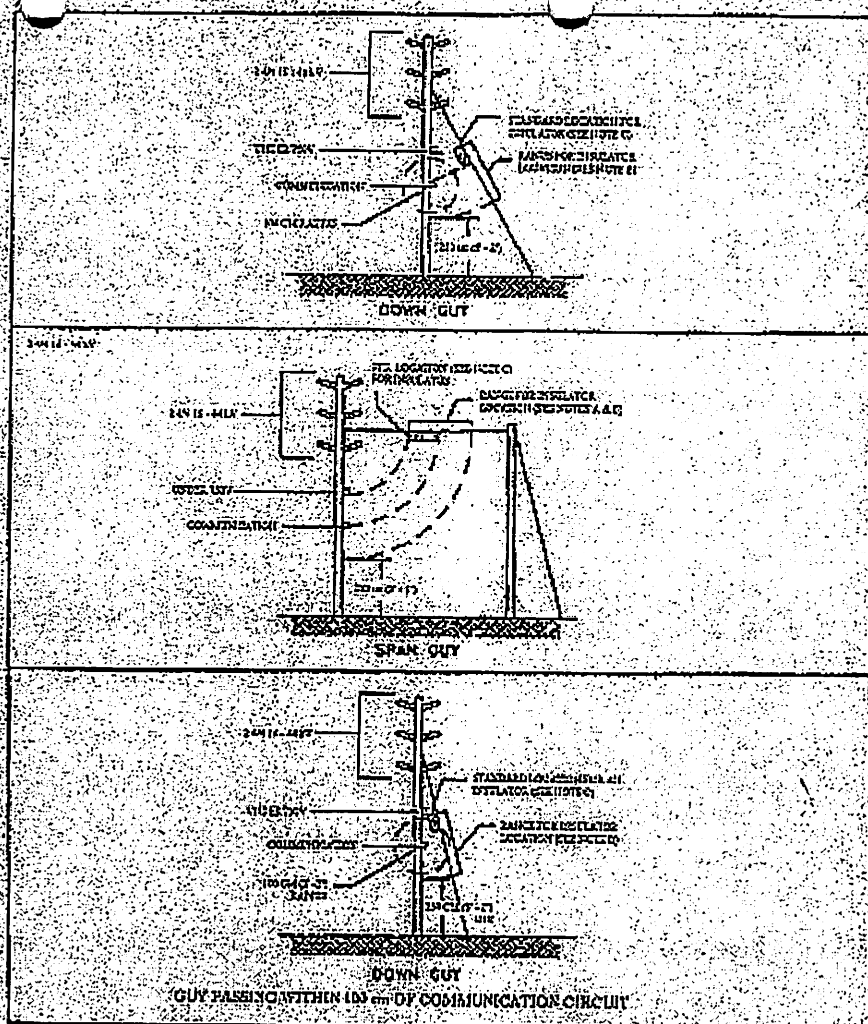
- If the pole has less than 2 inches average shell thickness, or has "SEVERE" damage, or both,
- bands to be placed (4 feet to 5 feet above ground line.)

9.2 In the event that either Party has marked a Joint Use Pole with a red belted tag holder for work protection, under no circumstances shall anyone work above the red band.

10.0 STRAIN INSULATORS

10.1 Strain insulators of the appropriate mechanical strength and voltage rating shall be installed on all down guys. The location of the guy strain insulator on Networks guys is specified in the diagram below. Strain insulators on the Licensee's guys must be installed between 2.5m and 3.5 metres (8 to 12 feet) above ground by the Licensee. The Licensee's insulators must be maintained in safe working condition at all times.

Location of Strain Insulators



NOTES

(A) A standard insulator is required if power circuit of a separate line is crossing above or below span guy. This second insulator should be located so as to insulate the section of the span guy which is exposed to the crossing circuit.

(B) The insulator should fall below all power attachments (including neutral) under broken guy conditions and it should be a minimum of 200 cm (where possible) from the pole attachment.

(C) If communication (telephone or cable TV) connections are on pole, guy insulator must be in the standard location as shown.

Notes:

Primary Phase conductor is defined in the Standard as a circuit having phase to phase voltage above 750 Volts.

The insulator shall be located below all primary and neutral conductors under broken guy conditions and should be a minimum of 2.0 meters (6 feet), where possible from the point of attachment at the Owner's Joint Use Pole.

One insulator may be used to meet both requirements, provided it is located below all primary and neutral conductors and it insulates or isolates the section of guy that is within 1.0 metre of the Licensee's Attachment from the top portion of the guy.

11.0 GUYING AND ANCHORING:

11.1 Each party shall provide guys and anchors with sufficient capacity to support its own Attachments and shall ensure that any such guys (except those used to support Attachments that form the subject of Existing Permits) are a minimum 3/8 of an inch thick.

11.2 Suitable anchoring and guying that is required to accommodate unbalanced or additional loads due to the Licensee's Attachments, shall be installed by the Licensee at the Licensee's expense.

11.3. Should the Licensee be unable to supply and install a suitable anchor, the Owner may, at the Licensee's request and expense, act as contractor for the Licensee to install an anchor.

11.4 The Licensee's anchors must be placed with a minimum separation of 1.5 metres (5 feet) from the Owner's anchor.

11.5 Where separate anchoring is undesirable, the parties may cooperate to jointly study the feasibility of and, if agreeable to the Owner, implement Joint Anchorage. If the Owner agrees to such Joint Anchorage, the Owner will install such Joint Anchorage at the Licensee's expense.

11.6 When adding or changing guys and anchors, the installing party shall not affect the existing tension on the other party's guys or disturb existing anchors.

11.7 Crossing guy wires is undesirable, however, where it is unavoidable, the minimum clearance between crossing guys (the point at which two guys cross) shall be 80 millimetres (3 inches).

APPLICATION FOR LICENSED OCCUPANCY OF POLES

(draft completed example)

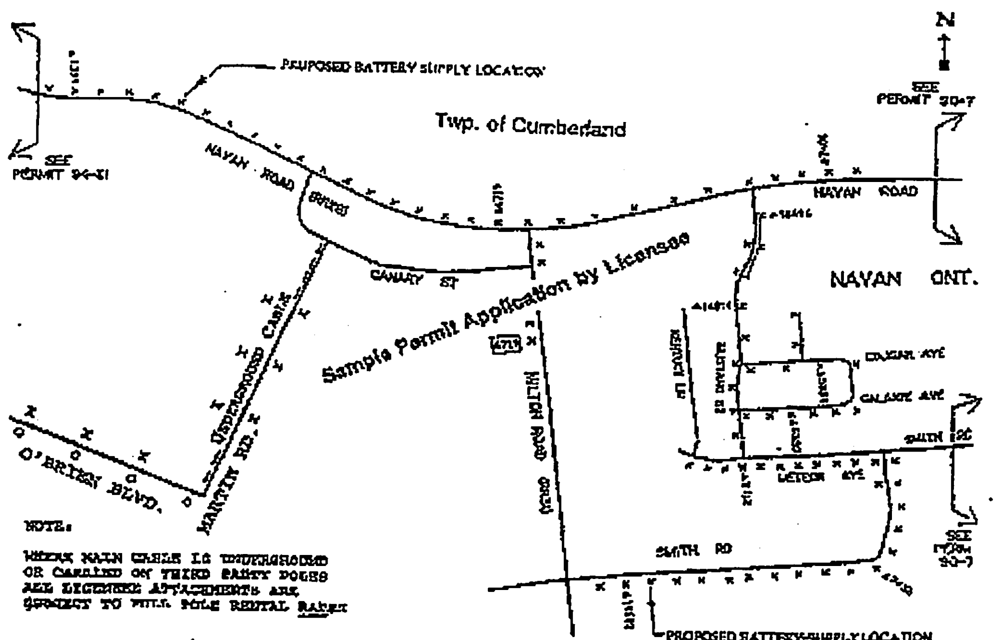
*Please complete all boxes above the dotted line.

To be attached to and form part of the agreement effective:		Licensee's project name/refer #
		Supercedes Permit No. , "New" or "Cancel" 90-12
Permission is requested by Name of company	Signature: (by authorized company rep)	Print Name and Title:

To place attachments as follows: (note specific quantity, size and nature of proposed attachment(s)) **Detail # of conductors, Size, & associated hardware** **Note, sketch should show any transformers, reclosures, switches etc.**

Company Division	External Permit #

Lot no. (in or between)	Conc./Street or Road Names	Township/village or town of	County/Municipality
Lots 7 - 11	*Con. 9 & 10*	Village of Navan	*Ottawa-Carleton*



* Please orient sketch to the north, show occasional Owner transformer numbers and adjacent Permit numbers

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For Internal Use Only

Approved Signature (Owner)	Legend **O = Third Party Pole** **X = Joint Use Pole**	No. of full rental poles 95
Name and Title (please print)		
Operations manager or designate Operations/ Front Line Manager		
Operations Centre Winchester SC	Permit no. 97-1	
Date	Other internal project YES NO	

APPLICATION FOR LICENSED OCCUPANCY OF POLES

*Please complete all boxes above the dotted line.

To be attached to and form part of the agreement effective:	Licensee's project name/refer #
	Supercedes Permit No., "New" or "Cancel"

Permission is requested by	Signature:	Name and Title: (please print)

To place attachments as follows: (note specific quantity, size and nature of proposed attachment(s)

Company Division	External Permit Number

Lot no. (in or between)	Conc./Street or Road names	Township/Village or town of	County/Municipality

* Please orient sketch to the north, show occasional Owner transformer numbers and adjacent Permit numbers

For Internal Use Only

Approved Signature (Owner)	Legend	No. of full rental poles
Name and Title (please print)		
Operations manager or designate		
Operations Centre	Permit no.	
Date	Other internal project	

1.0 POLE COSTS

1.1 A Normal Pole shall be a pole having length of up to and including 15.2 m (50 feet) and having other dimensions, which meet the strength and other requirements for Joint Use in accordance with the Standard.

The space which each Party will utilize on a Normal Pole shall be considered as follows:

Power Space: All that space above the separation space.

Separation Space: The space between the Power Space and the Telecommunication Space, a minimum 1.0 m (40 in.) measured at the pole.

Telecommunication Space: Any 0.6 m space above the Clearance Space that adheres to the clearance specifications in the Standard having regard to sag considerations.

Clearance Space: Height of Telecommunications Attachments, including conductors and other related equipment, that adheres to the clearance specifications in the Standard having regard to sag considerations.

Variations in the above space allotments may be adopted in any location where shorter poles can be economically used for Joint Use. In-span clearances between Telecommunications Attachments and the Attachments subject to the Agreement will, as a minimum, adhere to the Standard.

1.2 When a pole taller than 15.2m is required by one Party, that Party shall pay the extra height costs as outlined in Table 2 of Exhibit 4 in addition to the Residual Value of the existing 15.2 m pole determined in the Residual Cost Table 1 of Exhibit 4.

When the extra height is due to the requirements of both Parties, such as grading, the Licensee shall pay the Owner a sum equal to one half of the Residual Value of the existing pole as outlined in the Residual Value Table 1 of Exhibit 4 and one half of the extra height costs as outlined in Table 2 of Exhibit 4.

1.3 When a pole or Joint Use Pole is erected to replace another, solely because such other pole is insufficient in size and strength to provide for the Licensee's requirements, the Licensee shall pay to the Owner, the Residual Value of the existing pole as determined by Table 1 of Exhibit 4 and extra height costs for pole above 15.2 (50feet) as outlined in Table 2 of Exhibit 4. The cost of removing the replaced pole or Joint Use Pole shall be borne by the Owner and ownership of the replaced pole or Joint Use Pole shall be retained by the Owner.

1.4 When an existing pole in a pole line requires replacement to provide for a common pole crossing or guying facility of the other Party, such pole shall be replaced by the Owner, and the Licensee shall pay to the Owner a sum of money equal to the Residual Value of the replaced pole as determined by Table 1 of Exhibit 4, plus the incremental costs for extra pole height as outlined in Table 2 of Exhibit 4.

1.5 Where an additional pole must be erected in the existing pole line of the Owner to provide means for a common pole crossing or guying facility of the Licensee, the total cost for such a pole shall be paid by the Licensee. Notwithstanding any other provision of the Agreement, such additional poles may be sold to the Licensee at the nominal charge of $1.00 each, if the Owner abandons its Pole Line in this location.

1.6 The cost of maintaining or replacing deteriorated or defective Joint Use Poles shall be borne by the Owner of the Joint Use Poles. In such cases each Party shall be responsible for the costs of transferring its Attachments.

2.0 TRANSFER, ATTACHING AND REARRANGEMENT COSTS

2.1 Where the Owner, in order to establish new Joint Use or adding to existing Joint Use on the pole, is required to Transfer or Rearrange its Attachments on the pole, then the cost of such Transfer or Rearrangement shall be borne by the Licensee.

2.2 Where Transferring or Rearranging involves the replacement of existing Joint Use Poles to provide additional height or strength to meet the requirements of the Licensee, the Licensee shall pay the costs of Transferring or Rearranging the Attachments of the Owner. Payment for additional height shall be made as described in Table 2 of Exhibit 4. This payment must be noted on the Permit to avoid future incremental costs for additional height.

2.3 Where a change in the pole line required by the Owner of the poles causes the Licensee to remove or make a change to its Attachments, the Licensee shall bear all of its own costs involved whether or not a pole is replaced.

2.4 Where a change to the Attachments by the Licensee on Joint Use Poles causes the Owner to make a change to its Attachments or Joint Use Poles, the Licensee shall bear the cost of the changes incurred by the Owner whether or not a pole is replaced.

2.5 Each Party shall bear its own costs where Transferring or Rearranging is required due to the replacement of a Joint Use Pole in the same location for maintenance necessary in the opinion of the Joint Use Pole Owner.

2.6 Where Transferring or Rearranging involves the replacement of a Joint Use Pole requested by a property owner or Governing Body, each Party hereto shall be responsible for its own costs of Transferring or Rearranging its Attachments. Each Party shall, at its option, be responsible for recovering all or part of its costs from the initiating Third Party. Reconstruction of the existing Joint Use Pole line shall not proceed without the approval of both Parties.

2.7 Where Attaching, Transferring or Rearranging is required to accommodate the Attachments of a Third Party, such costs shall be identified and borne by the Third Party and recovered by the Joint Use Pole Owner.

2.8 Where the Transferring or Rearranging of Attachments on an existing non-Joint Use Pole line is required to accommodate an overbuild in the same Pole Line Location by the other Party, the original Party's transfer costs and Residual Value costs will be the responsibility of the other Party overbuilding the existing non-Joint Use Pole line in the manner specified in clauses 8.1 and 8.2 of this CAG.

EXHIBIT 3 – LINE CLEARING

1.0 GENERAL

1.1 Line Clearing on all Joint Use Pole lines will be carried out in accordance with the Standard and the specifications provided in Section 3.0 below.

1.2 The costs for maintenance Line Clearing are part of the Permit Fee payable by the Licensee and which Permit Fee is subject to escalation as per Article 9, Clause 9.5 of the Agreement.

1.3 One Party may engage the other Party to perform Line Clearing as required and share the costs as agreed.

2.0 RATIONALE

The costs for maintenance Line Clearing embedded in the Permit Fee are based upon and recognizes the following:

- The Owner's incremental costs to manoeuvre in and around the Licensee's Attachments as part of routine Line Clearing of Joint Use Pole lines
- Benefits, in the context of avoided costs, derived by the Licensee through costs incurred by the Joint Use Pole Owner in clearing around its Attachments in the upper position on the Joint Use Pole.
- Maintenance Line Clearing reduces subsequent Line Clearing costs for new or added installations and reduces both Parties' exposure to Third Party liability.

3.0 SPECIFICATION FOR MAINTENANCE LINE CLEARING

3.1 Where trees exist near supply line conductors, they shall be trimmed, where practicable, so that neither the movement of the trees nor the swinging or increased sagging of the conductors in the wind, in ice storms, or at high temperatures will result in contact between the conductors and the trees. Where trimming is impracticable, the conductors shall be protected as necessary to prevent damage and electrical hazards.

3.2 If the Licensee's Attachments are in particular conflict with sensitive Third Party -owned vegetation, then the Licensee shall address the issue with the Third Party.

3.3 All pruner and saw cuts are to be performed to a professional standard.

3.4 All side or overhanging limbs, including dead wood, that could come into contact with conductors either by wind or by the weight of ice or snow, shall be shortened or removed.

3.5 All danger trees, where possible, shall be removed.

3.6 The Party performing Line Clearing will obtain any required municipal or private property approvals and be accountable for any damage or liability claims resulting from its operations and endeavor to manage public relations issues appropriately.

3.7 The Party conducting Line Clearing is responsible for clean up, removal of debris, and restoration of the site.

1.0 GENERAL

1.1 Engineering charges shall not be charged by either Party for matters relating to Joint Use of poles under this Agreement provided that work is started within 6 months after the engineered charges are approved by a Permit. In the event no Permit is submitted or the project is cancelled, the applicant will be responsible for engineering costs incurred.

1.2 The Residual Value Table 1 and the Unit Transfer or Rearrangement Costs Table 2, both of which are attached to this Exhibit 4 shall be updated by the Owner annually using 100% of the change in the CPI for August for Ontario, for use commencing January 1 of the following year.

2.0 RESIDUAL VALUE TABLE

2.1 The Residual Values specified in Table 1 to this Exhibit 4 represent the value in place of a pole in accordance with the age of the pole. These costs are based on a class 3-pole strength in all soil conditions.

2.2 Table 1 attached to this Exhibit 4 may be used to determine the Residual Value where a pole is replaced prematurely or when a pole is sold. A deduction shall be allowed for a previous payment made for extra height where noted on existing Permits.

3.0 UNIT TRANSFER OR REARRANGEMENT COSTS TABLE

3.1 In accordance with Clause 10.2 of the Agreement, flat rate charges outlined in the Unit Transfer or Rearrangement Costs Table 2 to this Exhibit 4 may be used in invoicing between the Parties. Accordingly, an invoice may be prepared, using the unit costs outlined in Table 2.

3.2 The attached Unit Transfer or Rearrangement Costs Table 2 represents the average cost of Transferring Attachments from an existing Joint Use Pole to a new pole. This Table represents an average of all costs that could be incurred when Transferring or Rearranging excluding material unless otherwise noted. If there is an instance where costs are not defined in the Table, then actual costs shall be used.

3.3 Table 2 attached to this Exhibit 4 may be used for estimating purposes and invoicing.

3.4 The Unit Transfer or Rearrangement Costs Table 2 may be used where the work involves only Attaching or only removing a Joint Use Pole, by taking 50% of the amount indicated. For purposes of the Agreement, the value indicated in the Residual Value Table attached to this Exhibit shall be used to determine additional height charges for each 1.5m (5ft) difference in pole height to 50 feet. The amount determined shall be used for charges to the Licensee for height in excess of a Normal Pole. E.g only. (figures used are not from tables). The Licensee requests a 55' pole. Value of a 50' pole is $2101, Value of a 55' pole is $2795, Subtract the difference, the Licensee pays additional height charges of $694.00. (Calculations will be done using the Tables attached to this Exhibit 4)

4.0 INVOICING FOR JOINT USE WORK

4.1 The Parties agree that the costs charged for any work carried out in relation to Joint Use shall be those specified in Table 2 to this Exhibit 4 where applicable and shall contain the following:

a) total cost of labour, together with transport and work equipment, plus overhead in accordance with the practices of the Party carrying out the work; and

b) other miscella[illegible]s expenses, such as Make Ready Line Cle[illegible], advertising, Permit Fees, special work equipment, switching or contract work.

4.2 The Party carrying out any work in relation to Joint Use for the other Party shall provide the other Party with an estimate of the project cost prior to commencing the work and shall only be obligated to perform the work if agreed to by the other Party. The Party that has carried out the work for the other Party shall issue an invoice to the other Party upon completion of the work and shall provide a written explanation to the other Party in the event that the amount payable pursuant to the invoice is in excess of 10% of the estimate.

TABLE 1 – RESIDUAL VALUE TAB[illegible]

BLENDED (60% ROCK 40% EARTH) ROCK DRILLED SET POLES									
Revised/Issued: January 2005									
AGE	CONDITION	30 FT	35 FT	40 FT	45 FT	50 FT	55 FT	60 FT	65 FT
0	100.00%	$ 1,303	$ 1,327	$ 1,511	S 1,675	$ 1,806	$ 2,505	$ 3,197	$ 3,476
1	98.00%	$ 1,277	$ 1,300	$ 1,481	S 1,642	$ 1,770	$ 2,455	$ 3,133	$ 3,406
2	96.00%	$ 1,251	$ 1,274	$ 1,451	S 1,608	$ 1,734	$ 2,405	$ 3,069	$ 3,337
3	94.00%	$ 1,225	$ 1,247	$ 1,420	S 1,575	$ 1,698	$ 2,355	$ 3,005	$ 3,267
4	92.00%	$ 1,199	$ 1,221	$ 1,390	S 1,541	$ 1,662	$ 2,305	$ 2,941	$ 3,198
5	90.00%	$ 1,173	$ 1,194	$ 1,360	S 1,508	$ 1,625	$ 2,255	$ 2,877	$ 3,128
6	88.00%	$ 1,147	$ 1,168	$ 1,330	S 1,474	$ 1,589	$ 2,204	$ 2,813	$ 3,059
7	86.00%	$ 1,121	$ 1,141	$ 1,299	S 1,441	$ 1,553	$ 2,154	$ 2,749	$ 2,989
8	84.00%	$ 1,095	$ 1,115	$ 1,269	S 1,407	$ 1,517	$ 2,104	$ 2,685	$ 2,920
9	82.00%	$ 1,068	$ 1,088	$ 1,239	S 1,374	$ 1,481	$ 2,054	$ 2,622	$ 2,850
10	80.00%	$ 1,042	$ 1,062	$ 1,209	S 1,340	$ 1,445	$ 2,004	$ 2,558	$ 2,781
11	78.00%	$ 1,016	$ 1,035	$ 1,179	S 1,307	$ 1,409	$ 1,954	$ 2,494	$ 2,711
12	76.00%	$ 990	$ 1,009	$ 1,148	S 1,273	$ 1,373	$ 1,904	$ 2,430	$ 2,642
13	74.00%	$ 964	$ 982	$ 1,118	S 1,240	$ 1,336	$ 1,854	$ 2,366	$ 2,572
14	72.00%	$ 938	$ 955	$ 1,088	S 1,206	$ 1,300	$ 1,804	$ 2,302	$ 2,503
15	70.00%	$ 912	$ 929	$ 1,058	S 1,173	$ 1,264	$ 1,754	$ 2,238	$ 2,433
16	68.00%	$ 886	$ 902	$ 1,027	S 1,139	$ 1,228	$ 1,703	$ 2,174	$ 2,364
17	66.00%	$ 860	$ 876	$ 997	S 1,106	$ 1,192	$ 1,653	$ 2,110	$ 2,294
18	64.00%	$ 834	$ 849	$ 967	S 1,072	$ 1,156	$ 1,603	$ 2,046	$ 2,225
19	62.00%	$ 808	$ 823	$ 937	S 1,039	$ 1,120	$ 1,553	$ 1,982	$ 2,155
20	60.00%	$ 782	$ 796	$ 907	S 1,005	$ 1,084	$ 1,503	$ 1,918	$ 2,086
21	58.00%	$ 756	$ 770	$ 876	S 972	$ 1,047	$ 1,453	$ 1,854	$ 2,016
22	56.00%	$ 730	$ 743	$ 846	S 938	$ 1,011	$ 1,403	$ 1,790	$ 1,947
23	54.00%	$ 704	$ 717	$ 816	S 905	$ 975	$ 1,353	$ 1,726	$ 1,877
24	52.00%	$ 678	$ 690	$ 786	S 871	$ 939	$ 1,303	$ 1,662	$ 1,808
25	50.00%	$ 652	$ 664	$ 756	S 838	$ 903	$ 1,253	$ 1,599	$ 1,738
26	48.00%	$ 625	$ 637	$ 725	S 804	$ 867	$ 1,202	$ 1,535	$ 1,668
27	46.00%	$ 599	$ 610	$ 695	S 771	$ 831	$ 1,152	$ 1,471	$ 1,599
28	44.00%	$ 573	$ 584	$ 665	S 737	$ 795	$ 1,102	$ 1,407	$ 1,529
29	42.00%	$ 547	$ 557	$ 635	S 703	$ 759	$ 1,052	$ 1,343	$ 1,460
30	40.00%	$ 521	$ 531	$ 604	S 670	$ 722	$ 1,002	$ 1,279	$ 1,390
31	38.00%	$ 495	$ 504	$ 574	S 636	$ 686	$ 952	$ 1,215	$ 1,321
32	36.00%	$ 469	$ 478	$ 544	S 603	$ 650	$ 902	$ 1,151	$ 1,251
33	34.00%	$ 443	$ 451	$ 514	S 569	$ 614	$ 852	$ 1,087	$ 1,182
34	32.00%	$ 417	$ 425	$ 484	S 536	$ 578	$ 802	$ 1,023	$ 1,112
35	30.00%	$ 391	$ 398	$ 453	S 502	$ 542	$ 751	$ 959	$ 1,043
36	28.00%	$ 365	$ 372	$ 423	S 469	$ 506	$ 701	$ 895	$ 973
37	26.00%	$ 339	$ 345	$ 393	S 435	$ 470	$ 651	$ 831	$ 904
38	24.00%	$ 313	$ 318	$ 363	S 402	$ 433	$ 601	$ 767	$ 834
39	22.00%	$ 287	$ 292	$ 332	S 368	$ 397	$ 551	$ 703	$ 765
40	20.00%	$ 261	$ 265	$ 302	S 335	$ 361	$ 501	$ 639	$ 695
41	18.00%	$ 235	$ 239	$ 272	S 301	$ 325	$ 451	$ 575	$ 626
42	16.00%	$ 208	$ 212	$ 242	S 268	$ 289	$ 401	$ 512	$ 556
43	14.00%	$ 182	$ 186	$ 212	S 234	$ 253	$ 351	$ 448	$ 487
44	12.00%	$ 156	$ 159	$ 181	S 201	$ 217	$ 301	$ 384	$ 417
45	10.00%	$ 130	$ 133	$ 151	S 167	$ 181	$ 250	$ 320	$ 348
46	8.00%	$ 104	$ 106	$ 121	S 134	$ 144	$ 200	$ 256	$ 278
47	6.00%	$ 78	$ 80	$ 91	S 100	$ 108	$ 150	$ 192	$ 209

49	2.00%	$ 26	$ 27	$ 30	$ 33	$ 36	$ 50	$ 64	$ 70
50	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EARTH SET POLES

Revised/Issued: Janua[illegible]005

AGE	CONDITION	30 FT	35 FT	40 FT	45 FT	50 FT	55 FT	60 FT	65 FT
0	100.00%	$ 559	$ 582	$ 767	$ 931	$ 1,078	$ 1,442	$ 2,134	$ 2,413
1	97.20%	$ 548	$ 570	$ 752	$ 912	$ 1,056	$ 1,413	$ 2,091	$ 2,365
2	94.40%	$ 537	$ 559	$ 736	$ 894	$ 1,035	$ 1,384	$ 2,049	$ 2,316
3	91.70%	$ 525	$ 547	$ 721	$ 875	$ 1,013	$ 1,355	$ 2,006	$ 2,268
4	88.90%	$ 514	$ 535	$ 706	$ 857	$ 992	$ 1,327	$ 1,963	$ 2,220
5	86.10%	$ 503	$ 524	$ 690	$ 838	$ 970	$ 1,298	$ 1,921	$ 2,172
6	83.34%	$ 492	$ 512	$ 675	$ 819	$ 949	$ 1,269	$ 1,878	$ 2,123
7	80.80%	$ 481	$ 501	$ 660	$ 801	$ 927	$ 1,240	$ 1,835	$ 2,075
8	78.20%	$ 470	$ 489	$ 644	$ 782	$ 906	$ 1,211	$ 1,793	$ 2,027
9	75.70%	$ 458	$ 477	$ 629	$ 763	$ 884	$ 1,182	$ 1,750	$ 1,979
10	73.30%	$ 447	$ 466	$ 614	$ 745	$ 862	$ 1,154	$ 1,707	$ 1,930
11	70.90%	$ 436	$ 454	$ 598	$ 726	$ 841	$ 1,125	$ 1,665	$ 1,882
12	68.60%	$ 425	$ 442	$ 583	$ 708	$ 819	$ 1,096	$ 1,622	$ 1,834
13	66.30%	$ 414	$ 431	$ 568	$ 689	$ 798	$ 1,067	$ 1,579	$ 1,786
14	64.10%	$ 402	$ 419	$ 552	$ 670	$ 776	$ 1,038	$ 1,536	$ 1,737
15	62.00%	$ 391	$ 407	$ 537	$ 652	$ 755	$ 1,009	$ 1,494	$ 1,689
16	59.90%	$ 380	$ 396	$ 522	$ 633	$ 733	$ 981	$ 1,451	$ 1,641
17	57.80%	$ 369	$ 384	$ 506	$ 614	$ 711	$ 952	$ 1,408	$ 1,593
18	55.80%	$ 358	$ 372	$ 491	$ 596	$ 690	$ 923	$ 1,366	$ 1,544
19	53.90%	$ 347	$ 361	$ 476	$ 577	$ 668	$ 894	$ 1,323	$ 1,496
20	52.00%	$ 335	$ 349	$ 460	$ 559	$ 647	$ 865	$ 1,280	$ 1,448
21	50.10%	$ 324	$ 338	$ 445	$ 540	$ 625	$ 836	$ 1,238	$ 1,400
22	48.30%	$ 313	$ 326	$ 430	$ 521	$ 604	$ 808	$ 1,195	$ 1,351
23	46.50%	$ 302	$ 314	$ 414	$ 503	$ 582	$ 779	$ 1,152	$ 1,303
24	44.70%	$ 291	$ 303	$ 399	$ 484	$ 561	$ 750	$ 1,110	$ 1,255
25	43.00%	$ 280	$ 291	$ 384	$ 466	$ 539	$ 721	$ 1,067	$ 1,207
26	41.30%	$ 268	$ 279	$ 368	$ 447	$ 517	$ 692	$ 1,024	$ 1,158
27	39.60%	$ 257	$ 268	$ 353	$ 428	$ 496	$ 663	$ 982	$ 1,110
28	37.90%	$ 246	$ 256	$ 337	$ 410	$ 474	$ 634	$ 939	$ 1,062
29	36.30%	$ 235	$ 244	$ 322	$ 391	$ 453	$ 606	$ 896	$ 1,013
30	34.70%	$ 224	$ 233	$ 307	$ 372	$ 431	$ 577	$ 854	$ 965
31	33.10%	$ 212	$ 221	$ 291	$ 354	$ 410	$ 548	$ 811	$ 917
32	31.50%	$ 201	$ 210	$ 276	$ 335	$ 388	$ 519	$ 768	$ 869
33	29.90%	$ 190	$ 198	$ 261	$ 317	$ 367	$ 490	$ 726	$ 820
34	28.40%	$ 179	$ 186	$ 245	$ 298	$ 345	$ 461	$ 683	$ 772
35	26.90%	$ 168	$ 175	$ 230	$ 279	$ 323	$ 433	$ 640	$ 724
36	25.30%	$ 157	$ 163	$ 215	$ 261	$ 302	$ 404	$ 598	$ 676
37	23.80%	$ 145	$ 151	$ 199	$ 242	$ 280	$ 375	$ 555	$ 627
38	22.30%	$ 134	$ 140	$ 184	$ 223	$ 259	$ 346	$ 512	$ 579
39	20.80%	$ 123	$ 128	$ 169	$ 205	$ 237	$ 317	$ 469	$ 531
40	19.30%	$ 112	$ 116	$ 153	$ 186	$ 216	$ 288	$ 427	$ 483
41	17.80%	$ 101	$ 105	$ 138	$ 168	$ 194	$ 260	$ 384	$ 434
42	16.30%	$ 89	$ 93	$ 123	$ 149	$ 172	$ 231	$ 341	$ 386
43	14.80%	$ 78	$ 81	$ 107	$ 130	$ 151	$ 202	$ 299	$ 338
44	13.30%	$ 67	$ 70	$ 92	$ 112	$ 129	$ 173	$ 256	$ 290
45	11.80%	$ 56	$ 58	$ 77	$ 93	$ 108	$ 144	$ 213	$ 241
46	10.30%	$ 45	$ 47	$ 61	$ 74	$ 86	$ 115	$ 171	$ 193
47	8.80%	$ 34	$ 35	$ 46	$ 56	$ 65	$ 87	$ 128	$ 145
48	7.30%	$ 22	$ 23	$ 31	$ 37	$ 43	$ 58	$ 85	$ 97
49	5.80%	$ 11	$ 12	$ 15	$ 19	$ 22	$ 29	$ 43	$ 48
50	4.30%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

AGE	CONDITION	30 FT	35 FT	40 FT	45 FT	50 FT	55 FT	60 FT	65 FT
0	100.00%	$ 856	$ 880	$ 1,064	$ 1,228	$ 1,359	$ 1,741	$ 2,433	$ 2,712
1	98.00%	$ 839	$ 862	$ 1,043	$ 1,203	$ 1,332	$ 1,706	$ 2,384	$ 2,658
2	96.00%	$ 822	$ 845	$ 1,021	$ 1,179	$ 1,305	$ 1,671	$ 2,336	$ 2,604
3	94.00%	$ 805	$ 827	$ 1,000	$ 1,154	$ 1,277	$ 1,637	$ 2,287	$ 2,549
4	92.00%	$ 788	$ 810	$ 979	$ 1,130	$ 1,250	$ 1,602	$ 2,238	$ 2,495
5	90.00%	$ 770	$ 792	$ 958	$ 1,105	$ 1,223	$ 1,567	$ 2,190	$ 2,441
6	88.00%	$ 753	$ 774	$ 936	$ 1,081	$ 1,196	$ 1,532	$ 2,141	$ 2,387
7	86.00%	$ 736	$ 757	$ 915	$ 1,056	$ 1,169	$ 1,497	$ 2,092	$ 2,332
8	84.00%	$ 719	$ 739	$ 894	$ 1,032	$ 1,142	$ 1,462	$ 2,044	$ 2,278
9	82.00%	$ 702	$ 722	$ 872	$ 1,007	$ 1,114	$ 1,428	$ 1,995	$ 2,224
10	80.00%	$ 685	$ 704	$ 851	$ 982	$ 1,087	$ 1,393	$ 1,946	$ 2,170
11	78.00%	$ 668	$ 686	$ 830	$ 958	$ 1,060	$ 1,358	$ 1,898	$ 2,115
12	76.00%	$ 651	$ 669	$ 809	$ 933	$ 1,033	$ 1,323	$ 1,849	$ 2,061
13	74.00%	$ 633	$ 651	$ 787	$ 909	$ 1,006	$ 1,288	$ 1,800	$ 2,007
14	72.00%	$ 616	$ 634	$ 766	$ 884	$ 978	$ 1,254	$ 1,752	$ 1,953
15	70.00%	$ 599	$ 616	$ 745	$ 860	$ 951	$ 1,219	$ 1,703	$ 1,898
16	68.00%	$ 582	$ 598	$ 724	$ 835	$ 924	$ 1,184	$ 1,654	$ 1,844
17	66.00%	$ 565	$ 581	$ 702	$ 810	$ 897	$ 1,149	$ 1,606	$ 1,790
18	64.00%	$ 548	$ 563	$ 681	$ 786	$ 870	$ 1,114	$ 1,557	$ 1,736
19	62.00%	$ 531	$ 546	$ 660	$ 761	$ 843	$ 1,079	$ 1,508	$ 1,681
20	60.00%	$ 514	$ 528	$ 638	$ 737	$ 815	$ 1,045	$ 1,460	$ 1,627
21	58.00%	$ 496	$ 510	$ 617	$ 712	$ 788	$ 1,010	$ 1,411	$ 1,573
22	56.00%	$ 479	$ 493	$ 596	$ 688	$ 761	$ 975	$ 1,362	$ 1,519
23	54.00%	$ 462	$ 475	$ 575	$ 663	$ 734	$ 940	$ 1,314	$ 1,464
24	52.00%	$ 445	$ 458	$ 553	$ 639	$ 707	$ 905	$ 1,265	$ 1,410
25	50.00%	$ 428	$ 440	$ 532	$ 614	$ 680	$ 871	$ 1,217	$ 1,356
26	48.00%	$ 411	$ 422	$ 511	$ 589	$ 652	$ 836	$ 1,168	$ 1,302
27	46.00%	$ 394	$ 405	$ 489	$ 565	$ 625	$ 801	$ 1,119	$ 1,248
28	44.00%	$ 377	$ 387	$ 468	$ 540	$ 598	$ 766	$ 1,071	$ 1,193
29	42.00%	$ 360	$ 370	$ 447	$ 516	$ 571	$ 731	$ 1,022	$ 1,139
30	40.00%	$ 342	$ 352	$ 426	$ 491	$ 544	$ 696	$ 973	$ 1,085
31	38.00%	$ 325	$ 334	$ 404	$ 467	$ 516	$ 662	$ 925	$ 1,031
32	36.00%	$ 308	$ 317	$ 383	$ 442	$ 489	$ 627	$ 876	$ 976
33	34.00%	$ 291	$ 299	$ 362	$ 418	$ 462	$ 592	$ 827	$ 922
34	32.00%	$ 274	$ 282	$ 340	$ 393	$ 435	$ 557	$ 779	$ 868
35	30.00%	$ 257	$ 264	$ 319	$ 368	$ 408	$ 522	$ 730	$ 814
36	28.00%	$ 240	$ 246	$ 298	$ 344	$ 381	$ 487	$ 681	$ 759
37	26.00%	$ 223	$ 229	$ 277	$ 319	$ 353	$ 453	$ 633	$ 705
38	24.00%	$ 205	$ 211	$ 255	$ 295	$ 326	$ 418	$ 584	$ 651
39	22.00%	$ 188	$ 194	$ 234	$ 270	$ 299	$ 383	$ 535	$ 597
40	20.00%	$ 171	$ 176	$ 213	$ 246	$ 272	$ 348	$ 487	$ 542
41	18.00%	$ 154	$ 158	$ 192	$ 221	$ 245	$ 313	$ 438	$ 488
42	16.00%	$ 137	$ 141	$ 170	$ 196	$ 217	$ 279	$ 389	$ 434
43	14.00%	$ 120	$ 123	$ 149	$ 172	$ 190	$ 244	$ 341	$ 380
44	12.00%	$ 103	$ 106	$ 128	$ 147	$ 163	$ 209	$ 292	$ 325
45	10.00%	$ 86	$ 88	$ 106	$ 123	$ 136	$ 174	$ 243	$ 271
46	8.00%	$ 68	$ 70	$ 85	$ 98	$ 109	$ 139	$ 195	$ 217
47	6.00%	$ 51	$ 53	$ 64	$ 74	$ 82	$ 104	$ 146	$ 163
48	4.00%	$ 34	$ 35	$ 43	$ 49	$ 54	$ 70	$ 97	$ 108
49	2.00%	$ 17	$ 18	$ 21	$ 25	$ 27	$ 35	$ 49	$ 54
50	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

AGE	CONDITION	30 F	35 FT	40 FT	45 FT	50	55 FT	60 FT	65 FT
0	100.00%	$ 2,367	$ 2,828	$ 3,006	$ 3,163	$ 3,885	$ 4,240	$ 4,925	$ 5,196
1	98.00%	$ 2,320	$ 2,771	$ 2,946	$ 3,100	$ 3,807	$ 4,155	$ 4,827	$ 5,092
2	96.00%	$ 2,272	$ 2,715	$ 2,886	$ 3,036	$ 3,730	$ 4,070	$ 4,728	$ 4,988
3	94.00%	$ 2,225	$ 2,658	$ 2,826	$ 2,973	$ 3,652	$ 3,986	$ 4,630	$ 4,884
4	92.00%	$ 2,178	$ 2,602	$ 2,766	$ 2,910	$ 3,574	$ 3,901	$ 4,531	$ 4,780
5	90.00%	$ 2,130	$ 2,545	$ 2,705	$ 2,847	$ 3,497	$ 3,816	$ 4,433	$ 4,676
6	88.00%	$ 2,083	$ 2,489	$ 2,645	$ 2,783	$ 3,419	$ 3,731	$ 4,334	$ 4,572
7	86.00%	$ 2,036	$ 2,432	$ 2,585	$ 2,720	$ 3,341	$ 3,646	$ 4,236	$ 4,469
8	84.00%	$ 1,988	$ 2,376	$ 2,525	$ 2,657	$ 3,263	$ 3,562	$ 4,137	$ 4,365
9	82.00%	$ 1,941	$ 2,319	$ 2,465	$ 2,594	$ 3,186	$ 3,477	$ 4,039	$ 4,261
10	80.00%	$ 1,894	$ 2,262	$ 2,405	$ 2,530	$ 3,108	$ 3,392	$ 3,940	$ 4,157
11	78.00%	$ 1,846	$ 2,206	$ 2,345	$ 2,467	$ 3,030	$ 3,307	$ 3,842	$ 4,053
12	76.00%	$ 1,799	$ 2,149	$ 2,285	$ 2,404	$ 2,953	$ 3,222	$ 3,743	$ 3,949
13	74.00%	$ 1,752	$ 2,093	$ 2,224	$ 2,341	$ 2,875	$ 3,138	$ 3,645	$ 3,845
14	72.00%	$ 1,704	$ 2,036	$ 2,164	$ 2,277	$ 2,797	$ 3,053	$ 3,546	$ 3,741
15	70.00%	$ 1,657	$ 1,980	$ 2,104	$ 2,214	$ 2,720	$ 2,968	$ 3,448	$ 3,637
16	68.00%	$ 1,610	$ 1,923	$ 2,044	$ 2,151	$ 2,642	$ 2,883	$ 3,349	$ 3,533
17	66.00%	$ 1,562	$ 1,866	$ 1,984	$ 2,088	$ 2,564	$ 2,798	$ 3,251	$ 3,429
18	64.00%	$ 1,515	$ 1,810	$ 1,924	$ 2,024	$ 2,486	$ 2,714	$ 3,152	$ 3,325
19	62.00%	$ 1,468	$ 1,753	$ 1,864	$ 1,961	$ 2,409	$ 2,629	$ 3,054	$ 3,222
20	60.00%	$ 1,420	$ 1,697	$ 1,804	$ 1,898	$ 2,331	$ 2,544	$ 2,955	$ 3,118
21	58.00%	$ 1,373	$ 1,640	$ 1,743	$ 1,835	$ 2,253	$ 2,459	$ 2,857	$ 3,014
22	56.00%	$ 1,326	$ 1,584	$ 1,683	$ 1,771	$ 2,176	$ 2,374	$ 2,758	$ 2,910
23	54.00%	$ 1,278	$ 1,527	$ 1,623	$ 1,708	$ 2,098	$ 2,290	$ 2,660	$ 2,806
24	52.00%	$ 1,231	$ 1,471	$ 1,563	$ 1,645	$ 2,020	$ 2,205	$ 2,561	$ 2,702
25	50.00%	$ 1,184	$ 1,414	$ 1,503	$ 1,582	$ 1,943	$ 2,120	$ 2,463	$ 2,598
26	48.00%	$ 1,136	$ 1,357	$ 1,443	$ 1,518	$ 1,865	$ 2,035	$ 2,364	$ 2,494
27	46.00%	$ 1,089	$ 1,301	$ 1,383	$ 1,455	$ 1,787	$ 1,950	$ 2,266	$ 2,390
28	44.00%	$ 1,041	$ 1,244	$ 1,323	$ 1,392	$ 1,709	$ 1,866	$ 2,167	$ 2,286
29	42.00%	$ 994	$ 1,188	$ 1,263	$ 1,328	$ 1,632	$ 1,781	$ 2,069	$ 2,182
30	40.00%	$ 947	$ 1,131	$ 1,202	$ 1,265	$ 1,554	$ 1,696	$ 1,970	$ 2,078
31	38.00%	$ 899	$ 1,075	$ 1,142	$ 1,202	$ 1,476	$ 1,611	$ 1,872	$ 1,974
32	36.00%	$ 852	$ 1,018	$ 1,082	$ 1,139	$ 1,399	$ 1,526	$ 1,773	$ 1,871
33	34.00%	$ 805	$ 962	$ 1,022	$ 1,075	$ 1,321	$ 1,442	$ 1,675	$ 1,767
34	32.00%	$ 757	$ 905	$ 962	$ 1,012	$ 1,243	$ 1,357	$ 1,576	$ 1,663
35	30.00%	$ 710	$ 848	$ 902	$ 949	$ 1,166	$ 1,272	$ 1,478	$ 1,559
36	28.00%	$ 663	$ 792	$ 842	$ 886	$ 1,088	$ 1,187	$ 1,379	$ 1,455
37	26.00%	$ 615	$ 735	$ 782	$ 822	$ 1,010	$ 1,102	$ 1,281	$ 1,351
38	24.00%	$ 568	$ 679	$ 721	$ 759	$ 932	$ 1,018	$ 1,182	$ 1,247
39	22.00%	$ 521	$ 622	$ 661	$ 696	$ 855	$ 933	$ 1,084	$ 1,143
40	20.00%	$ 473	$ 566	$ 601	$ 633	$ 777	$ 848	$ 985	$ 1,039
41	18.00%	$ 426	$ 509	$ 541	$ 569	$ 699	$ 763	$ 886	$ 935
42	16.00%	$ 379	$ 452	$ 481	$ 506	$ 622	$ 678	$ 788	$ 831
43	14.00%	$ 331	$ 396	$ 421	$ 443	$ 544	$ 594	$ 689	$ 727
44	12.00%	$ 284	$ 339	$ 361	$ 380	$ 466	$ 509	$ 591	$ 624
45	10.00%	$ 237	$ 283	$ 301	$ 316	$ 388	$ 424	$ 492	$ 520
46	8.00%	$ 189	$ 226	$ 240	$ 253	$ 311	$ 339	$ 394	$ 416
47	6.00%	$ 142	$ 170	$ 180	$ 190	$ 233	$ 254	$ 295	$ 312
48	4.00%	$ 95	$ 113	$ 120	$ 127	$ 155	$ 170	$ 197	$ 208
49	2.00%	$ 47	$ 57	$ 60	$ 63	$ 78	$ 85	$ 98	$ 104
50	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Revised: January 2005

AGE	CONDITION	30 FT	35 FT	40 FT	45 FT	50 FT	55 FT	60 FT	65 FT
0	100.00%	$ 2,509	$ 2,533	$ 2,717	$ 2,881	$ 3,012	$ 3,432	$ 4,124	$ 4,404
1	98.00%	$ 2,459	$ 2,482	$ 2,663	$ 2,823	$ 2,952	$ 3,363	$ 4,042	$ 4,316
2	96.00%	$ 2,409	$ 2,432	$ 2,608	$ 2,766	$ 2,892	$ 3,295	$ 3,959	$ 4,228
3	94.00%	$ 2,358	$ 2,381	$ 2,554	$ 2,708	$ 2,831	$ 3,226	$ 3,877	$ 4,140
4	92.00%	$ 2,308	$ 2,330	$ 2,500	$ 2,651	$ 2,771	$ 3,157	$ 3,794	$ 4,052
5	90.00%	$ 2,258	$ 2,280	$ 2,445	$ 2,593	$ 2,711	$ 3,089	$ 3,712	$ 3,964
6	88.00%	$ 2,208	$ 2,229	$ 2,391	$ 2,535	$ 2,651	$ 3,020	$ 3,629	$ 3,876
7	86.00%	$ 2,158	$ 2,178	$ 2,337	$ 2,478	$ 2,590	$ 2,952	$ 3,547	$ 3,787
8	84.00%	$ 2,108	$ 2,128	$ 2,282	$ 2,420	$ 2,530	$ 2,883	$ 3,464	$ 3,699
9	82.00%	$ 2,057	$ 2,077	$ 2,228	$ 2,362	$ 2,470	$ 2,814	$ 3,382	$ 3,611
10	80.00%	$ 2,007	$ 2,026	$ 2,174	$ 2,305	$ 2,410	$ 2,746	$ 3,299	$ 3,523
11	78.00%	$ 1,957	$ 1,976	$ 2,119	$ 2,247	$ 2,349	$ 2,677	$ 3,217	$ 3,435
12	76.00%	$ 1,907	$ 1,925	$ 2,065	$ 2,190	$ 2,289	$ 2,608	$ 3,134	$ 3,347
13	74.00%	$ 1,857	$ 1,874	$ 2,011	$ 2,132	$ 2,229	$ 2,540	$ 3,052	$ 3,259
14	72.00%	$ 1,806	$ 1,824	$ 1,956	$ 2,074	$ 2,169	$ 2,471	$ 2,969	$ 3,171
15	70.00%	$ 1,756	$ 1,773	$ 1,902	$ 2,017	$ 2,108	$ 2,402	$ 2,887	$ 3,083
16	68.00%	$ 1,706	$ 1,722	$ 1,848	$ 1,959	$ 2,048	$ 2,334	$ 2,804	$ 2,995
17	66.00%	$ 1,656	$ 1,672	$ 1,793	$ 1,901	$ 1,988	$ 2,265	$ 2,722	$ 2,907
18	64.00%	$ 1,606	$ 1,621	$ 1,739	$ 1,844	$ 1,928	$ 2,196	$ 2,639	$ 2,819
19	62.00%	$ 1,556	$ 1,570	$ 1,685	$ 1,786	$ 1,867	$ 2,128	$ 2,557	$ 2,730
20	60.00%	$ 1,505	$ 1,520	$ 1,630	$ 1,729	$ 1,807	$ 2,059	$ 2,474	$ 2,642
21	58.00%	$ 1,455	$ 1,469	$ 1,576	$ 1,671	$ 1,747	$ 1,991	$ 2,392	$ 2,554
22	56.00%	$ 1,405	$ 1,418	$ 1,522	$ 1,613	$ 1,687	$ 1,922	$ 2,309	$ 2,466
23	54.00%	$ 1,355	$ 1,368	$ 1,467	$ 1,556	$ 1,626	$ 1,853	$ 2,227	$ 2,378
24	52.00%	$ 1,305	$ 1,317	$ 1,413	$ 1,498	$ 1,566	$ 1,785	$ 2,144	$ 2,290
25	50.00%	$ 1,255	$ 1,267	$ 1,359	$ 1,441	$ 1,506	$ 1,716	$ 2,062	$ 2,202
26	48.00%	$ 1,204	$ 1,216	$ 1,304	$ 1,383	$ 1,446	$ 1,647	$ 1,980	$ 2,114
27	46.00%	$ 1,154	$ 1,165	$ 1,250	$ 1,325	$ 1,386	$ 1,579	$ 1,897	$ 2,026
28	44.00%	$ 1,104	$ 1,115	$ 1,195	$ 1,268	$ 1,325	$ 1,510	$ 1,815	$ 1,938
29	42.00%	$ 1,054	$ 1,064	$ 1,141	$ 1,210	$ 1,265	$ 1,441	$ 1,732	$ 1,850
30	40.00%	$ 1,004	$ 1,013	$ 1,087	$ 1,152	$ 1,205	$ 1,373	$ 1,650	$ 1,762
31	38.00%	$ 953	$ 963	$ 1,032	$ 1,095	$ 1,145	$ 1,304	$ 1,567	$ 1,674
32	36.00%	$ 903	$ 912	$ 978	$ 1,037	$ 1,084	$ 1,236	$ 1,485	$ 1,585
33	34.00%	$ 853	$ 861	$ 924	$ 980	$ 1,024	$ 1,167	$ 1,402	$ 1,497
34	32.00%	$ 803	$ 811	$ 869	$ 922	$ 964	$ 1,098	$ 1,320	$ 1,409
35	30.00%	$ 753	$ 760	$ 815	$ 864	$ 904	$ 1,030	$ 1,237	$ 1,321
36	28.00%	$ 703	$ 709	$ 761	$ 807	$ 843	$ 961	$ 1,155	$ 1,233
37	26.00%	$ 652	$ 659	$ 706	$ 749	$ 783	$ 892	$ 1,072	$ 1,145
38	24.00%	$ 602	$ 608	$ 652	$ 691	$ 723	$ 824	$ 990	$ 1,057
39	22.00%	$ 552	$ 557	$ 598	$ 634	$ 663	$ 755	$ 907	$ 969
40	20.00%	$ 502	$ 507	$ 543	$ 576	$ 602	$ 686	$ 825	$ 881
41	18.00%	$ 452	$ 456	$ 489	$ 519	$ 542	$ 618	$ 742	$ 793
42	16.00%	$ 401	$ 405	$ 435	$ 461	$ 482	$ 549	$ 660	$ 705
43	14.00%	$ 351	$ 355	$ 380	$ 403	$ 422	$ 480	$ 577	$ 617
44	12.00%	$ 301	$ 304	$ 326	$ 346	$ 361	$ 412	$ 495	$ 528
45	10.00%	$ 251	$ 253	$ 272	$ 288	$ 301	$ 343	$ 412	$ 440
46	8.00%	$ 201	$ 203	$ 217	$ 230	$ 241	$ 275	$ 330	$ 352
47	6.00%	$ 151	$ 152	$ 163	$ 173	$ 181	$ 206	$ 247	$ 264
48	4.00%	$ 100	$ 101	$ 109	$ 115	$ 120	$ 137	$ 165	$ 176
49	2.00%	$ 50	$ 51	$ 54	$ 58	$ 60	$ 69	$ 82	$ 88
50	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

AGE	CONDITION	30 FT	35 FT	40 FT	45 FT	50 FT	55 FT	60 FT	65 FT
0	100.00%	$ 2,645	$ 3,036	$ 3,178	$ 3,511	$ 3,919	$ 4,457	$ 5,325	$ 5,779
1	98.00%	$ 2,592	$ 2,975	$ 3,114	$ 3,441	$ 3,841	$ 4,368	$ 5,219	$ 5,663
2	96.00%	$ 2,539	$ 2,915	$ 3,051	$ 3,371	$ 3,762	$ 4,279	$ 5,112	$ 5,548
3	94.00%	$ 2,486	$ 2,854	$ 2,987	$ 3,300	$ 3,684	$ 4,190	$ 5,006	$ 5,432
4	92.00%	$ 2,433	$ 2,793	$ 2,924	$ 3,230	$ 3,605	$ 4,100	$ 4,899	$ 5,317
5	90.00%	$ 2,381	$ 2,732	$ 2,860	$ 3,160	$ 3,527	$ 4,011	$ 4,793	$ 5,201
6	88.00%	$ 2,328	$ 2,672	$ 2,797	$ 3,090	$ 3,449	$ 3,922	$ 4,686	$ 5,086
7	86.00%	$ 2,275	$ 2,611	$ 2,733	$ 3,019	$ 3,370	$ 3,833	$ 4,580	$ 4,970
8	84.00%	$ 2,222	$ 2,550	$ 2,670	$ 2,949	$ 3,292	$ 3,744	$ 4,473	$ 4,854
9	82.00%	$ 2,169	$ 2,490	$ 2,606	$ 2,879	$ 3,214	$ 3,655	$ 4,367	$ 4,739
10	80.00%	$ 2,116	$ 2,429	$ 2,542	$ 2,809	$ 3,135	$ 3,566	$ 4,260	$ 4,623
11	78.00%	$ 2,063	$ 2,368	$ 2,479	$ 2,739	$ 3,057	$ 3,476	$ 4,154	$ 4,508
12	76.00%	$ 2,010	$ 2,307	$ 2,415	$ 2,668	$ 2,978	$ 3,387	$ 4,047	$ 4,392
13	74.00%	$ 1,957	$ 2,247	$ 2,352	$ 2,598	$ 2,900	$ 3,298	$ 3,941	$ 4,276
14	72.00%	$ 1,904	$ 2,186	$ 2,288	$ 2,528	$ 2,822	$ 3,209	$ 3,834	$ 4,161
15	70.00%	$ 1,852	$ 2,125	$ 2,225	$ 2,458	$ 2,743	$ 3,120	$ 3,728	$ 4,045
16	68.00%	$ 1,799	$ 2,064	$ 2,161	$ 2,387	$ 2,665	$ 3,031	$ 3,621	$ 3,930
17	66.00%	$ 1,746	$ 2,004	$ 2,097	$ 2,317	$ 2,587	$ 2,942	$ 3,515	$ 3,814
18	64.00%	$ 1,693	$ 1,943	$ 2,034	$ 2,247	$ 2,508	$ 2,852	$ 3,408	$ 3,699
19	62.00%	$ 1,640	$ 1,882	$ 1,970	$ 2,177	$ 2,430	$ 2,763	$ 3,302	$ 3,583
20	60.00%	$ 1,587	$ 1,822	$ 1,907	$ 2,107	$ 2,351	$ 2,674	$ 3,195	$ 3,467
21	58.00%	$ 1,534	$ 1,761	$ 1,843	$ 2,036	$ 2,273	$ 2,585	$ 3,089	$ 3,352
22	56.00%	$ 1,481	$ 1,700	$ 1,780	$ 1,966	$ 2,195	$ 2,496	$ 2,982	$ 3,236
23	54.00%	$ 1,428	$ 1,639	$ 1,716	$ 1,896	$ 2,116	$ 2,407	$ 2,876	$ 3,121
24	52.00%	$ 1,375	$ 1,579	$ 1,653	$ 1,826	$ 2,038	$ 2,318	$ 2,769	$ 3,005
25	50.00%	$ 1,323	$ 1,518	$ 1,589	$ 1,756	$ 1,960	$ 2,229	$ 2,663	$ 2,890
26	48.00%	$ 1,270	$ 1,457	$ 1,525	$ 1,685	$ 1,881	$ 2,139	$ 2,556	$ 2,774
27	46.00%	$ 1,217	$ 1,397	$ 1,462	$ 1,615	$ 1,803	$ 2,050	$ 2,450	$ 2,658
28	44.00%	$ 1,164	$ 1,336	$ 1,398	$ 1,545	$ 1,724	$ 1,961	$ 2,343	$ 2,543
29	42.00%	$ 1,111	$ 1,275	$ 1,335	$ 1,475	$ 1,646	$ 1,872	$ 2,236	$ 2,427
30	40.00%	$ 1,058	$ 1,214	$ 1,271	$ 1,404	$ 1,568	$ 1,783	$ 2,130	$ 2,312
31	38.00%	$ 1,005	$ 1,154	$ 1,208	$ 1,334	$ 1,489	$ 1,694	$ 2,023	$ 2,196
32	36.00%	$ 952	$ 1,093	$ 1,144	$ 1,264	$ 1,411	$ 1,605	$ 1,917	$ 2,080
33	34.00%	$ 899	$ 1,032	$ 1,081	$ 1,194	$ 1,332	$ 1,515	$ 1,810	$ 1,965
34	32.00%	$ 846	$ 972	$ 1,017	$ 1,124	$ 1,254	$ 1,426	$ 1,704	$ 1,849
35	30.00%	$ 793	$ 911	$ 953	$ 1,053	$ 1,176	$ 1,337	$ 1,597	$ 1,734
36	28.00%	$ 741	$ 850	$ 890	$ 983	$ 1,097	$ 1,248	$ 1,491	$ 1,618
37	26.00%	$ 688	$ 789	$ 826	$ 913	$ 1,019	$ 1,159	$ 1,384	$ 1,503
38	24.00%	$ 635	$ 729	$ 763	$ 843	$ 941	$ 1,070	$ 1,278	$ 1,387
39	22.00%	$ 582	$ 668	$ 699	$ 772	$ 862	$ 981	$ 1,171	$ 1,271
40	20.00%	$ 529	$ 607	$ 636	$ 702	$ 784	$ 891	$ 1,065	$ 1,156
41	18.00%	$ 476	$ 546	$ 572	$ 632	$ 705	$ 802	$ 958	$ 1,040
42	16.00%	$ 423	$ 486	$ 508	$ 562	$ 627	$ 713	$ 852	$ 925
43	14.00%	$ 370	$ 425	$ 445	$ 492	$ 549	$ 624	$ 745	$ 809
44	12.00%	$ 317	$ 364	$ 381	$ 421	$ 470	$ 535	$ 639	$ 693
45	10.00%	$ 264	$ 304	$ 318	$ 351	$ 392	$ 446	$ 532	$ 578
46	8.00%	$ 212	$ 243	$ 254	$ 281	$ 314	$ 357	$ 426	$ 462
47	6.00%	$ 159	$ 182	$ 191	$ 211	$ 235	$ 267	$ 319	$ 347
48	4.00%	$ 106	$ 121	$ 127	$ 140	$ 157	$ 178	$ 213	$ 231
49	2.00%	$ 53	$ 61	$ 64	$ 70	$ 78	$ 89	$ 106	$ 116
50	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

TABLE 2 - IT TRANSFER AND REARRANGEME COSTS TABLE

Unit Transfer or Rearrangement Costs 2005			
Crossarm	Single, (wood) ea.		$ 200
Crossarm	Double, (wood) ea.		$ 466
Crossarm	Triple, (wood) ea.		$ 599
Crossarm	(steel) ea.		$ 333
Secondary Rack	or Bracket		$ 84
Pole Top Pin ea.			$ 95
Saddle Clamp, ea.			$ 89
Spool Bolt or 1 Pt. Rack, ea.			$ 73
Post Type Insulator -	ea. up to 14KV		$ 111
Post Type Insulator -	ea, over 14KV		$ 133
Conductor Dead End	Primary, De-energized, ea.		$ 258
Conductor Dead End	Primary, Live up to 14KV, ea.		$ 383
Conductor Dead End	Primary, Live over 14KV, ea.		$ 433
Conductor Dead End	Secondary per Bus (1 Rack)		$ 326
Conductor Dead End	Secondary per Wire (Single Point Racks)		$ 198
Splices	Primary ea. Conductor Live		$ 314
Splices	Primary ea. Conductor De-Energized		$ 246
Splices	Secondary ea. Conductor		$ 82
Conductor Semi Strain	Primary, De-energized, ea.		$ 264
Conductor Semi Strain	Primary, Live up to 14KV, ea.		$ 344
Conductor Semi Strain	Primary, Live over 14KV, ea.		$ 389
Line Wire	Primary De-energized, Tang, ea.		$ 98
Line Wire	Primary Live up to 14 KV, Tang. ea.		$ 133
Line Wire	Primary Live over 14 KV, Tang. ea.		$ 155
Line Wire	Primary De-energized, Angle, ea.		$ 98
Line Wire	Primary Live up to 14 KV, Angle. ea.		$ 133
Line Wire	Primary Live over 14 KV, Angle ea.		$ 155
Line Wire	Secondary ea.		$ 69
Spun Secondary	Tangent or Small Angle	(0-30deg)	$ 195
Spun Secondary	Medium Angle	(30-60deg)	$ 278
Spun Secondary	Heavy Angle	(60-90deg)	$ 655
Spun Secondary	Dead End		$ 344
Triplex Service	one end on pole		$ 155
Triplex Service	one end on spun bus		$ 164
Triplex Service	replace service (100Ft)		$ 574

Triplex Service	splice		$ 170
Line Switch, ea.			$ 200
In Line Switch or Fuse Cutout			$ 588
Transformer Assembly, ea.			$ 996
Ground Wire, ea.			$ 133
Ground Rod, ea.			$ 148
Regulator, ea.			$ 2,220
Anchor	Plate or Log	ea.	$ 537
Anchor	Expansion	ea.	$ 577
Anchor	P.I.S.A.	ea.	$ 277
Anchor	Rock	ea.	$ 532
Guys			$ 257
Reclosers	1 Phase	Note- unit price does not include primary dead ends	$ 555
Reclosers	2 Phase	Note- unit price does not include primary dead ends	$ 833
Reclosers	3 Phase	Note- unit price does not include primary dead ends	$ 1,110
Street Light	Bracket, ea.		$ 278
Street Light	Relay, ea.		$ 133
Street Light	Photoelectric Controller		$ 178
Meter Test Box			$ 200
Under Ground	Primary Riser	No Splice	$ 1,082
Under Ground	Primary Riser	Splice and add 5 feet	$ 2,193
Under Ground	Secondary Riser	No Splice	$ 333
Under Ground	Secondary Riser	Splice and add 5 feet	$ 671
Triplex	Convert 3 wire service to triplex	1 spans	$ 521
Triplex	Convert 3 wire service to triplex	2 spans	$ 1,092
Pole Top Extension - Epoxy			$ 278
Pole Cribs, ea. (0.6meters)			$ 1,166
No. 44 Crossarm			$ 306
Connect/Disconnect Bell Bond To/From Neutral (Hydro Owned Poles Only)			$ 117
Extra Trip To job (Based on 2 Hrs. Travel - Round Trip)			$ 538
Special Work Vehicle Charge Billed as Extra Charge per pole, ie., Bombardiers or muskeg tractors applicable for work in locations not accessible to standard work vehicles ie. (Line Trucks)			$ 160
Float charge for Special Work Vehicle transportation			$ 400
Engineering Charge per hour	*Includes Truck		$ 138
Line Construction Labour Rate per man-hour			$ 117

Forestry Hourly Labour Rate per man-hour		$ 122
Administration Overhead for Contract Labour (% of contract)		16%
Miscellaneous Charges - Charges for other transfer and rearrangement activities for which unit cost is not provided may be established by estimating the time required for the work operation and applying the hourly labour rate that is provided above.		
Notes:		
1. Attachment or removal charges will be calculated at 50% of the transfer or rearrangement charges.		
2. When interspersing a pole charges will be calculated at 50% of the transfer or rearrangement charges.		
3. Unit Price Includes Material		
4. Miscellaneous Charges - Charges for other transfer and rearrangement activities for which unit cost is not provided may be established by estimating the time required for the work operation and applying the hourly labour rate that is provided above.		

New Pole Costs

Revised/Issued: Ja[illegible]ry 2005

Material Costs (dollars)	TYPE OF SETTING		
Height (Ft)	Earth, Earth Plus & Rock Drilled (Pole Only)	Cribbed Mount (pole, crib & backfill)	Rock Mount (Pole & rock mount)
30	$ 221	$ 689	$ 1,545
35	$ 244	$ 713	$ 2,006
40	$ 386	$ 855	$ 2,148
45	$ 508	$ 976	$ 2,269
50	$ 597	$ 1,065	$ 2,795
55	$ 916	$ 1,385	$ 3,114
60	$ 1,565	$ 2,033	$ 3,763
65	$ 1,800	$ 2,268	$ 3,998

Labour Costs (dollars)	TYPE OF SETTING					
Height (Ft)	Earth	Earth Plus or Swamp	Earth or Earth Plus Hydro Vac	Rock Drilled	Swamp with Cribbed Mount	Rock Mount
Pole Dig & Set (Includes delivery of pole from own yard, if required.)						
30	$ 338	$ 635	$ 1,380	$ 1,082	$ 1,820	$ 822
35	$ 338	$ 636	$ 1,380	$ 1,083	$ 1,820	$ 822
40	$ 381	$ 678	$ 1,423	$ 1,125	$ 1,862	$ 858
45	$ 423	$ 720	$ 1,464	$ 1,167	$ 1,905	$ 894
50	$ 481	$ 762	$ 1,507	$ 1,209	$ 1,947	$ 1,090
55	$ 526	$ 825	$ 1,569	$ 1,589	$ 2,047	$ 1,126
60	$ 569	$ 868	$ 1,612	$ 1,632	$ 2,091	$ 1,162
65	$ 613	$ 912	$ 1,656	$ 1,676	$ 2,136	$ 1,198
Pole Dig (only)						
30	$ 135	$ 407	$ 1,164	$ 892	$ 1,497	$ 534
35	$ 135	$ 408	$ 1,164	$ 893	$ 1,497	$ 534
40	$ 152	$ 424	$ 1,182	$ 909	$ 1,529	$ 558
45	$ 169	$ 441	$ 1,198	$ 875	$ 1,563	$ 581
50	$ 192	$ 458	$ 1,215	$ 907	$ 1,595	$ 709
55	$ 210	$ 483	$ 1,240	$ 1,192	$ 1,673	$ 732
60	$ 228	$ 500	$ 1,257	$ 1,224	$ 1,707	$ 755
65	$ 276	$ 502	$ 911	$ 1,257	$ 1,742	$ 779
Pole Set (only)						
30	$ 203	$ 228	$ 216	$ 190	$ 323	$ 288
35	$ 203	$ 228	$ 216	$ 190	$ 323	$ 288
40	$ 229	$ 254	$ 241	$ 216	$ 333	$ 300
45	$ 254	$ 279	$ 266	$ 241	$ 342	$ 313
50	$ 289	$ 304	$ 292	$ 266	$ 352	$ 381
55	$ 316	$ 342	$ 329	$ 303	$ 374	$ 394
60	$ 341	$ 368	$ 355	$ 328	$ 384	$ 407
65	$ 337	$ 394	$ 381	$ 355	$ 394	$ 419

Notes:	All pole digs other that (Blended or Rock Drilled) and (Rock Mounted) poles shall be supplied using a porta hole.	
Pole Removal & Recycling	$ 176	All lengths (each)
Extra Pole Space (charged if LDC requires more than 10 feet normal space on a pole)	$ 185	Per unit of additional 5ft.
Access Fee (to be charged per pole if no make ready exists)		$ 185

2-Staff-21 System Service - 9M2 Extension

Question:

Ref 1: 5.4.3.2.1.4 System Service – 9M2 Extension

Sudbury Hydro stated that the 44kV feeder project would be phased over 4-years to provide adequate supply capacity for the Kingsway Corridor. The Kingsway Corridor is fed by four stations MS6, MS11, MS16, and MS18.

a) Please confirm if the 44kV feeder will convert customer load to offload MS6 MS11, MS16, and MS18. If so, how many MVA will it offload and on which stations.
b) Please provide the designations of the 44kV circuits that feed the Kingsway Corridor.
c) Please provide the length of the 9M2 extension.
d) Sudbury Hydro stated that it would seek Hydro One's consent and participation in rebuilding the existing 9M4/9M5. Has Hydro One committed to this project and confirmed that they have the resources to complete the work in 2020?
e) As this project is completed over 4 years, will the extension at the end of each year leave that portion of the extension used and useful?
f) Sudbury Hydro stated that this investment is contingent on an ongoing legal process. To the extent possible, without filing for confidentiality, please explain the risk factors that affect this project. In the event that the legal proceeding causes the project to be cancelled/deferred, what alternative investment would Sudbury Hydro use the planned capital expenditures for?

Response:

a) The prospective investment related to the '9M2 Extension' is not intended to offload customer load from any existing municipal substations. Rather, the project would provide sufficient capability to connect load/REG at the **44kV** level.

b) The table below shows the four existing municipal substations which serve customer load along the “Kingsway Corridor” along with the 44kV Feeder designation:

Station Name	44kV Feeder
Levert	9M1
Gemmell	9M1
Barrydowne	9M1
Moonlight	9M4

c) The approximate length of the ‘9M2 Extension’ is 5.3km.

d) Hydro One has not yet committed to this project.

GSHi will be seeking Hydro One’s consent and participation in the rebuilding of the existing 9M4/9M5 44kV sub-transmission pole line that presently spans between Lasalle Blvd and Bancroft Dr. Hydro One owns the poles on which GSHi is currently a tenant. The expectation is that Hydro One will insist on placing the poles and performing all their own line work to complete transfer of plant to the new pole line, after which GSHi will attend the site to transfer/install its own plant.

e) Yes, the extension will be used and useful at the end of each year.

f) The optimal planning decisions for the “Kingsway Corridor” area are complex and are presently mired by considerable uncertainty with respect to ongoing legal processes involving the City of Greater Sudbury, Developer(s) and Interest Group(s) that are wholly outside of the control of GSHi. Once these issues are resolved, it is GSHi’s expectation that demand for electricity service to move prospective commercial developments toward commercialization will come quickly. However, the quantum and timing of the magnitude of the projected load growth along the “Kingsway Corridor” is contingent on decisions from the Local Planning Appeal Tribunal (LPAT) of Ontario, a topic which is presently the subject of considerable debate within our community.

As discussed in section **5.4.3.2 B.1d** of the DSP, the project is prioritized correctly. However, these plans may have to be re-visited/re-evaluated and are contingent on the outcomes of the legal processes which are currently underway.

The other crucial risk factor affecting this project will be securing a commitment from Hydro One to willingly participate in this project will greatly affect our utility's efforts to bring sufficient capacity to the proposed commercial developments in the "Kingsway Corridor" area at a reasonable cost.

In the event that the legal proceeding causes the project to be cancelled/deferred, Sudbury Hydro will instead use the planned capital expenditures to continue to implement a paced investment program that seeks to address a minimum number of assets on an annual basis to maintain expected electricity delivery service levels.

2-Staff-22 System Service - Sunnyside 12kV feeder relocation

Question:

Sudbury Hydro stated that it plans to relocate a portion of feeder from the bush to road allowance.

a) Please provide the total length of the feeder that will be constructed for the relocation.
b) Sudbury Hydro stated that it will be seeking consent and participation from Bell Canada. Has Bell Canada committed to this project?

Response:

a) The approximate total length of the feeder that will be constructed for the relocation project is 1.98km.

b) Bell Canada have not yet committed to this project.

GSHi will be seeking Bell Canada's consent and participation in the rebuilding of a portion of the proposed feeder relocation project spanning between municipal substation Long Lake MS20 and Sunnyside Rd. Bell Canada owns the poles along a right-of-way on which GSHi currently desires to become a tenant. The expectation is that Bell Canada will insist on placing the (higher) poles and performing all their own work to complete transfer of plant to the new pole line, after which GSHi will attend the site to transfer/install its own plant.

2-Staff-23 System Renewal - Cable Testing/Rejuvenation

Question:

Ref 1: 5.4.3.2.1.7 System Renewal – Cable Testing/Rejuvenation

Ref 2: Appendix I – Cable Testing

Sudbury Hydro completed an asset condition assessment by Kinectrics yet cables were not one of the assets that it reviewed.

a) Please explain why cables were not part of the ACA when underground cables represent 25% of Sudbury Hydro's distribution system.
b) There was no historical spending for the Cable Testing/Rejuvenation capital investments. Please provide the historical capital investments and kilometers of cable Sudbury Hydro made in cable testing/rejuvenation, if any.
c) Please provide the length of cable planned for testing/rejuvenation each year.

Sudbury Hydro used Energy Ottawa to complete cable testing on Sudbury Hydro's distribution system. Energy Ottawa tested twenty-seven cables and found seven were in good condition, eighteen were in fair condition, and two in poor condition.

d) Please explain why only twenty-seven cables were tested and on what basis were they selected.
e) Please confirm if the budgeted capital spending is for the replacement of cables found in poor condition.
f) Please explain why there is no forecasted spending for 2023 and 2024.

Response:

a) Historically, because most of the underground cable sections in GSHi's service territory are relatively short in length and are installed in conduit, they were physically removed from service and new cables were installed following an outage event.

   The challenge with this approach is that it is not sustainable when there are a number of cables that are either at or approaching their life expectancy. Unexpected outages can consume a signification portion of an O&M budget and lead to poor reliability. With the help of the novel testing method developed in partnership between Natural Resources Canada and Energy Ottawa, it will be possible for GSHi to transition from reactive-based cable maintenance to condition-based cable maintenance. With use of the sophisticated testing procedure, it is possible to identify cables whose condition has deteriorated due to the presence of water treeing within the cable itself. With this new asset data available to augment existing condition evaluations, an improvement in being able to correctly select and prioritize prospective underground *System Renewal* investments in particular is expected.

Cable sections that are ultimately targeted by this investment will not necessarily have a record of poor performance. It is expected that the majority of the cables that will require rejuvenation will have surpassed their expected in-service life of 40 years.

b) Historically, Sudbury Hydro has not introduced cable rejuvenation practices into its asset management process. With this prospective investment program, the intent is to test and rejuvenate as many cable segments as practicable.

In 2017, Sudbury Hydro undertook a $7,500 pilot program with Energy Ottawa to begin testing of its underground cables. That year, the program tested 27 segments with a combined total length of 3.54km.

c) The intent is to test and rejuvenate as many cable segments as practicable. Sudbury Hydro does not have an estimate for the length of cable that may be tested each year.
Factors that may affect the timing and/or priority of the project include:

- Availability of the Testing Service Provider;
- Availability of the Rejuvenation Service Provider;
- Competitive pricing from service providers (will not proceed if non-competitive);
- Availability of internal GSHi staff to provide ancillary support to service providers (e.g. isolation switching);
- Customer requirements (from consultations) regarding scheduling of planned outages

d) The cable testing pilot project which GSHi undertook in 2017 upon which this prospective investment program is now based was provided by Energy Ottawa. Energy Ottawa came to Sudbury and along with members of our Operations group tested as many cable sections as possible during the week of July 24-28, 2017.

With the testing, the reason for selecting certain cable sections was to ascertain to a greater degree of confidence the actual condition of those underground cable sections which were typically located in older portions of Sudbury Hydro's service territory. Then, using the testing results, the intent was to then confirm the reasonableness, from a risk perspective, of deferring prospective capital investment(s) in asset replacement(s).

e) No, the budgeted capital spending is <u>not</u> related to the physical replacement of cables found in poor condition. Rather, the proposed capital spending is intended to accomplish two goals:

1) For as many cable segments as possible, begin to generate condition data; and
2) For cable segments that test poorly – initiate refurbishment (rather than replacement) of the segments by procuring a cable rejuvenation services provider.

f) In terms of prospective investment prioritization, the 'Cable Testing/Rejuvenation' program scores fairly low compared to other investments which are tabled in the DSP. The cable rejuvenation technology has never been utilized by Sudbury Hydro and would need to show positive results for the utility to commit to expanding any kind of investment program. Thus, the DSP tables a program that would see prospective spending occurring in 2020 through 2022 without making a commitment to further spending in the years 2023 through 2024.

2-Staff-24 General Plant - Outage Management System

Question:

Ref 1: 5.4.3.2.1.8 General Plant – Outage Management System

Ref 2: Appendix J – GSU Routing Study Siemens Smart Grid Compass, p. 228

As part of Sudbury Hydro's grid modernization it plans to deploy an Outage Management System.

a) Please confirm if this investment is related to Sudbury Hydro's smart grid plans in reference 2, specifically Value Pack 7.
b) In reference 2, the estimated cost of the Outage Management System is $323,743, while in reference 1, the cost estimate was $440,000. Please explain the variance.

Response:

a) Sudbury Hydro confirms that this investment is related to the smart grid plans cited in reference 2, value pack 7.

b) In reference 2, value pack 7, the cost attributed to an *Outage Management System* was an initial estimate by Siemens to assist GSHi senior management in their consideration of an overall 'Smart Grid' program. Reference 1 lists a cost estimate of $440,000 (spread over 2020 and 2021) which reflects the recent price quotations received by GSHi from prospective vendors for this software product.

2-Staff-25 System Renewal - Cressey MS3 Rebuild/Voltage Conversion

Question:

Ref 1: 5.4.3.2.1.9 System Renewal – Cressey MS3 Rebuild/Voltage Conversion

Sudbury Hydro has planned to convert the existing 4.16kV system to 12.47kV in the City of Sudbury. This will result in the retirement of the municipal stations MS9, MS12, and MS14.

a) Please provide the length of the feeder planned to be converted each year.
b) Please provide a detailed scope of work and cost breakdown of the Cressey MS3 station rebuild.
c) Please explain Sudbury Hydro's decision to design the station underground and use pad-mounted structures.
d) Sudbury Hydro stated that the T1 and T2 will be upgraded from their present combined rating of 10MVA but the peak station loading is 6.96MVA. Please provide the size of the upgraded transformers and justification of the larger transformers when the peak load is well below the combined rating.

Response:

a) The length of the feeder planned to be converted each year is as follows:
   2020: 15.5km

   2021: 5.1km

   2022: 50.2km

b) Cressey MS3 Station Rebuild - Scope of Work.

   The Cressey MS3 substation is GSHi's largest municipal station based on property size. The total station contains a substation yard, with the '3T1' and ‘3T2’ bank of transformers, as well as the ‘3T3’ with its own 44kV Switch, transformer, switchgear and building. On the property is a large brick two storey building, which houses the switchgear for both the 3T1 and 3T2. In total, the station has ten distribution feeders which are fed by the three power transformers.

The existing station building is in generally good condition and is a twin to the Kathleen MS2 municipal substation building.

The prospective investment in 2021 to renew Cressey MS3 will see an anticipated installed capacity of 20/26.666 MVA (two x 10/13.333 MVA power transformers). The station will be rebuilt with two (2) - 44kV ingress feeds and eight (8)-12.47kV feeders egressing the substation building.

The design is expected to incorporate two pad-mounted 44kV load-break switches complete with fuses and motor controller (3T1-L & 3T2-L), two (2) x 10/13.333 MVA ONAF transformers with on-load tap changers (3T1, 3T2) and a lineup of eight feeders housed in arc-resistant switchgear.

The 15kV Switchgear will house incoming cells (3B1, 3B2) with breakers and a tie cell (3B1B2). The 15kV switchgear, protective relays and SCADA equipment will be located inside the existing building.

Work to be completed in the rebuild:

- Preliminary engineering completed by GSHi;
- Consulting services will be hired for detailed electrical and civil design;
- Existing end-of-life equipment to be removed;
- Tower in substation yard to be dismantled;
- GHSi to remove the existing foundations and structures. The substation yard is to be excavated, and old material removed;
- Disposal of existing station transformers;
- Disposal of existing 5kV switchgear lineup;
- Drain and Dispose existing 5kV Oil breakers;
- Excavate and demolish existing duct banks;
- New backfill and subgrade;
- New 44kV feeder ingress (concrete encased duct banks);
- New 44kV switchgear concrete foundations, with new S&C Electric 46kV outdoor metal clad load-break switches, c/w fuses and motor operators for remote control;

- New transformer foundations with oil containment pit and fire/noise barrier wall;
- Install new 44kV to 12.47kV, 10/13.333 MVA power transformers c/w on-load tap changers;
- Complete building restorations as required;
- New leveling pad for 15kV switchgear;
- New 15kV switchgear, 13 cells and station service. Switchgear will contain a Main-tie-Main configuration;
- Eight new 15kV distribution feeders in concrete-encased duct banks;
- New risers and riser poles, c/w switches. New tie switches for operational flexibility;
- New SCADA cabinet and equipment;
- New DC plant for each of the 3T1 and 3T2.

For a cost breakdown of the prospective plans to rebuild municipal substation Cressey MS3, please see **Attachment #1**.

c) The decision to build or rebuild a substation either overhead or underground is underpinned by a number of potential factors, some of which are listed below:

1 – **Proximity and Location** – GSHi's preference is to design stations to include pad-mounted equipment in higher-risk areas. (e.g., residential neighbourhoods, proximity to schools/playgrounds, or other high traffic areas).

2 – **Weather and Animals** – Pad-mounted equipment is less susceptible to outside impacts such as weather, animals, squirrels, etc.

3 – **Reliability** – Undergrounding of distribution systems tends to provide increased service continuity as compared with an overhead design. Further, maintenance costs are reduced with an underground distribution system where the cost to maintain items such as overhead structures and insulators can be avoided.

4 – **Excavation costs** – Because most of the prospective station rebuilds have existing foundations and structures, GSHi is already excavating

within the confines of the site and removing existing infrastructure. There is little to no additional cost to prep sub-surface for underground equipment or pad-mounted equipment.

5 – **Yard size and Aesthetics** – Typically, GSHi has had the necessary space within the footprint of existing municipal stations where the decision to build underground and use pad-mounted equipment was possible.

6 - **Community Input** – During previous customer consultations with the community, as for example those described in the *Distribution System Plan*, pg 40, customers have given the planning group at GSHi positive feedback regarding the utility's proposed pad-mounted equipment designs. The feedback gathered following these activities provided GSHi the consent needed to proceed with the project as planned.

With these factors in mind, GSHi decided to design the prospective station rebuild of the Cressey T1 and T2 employing an underground approach which will include pad-mounted equipment.

d) The upgraded T1 and T2 transformers at Cressey MS3 will each have a rating of 10/13.333 MVA. The increased capacity at Cressey MS3 will allow the loads from other existing 4kV stations to be transferred to the new 3T1 and 3T2. Upon completion of the 4kV to 12kV voltage conversion project, Cressey T1 and T2 will service loads that were previously supplied at 4kV by the combination of Cressey T1/T2, Cressey T3, as well as by municipal substation Centennial MS14, and a portion of municipal substation Regent MS9. In numbers, the magnitude of the load serviced is as follows:

Present Cressey T1/T2 peak load = 6.96MVA
Future Cressey T1/T2 load = [3T1/T2 + 3T3 + 14T1 + 0.5(9T1)] MVA
= [6.96 + 5.16 + 3.28 + 0.5(5.3)] MVA
= 18.05 MVA

Attachment 1 (of 1):

2-Staff-25 Attachment 1: Cressy Substation MS - Budget Costs

Greater Sudbury Utilities

Prepared by: K. England

Cressey MS3 Substation - Budget Costs

Cressey MS3 Details

Voltage	44 - 12.47/7.2 kV
Capacity	20/26.66 MVA ONAN/ONAF
Transformer(s)	Two - 10/13MVA, ONAN/ONAF - 44kV-12.47/7.2kV w. OLTC 17 Taps. +- 5%. Oil Filled Power Transformers
Switchgear Type	Indoor Metal Clad and Outdoor Padmount Metal Enclosed
44kV Main Breaker/Switch	S&C Electric 46kV LBS c/w fuses and motor operator
15kV Switchgear	Gas Insulated Swg. Main-Tie-Main configuration
Feeder Breakers	15 kV 800A Vacuum Breakers
Feeder Egress	8 Underground 15 kV Risers

Item	Cost Detail	Summary	Notes
Engineering & Design			
1.1) Preliminary Design	$ 10,000		300 man hours. Includes Building assessment, budget update
1.2) Geotechnical investigation	$ 18,000		Geotechnical
Construction Geotechnical	$ 22,000		
1.3) Public input session	$ 2,500		
1.4) Project Management	$ 62,000		Project oversight & includes Onsite Owners Engineer for Const.
1.5) Typical Grounding Design	$ 35,000		Includes Neutral Driving Point Impedance test
1.6) Detailed engineering & Design	$ 135,000		External Engineering
1.7) Protection Study and Final Commissioning	$ 15,000		Internal Protection study and Develop relay settings
		$ 299,500	
Civil Construction			
2.1) Construction Power	$ 7,500		
2.2) Clearing, Grubbing, Grading, compacting, fill	$ 50,625		No Allocation for rock removal, blasting or drilling.
Granular Backfill	$ 100,474		Assumes no contaminated soils, Assumes 3m excavation
2.3) Site access and controls	$ 10,000		
2.4) Oil Containment	$ 77,100		Shared containment, Concrete poured.
2.5) Duct Banks 15kV (approx. 490m)	$ 213,800		Estimated Distances, assumed concrete encased, 5 duct. No drilling
44kV (approx. 125m)	$ 52,800		Estimated Distances, assumed concrete encased, 4 duct
2.6) Concrete Foundations	$ 210,000		
2.7) TX Fire Wall ($465 pr sq m)	$ 130,000		Approx. dimensions 4m High, 80 Linear meters
2.8) Fence, Yard Stone and Landscaping	$ 125,000		
		$ 977,299	
Major equipment			
3.1) Power Transformers 10/13.33 MVA OLTC (x2)	$ 1,023,000		CSA and Hydro One Standard - OLTC
3.2) 44kV Switchgear	$ 220,000		Pad Mounted metal clad switchgear, c/w Motor operator and fuses
3.3) 15 kV Switchgear and breakers	$ 890,000		Metal clad with breakers
3.5) Cable Support and tray in building	$ 15,000		
3.6) Station DC Plant	$ 65,000		
3.7) Station Service / Street Service	$ 7,500		
3.8) 44 kV Cables/Terminators est. 390m	$ 22,680		Estimated Distances and # of terminations, includes labour
3.9) 15 kV 350 MCM Cables/Terminators est. 1720m	$ 118,860		Estimated Distances and # of terminations, includes Labour
3.10) Solid Blade Riser Switches (24)	$ 22,080		Riser Pole Switches
		$ 2,384,120	
Electrical			
4.1) Grounding	$ 62,580		
4.2) 44 kV Dip Pole x2	$ 16,200		
4.3) 15 kV Riser Poles x8	$ 38,400		
4.4) Installation of Transformers	$ 27,000		Assumes 1 crane visit, both units shipped together
4.5) Installation of Switchgear	$ 38,000		Forklift and equipment rental and installation
4.6) Power & Control Cabling. Building LV work	$ 67,000		
4.7) Station Service Panels, Disconnects	$ 22,000		
4.8) Electrical Commissioning	$ 35,000		
		$ 306,180	
Miscellaneous			
5.1) Mobilization, Bonding, Insurance	$ 15,200		
5.2) Fees & Permits	$ 8,000		
5.3) Building Improvements	$ 22,092		Building assessment + Minor Improvements
		$ 45,292	
SCADA & Protection and Control			
6.1) Communications and Fiber	$ 32,000		SCADA Equipment supplied and installed by GSHI
6.2) SCADA Equipment and RTU	$ 22,150		
6.3) Commissioning	$ 6,500		
		$ 60,650	
Sub-Total		$ 4,073,041	
Contingency 7.5%		$ 4,378,519	
Total		**$ 4,378,519**	

Further Assumptions

Assumed Average hourly wage per tradesperson with overheads $75.00
Assumed Construction labour 2 person crew with vehicle - $196
Budget is accurate within 15%, (+ or -7.5%)
Budget will be reviewed after preliminary studies and after detailed engineering in Q3 and Q4 of 2020
Equipment values are based on previous projects and budgetary estimates from vendors

2-Staff-26 Smart Grid

Question:

Ref 1: Appendix G IESO Letter of Comment/Green Energy Plan

Ref 2: Chapter 2 Appendices – 2-AA

Ref 3: Chapter 2 Appendices – 2-JC

Sudbury Hydro showed in its Green Energy Plan an expected cost of $18,000 each year between 2020-2024 for monitoring, control, and transfer trips.

a) The costs from the Green Energy Plan are not shown separately in Appendix 2-AA. Please confirm that the costs are rolled up in other distribution projects.

Sudbury Hydro showed in its Green Energy Plan an expected cost of $20,000 each year between 2020-2024 for Smart Grid/REG Education and Training.

a) The costs from the Green Energy Plan are not shown separately in Appendix 2-JC. Please confirm that the costs are rolled up in other distribution OM&A expenses.

Response:

Yes, GSHi confirms these costs are rolled up in other distribution projects and other OM&A expenses respectively.

2-Staff-27 Smart Grid

Question:

Ref 1: Appendix J – GSU Routing Study Siemens Smart Grid Compass

In Sudbury Hydro's grid modernization plan, it has divided the overall plan into 12 grouped investments called Value Packs, which share similar technology requirements and a distinct theme.

a) Please provide a schedule of Sudbury Hydro's progress on its grid modernization plan and include timelines for all 12 Value Packs.
b) The study forecasted key performance indicators (KPIs) for each Value Pack. For the Value Packs that are completed, please provide actual performance indicators and compare them to the forecasted KPIs.

Response:

a) The Siemens Smart Grid Compass was developed at a time when public policy was requiring utilities to engage in extensive planning and preparedness for the anticipated mass deployment of new energy technologies and associated network upgrades on accelerated timelines. Shortly after the Siemens Compass report was complete, GSHi began introducing formal change and project management practices to respond to Siemens' recommendations (grouped into value packs).

   However, with the change in provincial government in 2018 and the accompanying shift in public policy, the pace and rate of adoption of what was formerly seen as high-growth-potential technologies such as Distributed Energy Resource Management Systems has slowed considerably. As a result, GSHi has chosen to focus on value pack initiatives that build foundational capacity and add direct value to ratepayers. Projects have been prioritized based on an assessment of key organizational factors such as technology maturity, readiness, resource availability and workforce capability. Examples of some of these projects are presented in GSHi's response to 4-Staff-56 Innovation (Exhibit 10, Tab 1, Schedule 56).

Below is a listing of Siemens' value packs with examples of some of the initiatives that are in progress, planned, or which may be considered in the future:

Value Pack & some initiatives in progress, planned or viable for future consideration	Start	End Year	Ongoing Improvement
VP0 Change management, etc.	2016	2018	Y
VP.1 Enhanced Asset & Work Information Enterprise Asset Management - 360° Asset Register, introduce basic KPI system for asset class, introduce joint coordination and planning of IT/OT implementations and management, introduce internal employee briefings.	2019	2022	Y
VP.2 Basic Performance Monitoring Enterprise Asset Management Condition Based Maintenance, Integration - Visualization, manage asset information consistently across organizational boundaries, Introduce strategic prioritization of individual assets.	2021	2025	Y
VP.3 Grid Value Maximization Leveraging Grid Information Grid Segment Analysis, Workforce Management - Mobile Workforce, introduce a comprehensive approach to the management of change, Vary parameter sets to setup different scenarios, Introduce historic information access in the field	2021	2025	Y
VP.4 Leveraging Grid Information for Enhanced Performance Monitoring Enterprise Asset Management - GIS, Chronological Model, KPI system for all assets, grid structures as aggregation hierarchies, introduce analysis of consumption using historic data, establish electronic communication between control center and work crews	2019	2025	Y
VP.5 Introducing Business Value and Risk as Parameters for Asset Management Strategic Asset Management-Planning Integration and Risk Based Asset Management, Reporting on a regular basis, Analysis of consumption and supply over a period of time	2020	2024	Y
VP.6 Extending Network Planning through Lean Design Techniques Introduce active integration of new technologies and information into design and planning	2021	2023	Y
VP.7 Utilize Reliability and Communication Improvements to Improve Customer Satisfaction Leverage portal as broadcast channel for the utility	2021	2023	Y
VP.8 Basic Demand-Side Management	-	-	-
VP.9 Balance Load & Generation Based on Network Condition	-	-	-
VP.10 Advanced Demand Side Management	-	-	-
VP.11 Advanced Grid Management Based on Substation Automation	-	-	-
VP.12 Introduction of Self-Healing Network Characteristics	-	-	-

b) As none of the Value Packs have been completed, comparison between forecast KPIs and actual KPIs cannot be completed.

2-Staff-28 System Renewal - Lines

Question:

Ref 1: 5.4.3.2.2.1 System Renewal – Lines

Ref 2: 5.4.3.2.3.2 System Renewal – Lines

Ref 3: 5.4.3.2.4.2 System Renewal – Lines

Ref 4: 5.4.3.2.5.2 System Renewal – Lines

Ref 5: 5.3.3 Asset Lifecycle Optimization Policies and Practices

Sudbury Hydro provided a system renewal capital program for each year between 2021-2024. This program is intended to proactively address the replacement/refurbishment of vital distribution assets as an outcome of the ACA. In reference 5, Sudbury Hydro provided a table of flagged assets for action plan on a paced basis.

a) For each of the proposed line projects listed in reference 1-4 please provide the length of the line being replaced/refurbished, the estimated cost, and the equipment replaced, broken down the same way as table 45 provided in reference 5.
b) Please explain why the investments in reference 1-4 are not part of a capital program with paced capital expenditures.

Response:

a)

1) **5.4.3.2.2.1 System Renewal – Lines**
    a. Stewart/Marie/Windle/Wilson Rd
    b. Dew Drop Rd
    c. Lansing Ave (Maley to Madison)
    d. Attlee Ave (S4306 to S4290)
    e. Velray/Claudia Cres (S4175 to S3974; S3960 to S30728; S3973 to S3966)
    f. Peter St (S30988 to S15535)
    g. Caruso St (B18361 to S18513)
    h. Forest Lake Rd (S9251 to S9281)

i. Maley Dr (S20203 to H01480)
j. New Sudbury Shopping Centre (S4408 to TRP187)

2) 5.4.3.2.3.2 System Renewal – Lines

a. Ridgemount/Gagne/Claude
b. Kelvin/Melbourne
c. Paquette St (S1568 to S1576)
d. Beatrice Cres
e. Northshore Dr (S6347 to S6368)
f. Roy Ave (S1897 to S1880)
g. Attlee, Roland, Carmen
h. Redfern Cres
i. Kingslea Cres
j. Leon Ave

3) 5.4.3.2.4.2 System Renewal – Lines

a. Hawthorne (Barrydowne to Auger)
b. St. Andrew's Ave
c. Hildegarde Ave/Delaware Ave
d. Patrick Ave/Sharon Ave
e. Canterbury Ave
f. Lauzon/Wedgewood/Grandview (S1999 to S30773)
g. Robinson Dr
h. Niemi/Kivinen/Stone Hill G.C
i. Lynwood Dr
j. Afton St
k. Vine Ave
l. Downland/Maureen (S4376 to S4387)
m. Chief Lake Rd (S9227 to S9233)
n. Silver Lake Rd (S959 to B20347)

4) 5.4.3.2.5.2 System Renewal – Lines

a. Little Italy/Copper Cliff
b. Southview (B11085 to B10669)
c. Armstrong (B572 to B10669)
d. Moonlight Beach/Dube/Navanod
e. Roger St
f. Blyth/Colby

g. Montel/Virginia
h. Cranbrook Cres
i. Ramsey Lake Rd (S6563 to S6577)
j. Desloges Rd (S8424 to S8444)
k. Brady St (S17899 to S17877)
l. Diane Ave (S1426 to S1435)
m. Ida St (S9089 to S9109)
n. East St
o. Latimer (S689 to S31366)
p. 9M3 Rebuild outside Dash MS
q. Howey Dr (S6284 to S6289)
r. Drummond St

Tables showing the # of units replaced for each of 5.4.3.2.2.1, 5.4.3.2.3.2, 5.4.3.2.4.2 and 5.4.3.2.5.2 are provided hereto as follows:

5.4.3.2.2.1 "Attachment #1"

5.4.3.2.3.2 "Attachment #2"

5.4.3.2.4.2 'Attachment #3'

5.4.3.2.5.2 'Attachment #4'

Additionally, a table (Attachment #5) showing the length of line replaced and/or refurbished as well as the estimated cost for each of the projects in 5.4.3.2.2.1, 5.4.3.2.3.2, 5.4.3.2.4.2 and 5.4.3.2.5.2 is attached hereto.

c) Sudbury Hydro believes that the investments described in reference 1 through 4 are indeed part of a program that paces capital expenditures as demonstrated by, for example, the total number of 'GSU Wood poles' that are addressed in the attachment(s) from the response to part a) above.

   During the forecast period 2020-2024, proposed investments to proactively address the population of 'GSU Wood poles' are projected to affect a lower number of poles as compared with the recommendations made by Kinectrics in the Asset Condition Assessment for both the 'Flagged for Action Plan' and the 'Flagged for Action Plan – Levelized'. This is summarized in the table below:

Year	Flagged for Action	Levelized Flagged for Action	DSP
2020	1279	233	157
2021	76	233	184
2022	312	233	162
2023	111	225	189
2024	80	225	267

Attachment 1 (of 5):

2-Staff-28 Attachment 1: 5.4.3.2.2.1

# of Units Replaced										
Asset Category	**a. Stewart**	**b. Dew Drop**	**c. Lansing**	**d. Atlee**	**e. Velray**	**f. Peter**	**g. Caruso**	**h. Forest Lake**	**i. Maley Dr**	**j. New Sudbury Shopping Centre**
Substation Transformers	0	0	0	0	0	0	0	0	0	0
Pad Mounted Transformers	0	0	2	0	0	0	0	0	0	1
Pole Mounted Transformers	9	12	0	3	5	11	6	3	1	0
Submersible Transformers	0	0	0	0	0	0	0	0	0	0
Vault Transformers	0	0	0	0	0	0	0	0	0	0
Overhead Line Switches	2	2	0	3	3	3	2	1	0	0
Pad Mounted Switchgear	0	0	0	0	0	0	0	0	0	0
Pad Mounted Junction Enclosures	0	0	0	0	0	0	0	0	0	0
GSU Wood Poles	33	47	0	15	13	24	17	12	23	0
GSU Concrete Poles	0	0	0	0	0	0	0	0	0	0
Bell Wood Poles	0	0	0	0	9	0	0	0	0	0
Hydro One Wood Poles	0	0	0	0	0	0	0	0	0	0

Attachment 2 (of 5):

2-Staff-28 Attachment 2: 5.4.3.2.3.2

# of Units Replaced										
Asset Category	a. Ridgemount	b. Kelvin/Melbourne	c. Paquette	d. Beatrice	e. Northshore	f. Roy	g. Attlee Roland, Carmen	h. Redfern	i. Kingslea	J. Leon
Substation Transformers	0	0	0	0	0	0	0	0	0	0
Pad Mounted Transformers	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers	5	4	4	4	3	2	6	3	3	5
Submersible Transformers	0	0	0	0	0	0	0	0	0	0
Vault Transformers	0	0	0	0	0	0	0	0	0	0
Overhead Line Switches	0	0	7	0	0	1	3	0	0	0
Pad Mounted Switchgear	0	0	0	0	0	0	0	0	0	0
Pad Mounted Junction Enclosures	0	0	0	0	0	0	0	0	0	0
GSU Wood Poles	20	15	12	17	14	17	22	17	13	15
GSU Concrete Poles	0	0	0	0	0	0	0	0	0	0
Bell Wood Poles	3	0	0	0	0	0	0	0	2	0
Hydro One Wood Poles	0	0	0	0	0	0	0	0	0	0

Attachment 3 (of 5):

2-Staff-28 Attachment 3: 5.4.3.2.4.2

	# of Units Replaced													
Asset Category	**a. Hawthorne**	**b. St. Andrew's**	**c. Hildegarde/Delaware**	**d. Patrick/Sharon**	**e. Canterbury**	**f. Lauzon/Wedgewood /Grandview**	**g. Robinson**	**h. Niemi/Kivinen**	**i. Lynwood**	**j. Afton**	**k. Vine**	**l. Downland/Maureen**	**m. Chief Lake**	**n. Silver Lake**
Substation Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Transformers	0	0	0	0	0	1	0	0	0	0	0	0	0	0
Pole Mounted Transformers	3	1	5	5	0	4	6	0	5	1	0	4	1	7
Submersible Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Overhead Line Switches	0	3	0	0	0	1	8	0	0	0	0	0	0	2
Pad Mounted Switchgear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Junction Enclosures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSU Wood Poles	18	7	17	15	10	25	4	25	15	6	6	14	7	20
GSU Concrete Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bell Wood Poles	0	0	0	0	2	0	27	0	7	0	0	0	0	0
Hydro One Wood Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Attachment 4 (of 5):

2-Staff-28 Attachment 4: 5.4.3.2.5.2

# of Units Replaced																		
Asset Category	a. Little Italy	b. Southview	c. Armstrong	d. Moonlight	e. Roger	f. Blyth/Colby	g. Montel/ Virginia	h. Cranbrook	i. Ramsey Lake	j. Desloges	k. Brady	l. Diane	m. Ida	n. East	o. Latimer	p.9M3_Dash	q. Howey	r. Drummond
Substation Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers	9	7	6	4	3	4	1	2	1	6	3	3	2	5	4	0	0	1
Submersible Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Overhead Line Switches	2	6	5	3	1	1	2	1	2	1	0	7	2	0	3	0	0	3
Pad Mounted Switchgear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Junction Enclosures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSU Wood Poles	73	1	7	26	16	15	9	18	11	28	8	9	11	13	13	0	5	4
GSU Concrete Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bell Wood Poles	0	26	15	0	0	0	0	0	3	0	0	0	0	3	0	0	0	1
Hydro One Wood Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Attachment 5 (of 5):

2-Staff-28 Attachment 5: Length of line

DSP REFERENCE	YEAR	PROJECT NAME	LENGTH OF LINE REPLACED AND/OR REFURBISHED (m)	ESTIMATED COST ($)
5.4.3.2.2.1	2021	Stewart/Marie/Windle/Wilson Rd	1,313	318,921
		Dew Drop Rd	1,747	464,550
		Lansing Ave (Maley to Madison)	940	210,466
		Attlee Ave (S4306 to S4290)	585	192,649
		Velray/Claudia Cres (S4175 to S3974; S3960 to S30728; S3973 to S3966)	1,058	321,149
		Peter St (S30988 to S15535)	1,379	322,815
		Caruso St (B18361 to S18513)	405	188,113
		Forest Lake Rd (S9251 to S9281)	710	151,310
		Maley Dr (S20203 to H01480)	1,030	169,743
		New Sudbury Shopping Centre (S4408 to TRP187)	417	142,840
5.4.3.2.3.2	2022	Ridgemount/Gagne/Claude	699	214,349
		Kelvin/Melbourne	504	120,000
		Paquette St (S1568 to S1576)	405	124,400
		Beatrice Cres	499	150,000
		Northshore Dr (S6347 to S6368)	535	147,292
		Roy Ave (S1897 to S1880)	593	163,749
		Attlee, Roland, Carmen	749	230,829
		Redfern Cres	549	192,000
		Kingslea Cres	434	133,504
		Leon Ave	541	144,747
5.4.3.2.4.2	2023	Hawthorne (Barrydowne to Auger)	851	206,614
		St. Andrew's Ave	319	79,973
		Hildegarde Ave/Delaware Ave	764	171,555
		Patrick Ave/Sharon Ave	505	156,873
		Canterbury Ave	410	113,889
		Lauzon/Wedgewood/Grandview (S1999 to S30773)	992	228,449
		Robinson Dr	935	333,627
		Niemi/Kivinen/Stone Hill G.C	2,721	500,376
		Lynwood Dr	615	213,038
		Afton St	265	70,485
		Vine Ave	265	68,984
		Downland/Maureen (S4376 to S4387)	644	185,200
		Chief Lake Rd (S9227 to S9233)	310	54,291
		Silver Lake Rd (S959 to B20347)	1,290	325,824
5.4.3.2.5.2	2024	Little Italy/Copper Cliff	2,177	745,479
		Southview (B11085 to B10669)	581	344,886
		Armstrong (B572 to B10669)	564	246,759
		Moonlight Beach/Dube/Navanod	2,022	274,889
		Roger St	346	148,778
		Blyth/Colby	831	187,899
		Montel/Virginia	480	117,353
		Cranbrook Cres	652	197,471
		Ramsey Lake Rd (S6563 to S6577)	713	147,892
		Desloges Rd (S8424 to S8444)	1,098	250,548
		Brady St (S17899 to S17877)	295	97,748
		Diane Ave (S1426 to S1435)	270	141,302
		Ida St (S9089 to S9109)	698	160,337
		East St	492	206,716
		Latimer (S689 to S31366)	478	169,671
		9M3 Rebuild outside Dash MS	146	169,648
		Howey Dr (S6284 to S6289)	252	150,663
		Drummond St	230	75,009

2-Staff-29 Advance Capital Module (ACM) Model

Question:

Ref 1: EB-2019-0037 ACM ICM model

Ref 2: EB-2019-0037 Chapter 2 appendices 2-BA

Sudbury Hydro provided in tab 5 of the ACM model gross fixed asset opening balance, construction work in progress balance, and accumulated depreciation balance but it does not match the balances provided in the fixed asset continuity schedule in reference 2.

a) Please reconcile the balances or explain the variances.

Sudbury Hydro provided 2018 consumption data on tab 6 of the ACM model. There are discrepancies between the number of customers and consumption data provided in the Reporting and Record Keeping Requirements for the residential, GS<50kW, and GS 50 to 4,999kW rate classes.

b) Please reconcile the difference or provide an explanation.

Response:

a) The Chapter 2 appendices 2-BA has a line titled “Net of WIP and Cap Inv 1330 and 2055”. The gross fixed asset opening/closing balance and accumulated depreciation opening/closing balance both agree to this line. There were figures for CWIP in the ACM ICM model, however the same value was added and subtracted and had no impact as the gross fixed asset values already excluded them.

GSHi completed tab 5 of the ACM model with the intention of the calculated “Rate Base” value agreeing to the Revenue Requirement Workform and notes that it did. GSHi submits as part of this response an updated ACM model that appropriately ties to updated figures.

b) **Pertaining to the consumption data:** the consumption data used in the ACM model was sourced from the same data used in the load forecast. The consumption data used in the load forecast was billed consumption from GSHi's billing system, queried at the time of rate application preparation, prorated into months based on the bill days that the billings pertained to. The RRR consumption data was billed consumption from GSHi's billing system as at fiscal year-end when the unbilled revenue accrual was booked. The difference between the two totals is due to a difference in methodology for obtaining cut-off of the data – one method prorates the billed consumption based on billing days, and the other obtains more accurate annual cut-off by requesting billing quantities from the MDMR before and after the end of the year, however this method does not provide billing splits between months so could not be used for load forecast data.

The following table summarizes the differences between rate classes. GSHi notes that the overall difference is 0.10% between the two methodologies.

	Per 2.1.5 Annual RRRs	Per ACM Model	Difference
	2018 kWh	2018 kWh	
Residential	375,723,904	375,861,349	(137,445)
GS < 50 kW	137,871,409	138,106,022	(234,613)
GS > 50 kW	360,043,485	360,554,580	(511,095)
Street Lighting	7,471,085	7,471,085	-
Sentinel Lighting	403,670	403,671	(1)
Unmetered Scattered Load Connections	1,134,622	1,134,622	0
	882,648,175	883,531,329	(883,154)
	Difference, as a percent of RRR reported		-0.10%

Pertaining to the customer count data: The annual RRRs submitted for Q4 contained customer counts as of December 31, 2018. The customer counts used in the ACM model were sourced from the load forecast, where an average of the year's customer counts is used. The following table summarizes the quarterly customer counts that average to the count per the ACM model.

	Per 2.1.5 Annual RRRs	Per ACM Model (Average, Q1 to Q4)	Difference		2018 Q1 (RRR Reported)	2018 Q2 (RRR Reported)	2018 Q3 (RRR Reported)	2018 Q4 (RRR Reported)
Residential	42,982	42,890	92		42,849	42,864	42,864	42,982
GS < 50 kW	4,146	4,132	14		4,111	4,135	4,135	4,146
GS > 50 kW	498	496	2		504	490	490	498
Street Lighting	9,886	9,862	24		9,853	9,854	9,854	9,886
Sentinel Lighting	371	372	(1)		377	376	370	363
Unmetered Scattered Load Connections	292	292	-		293	293	292	290
		58,044	131		57,987	58,012	58,005	58,165

2-Staff-30 Advance Capital Module

Question:

Ref 1: 5.4.3.2.1.9 Cressey MS3 Rebuild/Voltage Conversion

Ref 2: 5.4.3.2.3.1 System Renewal – Moonlight MS18 Station Rebuild

Ref 3: 5.4.3.2.4.1 System Renewal – Marttila MS8 Station Rebuild

Ref 4: 5.4.3.2.5.1 System Renewal – Paris MS13 Station Rebuild

Ref 5: 5.4.3.2.1.1 System Renewal – Gemmell MS11 T1

Ref 6: EB-2014-0219 Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, p. 14

Ref 7: EB-2012-0126 Chapter 2 Appendices – 2-A

Sudbury Hydro requested four ACMs that include the replacement of transformers at Cressey MS3, Moonlight MS18, Marttila MS8, and Paris MS13. In reference 6, the report states that the ACM is most appropriate for a distributor that:

- does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding
- is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. “business as usual” type projects)

In the 2020 test year, Sudbury Hydro is proposing to replace Gemmell MS11 T1. In each subsequent year, Sudbury Hydro continues to propose replacing station transformers with similar scope and unit cost. The exception is the Cressy MS3 rebuild, in which Sudbury Hydro proposes to replace two transformers.

a) Please explain how Sudbury Hydro justifies the use of ACMs when there is one project for every IR year, which is seeking funding for a series of projects that are related to recurring replacement of transformers.

b) Did Sudbury Hydro consider using a Custom IR application to meet its needs? If not, why?
c) Collectively, the ACMs could be considered a station transformer replacement program and since there is the replacement of Gemmel MS11 T1 in the test year, how are the other ACMs outside of base rates?
d) Sudbury Hydro stated that the T1 will be upgraded for Moonlight MS18, Marttila MS8, and Paris MS13. Please provide the size of the upgraded transformers.
e) Sudbury Hydro has planned to replace two transformers in the Cressey MS3 rebuild. Is it possible to phase the rebuild/voltage conversion into two phases? If not why not?
f) Out of the four stations proposed for rebuild, Paris MS13 has the lowest risk index and planned for the final year. The risk index is also significantly lower than the other stations. Please provide justification, if any, on why this capital investment could not be deferred by a year.

In Sudbury Hydro's last cost of service (reference 7), the renewal of Arthur Substation was approved, at an estimated cost of $1,985,384. Sudbury Hydro also replaced Kathleen MS and Capreol in 2018 and 2019 respectively.

g) Please explain why Sudbury Hydro did not replace the stations proposed in this application during 2014 to 2017.

Response:

a) & b)

GSHi reviewed "The Report of the Board – New Policy Option for the Funding of Capital Investments: The Advanced Capital Module" dated September 18, 2014 (herein "the Report") in considering applying for ACM treatment of these capital projects.

In the Report, criteria for the use of ACM outlined in section 4.1.1 includes that the series of projects must not be recurring capital programs for replacements or refurbishments that are “business as usual” type projects (or “not part of typical annual capital programs”). GSHi rebuilt its Capreol MS32 substation in 2019 at a total cost of $1.5M, and its Kathleen MS2 substation in 2018 at a total cost of $3.3M. Prior to these substation rebuilds, GSHi’s last substation rebuild on this scale was in the year 2001 for Levert MS6, for an approximate cost of $1.0M, which included a re-purposed transformer. While substation rebuilds are part of GSHi’s immediate capital plans, the above demonstrates that these are not “business as usual” investments for GSHi.

The Report requires that ACM applications meet the defined materiality threshold and that they be discrete projects. The ACM / ICM model (“the Model”) submitted as part of GSHi’s initial application calculated a materiality threshold of approximately $6.2M in each of the Price Cap IR years. GSHi’s planned capital expenditures in each of the Price Cap IR years range from $9.7M to $11.6M, with the non “business as usual” distinct substation rebuild investments making up a significant portion of the planned expenditure that is in excess of the materiality threshold. These are distinct projects to rebuild specific substations. The above demonstrates that both the materiality and distinct project criteria of the Report are met.

Considering the above criteria being met, GSHi further considered using a Custom IR application to meet its funding needs. As Board Staff points out in section 4.1.1 of the Report, Custom IR is usually considered more appropriate for utilities requiring incremental funding for multiple discrete projects in each year of the IRM period; GSHi only requires incremental funding for a single discrete project in each year of the IRM period, with the rest of the capital spending contemplated during the IRM period to be managed by GSHi within base rates.

A Custom IR application is a more costly and time-consuming endeavor for a distributor, Board staff and for intervenors as compared to a Price Cap IR application. GSHi also does not require all of the funding options available under the Custom IR alternative. Given the specific circumstances of GSHi's rate application and DSP, GSHi is of the position that a Price Cap IR application with ACM treatment of discrete substation renewal in each Price Cap year is the most appropriate application to submit. GSHi believes that with this submission, including the identified ACM projects, it can appropriately manage within the funding available from annual IRM adjustments prior to the next CoS application. This type of application will meet GSHi's funding requirements while minimizing costs ultimately borne by ratepayers.

c)

GSHi details how it meets the eligibility criteria for ACM treatment in part a) and part b) above, and how these investments are not "business as usual" capital investment for GSHi. GSHi summarizes the approximate net book value of its substations that form part of rate base below, with figures replicated from Chapter 2 Appendix 2-BA:

		NBV	NBV		Average NBV
OEB Account	**Description**	**2020**	**2019**		
1808	Buildings	$ 1,143,321	$ 1,206,039		$ 1,174,680
1820	Distribution Station Equipment <50 kV	$ 12,472,900	$ 10,220,692		$ 11,346,796
					$ 12,521,476

As per the above, GSHi is submitting as part of this rate application a 2020 rate base that includes approximately $12.5M of net book value (NBV) pertaining to substations. As detailed in the ACM / ICM model, in the 4 years under Price Cap IR from 2021 through 2024, GSHi will spend approximately $12.75M on substation renewal. This will roughly double the NBV of substation assets that form part of GSHi's rate base.

The Asset Condition Assessment submitted as part of GSHi's initial application contains a summary of GSHi's 43 substation transformers and their ages (Exhibit 2, Tab 2, Schedule 1, Attachment 1, Appendix A – Asset Condition Assessment (2019), Page 45-46 of 114). The average age of GSHi's substation transformers is 40 years, and the average age of the four substations (five substation transformers) proposed for ACM treatment is 60 years. GSHi must rebuild the proposed substations in the timelines proposed in the DSP given the factors discussed therein. However, based on asset condition risk assessment and projected load growth, GSHi anticipates subsequent to 2024 the pace of substation renewal will become more sporadic.

The age of the assets proposed for ACM and the fact that NBV of substation assets will approximately double is evidence that this substation renewal work is outside of base rates. GSHi is applying for ACM treatment of these substation renewals because without the funding provided under ACM, GSHi will experience significant financial pressures to fund these necessary capital projects.

d)

The size of the upgraded transformers are as follows:
Moonlight 18T1 – 10/13MVA
Marttila 8T1 – 7.5/10MVA
Paris 13T1 – 7.5/10MVA

e)

Based on the station's construction and the present system configuration, the rebuild/voltage conversion cannot be built in two phases.

As part of the voltage conversion in the area, the existing Cressey T3 power transformer must remain in service, limiting the available working area within the existing substation footprint. The area required for the proposed rebuild will fully occupy the Cressey T1 and T2 footprint. The entire area will be reconstructed, with the new 3T1 and 3T2 being installed in this site.

As well, GSHI achieves considerable cost savings with one excavation, construction location and project. To complete the project over two years would mean additional construction, mobilization, engineering and project management, while delaying completion of the voltage conversion project.

f)

Based on the normal system configuration, Paris MS13 and Marttila MS8 are the preferred next candidates for rebuild. Under a normal system configuration, GSHi can remove either of the 10T1, 10T2, 13T1 or 8T1 without operating any of the remaining stations above nameplate capacity.

For the utility to put itself in a position to remove the Ramsey Lake 10T1 power transformer from service, the entire substation must be switched out – which includes the 10T2 as well. Under such a condition, **both** of Marttila MS8 and Paris MS13 would be required to take on the loads which, under a normal system configuration, are served by Ramsey Lake MS10. Unfortunately, the condition of both MS8, and MS13 have eroded to the point that GSHi is not confident that they should be relied upon to reliably serve any loads presently served by Ramsey Lake MS10 in the event that GSHi were to plan to proactively renew MS10 prior to either MS8 or MS13.

The *Distribution System Plan* lists Marttila MS8 as being scheduled for renewal in 2023 with Paris MS13 to follow in 2024. Again, in assessing the decision to renew **MS13** prior to MS10, both the existing condition and configuration of MS13 led to the decision to prioritize it for renewal prior to MS10. With Ramsey Lake MS10, although the risk index of the 10T1 power transformer is 57.4%, the existing 10T2 power transformer has sufficient capability to pick up the entire station load in the event of an unplanned failure of the 10T1. With Paris MS13, there is no such capability as this municipal station is equipped with only the single 13T1 power transformer.

g)

The majority of Sudbury Hydro's attention during the 2014 to 2017 period involved the planning and necessary make-ready work enabling the eventual conversion of 10,125 customers (26.55MW of load) from the existing 4.16kV distribution system to a 12.47kV distribution system at locations throughout GSHi's contiguous service territory in the City of Sudbury. The existing 4.16kV system is over 60 years old where the oldest transformer is 68 years old. The distribution system has reached the end of its useful life and the availability of spare parts is an issue. The renewal of two municipal stations (Kathleen MS2 and Cressey MS3), along with the permanent de-commissioning of three existing municipal stations (Regent MS9, Tedman MS12 and Centennial MS14) will significantly improve the reliability of the existing electricity supply as the system is converted to the higher voltage.

Whenever possible, the bundling of drivers to substantiate a prospective investment strives to ensure that the timing of construction activities provides the highest possible value for our customers (e.g. avoiding re-work costs by delaying prospective *System Renewal* activities until there is an accompanying *System Service* or *System Access* driver that stacks additional value).

Due to their comparatively high level of risk, substation-related *System Renewal* investments are ascribed the highest possible priority and must be addressed proactively in the *Capital Expenditure Plan*. Further, investments that address the significant numbers of wood poles in either “poor” or “very poor” condition often can be made in the few remaining “4 – 12kV voltage conversion zones” throughout GSHI’s operating districts. This beneficial approach to prioritization schedules the timely renewal of vital assets while ensuring that the new system build incorporates important features that will maximize the effort expended to renew critical substation assets (e.g. installing poles with sufficient capability to carry multiple circuits and multiple voltage levels).

A goal of the GSHi capital expenditure plan is to leverage its’ asset management plan to ensure spending levels, particularly in the *System Renewal* expense category, are appropriately smoothed, or levelized, to respect customer expectations with respect to efficiently balancing the risk of unplanned outages with costs. In respect of the foregoing, GSHi proceeded with the urgent replacement(s) needed in the voltage conversion zone from 2014 to 2017 and chose to defer prospective capital investments in additional municipal substation renewal, such as the investments proposed in the *Distribution System Plan* (particularly with respect to Gemmell MS11, Moonlight MS18, Marttila MS8 and Paris MS13).

2-Staff-31 Asset Condition Assessment

Question:

Ref 1: Appendix A – Asset Condition Assessment

Sudbury Hydro provided a risk based prioritized list for station transformers in reference 1. Ramsey Lake T1 was ranked ninth and had a risk index of 57.4%, which means the station is in poor condition. Sudbury Hydro had capital investment plans for stations that were ranked lower priority than Ramsey Lake T1.

a) Please explain why Sudbury Hydro does not have a capital plan for Ramsey Lake even though it has a higher risk prioritization.

The ACA showed that there are 16 submersible transformers that are in very poor and poor condition and Sudbury Hydro planned to replace two each year for the first three years and one each year thereafter.

b) Please confirm that these transformers are being replaced within the proposed projects list.

In the ACA, the final health index of an asset is based on the lower of either the calculated health index or the health index from an age curve.

c) Please provide justification that the age of an asset should be relied on over a calculated health index.

Response:

a) The plan to proactively address the distribution system assets located at Ramsey Lake MS10 falls outside of the DSP forecast period (2020-2024). There are a couple of reasons for this. Operationally, for the utility to put itself in a position to remove the Ramsey Lake 10T1 power transformer from service, the entire substation must be switched out. Under these conditions, both Marttila MS8 and Paris MS13 would be required to take on the loads which under a normal system configuration are served by Ramsey Lake MS10. Unfortunately, the condition of each of these stations have eroded to the point that GSHi is not confident that they should be relied upon to serve any loads presently served by Ramsey Lake MS10 if the utility were to plan to proactively renew MS10 first.

The DSP lists Marttila MS8 as being scheduled for renewal in 2023 with Paris MS13 to follow in 2024. In assessing the decision to renew MS13 prior to MS10, both the existing condition and configuration of MS13 led to the decision to prioritize it for renewal prior to MS10. With Ramsey Lake MS10, although the risk index of the 10T1 power transformer is 57.4%, the existing 10T2 power transformer has sufficient capability to pick up the entire station load in the event of an unplanned failure of the 10T1. With Paris MS13, there is no such capability as this municipal station is equipped with only the single 13T1 power transformer.

b) GSHi confirms that these transformers are being proposed to be replaced within its prospective *System Renewal* investments tabled as part of its DSP.

c) The 2019 ACA uses Kinectric's up-to-date methodologies to develop Health Index (HI) distributions and to estimate condition-based action plans.

In the 2019 ACA methodology, the final HI assigned to an individual asset is limited by the asset's age. An *Age Limiter (AL)*, which is equal to the cumulative survival probability at a given age of an asset group, is compared to the calculated HI. If the calculated HI is less than or equal to the AL, the final HI assigned is the calculated HI. Otherwise, the final HI assigned is equal to the AL. Note that in using the AL that it is possible that condition data (i.e. test results, inspections, loading, etc.) may be good and thus the calculated HI is high.

The final HI score is:

$$HI_{Final} = \begin{Bmatrix} if\,(AL < HI, HI_{Final} = AL) \\ else(HI_{Final} = HI) \end{Bmatrix}$$

AL	Age Limiter
HI	Health Index calculated per Equation 1

Health Index score is merely a "filter" that quantifies relative condition of assets based on available - sometime scarce - input condition data. As a result, it is possible to have a high calculated Health Index score for a rather old asset if the recent test and inspection results did not show any problems. This does not mean, however, that this asset is as good as "new" and it not realistic to expect it to remain in service for as long as a brand new asset. To avoid such a false positive, i.e. account for ageing not detected by Health Indexing, *Age Limiter* is used to "cap" the maximum allowable Health Index score to a cumulative survival probability at a given age. This ensures that Health Index results are more realistic and forces utilities to take a closer look at ageing units to prevent unexpected failures due to undetected ageing mechanisms.

2-Staff-32 Green Button

Question:

Ref 1: Distribution System Plan – 5.4.1 (e) Strategy to Implement Cost-Effective Modernization of the Distribution System

Sudbury Hydro stated it is considering the deployment of the Green Button protocol.

a) Please provide the anticipated cost, if any, for the deployment of the Green Button protocol.

Response:

At this time, there are no anticipated costs for the deployment of the Green Button protocol.

2-Staff-33 Fixed Asset Continuity Schedules

Question:

Ref 1: Chapter 2 Appendix 2-BA

Ref: 2: Exhibit 2 – Tab 1 – Schedule 1 – Attachment 2

Attachment 2, shows PP&E decreased by $460,787 as at January 1, 2014 and $946,000 as at January 1, 2015 as result of transitioning to IFRS. In the 2014 Appendix 2-BA, there is a column for “IFRS Adjustments” column. In the 2015 Appendix 2-BA, there is a column for “Adjustment through RE”.

a) Please confirm that the $467,787 adjustment shown in the financial statements is not included in the 2014 Appendix 2-BA, and therefore, Appendix 2-BA is shown under CGAAP (except for the capital contribution reallocation). If not, please explain how the $467,787 is reflected in Appendix 2-BA.
b) Please confirm that the $946,000 “Adjustment through RE” in the 2015 Appendix 2-BA is cumulative and includes the 2014 $467,787 adjustment already.

Response:

a) GSHi confirms the $467,787 adjustment shown in the financial statement is not included in the 2014 Appendix 2-BA.

b) GSHi confirms the $946,000 “Adjustment through RE” in the 2015 Appendix 2-BA is cumulative and does include the 2014 $467,787 adjustment.

3-Staff-34 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1

Sudbury Hydro has used monthly consumption data underpinning its energy load forecast.

a) Does Sudbury Hydro rely on metered energy usage by rate class by calendar month, or a calculated value based on some other metering interval or data source?
b) If the monthly consumption is a calculated value, please explain source data, and the method used to arrive at the monthly usage.

Response:

a) & b)

GSHi relies on metered energy usage by rate class. This is sourced from its customer billing system. The billing system contains data on the date range that a bill issued pertains to. To split the billed data into monthly consumption data, GSHi prorates the consumption into separate monthly "buckets" based on the days billed for a given month.

Example: A residential customer is billed 750kWh for consumption beginning at midnight on Jan 18, 2018 and ending at midnight on Feb 18, 2018. There are therefore 14 billed days in January and 17 billed days in February, for a total of 31 billed days.

January 2018 consumption: 14 / 31 * 750kWh = 338.71 kWh
February 2018 consumption: 17 / 31 * 750kWh = 411.29 kWh

In the monthly load forecast data, this customer's bill would be included for 338.71 kWh in January 2018 and 411.29 kWh in February 2018.

3-Staff-35 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, page 1

Ref 2: Exhibit 3, Tab 1, Schedule 1, Attachment 1, pages 4-5

In reference to Heating Degree Days (HDD), Sudbury Hydro states that:

> In particular, residential consumption does not increase as average temperatures decline from 18°C to 16°C, which suggests there is not a material heating load when temperatures are in that range, so the HDD variable with a base of 16°C is used.

However, Elenchus states that:

> HDD relative to 12°C and CDD relative to 18°C were found to provide the strongest results.

The included model goes on to include a variable named DD12, implying a base of 12°C is used.

a) Please confirm that the variable DD12 refers to HDD.
b) Please confirm which definition of HDD is used in the residential class.

Response:

a) Confirmed.
b) HDD relative to 12°C is used for the residential class.

3-Staff-36 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1, pages 1, 5

Elenchus states that:

> To isolate the impact of Conservation Demand Management (CDM), persisting CDM as measured by the Independent Electricity System Operator is added back to rate class consumption to simulate the rate class consumption had there been no CDM program delivery.

And that:

> Ordinary Least-Squares (OLS) regressions exhibited errors with a high level of autocorrelation with a Durbin-Watson statistic near 1.00. A time-series autoregressive model using the Prais-Winsten estimation was used instead of an OLS regression for the Residential class to account for autocorrelation.

a) Please provide a scenario for Residential, General Service < 50 kW, and General Service > 50 kW where the dependant variable is energy usage without an adjustment for CDM, and the CDM is added as an explanatory variable. When providing the scenario, please provide both the statistical model and the resulting forecast.
b) In the case of Residential, please provide the scenario using both Prais-Winsten and OLS.
c) Were different time horizons other than ten years of historic data attempted to address the autocorrelation. If so, what were the results?

Response:

a) & b)
Please see the statistical model outputs and summary results tables below. Aside from the change to the dependent variable to kWh

unadjusted for CDM and addition of the CDM variable, the trend variable was removed from the GS>50 kW model because it was not significant. All other variables in the GS>50 kW model, and all other variables in each of the other models are the same as the filed load forecast model.

Residential Prais-Winsten

Model 1: Prais-Winsten, using observations 2009:01-2018:12 (T = 120)

Dependent variable: Residential_kWh

rho = 0.272521

	coefficient	std. error	t-ratio	p-value
const	-64138443.71	20464283.87	-3.13417	2.20E-03
Trend	-98473.49631	30040.90909	-3.27798	1.39E-03
CDD	29762.01078	8564.194308	3.475168	7.25E-04
MonthDays	1182251.998	155828.8403	7.586863	1.00E-11
HDD12	29491.85593	762.7585655	38.66473	5.42E-67
OntFTEs	8430.695979	3170.302819	2.659272	8.97E-03
Res_CDM	-0.220060538	1.134310038	-0.194	8.47E-01

Statistics based on the rho-differenced data

Mean dependent var	32215776.37	S.D. dependent var	7.90E+06
Sum squared resid	2.86814E+14	S.E. of regression	1.59E+06
R-squared	0.961379145	Adjusted R-squared	9.59E-01
F(6, 113)	336.2186355	P-value(F)	1.32E-69
rho	-0.025572237	Durbin-Watson	1.979711

Residential OLS

Model 2: OLS, using observations 2009:01-2018:12 (T = 120)

Dependent variable: Residential_kWh

	coefficient	std. error	t-ratio	p-value
const	-63978019.15	17668051.79	-3.62111	0.000441
Trend	-94516.78185	24863.61469	-3.80141	2.34E-04
CDD	29404.93169	8526.655965	3.448589	7.93E-04
MonthDays	1155624.445	190851.4844	6.055098	1.88E-08

HDD12	29707.41341	674.8365557	44.02164	5.76E-73
OntFTEs	8503.589428	2711.330637	3.136316	2.18E-03
Res_CDM	-0.44988436	0.891473302	-0.50465	6.15E-01

Mean dependent var	32215776.37	S.D. dependent var	7897986
Sum squared resid	3.10721E+14	S.E. of regression	1658236
R-squared	0.958140744	Adjusted R-squared	9.56E-01
F(6, 113)	431.0870703	P-value(F)	2.09E-75
Log-likelihood	-1885.218193	Akaike criterion	3.78E+03
Schwarz criterion	3803.948827	Hannan-Quinn	3.79E+03
rho	0.26475972	Durbin-Watson	1.398261

GS<50 kW OLS

Model 4: OLS, using observations 2009:01-2018:12 (T = 120)

Dependent variable: GS_lt_50_kWh

	coefficient	std. error	t-ratio	p-value
const	-5168997	1993078	-2.593474173	1.08E-02
Trend	-18475.5	4576.56	-4.036975311	9.89E-05
GSFTEs	40380.63	19175.78	2.105814391	3.74E-02
MonthDays	407558.2	47645.91	8.55389651	6.62E-14
CDD	17991.35	1937.59	9.285425522	1.37E-15
HDD10	5790.832	173.5066	33.37527989	2.38E-60
GS_lt_50_CDM	1.490214	0.742213	2.007799129	4.71E-02

Mean dependent var	11697031	S.D. dependent var	1424660.863
Sum squared resid	1.94E+13	S.E. of regression	414018.8738
R-squared	0.919805	Adjusted R-squared	0.91554657
F(6, 113)	216.0101	P-value(F)	1.73E-59
Log-likelihood	-1718.71	Akaike criterion	3.45E+03
Schwarz criterion	3470.925	Hannan-Quinn	3.46E+03
rho	-0.09927	Durbin-Watson	2.154224689

GS>50 kW OLS

Model 7: OLS, using observations 2009:01-2018:12 (T = 120)

Dependent variable: GS_gt_50_kWh

	coefficient	std. error	t-ratio	p-value
const	17187620	4087914	4.204496657	5.20E-05
HDD10	11794.85	517.2696	22.80213745	1.76E-44
CDD16	20005.7	3339.622	5.990408936	2.45E-08
MonthDays	386422.7	134059.2	2.882477602	4.71E-03
GS_gt_50_CDM	-1.8032	0.178832	-10.08322665	1.63E-17

Mean dependent var	30875266	S.D. dependent var	3039597.659
Sum squared resid	1.59E+14	S.E. of regression	1176345.407
R-squared	0.85526	Adjusted R-squared	0.850225624
F(4, 115)	169.8821	P-value(F)	2.72E-47
Log-likelihood	-1845.07	Akaike criterion	3.70E+03
Schwarz criterion	3714.077	Hannan-Quinn	3.71E+03
rho	-0.0106	Durbin-Watson	1.95684623

Normal Forecast

kWh	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Normaliz	2019 Forecast	2020 Forecast
Residential PW	401,059,652	378,767,131	363,718,803	354,425,141	375,861,349	361,125,532	364,742,721	359,684,778
Residential OLS	401,059,652	378,767,131	363,718,803	354,425,141	375,861,349	360,925,413	365,203,277	360,904,801
GS < 50	144,307,855	138,792,580	135,472,797	132,427,313	138,106,022	120,894,989	119,192,123	117,357,332
GS > 50	378,009,413	362,799,633	350,224,516	352,367,387	360,554,580	349,180,294	348,478,277	351,245,315
Street Light	7,654,363	7,541,644	7,520,842	7,471,833	7,471,085	7,471,085	7,360,232	7,293,440
Sentinel Light	438,854	428,604	426,193	412,948	403,671	403,671	396,554	389,563
USL	1,346,883	1,276,038	1,219,818	1,179,515	1,134,622	1,134,622	1,106,746	1,081,447
Total	932,817,019	889,605,630	858,582,969	848,284,136	883,531,330	840,210,193	841,276,654	837,051,876

CDM Adjusted

kWh	2020 Weather Normal Forecast	CDM Adjustment	2020 CDM Adjusted Forecast
Residential PW	359,684,778	853,358	358,831,420
Residential OLS	360,904,801	853,358	360,051,443
GS < 50	117,357,332	2,024,086	115,333,246
GS > 50	351,245,315	3,875,781	347,369,534
Street Light	7,293,440	0	7,293,440
Sentinel Light	389,563	0	389,563
USL	1,081,447	0	1,081,447
Total	837,051,876	6,753,225	830,298,650

Normal Forecast

kW	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2018 Normalize	2019 Forecast	2020 Forecast
GS > 50	936,619	910,216	894,192	882,488	887,145	871,345	869,594	876,498
Street Light	21,396	21,075	20,946	20,884	20,878	20,870	20,560	20,373
Sentinel Light	1,212	1,182	1,078	1,137	1,111	1,102	1,082	1,063
Total	959,227	932,473	916,216	904,510	909,134	893,317	891,236	897,935

CDM Adjusted

kW	2020 Weather Normal Forecast	CDM Adjustment	2020 CDM Adjusted Forecast
GS > 50	876,498	9,672	866,827
Street Light	20,373	0	20,373
Sentinel Light	1,063	0	1,063
Total	897,935	9,672	888,263

c) Longer time horizons were not considered to address autocorrelation.

3-Staff-37 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1, pages 4, 7, 10

Elenchus states that a Trend variable was used in each of the Residential, General Service < 50 kW, and General Service > 50 kW rate classes. Elenchus notes that a linear trend variable is included, which begins with a value of 1 in January 2009 and increasing to 120 for December 2018. The estimated coefficient in each rate class is negative and statistically significant.

a) Since the historical consumption data are adjusted to add back CDM, in the view of Sudbury Hydro or Elenchus, what is this trend variable actually measuring?

Response:

a) Elenchus' view is that the trend variable accounts for any energy consumption trends that are not reflected in the variables within the model. This may include energy conservation efforts that are not reflected in the IESO's results, changes in energy-consuming technologies, improved building code and standards, and changes to the composition of customers within a class or end users within customer accounts (ie. the average number of individuals within a household/residential account).

3-Staff-38 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1, page 2

Sudbury Hydro's forecast is based on 2019 as a forecast year.

a) Please update the forecast using 2019 as an actual year, or as much of 2019 for which actual energy usage data is available.

Response:

a) Please see the updated load forecast filed as a live model with this interrogatory submission. The updated load forecast includes full 2019 energy and customer data, 2019 weather and economic data, updated 2016-2018 CDM data, and updated 2020 economic forecasts. Additionally, the average use per device trend now begins with the change from 2014-2015 (instead of 2013-14) and a correction has been made to the 2016 kW figure for the GS>50 class.

3-Staff-39 Load Forecast

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1, pages 20-21

An average reduction in energy use of 1.2% per street lighting device per year over the years 2013-2018 is observed, following a 9% reduction between 2012 and 2013. This is seen in the following table:

Year	Average Energy per Device	Reduction from prior year
2012	893	
2013	811	-9.1%
2014	790	-2.6%
2015	781	-1.1%
2016	779	-0.2%
2017	771	-1.0%
2018	765	-0.8%

The reason given is that “Greater Sudbury has had a gradual phase-in of LED lights over a number of years.”

a) Why was the reduction from 2013 – 2014 included in the multi-year average when it immediately followed the 9% reduction in the prior year, and itself experienced a reduction of more than double any year since?
b) How many streetlights were converted to Light Emitting Diode technology in each year from 2012-2019, and how many are planned for 2020?

Response:

a) Elenchus discussed the trend of average energy per device and the LED replacement program with GSHi during the preparation of the load forecast. GSHi expected LED replacements to increase relative to recent years so Elenchus decided to include the 2013-2014 change in the trend to reflect a greater annual reduction than what has been experienced in more recent years.

Given that the actual decline in average consumption per device in 2019, which was 762kWh/device, did not reflect the more rapid trend that includes 2013-2014, the change between those years has been removed from the trend calculation in the revised load forecast.

b) Historic annual LED conversion information is not readily available and GSHi is unable to collect this data in the time allotted for interrogatories.

The number of planned 2020 LED conversions is uncertain. An LED conversion program has been submitted to Sudbury city council but has not yet been approved. Given the uncertainty, the data used in GSHi's updated load forecast, cost allocation, and rate design models does not include potential consumption and load impacts of the unapproved conversion program. The load forecast does account for a more gradual decline in average use per device to reflect GSHi's actual pace of conversions over the past 5 years.

3-Staff-40 CDM Adjustment

Question:

Ref 1: Exhibit 3, Tab 1, Schedule 1, Attachment 1, Load Forecast Report (p. 27)

Ref 2: Load Forecast Model, Tabs "CDM Adjustment"/ "2018 CDM"/ "2019-2020 CDM"

Ref 3: Appendix 2-I

OEB staff could not reconcile the forecast savings in the CDM adjustment to the Participation and Cost Reports, and requests clarification on the quantum of the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) threshold requested for approval.

2018 Savings

For 2018, Non-Residential CDM savings of 2,810,783 kWh based on the sum of savings from the GS<50 kW and GS>50 kW classes, it appears there are additional savings of 60,659 kWh included in the LRAMVA threshold, which were not identified in the Participation and Cost Report (per Tab "2018 CDM").

Extract of Tab "CDM Adjustment" of Load Forecast Model:

	2018-2020 Forcasted kWh Savings by Rate Class									
	Rate Class	2018			2019	2020			CDM Adjustment	LRAMVA Target
		kWh	CDM Adj Weight	Amount	kWh	kWh	CDM Adj Weight	Amount	kWh	kWh
		A	B	C = A * B	D	E	F	G = E * F	H = C + D + G	I = A + D + E
	Residential	1,706,716	0.5	853,358	-	-	0.5	-	853,358	1,706,716
	GS < 50	891,199	1	445,599	1,253,557	649,859	1	324,929	2,024,086	2,794,615
	GS > 50	1,919,585	0.5	959,792	1,539,914	2,752,148	0.5	1,376,074	3,875,781	6,211,648
	TOTAL	**4,517,499**	**0.5**	**2,258,750**	**2,793,472**	**3,402,007**	**0.5**	**1,701,004**	**6,753,225**	**10,712,978**
Staff calcs:	GS<50 + GS>50 kW	2,810,783								
	Savings from P&C	2,750,124								
	Additional savings	60,659								

2019 and 2020 Savings

For the 2019 CDM savings forecast, it appears that the Participation and Cost Report identified more savings than what is proposed to be included in the CDM Manual Adjustment.

Extract of Tab “2019-20 CDM” of Load Forecast Model:

			2019	2020	Total
Total	Audit Funding		-	-	
	HPNC		152,433	16,185	
kWh	Retrofit		2,617,353	3,385,822	
	Small Business Lighting		26,886	-	
			2,796,671	**3,402,007**	**6,198,679**
Staff calcs:	2019-2020 CDM		2,793,472		
	Difference in savings		(3,199)		

LRAMVA Threshold

In Appendix 2-I, it appears that Sudbury Hydro is seeking approval of an LRAMVA threshold of 42,047,875 kWh (established on 2015-2020 forecast savings) but the table in the Load Forecast Model shows 10,712,978 kWh (established on 2018-2020 forecast savings).

a) For the half year of 2018 forecast savings projected to persist to 2020, please provide the rationale for including a half year’s savings from 2018 programs in the CDM adjustment, if 2018 savings are actual verified from the IESO.

   i. Please confirm whether there are additional savings of 60,659 kWh from non-residential CDM programs proposed to be included in the CDM adjustment. If yes, why are these additional savings are not listed in the Participation and Cost Report? Please discuss eligibility of these additional savings for recovery in the LRAMVA threshold.
   ii. Please reconcile the additional savings to the detailed level (CDM-IS) project savings documentation.

b) For the 2019 and 2020 savings, please confirm the source of these forecast savings, as it appears that only an extract of the data was provided.

   i. Please file the original project lists supporting the 2019 and 2020 forecast savings in Tab “2019-20 CDM” of the Load Forecast model.

c) Please confirm that the 2019 savings of 2,793,472 kWh represent only the savings related to those Conservation First Framework (CFF) projects that the distributor is contractually obligated to complete. Specifically, please confirm that these CFF projects were entered into on/before March 31, 2019, and the savings from the projects are not expected to take place until the 2020 test year.

   i. Please provide the rationale for including 100% of savings from 2019 programs in the CDM adjustment, if the first three months of 2019 are actual verified from the IESO.

d) Please confirm that the 2020 savings of 3,402,007 kWh represent only the savings related to those CFF projects that the distributor is contractually obligated to complete. Specifically, please confirm that these CFF projects were entered into on/before March 31, 2019, and the savings from the projects are not expected to take place until the 2020 test year.

   i. Please explain why the forecast savings from 2020 are higher than in 2019.

e) Based on your responses to a), c), and d) please confirm whether there are updates to the CDM adjustment to the load forecast.

f) Please confirm whether Sudbury Hydro is seeking approval of a LRAMVA threshold of 42,047,875 kWh (as noted in Appendix 2-I) or whether it requests approval of a LRAMVA threshold of 10,712,978 kWh.

   i. Please reconcile the LRAMVA threshold amounts between Appendix 2-I and the Load Forecast Model.

Response:

a) Please note for all parts of this response that the load forecast and LRAMVA workforms have been revised.

Half of 2018 savings were included in the CDM adjustment because it is assumed that only half of a given year's CDM activities impact energy use in its first year. This is because the figures provided by the IESO are annual savings figures and CDM activities can begin at any point throughout the year. Further, it is not clear that the 2018 IESO savings are "verified".

The revised load forecast model uses actual 2019 data that would reflect full 2018 CDM activities so the CDM adjustment now includes only half of forecast 2019 CDM activities and half of 2020 CDM activities.

i. & ii. The load forecast was prepared with the February 2019 version of the Cost & Participation report. That version understated GSHi's savings for certain programs so figures that were submitted to the IESO were also used to approximate actual 2018 savings. The 2018 CDM figures are now derived entirely from the April version of the 2019 Cost and Participation report. The 2018 savings figures in the updated load forecast are also consistent with the updated LRAMVA workform.

b) The source of the savings was a list of projects that were expected to be completed in 2019 & 2020. The project list is included as a live model with this interrogatory submission. Note that certain projects that were expected to be completed have since been canceled (see highlighted rows).

c) The 2,793,472 kWh figure cited in the interrogatory was the forecast savings related to 2019 CFF projects entered into before March 31, 2019 that GSHi is legally obligated to complete, persisting to 2020. It is a small adjustment to the 2019 forecast to account for the Small Business Lighting programs' typical loss in persistence by the second year. For clarity, it is for programs that were expected to be complete in 2019, not 2020. Note that some programs have since been cancelled and the figure is now 2,650,373 kWh.

i. The first three months of 2019 results were not verified, nor would those savings be reflected in 2009-2018 data. The CDM adjustment accounts for CDM savings that did not occur by 2018 but is expected to occur by the 2020 test year.

d) Confirmed, except the revised figure is now 3,375,251 kWh.

i. The forecast is higher because more savings are expected in programs that are completed in 2020 than 2019. This is largely due to one retrofit project for a customer within the GS>50 kW class.

e) Confirmed. There have been corrections to 2016-2018 savings, which are reflected in the updated LRAVMA workform, and the cancellation of 2019-2020 projects, which is reflected in the attachment to part b) of this interrogatory.

f) The LRAMVA amount in Appendix 2-I is incorrect. The LRAMVA threshold should have been 10,712,978 kWh as per the load forecast. The revised figure is 6,025,625 kWh. The LRAMVA threshold no longer includes 2018 CDM because actual 2019 consumption figures that have been added to the revised load forecast account for CDM activities in 2018.

3-Staff-41 Other Revenue

Question:

Ref 1: Chapter 2 appendices – 2-H

Ref 2: Exhibit 3 – Tab 3 - Schedule 1

The Other Revenue received from Specific Service Charges have decreased since 2013. Sudbury Hydro explained that this was due to the winter disconnection ban and the removal of Collection of Account charge.

a) Please provide, since 2013, the revenue received for disconnection/reconnection and Collection of Account charges.

The Rent from Electric Property account increased between 2019 and 2020. Sudbury Hydro explained that this was due to the increase in the wireline pole attachment charge. However, the first transitional increase was effective September 1, 2018 to December 31, 2019 and the full increase was effective January 1, 2019.

b) Please confirm if Sudbury Hydro implemented the wireline pole attachment charge in 2019.
c) If so, please explain why the Rent from Electric Property account balance does not appear to include it.
d) Please confirm that the 2020 Rent from Electric Property amount takes into consideration the 2020 inflationary increase for the wireline pole attachment charge.

Response:

Please note, in addition to the correction for errors discussed below, GSHi has also updated the 2019 figures to include GSHi's current unaudited yearend figures.

a) Please see the breakdown of disconnection/reconnection and Collection of Account Charges below.

	2013	2014	2015	2016	2017	2018	2019	2020 Budget
Disconnect/ Reconnect	$56,185	$51,590	$49,305	$58,285	$36,150	$21,440	$30,675	$23,000
Collection of Account Charges	$192,085	$212,460	$201,545	$221,520	$175,465	$115,800	$45,600	$0
Total	**$248,270**	**$264,050**	**$250,850**	**$279,805**	**$211,615**	**$137,240**	**$76,275**	**$23,000**

b) GSHi implemented the increased wireline pole attachment charge as of September 1, 2018 per EB-2015-0304 and deferred the increased revenue as per the Wireline Pole Attachment Charges report dated March 22nd, 2018. GSHi split out the incremental revenue and included it in account 4310 (Other Regulatory Credits) for 2018 in Appendix 2-H. However, GSHi notes that there was an error in Appendix 2-H where the incremental revenue from 2019 of $491,079 was omitted from the balance of account 4310. GSHi now recognizes that this was incorrect and has updated Appendix 2-H to show the gross amount of pole rental revenue in 4210 with a debit to account for 4305 for the incremental portion to be returned to rate payers. For 2020, the total amount of pole rental revenue is included in 4210, as there will no longer be an incremental portion. The corrected balances in account 4210 and 4310 are shown in Table 1 below.

The budget value for 2020 also includes an adjustment to the inflationary value used for 2020 as discussed in part d) below. GSHi has also corrected for an error noted in its original budget (one attacher was budgeted for twice) and also updated its projection for pole counts for 2020 based on its 2019 year end. GSHi also noted some description and grouping errors and has corrected those as well. A corrected Appendix 2-H is included as Attachment 1 to this interrogatory response (Tab 1, Interrogatory 41, Attachment 1) and is also included in the live Chapter 2 Appendix model included with this submission.

Table 1 – Pole Rental Revenue Reconciliation

		2013	2014	2015	2016	2017	2018	2019	2020 Budget
	Other Rent	$90,627	$90,627	$90,627	$61,234	$59,807	$59,807	$61,235	$61,235
A	Pole Rental Revenue	$458,599	$423,740	$686,732	$526,448	$517,395	$559,739	$1,034,618	$1,049,720
4210	**Rent From Electric Property**	**549,227**	**514,367**	**777,359**	**587,682**	**577,201**	**619,546**	**1,095,853**	**1,110,955**
B	Incremental Pole Rental - Deferred						- 38,525	- 507,989	-
4305	**Regulatory Debits**	-	-	-	-	-	**- 38,525**	**- 507,989**	-
A+B	**Total Pole Rental Revenue**	**458,599**	**423,740**	**686,732**	**526,448**	**517,395**	**521,214**	**526,629**	**1,049,720**

c) Please see part a) above for a description of how the incremental revenue was included in Appendix 2-H in the initial application and how GSHi has corrected it.

d) In its initial application, GSHi used an inflationary increase of 1.5% as a placeholder until the inflationary increase was announced. GSHi has now updated its budget using a 2% increase as per the letter from the Board on November 28th, 2019 regarding the *Inflation Adjustment for Energy Retailers Service Charges (EB-2019-0280) and Wireline Pole Attachment Charge (EB-2015-0304) for Electricity Distributors*. Table 1 and the corrected Appendix 2-H above reflects the adjustment. The adjustment has also been reflected in the RRWF.

Attachment 1 (of 1):

3-Staff-41 Attachment 1: Updated Appendix 2-H

File Number:	EB-2019-0037
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
		2013	2014	2015	2016	2017	2018	2019	2020	2015
	Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
4235	**Specific Service Charges**	-$ 486,033	-$ 500,020	-$ 477,143	-$ 516,505	-$ 441,434	-$ 320,068	-$ 299,383	-$ 218,602	-$ 477,143
4225	**Late Payment Charges**	-$ 144,064	-$ 175,092	-$ 182,322	-$ 195,236	-$ 166,761	-$ 148,898	-$ 155,235	-$ 156,800	-$ 182,322
4082	**Retail Services Revenues**	-$ 39,393	-$ 33,127	-$ 30,989	-$ 30,666	-$ 21,848	-$ 20,810	-$ 29,915	-$ 35,915	-$ 30,989
4086	Standard Supply Service - Administrative Charge	-$ 134,163	-$ 135,548	-$ 135,841	-$ 157,979	-$ 139,356	-$ 140,733	-$ 141,750	-$ 140,473	-$ 135,841
4084	Service Transactions Requests	-$ 1,114	-$ 733	-$ 853	-$ 643	-$ 306	-$ 302	-$ 496	-$ 930	-$ 853
4210	Rent from Electric Property	-$ 549,227	-$ 514,367	-$ 777,359	-$ 587,682	-$ 577,201	-$ 619,546	-$ 1,095,853	-$ 1,110,955	-$ 777,359
4360	Loss on Disposition of Utility and Other Property			$ 538,014	$ 637,754	$ 454,852	$ 624,722	$ 515,799	$ 564,690	$ 538,014
4375	Revenues from Non-Utility Operations	-$ 499,147	-$ 984,572	-$ 1,106,728	-$ 1,383,432	-$ 2,033,252	-$ 3,188,326	-$ 2,886,713	-$ 2,495,805	-$ 1,106,728
4380	Expenses of Non-Utility Operations	$ 487,219	$ 966,943	$ 878,607	$ 1,383,432	$ 2,033,252	$ 2,725,752	$ 2,886,714	$ 2,495,805	$ 878,607
4390	Miscellaneous Non-Operating Income[5]	-$ 168,815	-$ 98,068	-$ 165,644	-$ 202,201	-$ 130,581	-$ 147,480	-$ 117,098	-$ 133,000	-$ 165,644
4405	Interest and Dividend Income[2]	-$ 413,019	-$ 333,360	-$ 361,395	-$ 196,989	-$ 290,798	-$ 233,287	-$ 200,065	-$ 60,000	-$ 361,395
4385	Non Rate-Regulated Utility Rental Income	-$ 12,418	-$ 21,537	-$ 21,758	-$ 23,029	-$ 20,106	-$ 20,073	-$ 19,504	-$ 20,000	-$ 21,758
4220	Other Electric Revenues	$ -	$ -	-$ 8,242	-$ 1,268	-$ 121,903	$ -	$ -	$ -	-$ 8,242
4305	Regulatory Debits						$ 38,525	$ 507,989	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -	-$ 1,624,754	-$ 461,851	-$ 624,722	-$ 515,799	$ -	$ -
4245	Deferred revenue			-$ 42,626	-$ 70,037	-$ 92,007	-$ 115,823	-$ 131,564	-$ 207,802	-$ 42,626
4355	Gain on Disposition of Utility and Other Property	-$ 1,402	-$ 26,005					-$ 2,696	$ -	$ -
Specific Service Charges		-$ 486,033	-$ 500,020	-$ 477,143	-$ 516,505	-$ 441,434	-$ 320,068	-$ 299,383	-$ 218,602	-$ 477,143
Late Payment Charges		-$ 144,064	-$ 175,092	-$ 182,322	-$ 195,236	-$ 166,761	-$ 148,898	-$ 155,235	-$ 156,800	-$ 182,322
Other Operating Revenues		-$ 723,897	-$ 683,775	-$ 995,911	-$ 848,274	-$ 952,621	-$ 897,215	-$ 1,399,577	-$ 1,496,075	-$ 995,911
Other Income or Deductions		-$ 607,581	-$ 496,598	-$ 238,904	-$ 1,409,220	-$ 448,483	-$ 824,889	$ 168,626	$ 351,690	-$ 238,904
Total		-$ 1,961,576	-$ 1,855,484	-$ 1,894,278	-$ 2,969,236	-$ 2,009,298	-$ 2,191,070	-$ 1,685,569	-$ 1,519,787	-$ 1,894,278

Description **Account(s)**
Specific Service Charges: 4235
Late Payment Charges: 4225
Other Distribution Revenues: 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4230, 4240, 4245
Other Income and Expenses: 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4357, 4360, 4362, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4410, 4415, 4420

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income. Tables for the detailed breakdowns will be generated after cell B89 is filled in.

Example: Account 4405 - Interest and Dividend Income

	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
Short-term Investment Interest									
Bank Deposit Interest									
Miscellaneous Interest Revenue									
etc.[1]									
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 List and specify any other interest revenue.
2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. In column N, present CGAAP transition year information. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

15	**Enter the number of "Other Operating Revenue" and "Other Income or Deductions" Accounts that require a detailed breakdown of the account components.**

Account 4405 - Interest and Dividend Incon	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
Bank Interest	-$ 53,537	-$ 57,046	-$ 52,963	-$ 42,964	-$ 51,721	-$ 72,061	-$ 84,121	-$ 60,000	-$ 52,963
Deferral & Variance Account Interest	-$ 171,895	-$ 79,031	-$ 127,357	-$ 4,713	-$ 78,340	-$ 60,952	-$ 15,670	$ -	-$ 127,357
Intercompany interest	-$ 187,586	-$ 197,283	-$ 181,074	-$ 149,312	-$ 160,737	-$ 100,274	-$ 100,274	$ -	-$ 181,074
Total	-$ 413,019	-$ 333,360	-$ 361,395	-$ 196,989	-$ 290,798	-$ 233,287	-$ 200,065	-$ 60,000	-$ 361,395

Account 4082 - Retail Services Revenue	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
DCBR Bill Charges	-$ 13,170	-$ 11,015	-$ 9,912	-$ 9,734	-$ 6,778	-$ 6,240	-$ 8,484	-$ 9,926	-$ 9,912
Monthly Fixed Fees Retailers	-$ 4,180	-$ 3,920	-$ 4,320	-$ 4,580	-$ 3,760	-$ 4,440	-$ 7,220	-$ 9,302	-$ 4,320
Monthly Variable Charges	-$ 22,044	-$ 18,192	-$ 16,757	-$ 16,352	-$ 11,310	-$ 10,131	-$ 14,211	-$ 16,687	-$ 16,757
Total	-$ 39,393	-$ 33,127	-$ 30,989	-$ 30,666	-$ 21,848	-$ 20,810	-$ 29,915	-$ 35,915	-$ 30,989

Account 4086 - Standard Supply Service	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
Residential Customers	-$ 120,399	-$ 121,707	-$ 122,265	-$ 142,590	-$ 125,796	-$ 127,053	-$ 128,066	-$ 126,713	-$ 122,265
GS < 50 kW Customers	-$ 11,311	-$ 11,401	-$ 11,194	-$ 12,795	-$ 11,243	-$ 11,420	-$ 11,439	-$ 11,500	-$ 11,194
GS > 50 kW Customers	-$ 1,290	-$ 1,297	-$ 1,288	-$ 1,389	-$ 1,289	-$ 1,260	-$ 1,265	-$ 1,250	-$ 1,288
Non-metered Customers	-$ 584	-$ 576	-$ 559	-$ 633	-$ 526	-$ 506	-$ 504	-$ 510	-$ 559
Sentinel Light Customers	-$ 573	-$ 560	-$ 529	-$ 565	-$ 496	-$ 489	-$ 470	-$ 500	-$ 529
Streetlight Customers	-$ 7	-$ 6	-$ 6	-$ 7	-$ 6	-$ 6	-$ 6	$ -	-$ 6
Total	-$ 134,163	-$ 135,548	-$ 135,841	-$ 157,979	-$ 139,356	-$ 140,733	-$ 141,750	-$ 140,473	-$ 135,841

Account 4084 - Standard Supply Service- A	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
Service Transaction Request Fees	-$ 1,114	-$ 733	-$ 853	-$ 643	-$ 306	-$ 302	-$ 496	-$ 930	-$ 853
Total	-$ 1,114	-$ 733	-$ 853	-$ 643	-$ 306	-$ 302	-$ 496	-$ 930	-$ 853

Account 4210 - Rent from Electric Property	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
Rental Income	-$ 90,627	-$ 90,627	-$ 90,627	-$ 61,234	-$ 59,807	-$ 59,807	-$ 61,235	-$ 61,235	-$ 90,627
Pole Rental Income	-$ 458,599	-$ 423,740	-$ 686,732	-$ 526,448	-$ 517,395	-$ 559,739	-$ 1,034,618	-$ 1,049,720	-$ 686,732
Total	-$ 549,227	-$ 514,367	-$ 777,359	-$ 587,682	-$ 577,201	-$ 619,546	-$ 1,095,853	-$ 1,110,955	-$ 777,359

Account 4375 - Revenues from Non Utility (	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
OPA programs	-$ 499,147	-$ 984,572	-$ 1,106,728	-$ 1,383,432	-$ 2,033,252	-$ 2,432,446	-$ 921,770	-$ 1,418,525	-$ 1,106,728
Affordability Fund Trust						-$ 755,880	-$ 1,964,944	-$ 1,077,280	$ -
Total	-$ 499,147	-$ 984,572	-$ 1,106,728	-$ 1,383,432	-$ 2,033,252	-$ 3,188,326	-$ 2,886,713	-$ 2,495,805	-$ 1,106,728

Account 4380 - Expenses of Non Utility Op	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	2017 Actual[2]	2018 Actual	Bridge Year	Test Year	CGAAP
	2013	2014	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis									CGAAP
OPA programs - Expenditure Offset	$ 487,219	$ 966,943	$ 878,607	$ 1,383,432	$ 2,033,252	$ 1,969,873	$ 921,770	$ 1,418,525	$ 878,607
Affordability Fund Trust						$ 755,880	$ 1,964,944	$ 1,077,280	

Total	$ 487,219	$ 966,943	$ 878,607	$ 1,383,432	$ 2,033,252	$ 2,725,752	$ 2,886,714	$ 2,495,805		$ 878,607

Account 4390 - Expenses of Non Utility Op										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Sale of materials/service	-$ 225	-$ 1,538	-$ 1,944	-$ 3,856	-$ 7,330	-$ 5,509	-$ 12,682	-$ 5,000		-$ 1,944
Sale of Scrap Material	-$ 157,304	-$ 82,477	-$ 114,377	-$ 170,869	-$ 102,368	-$ 119,371	-$ 99,046	-$ 128,000		-$ 114,377
Miscellaneous Revenue	-$ 11,286	-$ 14,053	-$ 49,323	-$ 27,476	-$ 20,884	-$ 22,600	-$ 5,369	$ -		-$ 49,323
Total	-$ 168,815	-$ 98,068	-$ 165,644	-$ 202,201	-$ 130,581	-$ 147,480	-$ 117,098	-$ 133,000		-$ 165,644

Account 4385 - Non Rate-Regulated Utility										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Equipment Buyout/Sentinel	-$ 12,418	-$ 21,537	-$ 21,758	-$ 23,029	-$ 20,106	-$ 20,073	-$ 19,504	-$ 20,000		-$ 21,758
Total	-$ 12,418	-$ 21,537	-$ 21,758	-$ 23,029	-$ 20,106	-$ 20,073	-$ 19,504	-$ 20,000		-$ 21,758

Account 4220 - Other Electric Revenues										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Fit Fees Revenue			-$ 8,242	-$ 1,268	-$ 1,903					-$ 8,242
Misc revenue					-$ 120,000					
Total	$ -	$ -	-$ 8,242	-$ 1,268	-$ 121,903	$ -	$ -	$ -		-$ 8,242

Account 4310 - Regulatory Credits										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Loss on PP&E Disposal - transfer to deferral				-$ 1,624,754	-$ 461,851	-$ 624,722	-$ 515,799			
Total	$ -	$ -	$ -	-$ 1,624,754	-$ 461,851	-$ 624,722	-$ 515,799	$ -		$ -

4360- Loss on Disposition of Utility and Oth										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Loss on PP&E Disposal			$ 538,014	$ 637,754	$ 454,852	$ 624,722	$ 515,799	$ 564,690		$ -
Total	$ -	$ -	$ 538,014	$ 637,754	$ 454,852	$ 624,722	$ 515,799	$ 564,690		$ -

4245- Government and Other Assistance D										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Deferred Revenue			-$ 42,626	-$ 70,037	-$ 92,007	-$ 115,823	-$ 131,564	-$ 207,802		
Total	$ -	$ -	-$ 42,626	-$ 70,037	-$ 92,007	-$ 115,823	-$ 131,564	-$ 207,802		$ -

4355 Gain on Disposition of Utility and Othe										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Gain on Disposal	-$ 1,402	-$ 26,005					-$ 2,696			

Total	-$ 1,402	-$ 26,005	$ -	$ -	$ -	$ -	-$ 2,696	$ -		$ -

4305 - Regulatory Debits										
	2013 Actual²	**2014 Actual²**	**2015 Actual²**	**2016 Actual²**	**2017 Actual²**	**2018 Actual**	**Bridge Year**	**Test Year**		**CGAAP**
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		**$ 2,015**
Reporting Basis										**CGAAP**
Incremental Pole Rental Revenue - trf to de						$ 38,525	$ 507,989			
Total	$ -	$ -	$ -	$ -	$ -	$ 38,525	$ 507,989	$ -		$ -

3-Staff-42 Other Revenue

Question:

Ref 1: Chapter 2 appendices – 2-H

In appendix 2-H, interest and dividend income dropped since 2013. This appears to be the result of declining Miscellaneous Interest Revenue and Intercompany Interest.

a) Please explain why there are declining balances since 2013 and why there are no amounts for 2020.

Response:

The intercompany debt balance has varied over the years depending on the needs of the companies and the cash available. Through managing its cash during 2019, GSHi called its loan to its affiliate to delay obtaining external debt. GSHi has no plans to extend loans to any affiliate in 2020 and beyond, therefore no intercompany interest revenue will be collected. The miscellaneous interest revenue was not properly labelled in the exhibit and was actually GSHi's interest on deferral and variance accounts. GSHi has not included any interest (or expense) related to the deferral and variance accounts in the 2020 test year budget.

4-Staff-43 OM&A Cost Driver

Question:

Ref 1: Chapter 2 Appendices - 2-JB

Ref 2: Exhibit 4 – Tab 1 – Schedule 1

Sudbury Hydro provided explanations for all material changes for each cost drivers provided in reference 1 except for Other Miscellaneous costs.

a) Please provide an explanation for the change in the Other Miscellaneous cost driver.
b) Please provide a description of the costs included in this cost driver.

Response:

a) GSHi has performed further analysis on the cost drivers and noticed changes in contract labour worth highlighting and has added a line to the cost driver table and included a revised table (included as Attachment 1 to this response). Table 1 below shows the changes year over year.

Table 1 - Contract Labour

Board Approved 2013 vs Actual 2013	-$	218,669
Actuals 2013 vs 2014	-$	9,772
Actuals 2014 vs 2015	$	161,377
Actuals 2015 vs 2016	$	73,876
Actuals 2016 vs 2017	$	52,588
Actuals 2017 vs 2018	-$	89,205
Actual 2018 vs Unaudited 2019	-$	138,286
Unaudited 2019 vs Budget 2020	-$	50,383
Total Fluctuation 2013 to 2020	***-$***	***218,475***

When comparing 2013 Board Approved and 2013 Actual, the variance of $218,669 can be primarily attributed to an ArcFlash program that was budgeted for $100,000 and not spent, PCB removal costs for 2013 coming in $50,000 under budget (some deferred to the following year), back up costs for the MDMR sync coming in $20,000 less than expected and the contract labour expected for the integration of the MDMR was $40,000 less than budget.

When comparing 2015 and 2014 actuals, contract labour costs increased by over $160,000. The main driver of this cost increase was $85,000 from Hydro One for transferring GSHi's 44KV overhead conductor onto their new poles as result of three separate line rebuilds that they completed during the year. Also in this year, GSHi started charging the cost of restoration (approximately $70,000 in 2015) incurred as a result of capital projects to OM&A expenses. It was GSHi's understanding at the time that these costs could not be capitalized. It is worth noting that in 2019, after further discussions both internally and with GSHi's auditors, it was decided these costs can be capitalized and beginning in 2019 are now charged to the Capital Projects to which they pertain. This amounts to approximately $95,000 and explains the majority of the variance when comparing 2019 and 2018.

Table 2 below shows the revised Other Miscellaneous cost drivers.

Table 2 - Other Miscellaneous Cost Drivers

Board Approved 2013 vs Actual 2013	$	23,147
Actuals 2013 vs 2014	$	193,488
Actuals 2014 vs 2015	-$	32,530
Actuals 2015 vs 2016	-$	15,088
Actuals 2016 vs 2017	$	89,592
Actuals 2017 vs 2018	-$	12,332
Actual 2018 vs Projection 2019	$	63,952
Projection 2019 vs Budget 2020	$	40,009
Total Fluctuation 2013 to 2020	***$***	***350,237***

b) Costs included in the Other Miscellaneous cost drivers line pertain to other items that have some normal fluctuations year over year. In years closer to 2013, analysis was more challenging due to the way GSHi budgeted, recorded and tracked costs. Since 2016, GSHi budgets within its financial system and has since refined its processes allowing for more valuable analysis. By the end of 2020, as a result of the work involved in preparing the Cost of Service Application, GSHi also has plans to further refine its processes with respect to allocations to and from other companies, which will allow for more precise analysis in those areas.

The change of $193,488 between 2013 and 2014 actuals is made up of the following and provides an example of what is included in that line.

Table 3 - Other Miscellaneous Actuals 2013 vs 2014

Meetings & Networking	-$	23,670
Expendable Tools	$	46,977
Material Purchases	$	69,855
Computer Software	$	21,605
Membership and OEB Cost Awards	$	23,327
Maintenance & Support	$	10,462
IT Redistribution	$	13,946
Other insignificant items	$	30,985
Total Other Miscellaneous 2013 vs 2014 Fluctuation	***$***	***193,488***

Attachment 1 (of 1):

4-Staff-43 Attachment 1: Cost Drivers

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Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 13,937,539	$ 14,244,666	$ 13,729,965	$ 14,313,935	$ 15,162,845	$ 14,647,473	$ 14,941,781	$ 15,359,614
Labour Complement & Burdens	-$ 1,147,029	$ 190,636	$ 299,528	-$ 182,849	$ 447,777	-$ 209,090	$ 353,777	$ 973,874
Other Post Employment Benefit Costs	$ 895,111	$ 98,028	-$ 137,689	$ 65,099	-$ 295,590	-$ 32,162	-$ 229,202	-$ 5,795
Costs Allocated from Affiliates	-$ 489,637	$ 310,633	$ 560,798	$ 263,927	-$ 134,616	$ 60,362	$ 86,526	$ 813,851
Succession Planning/Training	$ -	$ -	$ -	$ -	$ -	$ -	$ 136,181	$ 160,904
Bad Debt Expense	-$ 94,791	$ -	-$ 300,209	$ 431,626	-$ 165,364	-$ 105,580	$ 267,726	-$ 164,592
Productivity and Business Planning	-$ 148,447	$ 196,451	$ -	$ 31,687	-$ 185,405	$ -	-$ 77,870	$ 122,143
Governance	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,988	-$ 16,183
Vehicles & Material Costs	-$ 165,577	$ 45,528	$ 202,552	$ 155,016	-$ 289,086	-$ 19,637	$ 81,673	$ 38,213
Conservation & Demand Management	$ 524,978	-$ 485,530	$ 25,689	-$ 65,137	$ -	$ -	$ -	$ -
Tree Trimming	-$ 261,813	$ 233,369	-$ 45,929	$ 178,012	-$ 185,489	$ 74,126	$ 118,485	-$ 87,170
Construction Write Offs	$ 149,843	-$ 47,521	-$ 73,634	-$ 87,257	$ 61,402	$ -	$ -	$ -
Insurance	$ -	$ -	-$ 75,984	$ -	$ 46,503	-$ 34,324	-$ 20,504	$ -
Monthly Billing Deferral Account	-$ 0	$ -	$ 0	$ 0	-$ 229,750	$ 459,500	-$ 229,750	$ -
Smart Meter Disposition	$ 1,240,010	-$ 1,240,010	$ -	$ -	$ -	$ -	$ -	$ -
Locates Contract	$ -	$ -	$ -	$ -	$ -	$ 202,650	-$ 202,650	$ -
Cost of Service Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,000
OEB Quarterly Assessment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,000
Deferral Account Write-Offs	$ -	$ -	$ -	$ -	$ -	$ -	$ 49,713	-$ 49,713
Pole Attachment Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 86,076	$ 58,939
Cybersecurity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 65,246
Monthly Billing Costs	$ -	$ -	$ -	$ -	$ 272,066	$ -	$ -	$ -
Contract Labour	-$ 218,669	-$ 9,772	$ 161,377	$ 73,876	$ 52,588	-$ 89,205	-$ 138,286	-$ 50,383
Other Miscellaneous	$ 23,147	$ 193,488	-$ 32,530	-$ 15,088	$ 89,592	-$ 12,332	$ 63,952	$ 40,009
Closing Balance[2]	$ 14,244,666	$ 13,729,965	$ 14,313,935	$ 15,162,845	$ 14,647,473	$ 14,941,781	$ 15,359,614	$ 17,388,957

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

4-Staff-44 Labour Complement & Burdens

Question:

Ref 1: Exhibit 4 – Tab 2 – Schedule 1, p. 1

Ref 2: Exhibit 4 – Tab 4 – Schedule 2

In reference 1, Sudbury Hydro stated that since 2013 Sudbury Hydro had added six positions and eliminated four. In reference 2, Sudbury Hydro provided positions that were added between 2013 and 2019 but only showed five positions fully allocated to Sudbury Hydro's budget.

a) Please confirm that the five positions fully allocated to Sudbury Hydro's budget in reference 2 were the positions Sudbury Hydro added.
b) Please provide the sixth position that was added by Sudbury Hydro.
c) Please provide the four positions that were eliminated by Sudbury Hydro and provide an explanation why they were no longer required.

Response:

a) GSHi confirms the five positions detailed in reference 2 were added since 2013, in addition GHSi also added a Technical Services Supervisor which was omitted from the discussion in error.

b) GSHi added the Technical Services Supervisor position to focus on substation assets, SCADA communication equipment (including software and servers) and field RTUs.
c) GSHi eliminated the following positions:
    1. Power System Inspector: GSHi had to accommodate a worker due to injury and once the individual retired, GSHi forecasted the workload for the Inspectors and decided filling the vacancy was not required.

2. System Operator: GSHi tried to fill this vacancy in order to return to a 24/7 control room, however a suitable candidate was never found. GSHi was forced to continue a 24/5 schedule.
3. Engineering Manager: The Engineering Manager position was implemented for succession planning and upon the Vice-President's retirement, the Engineering Manager was promoted and the position was no longer required.
4. Project Coordinator: A vacancy was created when the individual in the role took another opportunity within the utility. Based on budget and forecasted workload, GSHi decided to eliminate this position and allocate work amongst the remaining Project Coordinators.

4-Staff-45 Costs allocated from affiliates

Question:

Ref 1: Exhibit 4 – Tab 2 – Schedule 1, p. 5

Ref 2: Exhibit 4 – Tab 4 – Schedule 2

Ref 3: Exhibit 4 – Tab 1 – Schedule 1, p. 4

Ref 4: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study

Ref 5: Exhibit 4 – Tab 5 – Schedule 1

In reference 1, Sudbury Hydro stated that since 2013 Greater Sudbury Hydro Plus (GSHP) has added ten positions. In reference 3, Sudbury Hydro stated that GSHP added 12 positions and eliminated 2. In reference 2, Sudbury Hydro provided ten positions that were partially allocated to Sudbury Hydro's budget.

a) Please confirm that the ten positions provided in reference 2 are the positions added to GSHP.
b) Please provide the remaining two positions added by GSHP.
c) Please provide the two positions that were eliminated by GSHP and provide an explanation why they were no longer required.

In reference 4, Sudbury Hydro provided a breakdown of services provided by affiliates in Table ES-1.

d) Please provide a cost breakdown for each service for each year between 2013 and 2020, before and after allocation.
e) Please provide the service agreement with GSHP.
f) Please provide what additional services Sudbury Hydro has received from GSHP to justify the cost increase allocated to Sudbury Hydro from GSHP.

Sudbury Hydro stated in reference 5 that it receives the following services from GSHP: Financial, Human Resources, Communications, Information Technology, Customer Service and Billing, President and CEO, Risk Management, Board of

Directors, Procurement, Payroll, Accounts Payable, Regulatory, Accounting, Innovation, Quality and Project Management.

g) For services where a competitive market exists, please provide the business case that supports the business need and that GSHP is more competitive than market rates.

Response:

a) GSHi confirms that only ten positions were added to GSHP since 2013. Reference 3 was incorrect. Two positions were transferred within the utility but the positions were not eliminated, nor were new positions added. The Administration Clerk who performed purchasing functions was transferred from the Administration Department to the Purchasing Department. The Business Analyst position, which was vacant for a period of time, was renamed CIS Analyst when it was filled, however the function remained the same, as did the reporting structure.

b) As discussed in a) above, there were only 10 positions added, as described in Reference 2.

c) Please see a) and b) above – the two positions were not eliminated, simply transferred or renamed.

d) Please see Attachment 1 of this submission for a cost breakdown for each service for each year between 2013 and 2020, before and after allocation. GSHi would like to note that in its original submission of Exhibit 4 – Tab 5 – Schedule 1 and Exhibit 4 – Tab 5 – Schedule 1 – Attachment 1, and the Chapter 2 Appendix 2-N, GSHi did not include costs related to IT and a few other small amounts in 2013 actuals through 2016 actuals. GSHi has updated Chapter 2 Appendix 2-N for these changes. GSHi also noticed that the pre settlement budget was used in its initial submission of Exhibit 4 – Tab 5 – Schedule 1 and Exhibit 4 – Tab 5 – Schedule 1 – Attachment 1, and the Chapter 2 Appendix 2-N. GSHi has updated Chapter 2

Appendix 2-N for the final post settlement Board Approved Budget figures with this submission. These updates can call be found in Attachment 1 of this submission as well as in the Chapter 2 Appendices Live Models included with this submission. GSHi would like to note that this has not changed GSHi's explanation for the variances between the 2020 Test Year vs. 2013 Board Approved or the 2018 Actual vs. 2020 Test Year.

e) Please see Attachment 2 to this interrogatory response for the Service Level Agreement between GSHi and GSHP (Tab 1, Interrogatory 45, Attachment 2).

f) The majority of the cost increase from GSHP is primarily related to the increased positions in the affiliate which include:
   - Customer Service Manager
   - Senior Customer Service Representative
   - Innovation Officer
   - Accounting Analyst
   - Communications Assistant
   - Strategic Planning Officer
   - Grant Writer
   - Project Manager

Also included in the increased costs is the Sync Operator which was transferred to Customer Service from the Metering Department since 2013. This was not a new position, however is now included with the costs allocated from the affiliate. The increased costs also include the costs associated with monthly billing. There are also increased maintenance and support costs to maintain the systems used to service GSHI. Another component to the increased costs is the Innovation Office whose services are discussed in more detail in 4-Staff-56.

g) As stated in the 2020 Cost of Service application, GSHP's sole business is to provide services to GSHi and its affiliates. The arrangement creates economies of scope and scale through the sharing of human and other resources.

This structure has been supported by a detailed transfer pricing methodology, developed at the Board's request following GSHi's 2009 Cost of Service application (EB-2008-0230), to ensure that affiliates responsible for costs carry their share of the financial burden. The pricing methodology was validated through a transfer pricing study conducted by an independent third-party consultant, BDR North America Inc., in 2011. GSHi submitted the completed study with its 2013 Cost of Service Application (EB-2012-0126). The transfer pricing study has been updated for the 2020 Cost of Service application and a copy of the study is included in Exhibit 4, Tab 5, Schedule 1, Attachment 2.

Although GSHi has not created a business case to demonstrate that GSHP offers services that are more competitive than market rates, potential cost benefits realized through this shared services structure were quantified in BDR North America Inc.'s initial transfer pricing study (EB-2012-0126, Exhibit

1 Tab 1 Schedule 11 Attachment 1). As stated in the study: "Based on the analysis of costs, it was determined that the potential cost sharing benefit that [GSHi] derives from affiliates is approximately $1.6 million per year." The study states that these cost savings will ultimately benefit both the utility and its customers.

Attachment 1 (of 2):

4-Staff-45 Attachment 1: Appendix 2-N

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2013 Board Approved

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	83%	$748,948	$897,724
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$144,339	$144,339
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	86%	$288,060	$335,463
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	87%	$244,314	$282,378
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$155,842	$155,842
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	79%	$214,767	$271,733
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	33%	$316,896	$965,425
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	77%	$773,456	$1,000,220
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	61%	$1,571,801	$2,595,977
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	50%	$29,400	$58,800
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$44,200	$88,400
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	83%	$568,175	$686,988
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	12%	$160,000	$1,191,103
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$680,000	$680,000
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	260%	$90,627	$34,798
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	31%	$307,503	$678,220

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Amount Allocated
From	To				%	$

Year: 2013 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	83%	$590,981	$709,835
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$152,403	$152,403
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	84%	$206,278	$245,569
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	85%	$241,761	$283,733
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$128,830	$128,830
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	79%	$214,767	$271,733
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	46%	$435,302	$956,502
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	75%	$630,090	$839,231
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	63%	$1,517,288	$2,420,803
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	59%	$9,959	$16,801
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$36,334	$72,667
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	93%	$334,691	$359,427
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	93%	$97,387	$1,310,440
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$473,038	$473,038
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	276%	$90,627	$32,855
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	82%	$119,904	$665,341

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2014 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	87%	$663,490	$765,976
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$128,923	$128,923
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	84%	$195,967	$233,294
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	98%	$302,013	$308,491
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$140,822	$140,822
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	76%	$224,083	$295,475
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	46%	$438,485	$953,002
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	79%	$659,493	$830,221
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	78%	$1,688,936	$2,175,005
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	91%	$28,664	$31,441
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$32,593	$65,187
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	90%	$313,416	$347,815
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	95%	$49,275	$963,454
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$332,352	$332,352
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	280%	$90,627	$32,324
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	83%	$117,967	$688,540

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2015 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	83%	$848,144	$1,028,005
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$149,384	$149,384
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	84%	$270,254	$321,731
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	99%	$238,347	$240,868
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$131,659	$131,659
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	91%	$234,618	$259,150
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	47%	$484,699	$1,022,493
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	76%	$745,077	$974,196
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	79%	$1,894,586	$2,402,748
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	0%	$0	$8,682
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$29,769	$59,848
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	100%	$381,610	$381,610
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	94%	$65,876	$1,113,917
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$414,682	$414,682
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	87%	$90,627	$103,759
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	48%	$354,639	$686,914

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2016 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	78%	$1,016,646	$1,300,620
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$200,011	$200,011
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	86%	$334,749	$389,832
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	97%	$233,641	$240,868
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$150,826	$150,826
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	79%	$225,367	$285,098
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	47%	$464,252	$991,138
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	78%	$682,969	$877,018
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	82%	$1,928,911	$2,366,183
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	72%	$16,943	$23,607
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$28,764	$57,529
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	91%	$433,464	$476,540
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	93%	$78,488	$1,191,749
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$484,459	$484,459
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	278%	$61,234	$22,025
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	77%	$189,399	$826,877

Year: 2017 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	83%	$1,087,083	$1,304,397
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$257,177	$257,177
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	89%	$354,869	$398,730
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	98%	$262,107	$266,640
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$127,692	$127,692
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	81%	$225,217	$279,471
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	48%	$498,270	$1,030,362
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	54%	$373,787	$695,541
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	75%	$2,073,049	$2,761,191
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	86%	$50,033	$58,045
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	56%	$35,251	$63,474
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	92%	$476,299	$518,848
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	92%	$91,752	$1,128,205
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$503,246	$503,246
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	327%	$59,807	$18,309
Sudbury Hydro	Affiliate	Occupancy Costs	Cost recovery based on square footage	84%	$109,606	$701,013

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2018 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	83%	$1,080,877	$1,300,485
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$253,456	$253,456
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	89%	$334,947	$376,345
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	98%	$336,231	$341,999
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$126,387	$126,387
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	81%	$208,255	$258,552
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	48%	$546,047	$1,138,785
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	54%	$336,708	$626,129
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	75%	$2,130,734	$2,850,615
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	94%	$88,110	$93,437
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	56%	$50,230	$90,414
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	93%	$474,928	$512,900
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	92%	$101,083	$1,208,358
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$483,837	$483,837
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	277%	$59,807	$21,558
Greater	Affiliate	Building Services and	Cost recovery based on square footage	82%	$144,563	$822,329

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2019 Bridge

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	75%	$1,184,661	$1,571,440
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$284,117	$284,117
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	77%	$363,748	$474,547
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	98%	$268,142	$272,780
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$127,126	$127,126
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	79%	$212,120	$268,638
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	41%	$500,740	$1,215,446
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	54%	$342,260	$635,813
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	75%	$2,152,088	$2,869,852
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	96%	$174,124	$181,794
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	56%	$97,678	$175,821
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	92%	$493,513	$535,428
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	90%	$138,399	$1,379,939
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$449,755	$449,755
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	309%	$61,235	$19,798
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	82%	$135,794	$772,101

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: 2020 Test

Shared Services

Name of Company		Service Offered	Pricing Methodology	% Cost Allocation	Price for the Service	Cost for the Service
From	To				$	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	75%	$1,539,617	$2,039,769
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	100%	$285,986	$285,986
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	74%	$355,076	$479,832
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	98%	$380,388	$386,966
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	100%	$117,494	$117,494
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	80%	$211,901	$264,519
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	51%	$721,563	$1,401,140
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	54%	$392,144	$729,272
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	76%	$2,455,443	$3,228,782
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	91%	$128,628	$141,641
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	50%	$109,675	$219,350
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	91%	$527,359	$580,080
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	92%	$104,738	$1,347,616
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	100%	$441,246	$441,246
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	309%	$61,235	$19,798
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	82%	$132,773	$755,178

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Price for the Service	Cost for the Service
From	To				%	$

Year: Variance Analysis

Shared Services

Name of Company		Service Offered	Pricing Methodology	2013 Board Approved (BA)	2020 Test Year	Variance 2020/2013 BA		2018 Actual	2020 Test Year	Variance 2018/2020 Test	
From	To			$		%	$	$	$	%	$
Affiliate	Greater Sudbury Hydro	Executive/Finance/Communications/Innovation	Time Records	748,948	1,539,617	106%	790,669	$1,080,877	1,539,617	42%	458,740
Affiliate	Greater Sudbury Hydro	Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Greater Sudbury	144,339	285,986	98%	141,647	$253,456	285,986	13%	32,530
Affiliate	Greater Sudbury Hydro	HR	HR - Directly assigned where possible, number of employees for other costs; 2nd tier allocation to reallocate portionassociated with shared services/	288,060	355,076	23%	67,016	$334,947	355,076	6%	20,129
Affiliate	Greater Sudbury Hydro	Risk Management	97% of costs allocated to Greater Sudbury, based on time records	244,314	380,388	56%	136,074	$336,231	380,388	13%	44,157
Affiliate	Greater Sudbury Hydro	Quality Management	QMS - Costs of the Plus Company directly assigned to Greater Sudbury, as the other affiliates pay for their own programs directly	155,842	117,494	-25%	(38,348)	$126,387	117,494	-7%	(8,893)
Affiliate	Greater Sudbury Hydro	Insurance	Revenue	214,767	211,901	-1%	(2,866)	$208,255	211,901	2%	3,646
Affiliate	Greater Sudbury Hydro	IT	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	316,896	721,563	128%	404,667	$546,047	721,563	32%	175,516
Affiliate	Greater Sudbury Hydro	Accounts Payable/Payroll/Accounting	AP - Time tracking for activities identifiable with one affiliate; number of invoices for other costs Payroll - Time tracking for activities identifiable with one affiliate number of employees for other costs Accounting - A time estimate for forecast; time records for actual	773,456	392,144	-49%	(381,312)	$336,708	392,144	16%	55,436
Affiliate	Greater Sudbury Hydro	Customer Billing and related services	Detailed analysis of each costcomponent, with differen allocation methods, including number of bills, call volumes, number of meters, and space occupied on the shared bill. Direct assignment where applicable.	1,571,801	2,455,443	56%	883,642	$2,130,734	2,455,443	15%	324,709
Affiliate	Greater Sudbury Hydro	Any costs of the Plus Company not otherwise allocated	For redistribution of costs which were allocated by other methodologies to the Plus Company. In proportion to the allocation of other costs.	29,400	128,628	338%	99,228	$88,110	128,628	46%	40,518
Affiliate	Greater Sudbury Hydro	Board of Directors	50% cost of two boards, (GSHi and GSU), plus direct assignment of two independent directors	44,200	109,675	148%	65,475	$50,230	109,675	118%	59,445
Affiliate	Greater Sudbury Hydro	Stores/Procurement	Materials Issued/Time record of staff	568,175	527,359	-7%	(40,816)	$474,928	527,359	11%	52,431
Greater Sudbury Hydro	Affiliate	Garage/Fleet Services	Hourly charge out rate based on full cost recovery	160,000	104,738	-35%	(55,262)	$101,083	104,738	4%	3,655
Greater Sudbury Hydro	Affiliate	Streetlight Maintenance	Time of staff as recorded in the work order system	680,000	441,246	-35%	(238,754)	$483,837	441,246	-9%	(42,591)
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Market Rate applied to square footage	90,627	61,235	-32%	(29,393)	$59,807	61,235	2%	1,428
Greater Sudbury Hydro	Affiliate	Building Services and Occupancy Costs	Cost recovery based on square footage	307,503	132,773	-57%	(174,730)	$144,563	132,773	-8%	(11,790)

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology		Costs Allocated	Amount Allocated
From	To				%	$

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent

· ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence

· ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide

Attachment 2 (of 2):

4-Staff-45 Attachment 2:GSHP/GSHi Service Level Agreement

CORPORATE SERVICES AGREEMENT

Between

GREATER SUDBURY HYDRO PLUS INC/HYDRO PLUS DU GRAND SUDBURY INC.
("Servicesco")

and

GREATER SUDBURY HYDRO INC./HYDRO DU GRAND SUDBURY INC.
("Wiresco")

DATED AS OF July 1, 2019

RECITALS

1. Greater Sudbury Hydro Plus Inc./Hydro Plus du Grand Sudbury Inc. ("Servicesco") is a corporation established under the laws of the Province of Ontario and is in the business of providing Corporate Services to corporations and other entities operating electrical, , telecommunications or property rentals, generation facilities

2. Greater Sudbury Hydro Inc. / Hydro du Grand Sudbury Inc. ("Wiresco") is a corporation established under the laws of the province of Ontario and is in the business of distributing electricity throughout certain parts of the City of Greater Sudbury and the Municipality of West Nipissing.

3. Servicesco and Wiresco have agreed to enter into this Corporate Services Agreement dated as of July 1, 2019 (the "Agreement"), pursuant to which Servicesco will provide Corporate Services to Wiresco and Wiresco will provide certain services to Servicesco as described in Schedule A, on and subject to the terms and conditions set forth herein;

NOW THEREFORE, THIS CORPORATE SERVICES AGREEMENT WITNESSES THAT, in consideration of the covenants and agreements herein contained, the Parties hereto agree as follows:

ARTICLE I
INTERPRETATION

1.1 **Definitions.** Whenever used in this Agreement, unless the context otherwise requires, the capitalized words and terms used herein shall have the following meanings:

"Affiliate Relationships Code" means the OEB's *Affiliate Relationships Code for Electricity Distributions and Transmitters*, dated April 1, 1999, and revised March 15, 2010, and any supplements or amendment thereto:

"Agreement" means this Corporate Services Agreement, including all schedules and all documents, instruments and agreements supplemental hereto or in amendment or confirmation hereof;

"Applicable Laws" means all laws or ordinances and all judgments, decrees, injunctions, writs and orders of any court, arbitrator or Governmental Authority, and all statutes, rules, regulations orders, interpretations, directives, licenses and permits of any governmental body, instrumentality, agency or other regulatory authority applicable to this Agreement and/or the services provided pursuant to the Agreement.;

"Arbitration Act" means the *Arbitration Act, 1991,* S.O. 1991, Chap. 17;

"**Base Fees**" shall have the meaning ascribed in Section 4.1;

"**Business Day**" means a day other than Saturday, Sunday or a legal holiday in Sudbury, Ontario;

"**Confidential Information**" means information that Wiresco has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective electrical distribution or transmission services;
"Event of Default" means any of the events described in Section 6.1;

"**Corporate Services Expenses**" means with respect to any period, without duplication, all costs and expenses incurred by Servicesco in connection with the provision of the Corporate Services and calculated in accordance with the transfer pricing methodology attached to this agreement as Schedule A;

"**Fair Market Value**" means the price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act;

"**Force Majeure**" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of god, lack of materials or supply of service which results notwithstanding the diligent efforts of Servicesco and Wiresco;

"**Governmental Authority**" means any court or governmental department, commission, board, bureau, agency, or instrumentality of Canada. or of any province, territory, county, municipality, city, town or other political jurisdiction and whether now or in the future constituted or existing that has jurisdiction over some aspect of the services provided under this Agreement or over either of Servicesco or Wiresco;

"**HST**" means the harmonized sales tax levied under Part IX of the *Excise Tax Act* R.S.C., 1985, c. E-15;

"**Insolvent**" means, with respect to any Person, being insolvent, bankrupt, making a proposal under the *Bankruptcy and Insolvency Act* R.S.C., 1985 c. B-3 or having a trustee or receiver or manager appointed in respect of its assets;

"**OEB**" means the Ontario Energy Board;

"**OEB Act**" means the *Ontario Energy Board Act, 1998 S.O. 1998, C 15, Sched B;*

"**Party**" means Servicesco or Wiresco, or both, as applicable;

"**Person**" means any natural person, corporation, division of a corporation, partnership, trust, joint venture, association, company, estate, unincorporated organization, public utilities commission, or Governmental Authority;

"Required Consents" means all permits, by-laws, licences, waivers, exemptions, consents, certificates, authorizations, approvals, rights, rights of way and entitlements and the like which are required from any Governmental Authority or any other Person in respect of, or which are in any way material to, the performance of the Services by Servicesco on Wiresco's behalf;

"Services" and "Corporate Services" means the services that Wiresco requires to be performed by Servicesco and the services that Servicesco requires to be performed by Wiresco as listed in Schedule A

"Servicesco" means Greater Sudbury Hydro Plus Inc./Hydro Plus du Grand Sudbury Inc.;

"Taxes" means any and all governmental fees (including license, documentation and registration fees), taxes (including income, gross receipt, sales, rental, use, turnover, value added, property (tangible and intangible), excise and stamp taxes), licenses, levies, imposts, duties, recording charges or fees, charges, assessments, reassessments or withholdings of any nature whatsoever, including commodity taxes, together with any and all assessments, penalties, fines, additions and interest thereon;

"Term" shall mean the period from the date hereof to December 31, 2024 or such earlier date as this Agreement may be terminated in accordance with the provisions herein; and

"Wiresco" means Greater Sudbury Hydro Inc./Hydro du Grand Sudbury Inc.

1.2 Termination of Prior Agreement
Effective as of 11:59 pm EST on June 30, 2019 the Prior Agreement is terminated. Effective as of 12:00 am EST on July 1, 2019 this Agreement shall be in full force.

1.3 Interpretation. Throughout this Agreement;

(a) any word importing the singular number shall include the plural and vice versa;

(b) any word importing gender shall include all genders;

(c) all references to sections and schedules are to sections and schedules to and forming part of this Agreement; and

(d) all dollar amounts are in lawful money of Canada,

1.4 **Headings**. The headings in this Agreement are for convenience only and shall not in any way limit or be deemed to construe or interpret the terms and provisions of this Agreement.

1.5 **Schedules**. The following Schedules annexed hereto and incorporated by reference are deemed to be an integral part of this Agreement as if they had been set forth herein:

Schedule "A"- Transfer Pricing Methodology

1.6 **Applicable Law.** This Agreement and all documents, instruments and agreements related thereto shall be construed and enforced in accordance with the laws of the Province of Ontario.

1.7 **Successors and Assigns.** This agreement shall ensure to the benefit of and shall be binding on Servicesco and Wiresco, and their respective successors and assigns.

1.8 **Severability.** Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall not invalidate the remaining provisions hereof and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. In respect of any provision so determined to be unenforceable or invalid, the Parties agree to negotiate in good faith to replace the unenforceable or invalid provision with a new provision that is enforceable and valid in order to give effect to the intent of the original provision to the extent permitted by law and in accordance with the intent of this Agreement.

1.9 **Time of the Essence.** Time shall be of the essence of this Agreement.

1.10 **No Partnership.** It is understood and agreed that nothing contained in this Agreement nor any acts of the Parties shall be deemed to constitute the Services and Wiresco as partners of each other.

ARTICLE II
PROVISION OF SERVICES BY SERVICESCO

2.1 **Appointment of Servicesco.** Servicesco will provide Services to Wiresco in accordance with the terms of this Agreement, throughout the Term.

2.2 **Duties and Responsibilities of Servicesco.** Subject to any Required Consents and to Section 2.4 hereof, Servicesco shall have the duty and responsibility during the Term to provide Services to Wiresco, including without limitation providing the necessary staff to provide the Services to Wiresco. Without limiting the generality of the foregoing, Servicesco shall have the following duties and responsibilities:

(a) to prepare an annual plan and budget for the performance of the Services by Servicesco and to submit such Plan to Wiresco for approval at least 30 days prior to the beginning of each fiscal year;

(b) to prepare and deliver to Wiresco on the 15th day of each month, a report detailing all Services which have been provided by Servicesco in the previous month including detailed and summary costing information calculated in accordance with Schedule A as acceptable to Wiresco;

(c) to provide any further report to Wiresco with respect to the Services, as may be requested from time to time by Wiresco;

(d) to provide the services of trained and accredited (where applicable) Servicesco personnel to provide the Services to Wiresco and otherwise meet Servicesco's obligations under this Agreement;

(e) to assist Wiresco in obtaining and maintaining and fulfilling all necessary permits, consents and permissions, or other regulatory requirements related to the Services, including any licensing requirements pursuant to the OEB Act;

(f) to use its reasonable efforts to secure and maintain from vendors, suppliers and subcontractors the best indemnities, warranties and guarantees as may be commercially available regarding all supplies, equipment and services purchased in relation to the Services, all of which shall be assigned to Wiresco, and assist Wiresco in preserving and enforcing such indemnities, warranties or guarantees;

(g) to promptly notify Wiresco of:

  (i) any default hereunder;

  (ii) any condition or occurrence which is likely to result in a material difference in the costs agreed to by Wiresco in the annual plan;

  (iii) any occurrence, accident, safety violation, lawsuit claim by any Person which might reasonably be expected to result in an investigation or penalty under Applicable Laws or any material violation of any Applicable Laws; or

(iv) any other event which might reasonably be expected to have a material adverse effect on the Services;

2.3 **<u>Powers of Servicesco</u>.** Subject to the overall direction and requirements of Wiresco and subject to any Required Consents and to Section 2.4, Servicesco shall have the authority to administer, perform and carry out the terms of all necessary agreements and commitments, the performance of which is necessary or advisable in respect of the Services provided to Wiresco. Wiresco shall notify all other parties and shall execute all directions and other instruments as may be necessary to document Servicesco's authority under this Agreement to provide Services on behalf of Wiresco.

2.4 **Limit of Servicesco Expenditures.** In the conduct of its duties hereunder, Servicesco shall not, without first obtaining the written approval of Wiresco, undertake an expenditure which would result in a variance to the budget, as set out in the annual plan.

2.5 **Apportionment of Risks.**

(a) Servicesco shall have no liability as a result of this Agreement to make or arrange for payments on account of Wiresco expenses, or any other expenses relating to this Agreement, out of its own funds; and

(b) Servicesco will remain liable for any negligence, omission or failure in the performance of its obligations under this Agreement.

2.6 **Services Provided by Wiresco:** Wiresco shall provide services to Servicesco on the terms outlined in Schedule A. Servicesco in its sole discretion shall determine the amount of services required from Wiresco and agrees to be bound by the pricing methodology in Schedule A for all services procured.

ARTICLE III
TERM

3.1 **Term of Agreement.** This Agreement shall become effective as of the date hereof and shall continue in full force and effect throughout the Term unless sooner terminated in accordance with the provisions of this Agreement. This Agreement shall be automatically renewed for successive periods of five (5) years unless either Party provides the other with written notice to the contrary at least one hundred and eighty (180) days prior to the end of the then incumbent term.

ARTICLE IV
FEES AND PAYMENT OF EXPENSES

4.1 **Services Fee.** In consideration of the Services provided by Servicesco pursuant to this Agreement, Wiresco shall pay to Servicesco, in advance, a monthly Services fee, payable on the last day of the month in which the Services are performed. This fee shall consist of:

(i) a base fee (the "Base Fee") of $3,500 per month, exclusive of HST. The Base Fee may be reset annually by the Parties, in conjunction with the preparation of the Annual Plan; and

(ii) an amount equal to the amount of the Expenses projected to be disbursed by

Servicesco during each month, as reflected in each year's Annual Plan. Such amount shall be adjusted within 30 days of the end of each month based on the actual amount of the Expenses incurred by Servicesco during that month.

4.2 **Calculation of Services Expenses.** Wiresco hereby acknowledges and agrees that:

(a) Servicesco may provide Services to third parties and to itself which are similar to the Services which Servicesco provides to Wiresco hereunder;

(b) Servicesco shall be entitled, from time to time, to reasonably allocate its cost in respect of the Services it provides to Wiresco, among Wiresco, Servicesco and all other third parties to which Servicesco provide services; and

(c) The allocation of Servicesco's cost in respect of the Services as set out in Schedule "A" is reasonable and may be revised by Servicesco from time to time on written notice to Wiresco.

ARTICLE V
COVENANTS

5.1 **Covenants of Servicesco.** Servicesco covenants and agrees that in the performance of its obligations pursuant to this Agreement it shall:

(a) perform all services at all times in accordance with due care and diligence, and in compliance with Applicable Laws;

(b) comply with all instructions of Wiresco in relation to the performance of its Services under this Agreement.

5.2 **Covenants of Wiresco.** Wiresco covenants and agrees that it shall, throughout the Term of this Agreement:

(a) comply in every material respect with all Applicable Laws;

(b) at all times pay all taxes, government fees, and assessments of whatever nature or kind with respect to Wiresco's property and/or operations including any interest and penalties thereon when and as the same become due and payable, except when and so long as the validity of any of the same is in good faith being contested by Wiresco;

(c) execute all directions and other instruments as may be necessary or requested from time to time by Servicesco to document Servicesco's authority under this Agreement; and

(d) provide prompt notice to Servicesco of any material facts or information of which it is aware in relation to and which may affect the Services, including, without limitation, any pending or threatened claims by or against Wiresco before any court or administrative tribunal.

5.3 **Affiliate Relationships Code.** Each of the Parties acknowledge and agree that this Agreement is to be construed as a "Services Agreement" pursuant to the Affiliate Relationships Code, and as such is subject to the following:

(a) the fees paid to the Servicesco under this Agreement shall be calculated in accordance with Schedule A Transfer Pricing Methodology based on the Transfer Pricing Study completed for Wiresco by BDR North America Inc dated June 30, 2019 and as updated from time to time to reflect changes in Servicesco's operating environment;

(b) each of Wiresco and Servicesco shall maintain separate financial records and books of accounts;

(c) Wiresco shall provide the OEB with information regarding its transactions with Servicesco, in a form and manner and at such times as may be requested by the OEB, including without limitation:

(i) the business address, list of officers and directors, and description of Servicesco's business activities; and

(ii) a copy of this Agreement.

5.4 **Confidentiality Arrangements.** Pursuant to the Affiliate Relationships Code, the Parties hereby agree to establish and maintain the following confidentiality arrangements:

(a) Servicesco shall install and maintain appropriate computer data management and data access protocols to ensure that all Wiresco Confidential Information is protected from access by any affiliate that is an "energy service provider" as defined in the Affiliate Relationships Code;

(b) Operations staff shall not be directly involved in the collection of, and shall not have access to, Confidential Information;

(c) Servicesco shall not release Confidential Information to any party without first obtaining the written consent of the consumer, retailer or generator in question, except where Confidential Information is required to be released by Servicesco:

(i) for billing or market operation purposes;

(ii) for law enforcement purposes;

(iii) for the purpose of complying with a legal requirement; or

(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

ARTICLE VI
DEFAULT AND TERMINATION

6.1 Event of Default.

Servicesco shall be in default under this Agreement upon the happening or occurrence of any of the following events, each of which shall be deemed to be "Event of Default" for the purposes of this Agreement:

(a) if Servicesco breaches or fails to observe or perform any of Servicesco's obligations, covenants, or responsibilities under this Agreement, and, within thirty (30) days after notice from Wiresco specifying the nature of such breach or failure, Servicesco fails to cure such breach of failure or to take steps to remedy such breach or failure to the satisfaction of Wiresco;

(b) if Servicesco:

(i) becomes Insolvent;

(ii) is subject to any proceeding, voluntary or involuntary under the provisions of the *Bankruptcy and Insolvency Act* (Canada), the *Companies Creditors Arrangement Act* (Canada), or any other Act for the benefit of creditors;

(iii) winds up either voluntarily or under an order of a Court of competent jurisdiction;

(iv) makes a general assignment for the benefit of its creditors; or

(v) otherwise takes any corporate action that acknowledges its Insolvency; or

(c) if there is gross negligence, willful default or fraud by Servicesco in the performance of any of its obligations, covenants, or responsibilities under this Agreement

6.2 Termination upon Event of Default. Upon the occurrence of an Event of Default, Wiresco in its absolute discretion may elect to terminate this Agreement, upon providing notice to Servicesco and paying any outstanding Base Fee and Corporate Service Expenses therein.

6.3 **Termination.** Subject to Section 8.1 either Party may terminate this Agreement, without cause and at any time, by providing at least one hundred and eighty (180) days' prior written notice of termination to the other Party.

6.4 **Restriction on Termination during Force Majeure.** During the occurrence of an event of Force Majeure, the obligations of the Party affected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure. shall be suspended, and such Party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting Wiresco (but not affecting the performance of Servicesco's obligations hereunder) shall not relieve it of its obligation to make payments to Servicesco hereunder. The non-performing Party shall give the other Party prompt written notice of the particulars of the event of Force Majeure and its expected duration, and shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

6.5 **Post-Termination Arrangements.** In the event of termination of this Agreement, for any reason:

(a) Servicesco shall deliver to Wiresco all books, records, accounts, systems and manuals which it has developed and maintained relating to the Services pursuant to this Agreement;

(b) Servicesco and Wiresco shall take all steps as may be reasonably required to complete any final accounting between them and to provide, if applicable, for the orderly transfer of any matter contemplated by this Agreement; and

(c) title to all materials, equipment, supplies, parts and other items purchased or obtained by Servicesco in relation to the Services shall pass to and vest in Wiresco upon payment or reimbursement of costs by Wiresco.

ARTICLE VII
SUCCESSION AND DELEGATION

7.1 **No Assignment.** This Agreement may not be assigned by either of the Parties hereto.

7.2 **Delegation of Servicesco's Obligations.** Servicesco shall not delegate any of its obligations under this Agreement to a third party without the prior written consent of Wiresco, which consent may not be unreasonably withheld provided that such third party is a reputable and experienced person capable of fulfilling such obligation and further provided that Servicesco shall have provided Wiresco with at least ten (10) days' prior written notice, failing which such consent may be unreasonably withheld. Servicesco shall at all times remain liable and responsible for all obligations under this Agreement notwithstanding delegation of any obligations hereunder to a third party.

ARTICLE VIII
DISPUTE RESOLUTION

8.1 Arbitration.

(a) Any dispute, controversy or claim arising out of or in connection with, or relation to, this Agreement, or the performance, breach, termination or validity hereof, shall be finally settled by arbitration. Either Party may initiate arbitration within a reasonable time after any such dispute, controversy or claim has arisen, by delivering a written demand for arbitration upon the other Party. The arbitration shall be conducted in accordance with the Arbitration Act. The arbitration shall take place in Sudbury, Ontario, and shall be conducted in English;

(b) The arbitration shall be conducted by a single arbitrator having no financial or personal interest in the business affairs of either of the Parties. The arbitrator shall be appointed jointly by agreement of the Parties, failing which an arbitrator shall be appointed by application to the Superior Court of Ontario, in Sudbury;

(c) Absent agreement or an award in the arbitration to the contrary, the arbitration fees and expenses shall be paid by the Parties jointly; and

(d) The arbitral award shall be in writing, stating the reasons for the award and be final and binding on the Parties with no rights of appeal. The award may include an award of costs, including reasonable legal fees and disbursements and fees and expenses of the arbitrator. Judgement upon the award may be entered by any court having jurisdiction thereof or having jurisdiction over the Parties or their assets.

8.2 Confidentiality of Arbitration. The arbitration shall be kept confidential and the existence of the proceeding and any element of it (including but not limited to any pleadings, briefs or other documents submitted and exchanged, and testimony or other oral submission and any awards) shall not be disclosed beyond the arbitrator, the Parties, their counsel and any person necessary to the conduct of the proceeding, except as may be lawfully required in judicial proceedings relating to the arbitration or otherwise.

ARTICLE IX
GENERAL MATTERS

9.1 Notice. Any demand, notice or communication to be made or given hereunder shall be in writing and may be made or given by personal delivery or by transmittal by telecopy, rapifax or other electronic means of communication addressed to the respective Party as follows:

To Wiresco:

Greater Sudbury Hydro Inc.
500 Regent Street
P.O. Box 250
Sudbury, Ontario
P3E 4P1
Attention: Vice President Engineering and Operations
Fax No.: (705) 671-1413

To Servicesco:

Greater Sudbury Hydro Plus Inc.
500 Regent Street
P.O. Box 250
Sudbury, Ontario
P3E 4P1

Attention: President and C.E.O.
Fax No.: (705) 675-0528

or to such other address, telecopy number or rapifax number as a Party may from time to time notify the other in accordance with this Section 9.1. Any demand, notice or communication made or given by personal delivery shall be conclusively deemed to have been given on. the day of actual delivery thereof, or, if made or given by electronic means of communication, on the first Business Day following the transmittal thereof.

9.2 **Further Assurances.** Each of Wiresco and Servicesco shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other Party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

9.3 **Whole Agreement.** This Agreement together with the Schedules attached hereto constitute the whole and entire agreement between the Parties with respect to the subject matter hereof.

9.4 **Amendments and Waivers.** No modification of or amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the Parties hereto and no waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided, shall be limited to the specific breach waived.

9.5 **Effective Date.** This Agreement is to take effect as and from July 1, 2019 notwithstanding the date of execution of this Agreement.

IN WITNESS WHEREOF this Agreement has been executed by the Parties hereto as of 30th of June, 2019.

GREATER SUDBURY HYDRO PLUS INC. / HYDRO PLUS DU GRAND SUDBURY INC.

Per: ______________________________

Name: MARK SIGNORETTI
Title: **Director**

c/s

Per: ______________________________

Name: **Catherine Huneault**
Title: **Vice President Corporate Services and CFO**

GREATER SUDBURY HYDRO INC./ HYDRO DU GRAND SUDBURY INC.

Per: ______________________________

Name: MARK SIGNORETTI
Title: **Director**

c/s

Per: ______________________________

Name: **Frank Kallonen**
Title: **President and CEO**

Schedule "A" - Transfer Pricing Methodology

Summary of Services Provided by Servicesco to Wiresco		
Nature of Service	**Allocation Method Used**	**BDR Comment or Recommendation**
Executive	Time Records	Reasonable and accordance with accepted principles of cost allocation.
Board of Directors	50% of the cost of two boards (Greater Sudbury and GSU), plus direct assignment of two independent directors	Reasonable and accordance with accepted principles of cost allocation.
Insurance	Direct assignment	Best treatment of identifiable costs
Risk management (employee safety)	97% of costs allocated to Greater Sudbury, based on time records	Recommend analysis of programs to determine correct balance for direct assignment.
Procurement, inventory and stores services	Value of issued inventory	Reasonable and accordance with accepted principles of cost allocation.
Human Resources	Directly assigned where possible, number of employees for other costs	Reasonable and accordance with accepted principles of cost allocation.
Information technology and telephone services	Telephone systems, PCs and ERP, by unweighted number of users; telephone sets by weighted number of users reflecting complexity of the units; systems for customer information and billing by factors related to that function; costs directly assigned where specifically identified with an affiliate or function.	Reasonable and accordance with accepted principles of cost allocation.
Payroll	Time tracking for activities identifiable specifically to Wiresco; number of employees for other costs	Reasonable and accordance with accepted principles of cost allocation.
Accounts payable	Time tracking for activities identifiable with Wiresco; number of invoices for other costs	Reasonable and accordance with accepted principles of cost allocation.
Regulatory	No current activities identifiable with affiliates; therefore 100% assigned to Wiresco	Reasonable and accordance with accepted principles of cost allocation.

Summary of Services Provided by Servicesco to Wiresco		
Nature of Service	**Allocation Method Used**	**BDR Comment or Recommendation**
Accounting, treasury, accounts receivable, financial reporting and audits	A time estimate for forecast; time records for actual Direct cost for audit	Reasonable and accordance with accepted principles of cost allocation.
Customer billing and related services (Where other services billed, costs allocated to electricity as per allocation method)	Direct assignment where costs can be specifically identified as attributable to electricity; other costs by number of bills, number of telephone calls, time tracking, calculated portion of service, or as appropriate for each type of cost	Reasonable and accordance with accepted principles of cost allocation.
Annual fee for cost recovery	For redistribution of costs which were allocated by other methodologies to Servicesco. In proportion to the allocation of other costs.	Reasonable and accordance with accepted principles of cost allocation.
Payment processing	Number of bills	Reasonable and accordance with accepted principles of cost allocation.
Quality management	Costs of Servicesco directly assigned to Wiresco, as other affiliates pay for their own programs directly	Reasonable and accordance with accepted principles of cost allocation.

Summary of Services Provided by Wiresco to Servicesco		
Nature of Service	**Allocation Method Used**	**BDR Comment or Recommendation**
Vehicles	Apply an hourly charge-out rate computed to recover all costs when applied to forecast vehicle usage hours. Time tracked through the work order system	Reasonable and accordance with accepted principles of cost allocation.
500 Regent Building	Market rate applied to square footage utilized to recover capital costs; allocation by square footage to recover operating costs; costs for utilization by the Plus Company reallocated to affiliates in accordance with the cost of the functional area occupying the space	Reasonable and accordance with accepted principles of cost allocation.
Staff and Vehicles for Street Lighting Services	Time of staff as recorded in the work order system.	Reasonable and accordance with accepted principles of cost allocation.

4-Staff-46 Construction Service Technician

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 2

Sudbury Hydro stated that a new Construction Service Technician was required due to the additional complexity of evaluating prospective attachment requests from interested third parties. Sudbury Hydro also stated that it has adopted non-linear pole loading as part of its design practice.

a) Please provide the number of staff in the engineering department.
b) Please provide the average weekly hours worked by staff in the engineering department prior to hiring the construction service technician.
c) Please provide the yearly historical hours spent on third party attachment requests by the engineering department prior to hiring the construction service technician.
d) Please provide yearly overtime charged by the engineering department because of third party attachment requests prior to hiring the construction service technician.

Response:

a) There are presently ten (10) staff members in the engineering department.

b) The average weekly hours worked by staff in the Engineering department prior to hiring the Construction Service Technician is shown in the table below:

YEAR	AVG WEEKLY HRS WORKED
2007	42.2
2008	48.0
2009	48.0
2010	44.3
2011	47.7
2012	45.9
2013	48.1

c) The below table provides the yearly historical hours spent on third party attachment requests by the Engineering department prior to hiring the Construction Service Technician:

YEAR	HRS
2007	25.0
2008	191.5
2009	181.5
2010	562.5
2011	554.5
2012	863.0
2013	94.8

d) The below table provides the yearly overtime charged by the engineering department because of third party attachment requests prior to hiring the Construction Service Technician:

YEAR	HRS
2007	0.0
2008	5.0
2009	0.0
2010	21.0
2011	40.5
2012	0.0
2013	0.0

4-Staff-47 Accounting Analyst

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 2

Ref 2: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study – Table ES-1

Sudbury Hydro stated that it added an accounting analyst to offload senior accountants, allowing them to provide monthly financial statements and capital spending reports, ensuring accurate recording of regulatory deferral and variance accounting transactions, and assisting with designing, implementing and monitoring processes around Regulated Price Plan true-up settlement.

a) Please provide the number of accountants responsible for the above duties.
b) Only 54% of the accounting analyst's time is allocated to Sudbury Hydro. Please confirm if the accounting analyst is part of GSHP and, if so, what service provided in Table ES-1 are they charged under?

Response:

a) There are two accountants responsible for the above duties. Their salaries are allocated to GSHi based on time spent performing the above duties.

b) The accounting analyst is employed and is part of GSHP. The service provided in Table ES-1 in which the accounting analyst is charged under is "Accounting, treasury, accounts receivable, financial reporting and audits".

4-Staff-48 Senior Customer Service Representative

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 2

Ref 2: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study – Table ES-1

Sudbury Hydro stated that it hired a senior customer service representative in 2013 to improve its service to customers and provide guidance and mentorship to more junior staff.

a) Please confirm if the senior customer service representative's salary is included in the 2013 OEB approved and 2013 actual OM&A.
b) Part of the reason that the senior customer service representative was hired was to mentor more junior staff. It has been seven years since they were hired. Is this mentorship still required?
c) Please provide the number of staff in the customer service department.
d) Please provide the number of inquiries received and the average call time for inquires for the past five years.
e) What service provided in Table ES-1 are they charged under?

Response:

a) No, it was not included in the 2013 OEB actual OM&A. The position was filled in 2013 by an existing Customer Service Representative (CSR) therefore creating a vacancy in the Customer Service Department so only the rate differential was included in 2013 OM&A costs.

b) Yes, GSHI has experienced constant turnover in the department as a result of retirements, organizational changes/transfers, and terminations. GSHI has hired and trained 22 Customer Service Representatives (CSR's) since 2013. GSHi currently has 2 staff that were hired within the last 4 months and 2 more vacancies that need to be filled.

c) There are 12.3 FTE's in the department.

d) There are a number of channels that are available to GSHi's customers in order to respond to their inquiries. GSHI provides our customers with front counter walk in access to Customer Service, emails, as well as phone inquiries.

Year	Number of Calls	Average Call Time
2019	48,671	4:17
2018	50,958	3:57
2017	59,828	Not available
2016	61,427	Not available
2015	57,577	Not available

e) They are charged under Customer Billing and Related Services.

4-Staff-49 IT/Applications Specialist

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 2

Ref 2: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study – Table ES-1

Ref 3: Appendix 2 - JC

Sudbury Hydro added an IT/Applications Specialist to address the increases in support tickets from internal users. Sudbury Hydro also stated that IT has also experienced increased demand for security, server requirements and network traffic, which has focused more staff time toward data center management and less toward increasing end user and application support.

a) Please provide the number of staff in the IT department.
b) Please provide the number of support tickets and the average time used to resolve a ticket from 2013 to 2019.
c) Sudbury Hydro stated that IT has see increased demand for security. In Appendix 2-JC, Sudbury Hydro is also requesting $61,200 for cyber security. Please confirm if the IT security and cyber security costs are the same thing.

Response:

a) There are 4 staff members in the IT department. Their time is allocated to GSHi and affiliates through the drivers stated in the Transfer Pricing Study submitted in Exhibit 4-Tab 5-Schedule 1-Attachment 2.

b) The number of support tickets and the average time used to resolve a ticket from 2013 to 2019 can be found in Table 1 below.

Table 1 – Number of Tickets and Average Time

Year	Tickets	Avg. Time (Hrs)
2013	2458	1.23
2014	2594	1.28
2015	2546	1.22
2016	2554	1.4
2017	2759	1.11
2018	1844	1.17
2019	1911	1.2

c) GSHi confirms that the IT security and cyber security costs are the same thing.

4-Staff-50 Building Services

Question:

Ref 1: Exhibit 4 – Tab 5 – Schedule 1

Ref 2: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study – Table ES-2

Ref 3: EB-2012-0126, Response to Interrogatories, February 13, 2013 (4-Staff-24)

Sudbury Hydro stated that Building Services and Occupancy Costs charged to affiliates has decreased because of building renovations and reconfigurations resulting in changes to cost allocation.

a) Please provide the square footage used by each affiliate for the last five years.
b) Please confirm that part of the changes to cost allocation is GSHP increasing staff that offers services to Sudbury Hydro and therefore a smaller portion of GSHP's building costs are allocated to affiliates. If so, will Sudbury Hydro update the allocation of GSHP's building costs if all the positions requested in this application are not approved?

In reference 2, Sudbury Hydro stated that the affiliate Agilis uses the space at Dash Substation for free in exchange for services provided by Agilis. In reference 3, Sudbury Hydro had previously provided a financial analysis supporting the reasonableness of providing free facilities to Agilis.

c) Please update the financial analysis and note any changes since the last COS.

Response:

a) Please see the square footage breakdown in Table 1 below

Table 1 – Square Footage breakdown 2013-2019

Building Sq Ft 2013-2019							
	2013	2014	2015	2016	2017	2018	2019
Plus	22,915	22,915	65,493	22,414	22,414	22,414	22,414
Agilis	5,923	5,923	16,929	3,726	3,726	3,726	3,726
@home	2,726	2,726	7,790	984	984	984	984
GSHi	152,233	152,233	93,585	151,212	152,547	152,547	152,547
	183,797	183,797	183,797	178,336	179,671	179,671	179,671

b) GSHi confirms that a portion of the building costs are driven by head count in each department, with some of these departments providing services to GSHi; however, the costs associated with this driver are insignificant ($423.08 per employee for common area space with a portion of this cost allocated to GSHi through departments providing services to GSHi) and do not make a material difference in the amount of costs absorbed by GSHi and affiliates for building costs. As such, GSHi does not intend to update the allocation of GSHP's building costs if all the positions requested in this application are not approved.

c) Please see Attachment 1 for a list of all services provided by Agilis with corresponding discounts. Table 1 and Table 2 below show the cost benefit to GSHi for the discounted telecom services in exchange for space at Dash.

Table 1 – Telecom Services to GSHi

Reconciliation				
Price for Agilis Services to GSHi	Total Monthly Price of Telco Service	Total Monthly Discount to GSHi	Net Cost to GSHi for Service	Total Annual Price (before discounts)
	$ 30,903	$ (28,975)	$ 1,928	$ 370,830

Table 2 – Price for Space at Dash with Net Benefit Calculation to GSHi

Price for industrial rent at Dash	**Space in Dash in Square Meters**	**Conversion Factor**	**Space in Dash in Square Feet**	**Greater Sudbury Utilization Factor**	**Space Chargeable to Agilis**	**Rate/Sq. Ft industrial**	**Annual Notional Value to Agilis**
	934	11	10,053	0.1245	8,802	$ 9	$ 79,216
	Total Annual Price (before discounts)	$ 370,830					
	Annual Notional Value to Agilis	$ 79,216					
	Net Benefit to GSHi	$ 291,614					

Attachment 1 (of 1):

4-Staff-50 Attachment 1: Agilis Telecom Services Provided to GSHi

Agilis Telecom Services Provided to GSHi

Row Labels	Monthly Price	Montly Discount
Greater Sudbury Hydro	**850**	**(850)**
1800 DESLOGES RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
GREATER SUDBURY HYDRO INC	**2,852**	**(2,852)**
127 KATHLEEN ST		
Preferred Customer Disc		(500)
TLS Service 10m	500	
176 ETHEL ST		
Preferred Customer Disc		(500)
TLS Service 10m	500	
500 REGENT ST		
Domain Name Registration	3	
Managed Hosted Firewall	650	
Preferred Customer Disc		(653)
500 REGENT ST, INNOVATION OFFICE		
Internet 10 mbps	199	
Preferred Customer Disc		(699)
TLS Service 10m	500	
745 GEMMELL ST		
Preferred Customer Disc		(500)
TLS Service 10m	500	
GREATER SUDBURY HYDRO INC.	**27,201**	**(25,273)**
100 RAMSEY LAKE RD - SOLAR PROJECT		
Internet 10 mbps	199	
Preferred Customer Disc		(699)
TLS Service 10m	500	
107 EDWARD ST		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
1085 LASALLE BLVD PLE#S02926		
Preferred Customer Disc		(900)
TLS Fibre Backup	450	
TLS Service 1m	450	
110 GOVERNMENT RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
127 KATHLEEN ST		
Preferred Customer Disc		(425)
TLS Service 1m	425	
1376 BARRYDOWNE RD		

Preferred Customer Disc		(850)
TLS Service 1m	850	
1721 BANCROFT DR PLE#S05665		
Preferred Customer Disc		(900)
TLS Fibre Backup	450	
TLS Service 1m	450	
179 BRADY ST		
Preferred Customer Disc		(425)
TLS Service 1m	425	
1954 LASALLE BLVD		
Preferred Customer Disc		(500)
TLS Service 10m	500	
2 EDISON RD		
Preferred Customer Disc		(425)
TLS Service 1m	425	
2246 MURIEL CRES		
Internet - 20 Mbps	50	
Preferred Customer Disc		(150)
TLS Service 10m	100	
235 COUNTRYSIDE DR		
Preferred Customer Disc		(425)
TLS Service 1m	425	
2870 KINGSWAY BLVD		
Local Loop - 10mbps	425	
Preferred Customer Disc		(425)
3 THIRD ST		
Internet 5 mbps	199	
Preferred Customer Disc		(199)
30 FRONT ST (WEST NIPISSING) B		
Internet - 100 Mbps	1,200	
IP Address IPv4/27	400	
Preferred Customer Disc	(1,147)	
TLS Serivce 100m	950	
3214 LONG LAKE RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
3270 LONG LAKE RD		
Preferred Customer Disc		(350)
TLS Service 1m	425	
382 MORRIS ST PLE#S13913		
Preferred Customer Disc		(900)
TLS Fibre Backup	450	
TLS Service 1m	450	
397 MAIN ST		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	

TLS Service 1m	425	
40 COBALT ST		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
500 REGENT ST		
Dark Fibre	2,100	
Preferred Customer Disc		(2,150)
Voice Conferencing Bridge	50	
621 RAMSEY LAKE RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
65 KING ST PLE#S12740		
Preferred Customer Disc		(900)
TLS Fibre Backup	450	
TLS Service 1m	450	
651 CRESSEY ST		
Preferred Customer Disc		(425)
TLS Service 1m	425	
960 NOTRE DAME AVE (GSU FIT)		
Preferred Customer Disc		(500)
TLS Service 10m	500	
960 ROBINSON DR		
Preferred Customer Disc		(425)
TLS Service 1m	425	
CACHE BAY RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
CANADIAN MICROWAVE TOWER		
Preferred Customer Disc		(350)
TLS Service 1m	425	
CAPREOL MS		
Preferred Customer Disc		(350)
TLS Service 1m	425	
CICI MCKIM TOWER-OFF FROOD RD		
Preferred Customer Disc		(350)
TLS Service 1m	425	
FALCONBRIDGE MS		
Preferred Customer Disc		(350)
TLS Service 1m	425	
GEMMELL SUBSTATION		
Preferred Customer Disc		(350)
TLS Service 1m	425	
HYLAND TOWER		
Preferred Customer Disc		(350)

TLS Service 1m	425	
LI22-POLE S30417, LONG LAKE RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
POLE S02690, MAIN ST		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
POLE S04405, BARRYDOWNE RD		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
POLE S30430 GEMMELL ST		
Preferred Customer Disc		(500)
TLS Service 10m	500	
POLE S30640, HARRISON DR		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
POLE S30705 MARTILLA DR		
Preferred Customer Disc		(500)
TLS Service 10m	500	
POLE S31975 KING ST		
Preferred Customer Disc		(850)
TLS Fibre Backup	425	
TLS Service 1m	425	
(blank)		
(blank)		
(blank)		
Grand Total	**30,903**	**(28,975)**

4-Staff-51 Transfer Price Study - Risk Management

Question:

Ref 1: Exhibit 4 – Tab 5 – Schedule 1 – Attachment 2 Transfer Pricing Study

Sudbury Hydro has changed the allocation methodology of the risk management service provided by GSHP. The allocation changed from 50% in 2013 COS to 97% in the current COS. The Transfer Pricing Study based this on tracking the Risk Officer’s time spent on risk management. In addition, the Transfer Pricing Study stated “safety risks are considered by management to be higher for employees involved with the electricity system”.

a) Please provide the Risk Officer’s duties and an explanation why GSHP considers safety risks higher for employees involved in the electricity system than other affiliates.

Aside from the Risk Officer’s salary, what other costs are recorded for this service?

Response:

a) The Risk Officer is primarily responsible for overseeing the administration of, and adherence to, the Occupational Health and Safety Act for all pertinent resources, liability insurance, security, environmental protection, and emergency preparedness programs for Greater Sudbury Utilities. The Risk Officer also oversees the care and maintenance of Greater Sudbury Utilities’ main office building located at 500 Regent Street, Sudbury Ontario. Duties include:

- Developing health and safety policies and procedures and providing guidance to senior managers on health and safety issues.

- Coordinating, developing, and delivering safety training programs for both supervisors and their employees.

- Participating in accident investigations and internal audits of the effectiveness of the safety programs and conducting risk management analysis of accident statistics.

- Attending all joint union/management safety committee meetings.

- Monitoring the effectiveness of and maintaining the building fire protection system; training staff in the emergency evacuation plan; acting as Chief Fire Warden, training fire warden team members, and conducting fire drill practices.

- Developing and presenting safety and electrical awareness programs for the general public, utility contractors, industry, and local school systems.

- Managing all WSIB and non-occupational injury claims and developing and managing an early and safe return to work program.

- Receiving liability property and vehicles claims from customers and the general public; investigating, reviewing and reporting claims to the insurance company; making appropriate recommendations and consulting with insurance company lawyers and representing Greater Sudbury Utilities in court.

- Preparing annual budget for safety related programs, insurance coverage, and security systems.

- Developing and implementing building security policies and procedures, performing security audits, and maintaining and upgrading the security system.

- Investigating security breeches and liaising with Greater Sudbury Police, the OPP, and the RCMP.

- Developing, implementing and modifying environmental protection and emergency preparedness policies, plans, and procedures.

- Conducting workplace audits and investigating incidents.

- Acting as EOC Logistical Support Director during emergency situations.

- Preparing an annual budget for the maintenance and repair of the Greater Sudbury Utilities' main office.

- Hiring contractors for various maintenance tasks.

- Organizing and delivering onboarding safety orientations for new staff, co-op students, summer students and contractors.

- Monitoring contractors to ensure quality of work and that work is performed within requirements of policies, procedures, and applicable legislation.

- Organizing training sessions, safety meetings, and making routine crew visits are also part of the Risks Management Officer's tasks.

GSHi recognizes that the potential for injury exists for all employees, regardless of their role within the utility, just as it does in all Ontario workplaces across many different industries. With that said, GSHi perceives the risks associated with working directly with the electrical system as being particularly significant. Exposure to adverse weather conditions, direct contact with members of the public who may be distressed and confrontational, demanding physical work (often at heights), and the inherent danger that comes with working in close contact with the systems and equipment used to control and facilitate the distribution of powerful electrical currents are all threats to personal safety. As reported by the Ministry of Labour, "it takes very little electrical current to kill a worker. Less than 1/10 of an amp of electricity can cause a worker to stop breathing."[1]

Within the Electrical Safety Authority's (ESA) 2018 Ontario Electrical Safety Report, electrical trade work is cited as one of four primary areas in which 70% of all electrical-related injuries and fatalities occur. What's more, utility-related deaths accounted for 50 per cent of all electrical-related fatalities in Ontario over the past 10 years.[2]

It is also important to acknowledge that electrical system workers, particularly Power Line Electricians, are exposed to elevated risk when performing their duties by virtue of their need to work in high traffic public areas, most often with large motorized equipment. According to Workplace Safety & Prevention Services (2005-2009):[3]

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[1] Electrical Hazards Fact Sheet - Ministry of Labour
https://www.labour.gov.on.ca/english/hs/sawo/pubs/fs_electrical.php
[2] Ontario Electrical Safety Report 2018 – Electrical Safety Authority
https://www.esasafe.com/assets/files/esasafe/pdf/Safety_Reports/ESA_OESR_2018_Final.pdf
[3] Motor Vehicle Incidents – Workplace Safety & Prevention Services
https://www.wsps.ca/Information-Resources/Topics/Motor-Vehicles.aspx

- motor vehicle collisions on Ontario roads are the greatest single cause of, and accounted for more than 30% of all Ontario worker fatalities - making motorized vehicle incidents the biggest risk Ontarians face each day they go to work;

- this number increases to 45% when we include powered industrial vehicles or powered mobile industrial equipment in the workplace; i.e. vehicles used to lift and move material, such as forklifts, pallet trucks, walkie stackers and scissor lifts.

- The other Affiliates do not have the same level of risk exposure due to the nature of their work.

b) The other costs recorded for this service include training and development, consultants, contract labour, vehicle, reference material, IT, space, and personal protection equipment.

4-Staff-52 Monthly Billing

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Appendix 1 – Customer Satisfaction Survey

Sudbury Hydro stated that it incurred an increase of $272,000 in 2018 costs as a result of monthly billing and due to increases in postage, stationary, and additional labour costs. Sudbury Hydro is actively encouraging customers to switch to e-billing.

a) Please provide the number of paper bills and e-bills sent from 2013-2019.
b) Please provide a breakdown of increased costs in postage, stationary, and labour costs.

All distributors in Ontario were required to bill their customers on a monthly basis by the end of 2016 yet the cost increase for monthly billing incurred in 2018.

c) Please confirm when Sudbury Hydro switched to monthly billing.

Sudbury Hydro stated that it added a Customer Service Manager in 2015 to handle the increased workload as a result of the change in billing frequency and complexity in the department. Sudbury Hydro also stated that the Customer Service Manager is developing a multi-year Customer Experience Enhancement Plan to continue to improve customers experience and drive efficiencies through the adoption of new processes and technologies.

d) Please provide the efficiency savings experienced or expected from new processes and technologies.

e) Please provide the approximate time the Customer Service Manager spends on billing changes and developing the Customer Experience Enhancement Plan.

In reference 3, Sudbury Hydro provided the results of customer satisfaction and service from 2013 to 2018 and it shows that customers are marginally more satisfied. However, the satisfaction of customers with the price they pay for electricity has been declining from 2013 to 2016.

f) Please explain how Sudbury Hydro justified a new Customer Service Manager position to develop a Customer Experience Enhancement Plan when customer satisfaction appeared to be constant but were increasingly unhappy with higher rates.

Response:

a) GSHi's CIS does not track billing detail to the level required to answer this question. However, GSHi has calculated an estimate based on the number of electricity customers who were enrolled in either EPOST (through Canada Post) type bills or E-Billing (through GSHi's CIS). GSHi averaged the number of customers enrolled in these programs at each year end to estimate the number of customers enrolled throughout the year and then multiplied that by either 6 (for monthly billing) or 12 (for monthly billing) based on when GSHi made the switch to monthly billing (2017).

	2013	2014	2015	2016	2017	2018	2019
Ebills	4,464	8,166	17,126	27,641	77,058	91,716	99,552
Epost	6,726	6,726	6,840	7,068	13,746	12,864	12,342
Paper Bills	273,972	270,582	262,083	251,865	483,234	471,006	465,438
Total Bills	285,162	285,474	286,049	286,574	574,038	575,586	577,332

b) Table 1 below provides the calculation to support the incremental billing costs of $272,000. In summary, GSHi took the amount included in its 2013 COS budget for postage and stationary and increased it based on the IRM increases GSHi received. GSHi compared that amount to the total costs experienced for the first full year of monthly billing (2017). GSHi also included the incremental labour required for monthly billing (at 50% based on the transfer pricing study).

Table 1 – Incremental Monthly Billing Cost

Incremental Monthly Billing Costs	A	B	=A-B		
		IRM Inflated	Expense in Excess		
	2017 Expense	COS Budget	of COS Budget		
Postage	350,141	178,791	171,350		
Stationary	147,211	84,381	62,829		
	497,352	263,173	234,180	C	
		Incremental Labour	37,886	D	
		Total Incremental	**272,066**	=C+D	
B COS Budget - IRM Increases					
	2013 COS	**2014**	**2015**	**2016**	**2017**
Pro-rated Inflationary Factor **(E)**		0.93%	1.23%	0.38%	1.07%
Postage Budget from 2013 COS **(F)**	172,472	174,082	176,229	176,904	178,791
Stationary Budget from 2013 COS **(G)**	81,399	82,159	83,172	83,491	84,381
(FxE)+(GxE)	253,871	256,240	259,401	260,395	263,173
E - Prorated Inflationary Factor	**2014**	**2015**	**2016**	**2017**	
Price Escalator	1.70%	1.60%	0.00%	1.90%	
Stretch Factor	0.30%	0.45%	0.00%	0.30%	
Price Cap Index	1.40%	1.15%	0.00%	1.60%	
May 1 Rate (4/12 x Year 1) + (8/12 x Year 2)	**0.93%**	**1.23%**	**0.38%**	**1.07%**	E

c) GSHi began to transition to monthly billing in October of 2016 and was fully transitioned in January 2017.

d) The plan is still being written and it has a target completion date of June 30, 2020.

e) The Customer Service Manager has spent less than 10% of their time on its development. The majority of time for this position is spent on implementing and managing projects within the department as detailed in (f) below.

f) The Customer Service Manager position was not developed solely for the purpose of creating a Customer Experience Enhancement Plan, the decision to create a plan came about in 2018 at a Strategic planning session with GSHi's Board of Directors. The impetus for the plan was to look at ways of improving GSHI's customer's experience. GSHi is exploring new channels for communicating with customers and looking at trying to find efficiencies to handle increased workload within the department.

The main reason for the creation of this position was to handle the increased work within the Customer Service department as a result of the constant and continuing changes within the electricity market. This position researches, plans, liaises with the Ministry and other utilities, tests, coordinates and documents system changes with our billing software provider and bill print contractor and provides staff training. Since 2015 the following initiative were undertaken:

- Bill presentment regulation for line losses for low-volume customers with a retailer came into effect, July 1, 2015. (O.Reg 275/04);
- The Ontario Electricity Support Program – planning meetings started in 2015 with implementation Jan 1, 2016;
- Bill 112, Strengthening Consumer Protection and Electricity System Oversight Act, 2015;
- Transition and implementation of monthly billing;
- O.Reg. 275/04, the Debt Retirement exemption for residential customers and the associated dynamic messaging;
- Expansion of the Industrial Conservation Initiative (ICI) under the Green Energy Act, 2009, which lead to Class A billing;
- O.Reg 363/16 -the Ontario Rebate for Electricity Consumers - 8% rebate, effective January 1, 2017
- Energy and Water Reporting and Benchmarking Initiative for Large Buildings in Ontario;
- Implementation of the disconnection ban and the changes to our procedures to accommodate this;
- EB-2017-0183 Reporting on Arrears, Disconnections and Arrears Management;
- The Ontario Fair Hydro Plan Act, 2017;
- Dynamic messaging relating to the OFHP – deadline March 1, 2018;
- RPP TOU Pilot;

- Implementation of the new Customer Service Rules, July 1, 2019 and March 1, 2020;
- New Ontario Electricity Rebate (OER), November 1, 2019;
- MIST meter requirement, EB-2013-0311

Other initiatives that were managed by this position include a phone system upgrade, several e-bill campaigns, legal activities with customers, settlement from both a retailer and net system load perspective and management of a staff of 18. This included interviewing and hiring new staff andsummer students.

Also, GSHi bills water on behalf of the City of Greater Sudbury under a water billing contract that includes: managing a meter reading contract, billing services, and responding to customer inquiries on their behalf. This position manages this contract and acts as the main liaison with the City. To account for this, 25% of the position’s time is allocated to water and therefore only 75% is charged to electricity customers.

4-Staff-53 Customer Premises

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro stated that the variance in the Customer Premises program is due to a portion of its System Operators budget being reallocated to the Load Dispatching program.

a) Please describe the work done under the Customer Premises program.

b) Please provide what year the costs of the System Operators were reallocated and the amount.

Response:

a) GSHI's Customer Premises program includes appointments at the customers' premises for new services or to attend to issues with existing services, trouble calls, and providing locates for customers.

b) The System Operators were reallocated in 2017 and the equivalent amount from the 2013 budget is included below.

GSHI notes that the variance for this program in Appendix 2-JC was as follows: 2020 vs 2013: Decrease of $121,188 and 2020 vs 2018: Decrease of $165,712. GSHI has further investigated the variance for this program and provides the following additional information.

For 2020 vs 2018, the variance is explained by the locate contract GSHi required while its Locator was on parental leave. The cost of the contract was approximately $200,000 and upon the Locators return to duties, the contract was no longer required in 2019 or 2020.

For 2020 vs 2013, in addition to the System Operators being budgeted in this program line in 2013 for locate dispatching, as was the relief for the Locator (for vacation, etc) and on-call time for emergency locates which was. For the

2020 budget, the relief was no longer budgeted in this line and was budgeted within the departments to which the employees belong (Engineering and GIS).

	2013 vs 2020	2018 vs 2020
Variance per 2-JC	- 121,188.00	- 165,712.00
System Operators	51,153.65	
Relief	32,171.35	
Locates Contract	2,000.00	202,000.00
Other Miscellaneous	- 35,863.00	36,288.00

4-Staff-54 Communications

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Appendix 1 – Customer Satisfaction Survey

Sudbury Hydro added a communications assistant position in 2016 to assist the communications officer in providing regular website updates, have an active social media presence, have a team-focused approach to event and outage management, more community outreach, more regular internal communications, back-up for holidays and vacations, as well as marketing communications support for affiliates.

a) How would Sudbury Hydro be impacted from an operational and financial standpoint if there were no communications assistant? Please quantify the impact if possible.
b) Sudbury Hydro stated that the communications assistant provides marketing communications support for its affiliates. Please breakdown the hours the communications assistant provides services to Sudbury Hydro and to each of its affiliates.
c) Please provide the duties of the communications officer and confirm if prior to the communications assistant position they were providing regular website updates, managing social media presence, community outreach, internal communication, and marketing communications for Sudbury Hydro's affiliates.
d) Customers are generally concerned with lower rates and reliability. Please explain how Sudbury Hydro justifies additional resources for communications and how does this meet the customers concerns.

Response:

a) The Communications team consists of only two (2) people, the Director of Communications and the Communications Assistant. Eliminating the Communications Assistant would handicap the communications efforts of the LDC not only during outages, but also undermine the effectiveness of the LDC's communications efforts in terms of GSHi's ongoing social media presence, the regularity of website updates, the ability to do community outreach, and efficacy of the internal communications of the LDC. There would be no back-up when the Director was on vacation, away on business or sick, and during prolonged outages, no support or assistance in communicating with the public. Communications with customers and the community, both reactive to outages and proactive on all issues including safety, would be set back significantly.

b) The Communications Assistant's time is tracked each day and allocated by company depending upon which file is being worked on. It varies from day to day, week to week. On average, over the course of the year, the Communications Assistant spends 78% of her time (of 27.5 hours each week) on GSHi business.

c) The Communications Director is ultimately responsible for Media Relations, Public Relations, Corporate Communications, Integrated Marketing Communications, External Promotion/Presentations, Outage Communication (Planned and Unplanned), Internal Communications, Support for the LDC and all affiliates in al communications. Marketing and advertising efforts, as well as other duties as assigned. Prior to hiring the Communications Assistant, the Communications Director was stretched beyond capacity, and was not able to update the websites or social media accounts as often as is desirable. The Assistant adds needed depth, back-stopping, and support allowing for more timely web updates, social media presence, internal and external communications for the LDC, for instance Internal and Community Safety Promotions, Major Capital Project Communications, Event Planning and other activities.

d) Customers do want lower rates and higher reliability, and they also want access to information about planned projects, resource material about their LDC, and in the case of a power outage, demand as much information as possible. A satisfying presence on Social media, conventional media and the website during short outages decreases call volume, calms customers' concerns, and allows them to plan for contingency, should it be necessary. Customers have a high need for information, and a single individual does not have the capacity to meet all communication needs and supply information through various channels to over 47,500 customers. GSHi believes this position and department aligns clearly with the Customer Focus outcome of the Renewed Regulatory Framework.

4-Staff-55 Administration

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro stated that in the 2020 proposed budget it has added a Project/Program Manager, responsible for overseeing many large projects that Sudbury Hydro engages on a continuing basis.

a) Please discuss whether the costs incurred for the Project/Program Manager would be considered directly attributable or not under IFRS, and whether it should be capitalized as part of the project.
b) Please provide a list of the large projects/programs the Project/Program Manager would oversee.

Response:

a) The Project/Program manager's responsibility is to lead the Project Management Office (PMO) and coordinate all activities regarding process change initiatives and technology deployment projects to ensure efficient implementation, effective leveraging of resource synergies, and integration within GSU processes. In addition to acting as the lead on technology deployment projects, the Project/Program manager will perform an increasingly consultative and supportive role for other Project Managers/Coordinators. The Project/Program manager will ensure proper project management techniques and processes are followed across the organization. The Project/Program manager costs will be charged to capital consistent with the costing practices as outlined in IAS 16 Property, Plant and Equipmen and as such, a portion the Project/Program manager's time may be capitalized, depending on the nature of their involvement in specific projects, however, the majority of the costs incurred for the Project/Program Manager will be charged to OM&A.

b) The Project/Program Manager (PM) will oversee project management fundamentals company wide. The PM will maintain and update the project server as well as all project management documents, processes, and procedures. The PM will also develop and maintain the GSHI capital project schedule to ensure the overall success of our capital expenditure program. In addition to the aforementioned, as well as other interdepartmental collaborations, the PM will oversee the following Material Investment projects:

- Planning and coordination of relevant cross silo program initiatives and technology deployments related to the Siemens Compass program.
- Outage management system procurement, deployment, and integrations.
- Cressey Substation Rebuild.
- Asset and work order management system procurement and integration.
- Event Monitoring/ Work Dispatch system deployment.

4-Staff-56 Innovation

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro has created a department called the “workshop” for digital transformation that primarily revolves around enterprise data. Sudbury Hydro also proposed a new position in 2020 for a Data, Integrations & Platform Specialist and hired an innovation officer in 2015.

a) Please provide a breakdown for the Innovation program (provided in Appendix 2-JC) by labour costs and each project costs.
b) For each project listed above please provide the expected efficiency gains or savings upon the completion of the project. For gains or savings that are reoccurring, state the number of years that they are expected to reoccur.
c) In the context that customers are most concerned about lower rates, if the expected efficiency gains or savings does not exceed the cost of the Innovation program, how does Sudbury Hydro justify the continuation of this Innovation program.
d) The innovation officer was hired in 2015, please confirm if their salary is included in the innovation program. If so, why was their salary not allocated to this program in 2015.
e) Please provide a cost benefit analysis for the Innovation program both on a historical and forecast basis.

Sudbury Hydro stated that the role of the Data, Integrations & Platform Specialist is to blend together Sudbury Hydro’s data in order to become more data driven. Without this role data-informed decision making will remain arduous and inefficient.

f) Please explain how Sudbury Hydro’s future investments will be data driven.

g) Please provide the anticipated cost savings or efficiencies from data driven planning as opposed to Sudbury Hydro's current planning practice.

Response:

Introduction (responses a-g)

All of GSHi's plans for investments are driven on data about its distribution assets, with the quality of the data affecting the ability of GSHi's to maximize the efficiency of its spending. The better the data GSHi has on the condition of its assets, the more precise it can be in planning for asset maintenance, both reactive and proactive, and asset renewal. GSHi is limited in the efficient management of its distribution system without timely and accurate data.

Sudbury Hydro has created a department called the "workshop" for digital transformation that primarily revolves around enterprise data. Sudbury Hydro also proposed a new position in 2020 for a Data, Integrations & Platform Specialist and hired an Innovation Officer in 2015.

a) **Breakdown of innovation labour and project operating costs to GSHI***

By Portfolio (related projects detailed in Appendix 1)	**2020 Allocation**	**2020 Labour**	**2020 Project**
Location Intelligence (Enterprise GIS & integrations) *Geodata, asset repository, visualization, integrations, operations dashboards, common operating pictures and operational dashboards, situational awareness, web and mobile GIS and analytics, event services, spatial-temporal data stores, AVL, Geo-events, IoT, asset management, mobile workforce, etc.*	**78%**	$196,313.87	$47,979.75
Innovation (Partnerships & engagement) *Corporate innovation, process improvement, enterprise architecture, coordination, innovation ecosystem participation, lean innovation methodology, employee engagement, collaboration, experimentation, culture, performance, agile.*	**12%**	$30,202.13	$7,381.50
Business Intelligence (Business integrations) *Data, pipelines, visualization, integrations, BI dashboards, KPI, analytics, temporal, enterprise services, self-service, power automation and flows.*	**10%**	$25,168.45	$6,151.25
Labour and project costs:	**$313,196.95**	**$251,684.45**	**$61,512.50**

Other - enterprise software maintenance:	$46,000.00	
Other - training, shared costs:	$19,398.05	
Total:	$378,595.00	

* See Attachment 1 for a project breakdown per portfolio

From 2018 to present, the three Innovation Office program portfolios were structured to meet demand for location intelligence services (78%) with a significant effort in enterprise GIS modernization. In February 2020, the Innovation Office launched the new location platform (a hybrid of new production enterprise geodatabase, servers and services as well as ArcGIS Online for organizations and portal configurations) facilitating corporate-wide rollout of mobile and web GIS viewers and data collectors with real-time capabilities.

In Q2 2020, the Innovation Office will launch the organization's business intelligence platform by leveraging Microsoft Azure Data Gateways, Active Directory Federated Services and Microsoft Power BI online. With the hiring of the *Data, Integrations & Platform Specialist*, the Innovation Office can ramp up efforts on the business intelligence portfolio in order to meet the demands of self-service and executive reporting through Power BI. In the future the Innovation Office's efforts will be distributed as **60% on location intelligence**, **30% to business intelligence** and **10% on efforts to sustain innovation, collaboration, learning and engagement activities**.

For a complete breakdown of Innovation Projects by portfolio, please refer to Attachment 1 of this response.

b) In describing the "Gain" column in the projects listing provided in Attachment 1 in response to the previous question, the Innovation Program Portfolios, Innovation Office, Officer and Policy have been geared to deliver efficiencies (36% of projects) that leverage corporate data and platform projects (49%) and build internal capabilities (10%) through workforce related engagement (4%), training, collaboration and improvement.

As it is difficult to accurately predict gains or savings for all projects listed in Attachment 1, efficiency gains for a sampling of projects are marked A-F with project listing and detailed in the attachment. A summary of cost/benefit and efficiency gains at a high level are first provided in context of the current Innovation Office program's three main portfolios and more detailed cost/benefits and efficiency gains for 6 of the 72 projects are provided in Attachment 1.

c) Based on the efficiencies already being realized through the Innovation Office projects detailed in Attachment 1, GSHi is confident that the work being done is creating efficiency gains and transforming its processes and workforce to continue to allow GSHI to better serve customers. The Workshop projects focus on foundational technologies, encourage innovation and asset optimization, and are introducing better ways to provide information to the ratepayer. For example, the release of the Empowered Community ArcGIS Online Portal (2020) which is a platform to distribute data services and interactive map-based applications to better serve our customer with modern enabling technologies and data. The foundational work facilitates benchmarking and performance monitoring, and the integrations and insights target datasets and solutions designed to enhance system reliability.

As presented in Attachment 1, 78% of the Innovation Office's current projects focus on location intelligence, enterprise GIS and development of solutions and datasets that support longer term technology initiatives such as asset management and field crew mobilization. In the article *Valuing GIS*[1] by Licker Geospatial Consulting Co., the concept of a value multiplier is introduced. Through their analysis, a value multiplier of 3.5 is realized (value of the work being done vs. the labour and related costs). The Innovation Officer is performing the duties as described in the article as well as that of a senior architect and geodatabase administrator with a higher value multiplier.

The Innovation Office portfolios detailed in Attachment 1 touch nearly all of the organizations processes, taking the whole enterprise approach to improvement as opposed to undertaking smaller siloed projects funneled through an ideation process.

The portfolio's presented in the Attachment provide foundational enterprise functions while engaging employees and customers in the organizations'

[1] https://www.lgeo.co/blog/2019/10/16/valuing-gis

innovation and digital transformation effort. Absent of the Innovation Office's services and capability, GSHi would have ongoing challenges in continuing to digitalize additional work processes or in continuing to build critical data and digital capabilities to the benefit front-line employees and customer.

d) In 2015, an individual was hired to fulfill the duties of a Project Manager. Their salary was charged to Administration. The Project Manager was replaced by an Innovation Officer in 2018 with salary allocated to Innovation in 2018.

e) Response included with b) above and detailed portfolio and a sampling of projects presented in Attachment 1.

f) In a recent Experian benchmark report[2] (February 18th, 2020), 85% of organizations see data as one of the most valuable assets to their organization. According to the report "this year's research highlights more businesses recognising these challenges and initiating the changes necessary to gain insights from their data. For some, this starts with equipping their workforce with the necessary skills-set to be able to manage data. Importantly, by creating a culture where sharing data knowledge and tools is the norm, these responsibilities can be distributed across a data-literate workforce, freeing up valuable time for your data specialists to be truly innovative and drive success." This quote is directly in line with the Innovation Office's strategic initiatives and projects aim to overcome data debt issues, build technology and workforce capabilities and provide data services that empower the organization and GSHi customers with better online tools and intelligence.
Under the direction of the Innovation Officer, incremental steps are being taken to put the organizations' foundational digital platforms (ArcGIS Online/Enterprise and Microsoft Power Platform) in place that support corporate-wide data-centric activities across silos. This "intelligent enterprise" allows for rapid experimentation supporting workforce and process transformation. Goals set

[2] https://www.experianplc.com/media/news/2020/the-cost-of-data-debt-rises-as-businesses-face-the-challenge-of-low-data-literacy/

forth in the Siemens Compass, and in the industry in general, aim at connecting every aspect of the utility—from the distribution network in GIS, sensor data in SCADA, inventory, operations and customer service.

Continued efforts to integrate data through data pipelines and analytical processes will be exposed to GHSi digital location and business intelligence platforms, facilitating the development of situational and operational awareness dashboards. Self-service reporting tools and views of the organization's integrated disparate structured and unstructured sources support decision making regarding future investments. Below are details of how investments are or will be data driven using a recent asset management related Innovation Office project as an example.

Strategic and Enterprise Asset Management

Together with risk-based asset management, topological aggregation of smart grid data will create the basis for meaningful KPI models, forecasting of these models, and determining asset risk levels. As a result, GSHi will be able to customize asset management strategies for chosen key assets based on business value and risk data.

Example A: The Innovation project *B-Asset Inspections (Version 1)* (detailed in Attachment 1) is already providing valuable real-time data that supports better decisions regarding the investment of capital expenditures for improvements, operations, maintenance and workforce management now and into the future.

Annual asset inspections (and pictures) are collected in the field using mobile devices. Resulting data is being/will be used to:

- feed front-line supervisors planning and field crew assignment dashboards and applications
- show the progress of work assignments with updates by crew leaders on completion
- streamline work assignments by being able to see what and where maintenance is required
- provide data views to engineering project coordinates to see condition as well as historical work orders in hand with material and installation date (for example, a recent request to view "areas with poles that have or had significant woodpecker damage")

Example B: Using asset location, installation date, material, asset condition assessment and inspections data centralized in enterprise GIS, parameterized geoprocessing routines will be developed in the Innovation Office. Common to taking the GIS-centric approach to asset management, these routines calculate business risk exposure (Bre) for each asset in GIS and establishes an index based on consequence of failure (CoF) and probability of failure (PoF). See projects "Cof, PoF and Bre Model" in answer to a) above.

Resulting data will be used to:

- visualize condition and asset prioritization indices in easy to use web and mobile GIS viewers (ubiquitous access)
- feed or directly drive more complex forecasting and financial models
- integrate with planning to streamline decisions and integrate in network applications
- develop and present short, medium and long-term capital improvement planning scenarios using web/mobile GIS viewers and with business intelligence projects

Further to this, the Data, Integrations and Platform Specialist will integrate and aggregate data from disparate databases including GIS, OMS, SCADA, CIS, and AMI to drive forecasting and predictive models that facilitate more granular and complex forecasting and analytics. The results are aggregated, centralized and delivered through the business intelligence platform and on the location platform with spatial-temporal/chronological model viewing (i.e. time-sliders, voxels, etc). Putting this information into views and tools designed for planning results in data-informed decisions regarding where and when best to invest in future investments. Furthermore, tracking of decisions in GIS with related asset data can be reviewed in common operating pictures allowing for a historical view of the performance of the decisions themselves. These insights are used to refine the underlying models and further improve and inform future decisions.

Strategic performance management (objectives and goals)

By centralizing, integrating and aggregating key data feeds for use in operational and business intelligence dashboards, GSHi front-line supervisors, managers, executive team members and board members will have access to information and visualizations where they need it and when they need it. Underlying data and views report on the performance of business units, progress of projects, workforce safety and performance and day-to-day activities as they relate to corporate objectives. These insights effectively bridge corporate strategy with execution, providing the views required to make better decisions.

g) Attachment 1 provides examples of the efficiencies being realized. The Innovation Office work on asset inspections for instance, immediately created efficiencies through digitalization. Efficiencies were gained throughout the process, including during preparation, inspection, planning and crew assignments. This data is available to streamline decisions in Engineering for capital improvements and will feed risk and condition assessment activities and modeling. This project was undertaken using the Innovation Office's internal enterprise capability, resulting in a cost avoidance (not hiring external consultants) while assuring continuity by maintaining an in-house capability. The Innovation Office sets and maintains the conditions required to collaboratively iterate and improve the solutions quickly, when employees are ready.
Prior to digitalization of these processes, the practice was paper intensive, time consuming, duplicative and prone to miscommunication. For an understanding of what had been completed, and where and when it was accomplished, significant time was previously spent with relevant staff and supervisors reviewing paper forms and reconciling records and spreadsheets.

Attachment 1 (of 1):

4-Staff-56 Attachment 1: Innovation Portfolios and Benefits

About The Workshop Projects

This business unit was initially designed to institute a change management practice, coordinate and manage the Siemens engagement, and develop and institute the innovation office. At this time, lean innovation practices and an ideation pipeline[1] were created to help improve employee engagement and garner feedback that could be used in continuous improvement efforts. Limitation of internal capabilities and operational constraints (time and resources) limited the organization's ability to move ahead with a growing number of projects increasingly reliant on enterprise system modernization, data centralization, integration and platform development.

In 2018, GSHi was able to adapt the innovation focus to meet the growing demands for enterprise GIS, operational and business data services, integrations, analytics and insights as identified in Siemens' Compass. A prerequisite of having location and business intelligence platforms in place are required prior to engaging in advanced enterprise geospatial and data engineering projects. From 2018 to present, projects have focused on building foundational systems and internal capabilities required to take advantage of the organization's continued investment in advanced technologies including the Esri ecosystem of cloud, server, desktop and mobile applications and commercial off-the-shelf (COTS) low code/no code solutions. To mitigate the expense and reliance on external consultants, digital transformation is being directed by the Innovation Officer whose activities are geared to empowering employees (building internal capabilities instead of buying external services). The 2020 budget reflects the cost of building and maintaining internal capability to support the accelerated adoption of technology and internal improvement and decision-making with enterprise data services.

From 2020 forward, a larger percentage of effort will be spent on building up the organization's business intelligence capability. This endeavour requires a capability focused on undertaking advanced data modeling, standardization, cleaning and loading as well as developing and maintaining the data pipelines, integrations and automations (scripts) designed to provide data services on self-service platforms (Microsoft Power BI Online and ArcGIS Online/Portal) for empowered employees. To build capacity to meet the demands for more centralized integrated data, data services (feeds) and platform solutions, the Data, Integrations and Platform Specialist will be hired in 2020.

All of GSHi's plans for investments are driven on data about its distribution assets, with the quality of the data affecting the ability of GSHi's ability to maximize the efficiency of its spending. The better the data GSHi has on the condition of its assets, the more precise it can be in planning for asset maintenance, both reactive and proactive, and asset renewal. GSHi is limited in the efficient management of its distribution system without timely and accurate data.

[1] The ideation pipeline was an online submission platform where employees could identify and rationalize their ideas for process improvement or business development projects. Resources were to be allocated to project teams to move the most promising projects forward.

The Innovation program has evolved to become an important corporate service as reflected by the Innovation Office's three functional portfolios focused on foundational systems, data, integrations and workforce capabilities:

78%	12%	10%
Location Intelligence Enterprise GIS, Geodata, Visualization, Integrations and Analytics	**Innovation** Innovation, Improvement, Partnerships and Engagement	**Business Intelligence** Business Data, Pipelines, Visualization, Integrations and Analytics
56 of 72 projects	9 of 72 projects	7 of 72 projects
72%	72%	43%
Support Siemens Compass Projects align with corp. vision	**Will continually improve** Continual improvement or iteration	**Stage 1 Completed** proof of concept or evolving
52 of 72 projects	52 of 72 projects	31 of 72 projects

Innovation Program Projects

Several projects are listed in the proceeding pages. The tables present a non-comprehensive list of planned, completed, in-progress and ongoing projects broken down by the Innovation Office's core portfolios.

The **"Gain"** column presents the five types of efficiency gains the projects have/will result in:

49%	36%	10%	4%	1%
F-Foundational Core enterprise tech and capability supporting enterprise digital transformation and SmartGrid 35 of 72 projects	**E-Efficiency** Streamline work processes with digital technologies (data, web, and mobile) 26 of 72 projects	**W-Workforce Capability** Training, rapid experimentation and learning so staff can use new data and solutions 7 of 72 projects	**EE-Engagement** Communication, engagement, sessions to prepare for change and foster innovation 3 of 72 projects	**C-Community** Participate in and support local innovation ecosystem and community 1 of 72 projects

Note: Gains are accumulative and ongoing – each project builds on preceding and ongoing transformation efforts, unlocking more data, insights and growing capability moving forward.

"Status" column

Ongoing – a program, solution or data source that will continue to evolve
In progress – currently being designed, developed, implemented or tested
On hold – other projects need to be completed before this project can progress
Proof of concept – an experiment is complete and a proof of concept is in place for review

"Siemens" column

Creates capability for or is a project listed in Siemens Compass

"Ongoing" column

Improve – solution will improve over time, with use and through collaboration
Iterate – solution will improve in steps through iterations
IT Support – project completed and being supported by IT
Maintain – completed and being maintained by the Innovation Office team
Decide – selecting the best approach based on internal capability and readiness

"Capacity" column

DIPS – Data, Integrations and Platform Specialist supports, accelerates, focuses on and helps ensure the success of the project
PM - Project Manager supports, accelerates, focuses on and helps ensure the success of the project

The Innovation Office acquired an enterprise capability in 2018 by hiring an Innovation Officer who has been able to actively implement the foundational enterprise technologies, datasets and integrations that support the organization’s corporate objectives while building the internal capability to support these projects. This capability results in an ongoing avoidance of costs (consulting) and avoids discontinuity from having to rely on external resources.

Location Intelligence Portfolio

Keywords: *Enterprise GIS, geodata, asset repository, visualization, integrations, operations dashboards, common operating pictures and operational dashboards, situational awareness, web and mobile GIS and analytics, event services, spatial-temporal data stores, AVL, Geo-events, IoT, asset management, mobile workforce, etc.*

	Project	Gain	Status	Ongoing	Siemens	Capacity
	Outage Mapping Automation SQL programming, procs, integration scripts for data centralization and Empowered Community Portal views	F	In progress	Improve	●	
	On Premise Enterprise and Web GIS Infrastructure Architecture, servers, data model & geodatabase, migration, scripts, etc.	F	Ongoing	Improve	●	
	Online Enterprise and Web GIS Configuration Groups, security, empowered community branding, etc.	F	Ongoing	Improve	●	DIPS
B	**Online public report enhancements** Ex. forestry, damaged asset, outage public reporting	E	POC	Improve	●	
A	**Joint Use Survey (Version 1)** Mobile GIS (ArcGIS Collector) app and data for joint use survey with partners	**E**	Completed	Iterate	●	
A	**Joint Use Survey + Permits (Version 2)** Mobile GIS (ArcGIS Collector) app & data for joint use survey with partners	**E**	Planned	Iterate	●	
B	**Asset Condition Assessment Data integration & viewer** Centralize and build GIS views & integrations to asset condition assessment results	**F**	In progress	Iterate	●	
D	**Web GIS Viewer (Hydro Distribution Map)** Viewer for all staff showing distribution network and other layers	**E**	Completed	Iterate	●	
D	**Mobile GIS Viewer (Hydro Distribution Map)** Mobile GIS app for all field staff showing distribution network and other layers	**E**	Completed	Iterate	●	

	Enterprise Logins and VPN Configuration of enterprise logins on location platform and VPN access	**F**	Completed	IT Support	●	
B	**Operations mobile dispatch improvements** Minor & major defects, mobile & tied to central data sources	E	In progress	Decide	●	
D	**Emergency Response Plan Technologies** Emergency response plan applications for damage assessment & situational awareness	**E**	In progress	Iterate	●	
	Control room log improvements Modernize, streamline, dashboards & leverage location data (Web GIS)	**E**	Planned	Iterate	●	
	GIS Data sharing mechanism Share data with partners (City) using our online platforms	F	POC	Improve	●	DIPS
	Locates version 2 (Web GIS & field apps) Modernize the GSU locates app to take advantage of web GIS for common operating pictures, etc.	**E**	Planned	Iterate	●	
D	**Records quick access through web GIS layers** Begin introducing quick linking to records and document related to address and assets (ex. permits)	**E**	Planned	Improve	●	DIPS
	360 deg asset register Architect and develop data catalog and linkages across databases to give 360 view of assets and related data	**F**	Ongoing	Iterate	●	DIPS
B	**Asset Inspections (Version 1)** Online database, supervisor dashboards and admin tools, field collectors OEB inspections (pole, transformer)	**F**	In progress	Iterate	●	
B	**Asset Inspections (Version 2)** On prem database, improved supervisor dashboards and admin tools, field collectors for more assets	**F**	Planned	Iterate	●	
B	**CoF, PoF and Bre Model (Version 1)** Asset Consequence of Failure, Probability of Failure & Business Risk Exposure GIS model and tool	**F**	Planned	Iterate	●	
B	**CoF, PoF and Bre, Forecasting, Segments, Financial Planning (Version 2)** CoF, PoF and Bre GIS model & tools extended for short medium and long-term financial planning	**F**	Planned	Improve	●	
B	**Engineering Dashboard (relates to V1 inspections)** Extends Asset Inspection (Version 1) with the ability to manage private assets in Engineering	**E**	Completed	Iterate	●	
B	**Inspection notification (pilot)** Automation that checks for new and updated inspection records, sends emails with quick admin links	**E**	POC	Improve	●	DIPS
B	**Data Quality Dashboard (POC)** Monitor **e**nterprise GIS dashboard reporting on data/streams that requires attention (null, qa/qc, etc.)	**F**	Planned	Iterate	●	DIPS

	Removed/Replaced asset tracking Streamline process by moving away from manual way in excel to leverage new web GIS capability	**E**	Planned	Iterate	●	
B	**Maintenance improvements (manhole, needles, etc.)** Extends Asset Inspection (Version 1) for special projects such as needles in downtown manholes.	**E**	Completed	Iterate	●	
	Address normalization, standardization and geocoding Standardize address, build geocoding service, clean & update existing databases, improve then maintain	**F**	Planned	Iterate	○	
	Migrate desktop GIS users to web and mobile GIS (capability, training, etc.) Reduce footprint of desktop GIS users (ArcMap) by getting them comfortable using new web viewer(s)	**E**	In progress	Maintain	○	
D	**Map camps** Corporate-wide training to empower employees to use self-service location platform and many tools	**W**	Ongoing	Iterate	○	
	Shared (general) & user field notes Field & web data collection layers & views for shared, shared public & private-to-user field notes	**E**	POC	Improve	●	
C	**Build estimates** Field data collect at pre-design, run web tool to export build estimate excel using SQL cost table(s)	**E**	In progress	Iterate	●	
	Enterprise GIS & Utility network migration (Milsoft to new server) Architect a two-server solution, build new GIS database and work with Milsoft to migrate to new architecture	**F**	Completed	Maintain	●	
B	**Control room GIS viewer** Modify and enhance new Web Viewer with Operator requirements, switch maintenance, crew assignments, etc.	**E**	In progress	Improve	●	
	Enterprise GIS licence agreement Review, consolidate and extend/modify license for additional advancements (ex. for IoT readiness, analytics)	**F**	Ongoing	Maintain	●	
	Online platform configuration (credit allocation, groups, etc.) Configure, build sites, groups, open data, credit allocation. ArcGIS Online for Orgs Administrator	**F**	Completed	Improve	●	DIPS
D	**Planned outages map (web GIS and public views)** Use empowered community portal to map & communicate planned outages	**F**	Planned	Iterate	●	
B	**Historical inspections (data centralization, integrations and views)** Consolidate, standardize, clean and load historical inspections for use in location platform / GIS	**F**	Planned	Maintain	●	
D	**Storytelling with data customer engagement pilot on the location platform (ex. PowerUP)** Empowered community portal interactive and data-driven stories for community/customer engagement	**W**	POC	Improve	○	DIPS
	Spatial Data Infrastructure (SDI) Memorandums of understanding and technical infrastructure for streamlined data-sharing with partners	**F**	Planned	Maintain	○	DIPS

B	**Mobile improvements (capability, have device, access more)** Build corporate digital capability and provide more access to productivity tools & learning corporate-wide	**F**	Planned	Improve	●	
	AED locations and inspections Inspection records, mobile technology and insights (last inspection, upcoming inspections, etc.)	**E**	POC	Iterate	○	
	Fire extinguisher locations and inspections Inspection records, mobile technology and insights (last inspection, upcoming inspections, etc.)	**E**	POC	Iterate	○	
	First aid kit location and inspections Inspection records, mobile technology and insights (last inspection, upcoming inspections, etc.)	**E**	POC	Iterate	○	
	Panic button location and inspections Inspection records, mobile technology and insights (last inspection, upcoming inspections, etc.)	**E**	POC	Iterate	○	
	Event Monitoring/Work dispatch Introduce real-time data driven insights and related work dispatch using OT, IoT and Web GIS	**F**	Planned	Iterate	●	DIPS
	Outage Management System (OMS) base software purchase, deployment, project management, integrations and training	**F**	Planned	Maintain	●	PM
B	**Enterprise GIS Platform Programming** QA/QC, python and sql server automation scripts, etc.	F	Ongoing	Improve	●	DIPS
B	**Mobile and Web GIS Solution Development (General)** external solution development/programming to streamline & centralize	F	Ongoing	Improve	●	DIPS
	OMS Additional Module extend base deployment with additional modules and required integrations, ex. mobile	E	Planned	Maintain	●	PM
	Asset and Work Order Management System base software purchase, deployment, project management, integrations & training	F	Planned	Maintain	●	PM
	Event monitoring, streams and work dispatch improvements IoT pipeline development, sensor purchase for key assets, etc.	F	Planned	Iterate	●	DIPS
	IoT readiness and testing SymboticWare, Esri location services, Geoevent server pilot, streaming data to operation data store, etc.	F	Planned	Iterate	●	DIPS
B	**Switch maintenance** Control room and field crew switch maintenance app extends Asset Inspection (version 1)	E	Completed	Iterate	●	
B	**Review and Optimize existing Asset Data Model and Geodatabase** hierarchy and introduce improvements (data strategy) consider CIM	F	Planned	Iterate	●	

B	**Enterprise Data Repository (SQL/GIS) & integrations** Central data repository for integrations and 360-degree views, ETL and reporting	**F**	In progress	Improve	●	DIPS
	IT OT GIS Collaboration Facilitate working group for better communication across technology silos	**F**	Ongoing	Iterate	●	

Innovation, Partnerships and Engagement Portfolio

Keywords: *Corporate innovation, process improvement, enterprise architecture, coordination, innovation ecosystem participation, lean innovation methodology, employee engagement, collaboration, experimentation, culture, performance, agile.*

	Project	Gain	Status	Ongoing	Siemens	Capacity
B	**Data Literacy Training Program** learning management system and associated training program curriculum deliverables ex. videos, manuals	W	Ongoing	Iterate	○	
	Plastic Free Utility (employee improvements) Facilitate employee collaborations on plastic reduction at GSU	**EE**	In progress	Improve	○	
	Plastic Free Utility (R & D field improvement tech) Research and develop product with potential for commercialization	**EE**	Planned	Decide	○	
	Microsoft Project Server (build internal capabilities) Expand use of Server across other divisions for an integrated approach to PM and Operations Scheduling Tool	**W**	Planned	Iterate	●	
	Quality Management System modernization Coordinate collaborations, experiments and review of current state and options for improvement	**F**	In progress	Iterate	○	
	Community innovation sponsorship/partnerships Make small community contributions to support the innovation ecosystem in GSU service territory	**C**	Ongoing	Maintain	○	
	Promote Lean Innovation practices Provide learning opportunities to help develop a growth and innovators mindset	**W**	Planned	Improve	○	
	Digital, Innovation, Business and Location Intelligence Strategy Develop comprehensive digital and data strategy designed to align corporate priorities and the enterprise vision	**F**	Planned	Improve	○	
E	**Tech Talk Tuesday** Monthly updates, learning, presentations, capability, prep for changes, etc.	**EE**	Ongoing	Maintain	○	

Business Intelligence

Keywords: *Data, pipelines, visualization, integrations, BI dashboards, KPI, analytics, temporal, enterprise services, self-service, power automation and flows.*

	Project	Gain	Status	Ongoing	Siemens	Capacity
F	**Power BI Dashboard Pilot (Corp)** BI desktop driven dashboard, KPI's, organizational & operational performance, SAIDI, SAIFI, etc.	E	In progress	Improve	●	DIPS
F	**Power BI Dashboard Pilot (HR)** BI desktop driven dashboard	E	In progress	Improve	○	DIPS
F	**Microsoft Azure Security, Data, BI Gateway** solution development, programming & config to support internal business intelligence developers	F	Ongoing	Improve	●	DIPS
F	**Document gateway candidates (data for BI reports)** As part of Master Data Management & data catalog activities, identify data and refresh cycle for BI gateway	**F**	Ongoing	Improve	●	DIPS
D	**Graph camps** Corporate-wide training to empower employees to use self-service BI platform and many tools	**W**	Planned	Iterate	○	DIPS
F	**Corporate scorecard** Coordinate and develop executive reporting scorecard	**W**	Planned	Iterate	○	DIPS
F	**Integration Analytics Platform upgrades** software upgrades, redundancy, performance, high availability improvements	F	Planned	Improve	●	DIPS

Cost/benefit At The Portfolio level

Location Intelligence Portfolio

Main Effort: Enterprise location platform infrastructure

Timeframe: 2018 - ongoing

Description:

Review current state of the organization's asset management, mobile and enterprise GIS technologies. Design, deploy and configure platform infrastructure (server, cloud, security, database, etc.), empower employees with data to support self-service and improve decision making.

Cost	Benefit
Leverages existing enterprise licence % Innovation Officer Labour % Data, Integrations and Platform Specialist (pending) IT support (occasional)	**Cost savings:** The Innovation Officer (MSc. (GIS), GISP and Enterprise Architect) was able to perform the following duties allowing GSHi to avoid incurring consulting costs estimated at: - Initial architecture: $25,000 (one time) - Data modeling services: $15,000 (one time) - Deployment: $8,000 (one time) - Configuration and solution development: $50,000 (one time) - Mentoring and training of internal GIS Team: $5k-10k/year (ongoing) - Solution development and deployment: $25,000 (ongoing) **Intangible benefits:** Meets several requirements of Siemens Compass around data access, KPI, reporting, asset management, enterprise GIS, real-time data feeds, etc. Provides access to data and analytics when and where they're needed on any device securely on premise and remotely Streamlines reporting to internal stakeholders and executive Integrates with business intelligence platform for reporting on costs, forecasting, etc. Empowers internal users (Engineering, Operations, Customer Service, Communications, etc.) with the capability to develop products that provide insights that stream-line decision making and improve online interaction with customer Introduces forms builders, data collectors, out of the box solutions and deployments that non-specialized power users can deploy – these include high accuracy data collection projects and wizards, web application builder wizards, etc. This self-service reduces cost and wait times for IT or other specialists to develop reports at a higher quality.

Cost of maintaining status quo:

Inability to deploy and maintain solutions	No streamlined access to asset data
Data quality issues	No streamlined collection of inspections or condition data
No self-service	Inspections process manual prone to error, slow to process and action

No mobile GIS	No continuity (after consultant leaves, there is no in-house capability) Heavily reliant on others for gathering data required to make decisions

Project details (efficiencies, costs, benefits):

A - Joint Use Survey (Version 1)
B - Asset Inspections (Version 1)
C - Build Estimates

Innovation, Partnerships and Engagement Portfolio

Main Effort: Corporate Innovation and Employee Engagement

Timeframe: 2017-Present

Description:

Introduce Lean Innovation concepts and foster collaboration around technology adoption and process improvement. Reduce risk through rapid experimentation leveraging the work being done with self-service low code/no code platforms (the location intelligence and business intelligence platforms).

Cost	Benefit
Small operating budget to support activities Employee time to work off desk Office supplies Training allocation % Grant Writer % Innovation Officer % Data, Integrations and Platform Specialist (pending)	**Cost savings:** Small experiments mitigate risk of large project failure (try small before large) **Intangible Benefits:** Consistent priority and focus on R&D, improvement & innovation activities Targeted improvement within a broader enterprise framework Priority on improving cost effectiveness & operational efficiency Provide employees with opportunity to introduce & participate in improvement initiatives Foster collaboration and knowledge sharing which develops a motivating work environment Prepare employees for upcoming change and build literacy Employee engagement benefits including increased employee safety, better employee health, happier employees, greater employee satisfaction, lower absenteeism, higher retention, greater employee loyalty, better customer service, greater productivity and many other benefits in *14 Employee Engagement Benefits backed by Research*[2].

Cost of maintaining status quo:

Innovation fits and starts
Projects undertaken in isolation
Duplicative efforts
Large projects with high risk (no chance to experiment)
Capabilities not commensurate with project requirements

Project details (efficiencies, costs, benefits):

D – Map Camps
E – Graph Camps

[2] https://www.quantumworkplace.com/future-of-work/14-benefits-of-employee-engagement-backed-by-research

Business Intelligence Portfolio

Main Effort: Business Intelligence Platform Infrastructure

Timeframe: 2018-ongoing

Description:

Review current state of the organization's enterprise business analytics and intelligence technologies. Design, deploy and configure platform infrastructure (server, cloud, security, database, etc.), empower employees with data to support self-service and improve decision making.

Cost	Benefit
External resource for initial custom, config, deploy Monthly Microsoft BI Developer accounts Monthly Microsoft BI User accounts % Innovation Officer % Data, Integrations, Platform Specialist (pending)	**Intangible Benefits:** Meets several requirements of Siemens Compass around data access, KPI, reporting Provides access to data and analytics when and where it's needed on any device securely on premise and remotely Streamlines reporting to internal stakeholders and executive Integrates with location intelligence platform for reporting on assets, etc. Empowers internal users (Accounting division, Customer Service, etc.) with the capability to develop products that provide insights that stream-line decision making Self-service reduces cost and wait times for IT or other specialists to develop reports at a higher quality. Facilitate or creates KPI, reporting dashboards & views (Siemens & others)

Cost of maintaining status quo:

Business intelligence dashboards not currently available to execs or stakeholders (sequestered on desktop)
Power user/subject matter experts with skills and requirements can't easily develop insights that drive decisions
Limited IT resources available to design reports which could easily be built by business unit end-users
BI critical for business transformation in areas like Accounting who are on hold until platforms are in place to support them
Executive demands for easily accessible business data, analytics and insights are not available to them

Project details (efficiencies, costs, benefits):

F - Microsoft Azure Security, Data, BI Gateway

Cost/benefit At The Project Level
Efficiency details (6 examples from existing project list above):

A - Joint Use Survey (Version 1):
Mobile GIS (ArcGIS Collector) app and data for joint use survey with partners

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing (iterative)	
	Having the right, digital-savvy leaders in place	High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways		1. Customer Focus
✔	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
	Communicating frequently via traditional and digital methods	✔	3. Public Policy Responsiveness
			4. Financial Performance

Description:

The joint use survey with partners (ex. Bell, Eastlink) using existing methods was estimated to take 6 months based on historical surveys. The move first to ArcMap on a laptop and then to the current version (2018) on Mobile GIS using ArcGIS Online and Collector for ArcGIS on Android allowed completion of the survey in 2 months' time. The field technician reported savings of approximately **2 hours per survey per day plus elimination of prep time by GIS technicians,** time that is being used for other data projects**.**

Benefits:	**Costs:**
Main efficiency Reduction in 2hrs/survey day + regular prep time by GIS technicians & shifts more time to other data review, verification and records management activities. **Avoided costs** Work done by Innovation Office staff saving external consultant costs Reduced truck rolls (less time on the road) **Intangible benefits:** Multiple other benefits were reported including ease of use and comfort, ability to easily build views direct to data for reporting to supervisors as well as many other benefits. From a transformation perspective, this project introduced the organization to the location platform-based web GIS capability, dashboards & mobile data collection to key employees in the Engineering division who could help promote.	Innovation Officer Labour

B - Asset Inspections (Version 1):

Database, supervisor dashboards and admin tools, field collectors OEB inspections (pole, transformer)

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing improvements introduced regularly	
	Having the right, digital-savvy leaders in place	Very High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways		1. Customer Focus
✔	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
	Communicating frequently via traditional and digital methods	✔	3. Public Policy Responsiveness
			4. Financial Performance

At a high level:

- This project made and continues to make significant improvements to the annual inspection process
- Puts mobile data collection in inspectors' hands and built their capability
- Provides supervisors with status dashboards, editing and crew assignment capability
- Introduced management & workers to a new streamlined "web GIS" way of working
- Created buy-in from the front-lines and executives

Continuity (efficiency gains are accumulative and ongoing):
As with most of the Innovation Office's projects, the *Asset Inspections (Version 1)* project was critical for transforming how several departments worked by leveraging the investment in platform technologies (in this case Esri products including ArcGIS Online). Moving forward, the application will continue to improve through continuous improvement and iteration with new asset inspection types coming online on a regular basis. More inspection data on assets continue to provide more opportunities for integration and operational intelligence allowing ubiquitous access to asset inspection data.

This foundational project has led to or will lead to the development of the following project listed in the project table presented above:

- *Operations mobile dispatch improvements*
- *Asset condition assessment data integration and viewer*
- *Online public report enhancements*
- *Engineering dashboard*
- *Inspection notifications (pilot)*
- *Data Quality Dashboard (POC)*
- *Maintenance Improvements (manhole, needles, etc.)*
- *Control Room GIS Viewer*
- *Historical Inspections*
- *Enterprise GIS Platform Programming*
- *Mobile and Web GIS Solution Development (General)*
- *Asset Inspections (Version 2)*

Data from this project supports:
- *CoF, PoF & Bre Models project*
- *Real-world training examples for the Data Literacy Training Program*
- *Several initiatives outlined in Siemens Compass*

Efficiency Gains: Inspection Process Improvements
3 months / inspector + material costs (paper plots) + numerous intangible benefits

The asset inspections application was designed to serve as a first iteration to develop a flexible field data collection system to streamline the collection and management of inspections, observations and defects. The work was developed by the Innovation Officer. This project is a good example of how the Innovation Office is creating efficiencies by leveraging its investment in Esri ecosystem of applications, enterprise GIS and the location platform.

Before this project, information was on paper and in Excel spreadsheets and not enterprise or centralized. The yearly OEB inspections used to require plotting approximately 125 D size plots and printed Excel sheets for transformer data. The move to the location platform eliminated this material cost plus labour costs associated with the preparation and production of these materials, pre-inspection preparation and post processing of this information sequestered on paper and spreadsheets.

The move to enterprise GIS resulted in time savings of approximately 3-4 months – valuable time that the organization was able to use to have the inspector assist with other field data verification and clean up projects, or for backfilling vacant positions to ensure continuity in operations. GIS technicians also benefited from the elimination of their previous manual processes. The result is centralized real-time inspection data storing, not just the location of defective assets but all assets that either did not have defects or were repaired at the time of inspection.

Efficiency Gains: Supervisor and Field Crew Improvements
2 hours / supervisor / week + numerous intangible benefits

At the time of inspection, this data is available in real-time giving supervisors access to location, attributes, inspector notes, crew notes, photos and status of inspections and defects. They are also able to easily assign and track progress of the work being done by field crews. The entire workflow from inspection, planning, assignments and field crew completion has been significantly streamlined. It reduced significant “back and forth” discussions from inspections to the planning process and printing, providing a streamlined, easier-to-use structure that is process oriented and easier to understand.

Supervisors reported difficulty in completing and repairing assets from prior annual inspections. They report that this is no longer the case, estimating a saving of time of approximately 2 hours per week for the current version. This time is being used to improve planning and proactively assign work. Future iterations will provide additional savings.

The project also reduced the crew leaders’ interaction, a reported “back and forth” calling of supervisors for information and assignments. Having defect related work assigned sent directly to their device has reduced frustration and given leaders ownership and accountability for their work as opposed to calling supervisors frequently.

Efficiencies of time savings are now being realized in the field by crew leaders. Additional benefits include changes in maintenance cycles and the ability to get a jump on certain maintenance as it’s made available online, where and when they need it, as opposed to waiting for the regular, manually intensive planning and work preparation cycles. For example, crews are currently performing pole repairs that normally would wait until the spring. By using data that is central, accessible and available for crew assignment, supervisors report an ability to “get a jump on things earlier”.

For more information, a presentation about this project was made at the Digital Utilities of the Future Conference 2 and *2019 Esri Canada User Conference in Toronto* [3]

Benefits:	**Costs:**
Efficiencies Reduction in inspection cycle by 3-4 months Reduction in GIS technician prep time Streamlined supervisor’s workflow Streamlined field repair with mobile work assignment Better reporting reduces/eliminates prep time for ESA audit, etc. **Avoided costs** Work done by Innovation Office staff avoids significant external consultant costs	Innovation Officer’s labour

3 https://esri.ca/sites/default/files/documents/McKennitt9-10Greater%20Sudbury%20Utilities_OKAY%20TO%20POST.pdf

Reduced truck rolls (less time on the road) Material cost reduction (no need to print ~125 plots) **Intangible benefits:** Crew leaders, supervisors, GIS techs, etc. engaged in process Project help drive foundational tech development (mobile VPN, etc.) Centralized data to support further projects Introduced the organization to cross-silo change using rapid experimentation.	

C – Build estimates:

Field data collection, redlines and integrated cost calculation to streamline capital improvement and maintenance.

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing	
	Having the right, digital-savvy leaders in place	High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways		1. Customer Focus
✔	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
	Communicating frequently via traditional and digital methods		3. Public Policy Responsiveness
		✔	4. Financial Performance

Description:
This application is currently being developed as an initial proof of concept in place and refinements in progress.

Project coordinators will use mobile GIS to red-line design of infrastructure upgrades and capital improvements. Web GIS (geoprocessing tasks) are being developed that use cost tables in the GIS database to automate the creation of the initial build estimate with measures and calculated costs. Estimate totals are stored on the main project map feature and the generated data is stored in the central database. The generated Excel build estimates are stored on a network location for access by the project coordinators while creating an historical archive.

Benefits: **Efficiency gain**: Time savings are expected for each estimate and afterwards by having data centralized, easily accessible through the online location intelligence platform (web GIS) and for the GIS technicians to reference for changes in the enterprise geodatabase. **Intangible benefits:** Introduce mobile data collection capability in Engineering Centralize engineering data for capital improvement – better situational awareness and capital planning processes Undertake build estimates and planning with historical data available as layers. Field situational awareness and digital notes streamline collection and improve usability	**Costs:** Innovation Officer’s labour

D – Map Camps and Graph Camps:

Corporate-wide training to empower employees to use self-service location platform, BI platform and their extensive toolsets

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing	
✔	Having the right, digital-savvy leaders in place	High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways	✔	1. Customer Focus
✔	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
✔	Communicating frequently via traditional and digital methods		3. Public Policy Responsiveness
			4. Financial Performance

Description:
These learning camps are developed by the Innovation Office to build workforce capability around the platform technologies and solutions being launched. Technology is easy, but only if the employees are being exposed to solutions, learning the platform and being encouraged to use the data and solutions being deployed corporately.

These camps are a small investment in time but sustain the requirement to have employees learn to use the tools being deployed by the organization.

Although free online training is available for some work, hands-on training in the Innovation Office or training room allows for users to learn using the organizations technologies, data products and internal tech leadership.

Map Camps:
Map camps introduce employees on how to use the online enterprise web GIS platform (ArcGIS Online, ArcGIS Enterprise & Portal) on a regular basis over time. Eventually, the office will introduce more advanced topics including how to generate their own solutions using corporate data feeds and the platform's solution templates such as web application builders, mobile maps and online analytics tools. Ongoing training and solutions support to be provided by Innovation Office employees.

Graph Camps:
Graph camps will introduce employees to the business intelligence platform (being deployed Q1-2020). They will learn how to find data, build and deploy self-service analytics products. Ongoing training and support will be provided by Innovation Office employees and departmental power users (ex. Accounting).

Recent examples:
- Map camp 1 – introduction to ArcGIS Online – creating your account and building your first online web GIS map using enterprise data.

Benefits:	**Costs:**
Avoided costs: the courses being developed evolve with the data available on the platforms as a result of innovation projects (ex. inspection data). These courses will continue to be offered and will evolve over time. To have these courses delivered by a third-party using tutorial data would typical cost $500 per user per day plus expenses. In-house development and delivery allow GSHi to avoid significant ongoing costs. **Intangible benefits:** Raise awareness of what data products are available and what can be done Get users actively involved in the organization's ongoing investment in data and platform technologies.	Innovation Officer's labour Department tech leader's labour (ex. Digital savvy accountants) Attendee time

Develop internal 'citizen developers' Learn what questions can be asked of the data and innovation office Allow for innovation officer to gauge and adjust enterprise improvement projects based on capability (i.e. Cadence) Foster collaboration between power users and new users so that employees can help each other streamline and improve how they work using these technologies. Foster a culture of innovation around corporate data (data is only valuable if it is understood and drives decisions).	

E – Tech Talk Tuesday:

Monthly updates, learning, presentations, capability, prep for changes, etc.

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing	
	Having the right, digital-savvy leaders in place	High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways	✔	1. Customer Focus
	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
✔	Communicating frequently via traditional and digital methods	✔	3. Public Policy Responsiveness
		✔	4. Financial Performance

Description:
Monthly 1-hour employee engagement sessions held at 9am & 2pm on the second Tuesday of every month, plus special sessions delivered quarterly to operations who are unable to attend the regular sessions. Updates are provided on innovation, business and location intelligence projects as well as presentations from internal divisions.

Recent examples:
- About Microsoft Power Tools and benefits of automation (delivered by Accounting)
- Eyes into the distribution system (delivered by Protection and Control)
- Privacy and Cybersecurity (delivered by Communications and Information Technology)
- Intranet Mapplications and GIS Map Viewer (delivered by Innovation, Business and Location Intelligence)

Benefits:	**Costs:**
Intangible benefits: - raise awareness of corporate improvement efforts - learn what other work units do to help tear down silos - foster collaboration - demonstrate new solutions as we roll out - help disseminate important information - encourage open discussion with executive often in attendance - gather feedback and new ideas - help staff keep up with rapid change in technology - gauge readiness for projects that may change process	Innovation Officer's labour Grant Writer's labour Attendee time

F – Microsoft Azure Security, Data, BI Gateway:

Architecture, configuration and deployment of Microsoft Power BI

Portfolio: Location Intelligence			
Related digital transformation success categories		Status: Ongoing	
	Having the right, digital-savvy leaders in place	High	Benefit
✔	Building capabilities for the workforce of the future	Low	Cost
✔	Empowering people to work in new ways	✔	1. Customer Focus
✔	Giving day-to-day tools a digital upgrade	✔	2. Operational Effectiveness
	Communicating frequently via traditional and digital methods	✔	3. Public Policy Responsiveness
		✔	4. Financial Performance

Description:

Activities in early 2018 by the acting Innovation Officer resulted in the development of desktop BI dashboards for SAIDI/SAIFI, call record intelligence (ex OEB, SLA), customer survey results, OEB scorecard, internal current and historical management objectives such as average customer satisfaction and work-related injury. These dashboards are only available on Power BI Desktop with no mechanism to publish and distribute to stakeholders, customers, executive team or the board. The project will put in place the foundational on premise and cloud technologies and related online named user accounts.

This is a foundational project similar to the work undertaken with the Location Intelligence Platform from 2018 to present in that it establishes core platform technologies that enable employee self-service. The Innovation Office will continue to bring online new data sets and introduce functionality required to support KPI and forecasting items of Siemens Compass as well as many other financial reporting and business intelligence views corporate wide.

Benefits:	**Cost**:
Faster reporting, analysis and planning More accurate reporting, analysis and planning Better, quicker more consistent decision Improved data quality Improved employee satisfaction Improved operational efficiency Improved customer satisfaction Reduced costs (report preparation, gathering, cleaning data, etc.)	Azure architect (approx. $5,000) Innovation Officer's labour IT support to stand up servers and provide access to architect

4-Staff-57 Bad Debt

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro stated that it has reduced bad debt with the help of a third-party over the previous rebasing period.

a) Please provide the costs of the third-party over the rebasing period and what OM&A program it was recovered under.

Response:

a) GSHi incurred expenses in 2015, 2018 and 2019 related to the recovery of Debt Retirement Charge and Harmonized Sales Tax from bad debt write-offs with the help of a third party as follows:

OM&A Program	2015	2018	2019	Total
Bad Debt Expense	59,796.71			59,796.71
Administration	351.79	22,637.42	7,917.07	30,906.28
	60,148.50	**22,637.42**	**7,917.07**	**90,702.99**

4-Staff-58 Maintenance of General Plant

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro stated that it chose to outsource building maintenance to a third party to ensure the smooth operation of the building. It also noted that it erroneously distributed building costs to all affiliates in the 2013 budget.

a) Please provide the scope of work for the building maintenance contract and confirm that it followed Sudbury Hydro's procurement policy.
b) Please provide the actual building costs in the 2013 budget had Sudbury Hydro not made the allocation error.
c) In-house staff historically completed building maintenance. Please provide the equivalent full-time employee's that was required in 2013 to maintain the building.

Response:

a) GSHI can confirm that the procurement policy was followed when securing the contract for building maintenance. The scope of the work for the building maintenance contract includes hiring, discharging and paying janitors maintenance personnel; to make or cause to be made all ordinary repairs and replacements necessary to preserve the premises in its present condition and for the operating efficiency thereof and all alterations required to comply with building code standards. It also includes decorating on the premises, negotiating contracts for nonrecurring items not exceeding $5,000 and to enter into agreements, purchase supplies and pay bills for all necessary repairs, maintenance, minor alterations and utility services.

b) Due to the way GSHi budgeted in 2013, isolating these costs is difficult. GSHi did not isolate general plant maintenance costs related to its West Nipissing depot and as such, the costs were allocated to all affiliates in error. As a comparison, included in the 2020 budget is $45,551 for costs associated with the maintenance of that depot which had previously been allocated to all companies and is driving part of the variance in this account.

c) GSHi did not track time for this activity. The Operations Superintendent was primarily responsible, however when his time became limited the responsibility was moved to other individuals. As far as actually carrying out maintenance tasks, it was given to whoever was available and the time was not tracked. GSHi estimates that approximately 0.5 FTE was spent on Building maintenance issues.

4-Staff-59 Business Excellence

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Sudbury Hydro has an OM&A program called Business Excellence but did not provide any information on the program.

a) Please explain what is the purpose of this program and the variances since the last cost of service.

Response:

a) The Business Excellence program is home to the Business Process Improvement and System Integration Project (BPI/SI), the Siemens initiative and Corporate Memberships. It contains expenditures that provide value to all aspects of the business and that are not reasonably able to be broken out and charged to specific business areas.

Business Excellence	
Board Approved 2013 vs Actual 2013	-$ 140,580
Actuals 2013 vs 2014	$ 200,191
Actuals 2014 vs 2015	$ 3,819
Actuals 2015 vs 2016	$ 32,826
Actuals 2016 vs 2017	-$ 191,892
Actuals 2017 vs 2018	-$ 26,848
Actual 2018 vs Unaudited 2019	-$ 221
Unaudited 2019 vs Budget 2020	$ 96,494
Total Fluctuation 2013 to 2020	***-$ 26,211***

This program is closely linked to the Cost Driver “Productivity and Business Planning” described in the original application at Exhibit 4, Tab 2, Schedule 1. The description of that cost driver is reproduced here for convenience.

“Productivity and Business Planning

Board Approved 2013 vs Actual 2013	-$ 148,447
Actuals 2013 vs 2014	$ 196,451

Actuals 2014 vs 2015	$	-
Actuals 2015 vs 2016	$	31,687
Actuals 2016 vs 2017	-$	185,405
Actuals 2017 vs 2018	$	-
Actual 2018 vs Projection 2019	$	29,102
Projection 2019 vs Budget 2020	$	15,171
Total Fluctuation 2013 to 2020	***-$***	***61,441***

Included in GSHi's 2013 Budget was an initiative called Business Process Improvement and System Integration Project (BPI/SI). Although BPI/SI was launched late in 2013, material expenses were not incurred until the project got heavily underway in 2014. After a lengthy tender process, GSHi selected consulting firm MNP LLP to assist with BPI/SI. GSHi worked with MNP through 2015, documenting significant business processes, analyzing process issues, and implementing process improvements suggested and engineered throughout the project. In late 2015, the project had progressed to a state where GSHi was confident it could continue the work it started without the assistance of the consultant. The process maps built during the project were then used to assist the organization in its transition to ISO 9001:2015, and they continue to be used and updated as part of present-day ISO documentation. The ISO 9001:2015 system continues the work of the BPI/SI in that it constantly improves processes and uses the maps and understanding of the processes gained through the BPI/SI project.

As BPI/SI was winding down, GSHi began to focus on industry-specific organizational development with the assistance of Siemens. The result of this partnership was the Siemens Compass Study, which expanded the focus of the BPI/SI effort to consider the type of organizational development that would be required to keep pace with the anticipated impacts of greater levels of distributed generation and electric vehicles on the distribution system. This extensive study drew on Siemens's global experience with energy and utilities.

The Compass Study considered four functional domains that were relevant to GSHi's business; namely:

- Network Operations
- Customer Service
- Asset and Workforce Management
- Organizational Excellence

Within these domains, GSHi's current capabilities were assessed with the assistance of functional leaders. The leadership group then considered the organization's desired proficiency level in each business capability being studied.

The Compass Study continues to guide GSHI's annual work plans and has contributed to the selection of asset management projects included in the DSP."

4-Staff-60 Meter Expenses

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Sudbury Hydro stated that the meter expenses are approximately lower by $180,000 from the 2013 OEB-approved budget because it re-evaluated the need for third-party support and decided to manage the system with internal resources.

a) What year did Sudbury Hydro stop using third-party support?

Response:

a) GSHi anticipates making the change in 2020 and has prepared the budget on that basis.

4-Staff-61 Operation Supervision and Engineering

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Exhibit 4 – Tab 4 – Schedule 2

Sudbury Hydro stated that the OM&A in 2018 was lower than the test year because of a vacancy and staff resources were allocated to capital projects. Historically, the average actual OM&A for Operation and Supervision was approximately $1.34 million.

a) The 2020 Operation and Supervision costs are high in comparison to the historical average or the escalated costs from 2018. Please provide the forecasting methodology used.
b) Please confirm if part of the cost increase for Operation and Supervision is due to additional positions. If so, please list the positions provided in reference 3.
c) Please provide a list of any vacant positions in this program and a status of the position to date.
d) Sudbury Hydro stated in reference 3 that part of the reason for the new staff is because of major asset renewals. Based on Sudbury Hydro's ACA and the major asset projects it has planned in the next five years, there should be minimal or no major asset renewals past the five years. Has Sudbury Hydro considered contract positions to meet the short-term need instead of full time positions?

Response:

a) This account was forecasted by reviewing historical actuals and normalizing for any known one-time adjustments and/or projected plans. Labour is budgeted based on positions and determining the OM&A and

Capital split by examining the historical actuals for each position and forecasted capital requirements for the coming year.

b) Part of the increase is related to the Distribution Engineer who was hired at the end of 2019.

c) There is one Project Coordinator vacancy in this program as March 2020. The employee that was in this position went on to fill the Distribution Engineer position in part b above. There is a transition period while that individual shifts over to the Distribution Engineer role and once fully immersed in that role, GSHi will hire a suitable replacement (this is expected to be in the coming months).

d) The positions that GSHi has added for major asset renewals since its 2013 COS have closed a substantial talent gap in the organization. Beyond their anticipated contributions to the prospective capital investments tabled in the DSP, this group of staff is responsible for the management of the SCADA system and are tasked to perform appropriate corrective actions to ensure the continued security and dependability of the distribution system's protective equipment and as well as the corporate protection philosophy. While the utility has had some success in addressing its talent needs through the labour pool, the type of contractor that could provide these types of services is becoming increasingly difficult to procure.

4-Staff-62 Overhead Distribution System Operations and Maintenance

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Exhibit 4 – Tab 4 – Schedule 2

Sudbury Hydro stated that the variance in the Overhead Distribution System Operations and Maintenance costs is due to unfilled vacancies.

a) Please provide a list of unfilled vacancies for 2018, 2019, and 2020 and the status of the positions to date.
b) Please provide the positions in reference 3 that are related to the Overhead Distribution System Operations and Maintenance costs.

Response:

a) With respect to vacancies in the Overhead Distribution System Operations and Maintenance program, all vacancies have now been filled.

Position	2018	2019	2020
Powerline electrician	0.42	0.50	
Powerline electrician	1.00	0.50	
Powerline electrician	0.54	0.29	
Powerline crewleader	0.46	0.83	
Powerline crewleader	0.67		
Powerline electrician	0.79	0.67	
Total FTE vacancies -GSH	3.88	2.79	-

b) There are no positions directly related to Overhead Distribution System Operations and Maintenance costs as noted in Reference 3.

4-Staff-63 Stations Operations and Maintenance

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Exhibit 4 – Tab 4 – Schedule 2

Sudbury Hydro stated that since 2013 it has added a Substation Crew Leader, a Technical Services Supervisor, a distribution engineer, a Senior Protection and Control Technologist and a 2nd Protection and Control Technologist in light of its plans for substation renewals and Supervisory Control and Data Acquisition (SCADA) needs.

a) The substation renewals are only anticipated for the next five years, and based on the ACA, there does not appear to be another station that needs to be renewed past the five years. Has Sudbury Hydro considered contract positions to meet the short-term need instead of full time positions?
b) If these positions are related to the substation renewals, why are the costs not capitalized as part of the project.
c) Please confirm if Sudbury Hydro had any staff that worked on or had experience with SCADA in its 2013 COS.
d) Please confirm if Sudbury Hydro had any stations with SCADA capabilities in its 2013 COS.
e) Please confirm if the distribution engineer, Senior Protection and Control Technologist, and 2nd Protection and Control Technologist are all in the engineering department.

The total stations operation and maintenance budget for 2020 is $1,427,860, while the 2019 bridge year was $1,000,514.

f) Please explain the increase between 2020 and 2019.

Response:

a) The positions listed above that Sudbury Hydro has added since its 2013 COS have closed a substantial talent gap in the organization. The need for these positions is not just for the SCADA capital program but also for ongoing operations. Beyond their anticipated contributions to the prospective capital investments tabled in the DSP, these positions are responsible for managing the SCADA system and performing appropriate corrective actions to ensure the continued security and dependability of the distribution system's protective equipment and as well as the corporate protection philosophy. Sudbury Hydro did not consider contract staff for these positions as the skill set for these specialized positions is difficult to source and the need for these positions are ongoing.

b) Staff occupying these positions will indeed be charging all of their labour-related costs to the capital renewal project as appropriate.

c) In its 2013 COS, Sudbury Hydro had one staff member that worked on/had experience with SCADA. Since that time, the utility has sought to acquire these skills from the available labour pool to boost its operational capabilities.

d) Sudbury Hydor confirms that it had stations with SCADA capabilities in its 2013 COS.

e) Except for the distribution engineer, all other position listed above are in the **Technical Services** department. The distribution engineer is in the Engineering department.

f) In 2019, staff in the stations department was heavily involved in several capital-intensive efforts, such as the renewal of municipal substation Capreol MS32 and the investment required to upgrade the relays at GSHi's largest substation (Dash MS19). In 2020, these same staff are being directed to address the current year program including maintenance activities.

4-Staff-64 Regulatory Expenses

Question:

Ref 1: Chapter 2 Appendices – 2 – JC

Ref 2: Exhibit 4 – Tab 3 – Schedule 1

Ref 3: Chapter 2 Appendices – 2 – M

Since Sudbury Hydro's last cost of service, the operating expenses associated with staff for regulatory matters has doubled. In addition, Sudbury Hydro stated that it has reallocated an accountant to the regulatory department.

a) Please explain the cost increase and the drivers behind them.

b) Please provide the OM&A program that the accountant was previously charged under and the year the accountant was reallocated.

In reference 3, Sudbury Hydro showed a total regulatory cost of $697,576 for 2020 but in reference 1, Sudbury Hydro showed a total regulatory cost of $657,576.

c) Please confirm the correct regulatory costs.

The consultant costs have increased since Sudbury Hydro's last cost of service.

d) Please provide of a table of the consultant services for 2020 and a breakdown of their estimated costs and costs incurred to date.

Response:

a) The cost increase is primarily related to the reallocation of an accountant to the regulatory department in 2017. The costs included in this caption also include training and IT allocation for the regulatory department. The increase in training between 2013 actual and 2020 Test Year budget exists because in 2013, the Regulatory Affairs Officer was occupied with the cost of service application and then was on maternity leave so there was no opportunity for training. In 2020, funds have been budgeted for both positions in the department, creating a 100% variance. Also, the IT allocation in 2013 was abnormally low and has increased by $25,000 in 2020 to reflect a more appropriate allocation of costs.

b) The Accountant that was reallocated in 2017 was previously charged to Administration.

c) The correct Regulatory costs are $697,576. The difference of $40,000 is due to the OEB Assessments which were shown on their own line in reference 1.

d) GSHi has reallocated budget for its 2020 Cost of Service Application between categories to better reflect what has actually transpired for the preparation versus what GSHi expected. GSHi has transferred $45,000 from Consultants' costs to Incremental operating expenses associated with staff resources allocated to the application. GSHi provides the following table with a breakdown of the revised consultant costs budget and the costs incurred for the preparation of the initial application. Costs related to this interrogatory submission are not known at the time of filing this response and as such, have not been included.

Table 1 – COS Consultant Budget & Costs (for initial application)

Consultant Service	Budget	Actual to Dec 2019
Application Assistance	80,000.00	37,635.00
Transfer Pricing Study Update	10,000.00	8,700.00
Distribution System Plan Assistance	50,000.00	45,000.00
Asset Condition Assessment	40,000.00	30,000.00
Customer Consultation	40,000.00	36,352.00
	220,000.00	157,687.00

Included in the Application Assistance line are the models GSHi purchased to aid in the preparation of the application, preparation of the load forecast and LRAMVA workform, assistance and review of cost allocation and rate design as well as evidence review prior to submission.

4-Staff-65 Cyber Security Costs

Question:

Ref 1: Exhibit 4 – Tab 2 – Schedule 1

Ref 2: Letter of the OEB – Cyber Security Readiness Report & Amendments to Electricity Reporting and Record Keeping Requirements, November 29, 2018

Sudbury Hydro stated in reference 1 that cyber security costs are non-discretionary and outside of Sudbury Hydro's operational control. In reference 2, the OEB expects that distributors incorporate cyber security investments into their distribution system plans and that these responsibilities should be addressed in the same manner as any other operational risk.

a) As the cyber security responsibilities should be addressed in the same manner as other operational risks so should costs. How has Sudbury Hydro try to manage its Cyber Security costs within its historical OM&A budget.

Sudbury Hydro also stated that this cost represents contract labour Sudbury Hydro intends to procure to monitor the Sudbury Hydro local area network and Sudbury Hydro external addresses for threats, malware, and unusual activity, as well as consultation on security and threat resolution.

b) Is the cyber security infrastructure on-site or cloud based?
c) What were Sudbury Hydro's selection criteria for the cyber security contract labour?
d) Does Sudbury Hydro have Cyber Security insurance? If so, how much does it cost?
e) Does Sudbury Hydro co-locate or share its customer systems with local municipality or telecom providers?
f) Has the Sudbury Hydro participated in the Cyber Security Advisory Committee and/or the IESO Cyber Security Information Sharing Forum?

Response:

a) GSHi has tried but not been able to manage its Cyber Security costs within its historical OM&A budget as the criteria to meet the requirements to better protect our network and customer information has increased and so has the corresponding costs.

Sudbury Hydro has managed costs by sharing ideas and work with the USF group in such tasks as policy development, incident response plans, disaster recovery planning, addressing privacy, and security programs. Additionally, services such as Security as a service costs are reduced for members of USF. Consultation service costs are either shared, or reduced for members of USF as well. Sudbury Hydro hosts it's RNI and Operational Data Store on premises resulting in cost savings for hosting services.

Previously, Sudbury Hydro did not monitor for threats in real time, or near real time. Instead, traditional approaches were being used such as firewalls, ACLs, etc. With ever increasing risk associated with cyber security, Sudbury Hydro has implemented a next generation layer 7 firewall along with 24/7 activity monitoring to better protect our network and customer information.

b) Network monitoring services are cloud based (Security as a Service). Firewall appliances are on-site.

c) The criteria were cost, competence, and service. Sudbury Hydro completed a 6 month proof of concept with their monitoring provider and have been satisfied with the results. Sudbury Hydro discussed the provider's service and ability with other utilities' IT departments prior to acquire the provider's services. Since Sudbury Hydro is a USF member, significant discounts have been applied to our monitoring services with this particular provider.

d) Yes, approx. $21,000/year.

e) Sudbury Hydro has colocation with their telecom provider. Systems are not rented, rather the cost is shared.

f) Yes, Sudbury Hydro has a staff member that sits on the Cyber Security Advisory Committee. Sudbury Hydro also has a CCTX membership and is currently in the process of dealing with the IESO to implement Lighthouse.

4-Staff-66 Other Post-Employment Benefits

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 3, p.4

Sudbury Hydro is proposing to change the basis in which OPEBs are recovered from the cash basis to the accrual basis. Table 3 shows that Sudbury Hydro recovered $343,913 annually under the cash basis since its 2013 cost of service rate application while accrual amounts for OPEBs ranged from $739,015 to $1,402,277 annually. In the Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs, September 14, 2017,

a) Page 9 considers the impact of transitioning to and from the accrual basis for recovering OPEBs.
   i. Please provide a calculation showing the cumulative recovery Sudbury Hydro has collected in rates to date with an indication of the recovery basis (cash or accrual).
   ii. Please also provide the annual cash and accrual amounts for OPEBs from the commencement of when Sudbury Hydro first recovered OPEBs to 2020.
   iii. Please discuss any transitional impacts (including consideration to actuarial gains and losses) due to the change from cash to accrual basis to recover OPEBs.

b) Page 8 states “The intended practice of maintaining a consistent method used to determine recovery over time may be one reason for not adopting the accrual method for rate setting.” Please explain whether Sudbury Hydro has considered continuing to recover OPEBs on a cash basis and discuss the results of this consideration.

Response:

a-i) Please see the table below, which shows the approximate cumulative recovery Sudbury Hydro has collected in rates for OPEB (cash basis) since its last rebasing. This adjusts the amount approved in 2013 rates by the Price Cap

Index percentage approved in each of GSHi's IRM applications in years 2014 through 2019.

	2013	2014	2015	2016	2017	2018	2019
OPEB recovered, cash basis (approximate)	$334,913	$ 339,602	$ 343,507	$ 343,507	$ 349,003	$ 351,621	$ 355,840
Price Cap Index applied in year		1.40%	1.15%	0.00%	1.60%	0.75%	1.20%
			Cumulative OPEB Recovery in Rates, 2013 to 2019				**$ 2,417,992**

a-ii) In the Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs, September 14, 2017, page 9, the Board acknowledges that this calculation would be difficult to perform for utilities. GSHi believes that this calculation is critical to perform in order to quantify a transitional amount, for the transition from the cash to the accrual basis of OPEB recovery, that can be paid to or recovered from ratepayers.

GSHi cannot respond to this question in the time allotted for interrogatories. GSHi proposes to perform this calculation before its next Cost of Service rebasing. GSHi would propose a recovery mechanism in order to dispose of the difference identified in the calculation in its next rebasing. GSHi anticipates that this difference for disposition would be offset against the deferral account proposed for OPEB gains/losses and discussed in part a-iii below.

a-iii) In Exhibit 9, Tab 1, Schedule 5, GSHi has proposed a deferral account to track the gains and losses effective beginning in 2020. GSHi is proposing to capture in this account the actuarial gains and losses that are currently being recognized in OCI beginning with fiscal year-ending December 31, 2020. GSHi would propose disposition of the account in a future cost-based rate proceeding.

b) GSHi has considered continuing to recover OPEBs on a cash basis, however in considering the Board's report on OPEB costs dated September 14, 2017, GSHi does not believe the cash basis of recovery best meets the regulatory principles noted above.

GSHi notes that its OPEB liability is approximately $17.1M at December 31, 2018. If GSHi had established rates on an accrual basis initially, this liability would be funded and the regulatory principles – namely fairness, minimizing intergenerational inequity, and minimizing rate volatility – would have been met. By transitioning to the accrual basis of recovery, combined with deferring future OPEB gains/losses, GSHi will ensure that any future change to its OPEB liability are recovered in a way that more appropriately aligns with the regulatory principles noted above.

GSHi notes that in the Board's report on OPEB costs dated September 14, 2017, page 13 discusses OPEB actuarial gains and losses and the OPEB expense associated with them. The report notes that the OEB will consider the potential need for further analysis and guidance on this matter in due course. GSHi will consider any further guidance released on this matter against the methodology proposed in this rate application.

4-Staff-67 Other Post-Employment Benefits

Question:

Ref 1: Exhibit 4 – Tab 4 – Schedule 3, p.5

Sudbury Hydro provided its 2015 actuarial report.

a) Please provide the 2018 actuarial valuation update.
b) Please provide the 2019 actuarial report if available.

Response:

a) Please see Attachment 1 for a copy of the 2018 actuarial valuation update.
b) The final 2019 report is not yet available.

Attachment 1 (of 1):

4-Staff-67 Attachment 1: Other Post-Employment Benefits

Greater Sudbury Utilities Inc.
Estimated Benefit Expense (IAS 19)
Greater Sudbury Hydro Inc.
FINAL

	Actual * CY 2018
Discount Rate at January 1	3.30%
Discount Rate at December 31	3.90%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	5.78%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2025
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actual

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

Net Defined Benefit Liability/(Asset) as at January 1	14,952,158
Defined Benefit Cost Recognized in Income Statement	707,760
Defined Benefit Cost Recognized in Other Comprehensive Income	(1,209,314)
Benefits Paid by the Employer	(492,120)
Net Defined Benefit Liability/(Asset) as at December 31	13,958,484

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

Current Service Cost	222,459
Interest Cost	485,301
Past Service Cost/(Gain)	-
Defined Benefit Cost Recognized in Income Statement	707,760

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	(1,209,314)
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-
Change in Effect of Asset Ceiling	-
Defined Benefit Cost Recognized in Other Comprehensive Income	(1,209,314)
Total Defined Benefit Cost	(501,554)

C. Change in the Present Value of Defined Benefit Obligation

Present Value of Defined Benefit Obligation as at January 1	14,952,158
Current Service Cost	222,459
Interest Cost	485,301
Benefits Paid	(492,120)
Past Service Cost/(Gain)	-
Net Actuarial Loss/(Gain)	(1,209,314)
Present Value of Defined Benefit Obligation as at December 31	13,958,484

* The CY 2018 defined benefit cost and expected December 31, 2018 PV DBO are calculated based on membership data at December 31, 2016 and management's best estimate assumptions at December 31, 2017.

Greater Sudbury Utilities Inc.
Estimated Benefit Expense (IAS 19)
Greater Sudbury Hydro Inc.
FINAL

	Actual * CY 2018
Discount Rate at January 1	3.30%
Discount Rate at December 31	3.90%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	5.78%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2025
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actual

D. Calculation of Component Items

Interest Cost	
Present Value of Defined Benefit Obligation as at January 1	14,952,158
Benefits Paid	(246,060)
Accrued Benefits	14,706,098
Interest Cost	485,301
Expected Present Value of Defined Benefit Obligation as at December 31	
Present Value of Defined Benefit Obligation as at January 1	14,952,158
Current Service Cost	222,459
Benefits Paid	(492,120)
Interest Cost	485,301
Expected Present Value of Defined Benefit Obligation as at December 31	15,167,798

E. Net Actuarial Loss/(Gain)

Net Actuarial Loss/(Gain) as at December 31	
Expected Present Value of Defined Benefit Obligation	15,167,798
Past Service Cost/(Gain)	-
Expected Present Value of Defined Benefit Obligation after Past Service Cost/(Gain)	15,167,798
Actual Present Value of Defined Benefit Obligation	13,958,484
Net Actuarial Loss/(Gain) as at December 31	(1,209,314)

* The CY 2018 defined benefit cost and expected December 31, 2018 PV DBO are calculated based on membership data at December 31, 2016 and management's best estimate assumptions at December 31, 2017.

Greater Sudbury Utilities Inc.
Estimated Benefit Expense (IAS 19)
Greater Sudbury Hydro Plus Inc.
FINAL

	Actual * CY 2018
Discount Rate at January 1	3.30%
Discount Rate at December 31	3.90%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	5.78%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2025
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actual

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

Net Defined Benefit Liability/(Asset) as at January 1	3,286,723
Defined Benefit Cost Recognized in Income Statement	246,606
Defined Benefit Cost Recognized in Other Comprehensive Income	(335,815)
Benefits Paid by the Employer	(58,515)
Net Defined Benefit Liability/(Asset) as at December 31	3,138,999

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

Current Service Cost	139,109
Interest Cost	107,496
Past Service Cost/(Gain)	-
Defined Benefit Cost Recognized in Income Statement	246,606

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	(335,815)
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-
Change in Effect of Asset Ceiling	-
Defined Benefit Cost Recognized in Other Comprehensive Income	(335,815)
Total Defined Benefit Cost	(89,210)

C. Change in the Present Value of Defined Benefit Obligation

Present Value of Defined Benefit Obligation as at January 1	3,286,723
Current Service Cost	139,109
Interest Cost	107,496
Benefits Paid	(58,515)
Past Service Cost/(Gain)	-
Net Actuarial Loss/(Gain)	(335,815)
Present Value of Defined Benefit Obligation as at December 31	3,138,999

* The CY 2018 defined benefit cost and expected December 31, 2018 PV DBO are calculated based on membership data at December 31, 2016 and management's best estimate assumptions at December 31, 2017.

Greater Sudbury Utilities Inc.
Estimated Benefit Expense (IAS 19)
Greater Sudbury Hydro Plus Inc.
FINAL

	Actual * CY 2018
Discount Rate at January 1	3.30%
Discount Rate at December 31	3.90%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	5.78%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2025
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actual

D. Calculation of Component Items

Interest Cost	
Present Value of Defined Benefit Obligation as at January 1	3,286,723
Benefits Paid	(29,257)
Accrued Benefits	3,257,466
Interest Cost	107,496
Expected Present Value of Defined Benefit Obligation as at December 31	
Present Value of Defined Benefit Obligation as at January 1	3,286,723
Current Service Cost	139,109
Benefits Paid	(58,515)
Interest Cost	107,496
Expected Present Value of Defined Benefit Obligation as at December 31	3,474,814

E. Net Actuarial Loss/(Gain)

Net Actuarial Loss/(Gain) as at December 31	
Expected Present Value of Defined Benefit Obligation	3,474,814
Past Service Cost/(Gain)	-
Expected Present Value of Defined Benefit Obligation after Past Service Cost/(Gain)	3,474,814
Actual Present Value of Defined Benefit Obligation	3,138,999
Net Actuarial Loss/(Gain) as at December 31	(335,815)

* The CY 2018 defined benefit cost and expected December 31, 2018 PV DBO are calculated based on membership data at December 31, 2016 and management's best estimate assumptions at December 31, 2017.

4-Staff-68 PILS

Question:

Ref 1: 2020 PILS Model

Ref 2: Chapter 2 Appendix 2-BA

The depreciation expense included as an addition to 2019 and 2020 taxable income in the PILS model appears to be different than the depreciation expense shown in Appendix 2-BA. The difference is shown in the table below. Please explain the difference and revise the evidence as needed.

	2019	**2020**
Appendix 2-BA (depreciation less allocated depreciation for stores and transportations)	4,128,860	4,404,632
PILS Model (tangible and intangible assets)	4,595,384	4,773,422
Difference	466,524	368,790

Response:

The PILs model submitted contained inaccurate values for amortization (both tangible and intangible assets). GSHi has updated the Chapter 2 appendices and the PILs model, and has re-submitted both models with these interrogatories.

4-Staff-69 2019 Tax Loss

Question:

Ref 1: 2020 PILS Model

The integrity checklist stated referred to Exhibit 5, Tab 1, Schedule 1 for a discussion of treatment of taxable loss projected in 2019. There does not appear to be such discussion provided in Exhibit 5.

a) Please provide the appropriate reference. Otherwise, please explain Sudbury Hydro's treatment of the projected 2019 tax loss and explain why there is an adjustment in the 2019 Schedule 4 to eliminate the tax loss carry forward.

b) Please estimate Sudbury Hydro's actual taxes for 2019.

c) Please explain any differences in Sudbury Hydro's estimated actual tax calculation for 2019 and the tax calculation included in the PILS model for 2019.

Response:

a) By including a deduction for non-capital losses in the test year, GSHi would embed in distribution rates a one-time non-capital loss, thereby reducing the revenue requirement for PILs until the next rebasing for a non-recurring loss. GSHi expects to pay PILs without reduction for a non-capital loss over the period until its next rebasing. Therefore, in the initial application, GSHi is deducting the non-capital loss to exclude the deduction from the PILs calculated for revenue requirement.

   Furthermore, as per the updated PILs model submitted as part of these interrogatories, the updated 2019 PILs calculation has Regulatory Taxable Income of $75,710. Therefore, there is no longer a 2019 tax loss and no adjustment in Schedule 4 to eliminate the tax loss carryforward.

GSHi would like to highlight that the updated 2019 Regulatory Taxable Income is $75,710 with Accelerated CCA elected in the Bridge Year, however Regulatory Taxable Income would equal $795,632 without the election for Accelerated CCA. The difference between regular CCA and Accelerated CCA results in approximately $190,779 in PILs (($795,632 - $75,710) * 26.5%= $190,779) that will be deferred in 2019 and returned to ratepayers, however this is not reflected in the PILs model calculation for Bridge Year PILs.

b) GSHi anticipates that its actual taxes for 2019 will approximate the value calculated in the PILs model submitted as part of these interrogatories. The calculation in the updated PILs model for 2019 is $20,063 in total income taxes.

A potentially material difference between the calculation in the PILs model and the actual taxes for 2019 is “Net movement in regulatory accounts” that is included as an adjustment for actual tax calculation purposes but excluded in the PILs model calculation. GSHi does not have an estimate for this figure at the time of interrogatory response submission.

c) GSHi anticipates that its actual taxes for 2019 will approximate the value calculated in the PILs model submitted as part of these interrogatories. A difference between the two calculations is “Net movement in regulatory accounts” that is included as an adjustment for actual tax purposes but excluded in the PILs model calculation. GSHi does not have an estimate for this figure at the time of interrogatory response submission.

4-Staff-70 PILS

Question:

Ref 1: 2020 PILS Model

a) In the 2019 PILS model, there is a deduction for the amortization of deferred revenue. There is no similar deduction in the 2020 PILS model. Please explain why not.
b) In the 2019 PILS model, there is a deduction for "net movement in regulatory accounts (excl. tax)". Page 36 of the *Chapter 2 Filing Requirements for Electricity Rate Applications for 2019 Rate Applications* which formed the basis of the Filing Requirements for 2020 Rate Applications stated "Regulatory assets and liabilities must be excluded from taxes/PILs calculations both when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts." Please explain why there is a deduction for regulatory accounts in the 2019 PILS model and revise the PILS model as necessary.

Response:

a) The intention with the adjustment for amortization of deferred revenue is to remove the amount from "Net Income for Tax Purposes". Amortization of deferred revenue is included in the number for "Amortization of tangible assets" in the 2020 PILs calculation. The amount is reducing this figure by $207,802. This can be seen in Appendix 2-BA, year 2020, line "2440 Deferred Revenue". Therefore, amortization of deferred revenue is being appropriated backed out of the Net Income figure. This differed from the numbers included for 2019, where it was necessary to deduct this amortization separately.

   GSHi has updated the PILs model and the 2019 PILs calculation is now consistent with the 2020 PILs calculation. The amortization of deferred revenue is included in the number for "Amortization of tangible assets" in the 2019 PILs calculation, as well as the 2020 PILs calculation, and therefore there is no line to adjust “deferred revenue” for either 2019 or 2020.

b) GSHi has removed the deduction for “net movement in regulatory accounts” from the Schedule 1 for the 2019 PILs calculation.

4-Staff-71 PILS

Question:

Ref 1: 2020 PILS Model

Sudbury Hydro has implemented accelerated CCA in the 2020 PILS Model. In the OEB's July 25, 2019 letter *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance,* it states "The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this."

a) Please discuss whether Sudbury Hydro has considered smoothing of accelerated CCA and what its conclusion is.
b) Please provide a calculation showing how Sudbury Hydro would smooth CCA over the IRM period, and what the impact to PILS would be under a smoothed and unsmoothed scenario.

Response:

a) Accelerated CCA will allow GSH to apply the prescribed CCA rate for a CCA class up to one-and-a-half times the net addition to the class for a given year's additions. If GSHi is unable to claim accelerated CCA in one or multiple years between 2020 and its next Cost of Service rebasing, GSHi proposes calculating the difference between accelerated CCA and normal CCA in the particular year. If the amount calculated is considered material, or if GSHi expects the balance will grow to become a material balance by the time it is proposed for disposition in its next rebasing, GSHi proposes deferring the amount in a sub account of OEB account 1508. GSHi proposes disposing of the account, following prudence review, in its next rebasing application. Given the value expected for deferral as calculated in part b) below, GSHi believes that smoothing offered under typical deferral and disposal treatment, where disposal over multiple years is an option if necessary, would provide a reasonable rate impact for its customers and therefore GSHi has not considered any other smoothing mechanism.

b) GSHi proposes in part a) above deferring the difference between accelerated CCA and normal CCA in any year between 2020 and its next rebasing that accelerated CCA is not available as a tax election. GSHi would smooth the rate impact by disposing of the deferral account over multiple years if deemed necessary based on the rate impact. The following calculation is provided to perform a "magnitude-of-numbers" calculation to determine if the amount is likely to be material. This calculation indicates that the difference will likely be material in a given year that the tax election is not available, as the difference in the test year is a grossed-up value of $409,218.

		2020 Test Year
CCA Claim per PILs model	A	8,195,836
CCA Claim per PILs model, removing Accelerated CCA	B	7,060,836
CCA Claim Difference in Test Year	A-B = C	1,135,000
Tax Rate	D	26.50%
Total Income Tax Impact	C * D = E	300,775
Tax Provision Gross Up (%)	1-D = F	73.50%
Tax Provision Gross Up ($)	E/F-E = G	108,443
Income Tax (grossed-up)	E + G	**409,218**

5-Staff-72 Cost of Capital Parameters

Question:

Ref 1: Exhibit 5 – Tab 1 – Schedule 1

Ref 2: Letter of the OEB – 2020 Cost of Capital Parameters, October 31, 2019

Sudbury Hydro used 2019 cost of capital parameters as a placeholder until 2020 cost of capital parameters were issued. The OEB issued 2020 cost of capital parameters on October 31, 2019.

a) Please update all models and calculations with the 2020 cost of capital parameters.

Response:

a) GSHi has updated the following for the 2020 cost of capital parameters:
   a. Revenue Requirement Workform.
   b. Chapter 2 Appendices, Appendix 2-OB (Debt Instruments)
   c. Chapter 2 Appendices, Appendix 2-EA (Account 1575 – IFRS-CGAAP)
   d. Chapter 2 Appendices, Appendix 2-OA (Capital Structure)

7-Staff-73 Weighting Factors

Question:

Ref 1: Exhibit 7, Tab 1, Schedule 1, page 4

Ref 2: Cost Allocation Model, Tab I3 TB Data

In table 3 of reference 1, Sudbury Hydro has provided an apportionment of 5315 – Customer Billing as follows:

Residential	$2,016,222
General Service < 50 kW	$205,315
General Service > 50 kW	$23,945
Unmetered Scattered Load	$205,315
Sentinel	$7,532
Street Lighting	$97
Total	$2,351,204

These portions reflect an equal allocation to all rate classes. In addition, $13,736 of contract labour is employed for meter reading for the General Service > 50 kW rate class, giving General Service > 50 kW the only weighting factor other than 1.00.

The 5315 – Customer Billing account balance per I3 trial balance is $1,790,905.

a) Please reconcile the account balance used in the derivation to the weighting factor to the Uniform System of Accounts (USoA).
b) Which USoA account is the contract labour related to meter reading tracked in?
c) If the contract labour related to meter reading is recorded in account 5310 – Meter Reading Expense, why is it included here as that account is allocated on the basis of the Weighted Meter Reading – CWMR allocator?

Response:

a) Table 1 was incorrect in GSHi's original application. Meter Reading Expense that is not related to contract labour was included the figures in table 3 of Exhibit 7, Tab 1, Schedule 1. Once this figure (Meter Reading net of contract labour = $8,764.04) is removed, the Billing and Collecting total is equal to the sum of USoA accounts 5305, 5315, 5320, and 5340.

b) Meter reading costs are tracked in account 5310 Meter Reading Expense.

c) Please see response a) and b) above – this has been corrected in the revised Cost Allocation Model included as a live model with this interrogatory response submission.

7-Staff-74 Meter Capital

Question:

Ref 1: Cost Allocation Model, Tab I6.2 Customer Data, Tab I7.1 Meter Capital, Tab I7.2 Meter Reading

The Meter Capital worksheet has been completed indicating a total of 447 meters for the General Service > 50 kW rate class. The Customer Data and Load Forecast indicate 492 customers.

The Meter Capital worksheet indicates 45 Demand with IT and Interval Capability – Primary meters for the Street Lighting rate class. There is no entry for meter reading of these meters.

A count of 492 meter reading events is included in the General Service > 50 kW rate class for the meter ready type, “GS>50 Reading”. However, there is no weighting assigned to this activity.

a) Please reconcile the apparent shortage of meters in the General Service > 50 kW rate class.
b) Please explain how primary meters are used with street lights, and whether these meters are read, or whether they belong in the General Service > 50 kW rate class.
c) Please explain why there is no weighting assigned to the reading of GS > 50 kW meters. When doing so, please consider whether the $13,736 of contract labour from the previous question should be factored in.

Response:

a) The shortage of meters is due to a data entry error in which 45 meters were included with the Streetlight class. This has been corrected in the revised cost allocation model.

b) See response to part a). There are no meters related to Streetlights.

c) The weighting factor for GS>50 reading was incorrectly entered in cell C33 of I7.2 Meter Reading. It should have been entered in cell C34 and applied to the GS>50 kW meter count. This is corrected in the updated cost allocation model.

7-Staff-75 Cost Allocation

Question:

Ref 1: Cost Allocation Model, Tab I6.2 Customer Data, Tab I8 Demand Data

Ref 2: Load Forecast Model

The Customer Data worksheet does not have any entries for General Service > 50 kW on rows 23-25, which should indicate the counts of customers using primary distribution, utility line transformers, and customers connected to the utility's secondary distribution system.

This is inconsistent with the load data on sheet I8 which indicates that all of the General Service > 50 kW load is served using primary distribution, and that a significant proportion of load is served using both utility line transformers and the utility's secondary distribution system.

On sheet I6.2 Customer Data, the connection counts for Sentinel and Unmetered Scattered Load reconcile to the load forecast. The Number of Bills is an entered value for these two classes, and the total number of customers is a formula referencing the number of bills divided by 12.

a) Please reconcile the apparent discrepancy in the General Service > 50 kW rate class
b) Please explain how the number of bills were derived for the Sentinel and Unmetered Scattered Load rate classes.

Response:

a) Customer counts for GS > 50 kW were not properly entered into the cost allocation model. The GS > 50 kW customer count, which has been revised from 492 to 500 in the updated load forecast, is now included in GSHi's total and primary customer bases. A lower count, 459, is included in GSHi's line transformer and secondary customer bases, which is the total count net of 41 customers that own their own line transformers and do not take secondary service.

b) The number of bills was based on an analysis of the number of bills sent, separate from the customer counts derived in the load forecast, which includes a forecast of device counts only. This is revised in the updated cost allocation model so that the number of bills is 12 times the number of customers.

7-Staff-76 Cost Allocation

Question:

Ref 1: Exhibit 7, Tab 1, Schedule 2, pages 3-4

Ref 2: Revenue Requirement Work Form, Tab 11. Cost Allocation

Ref 3: Tariff Schedule and Bill Impact Model, Tab 6. Bill Impacts

Sudbury Hydro proposes to reduce the revenue to cost ratio for Street Lighting over three years by increasing the revenue to cost ratio for Residential and Sentinel Lighting rate classes.

The Status Quo Ratio for the Residential rate class is 93.07%, and it is proposed to increase approximately 0.66% each year, reaching 95.04% in 2022.

The Status Quo Ratio for the Sentinel Lighting rate class is 83.34%, and it is proposed to increase 5-6% each year, reaching 100% in 2022.

This will enable a reduction of the Street Lighting ratio from a Status Quo of 206.93% to 178% in 2020 and 120% over three years.

The proposed bill impact in the Sentinel Lighting rate class is 11.4%.

a) In addition to extending the transition period to three years, has Sudbury Hydro considered any other opportunities for mitigating the bill impact to Sentinel Lighting customers?
b) Please explain why the sentinel lighting rate class is being transitioned to a 100% revenue-to-cost ratio.

Response:

a) GSHi has revised the transition period to 5 years to mitigate year-over-year bill impacts to the residential and sentinel light classes.

b) GSHi has revised the 2024 target R/C ratio of the sentinel lighting class to 91.44%, which is the target residential R/C ratio in 2020. Residential is the only other class with an R/C ratio materially below 100% and additional revenue is required to offset reductions to streetlight rates. In GSHi's view, it would not be reasonable to increase the R/C ratio for the residential class without increasing the R/C ratio of the sentinel class, nor would it be reasonable to increase the sentinel R/C ratio to above the R/C ratio of the residential class. The revised rate design reflects a measured approach that brings the Sentinel R/C ratio closer to 100% while holding the total bill impact in 2020 to 7.6% and subsequent total bill impacts to 2.2%.

8-Staff-77 Retail Transmission Service Rate (RTSR)

Question:

Ref 1: EB-2019-0037 Retail Transmission Service Rate Model

Ref 2: EB-2019-0296 2020 Uniform Transmission Rates, December 19, 2019

Ref 3: EB-2019-0043 Hydro One Networks Decision and Rate Order, December 17, 2019

The OEB issued 2020 Uniform Transmission Rates (UTRs) and 2020 Hydro One Sub-Transmission Rates on December 19, 2019 and December 17, 2019 respectively.

a) Please updated the RTSR Model with the updated UTRs and Hydro One Sub-Transmission Rates.

Response:

a) GSHi has updated the RTSR Model with the updated UTRs and Hydro One Sub-Transmission rates issued on December 19, 2019 and December 17, 2019 respectively and a live model has been included with this interrogatory response submission.

8-Staff-78 Retail Service Charges

Question:

Ref 1: EB-2019-0280 Decision and Rate Order, November 28, 2019

Ref 2: EB-2019-0037 Tariff Schedule and Bill Impact Model

In reference 1, the OEB updated the Retail Service Charges on November 28, 2019.

a) Please work with OEB staff to update the Tariff Schedule and Bill Impact Model.

Response:

a) GSHI has worked with Board Staff to update the Tariff Schedule and Bill Impact model and confirms the updated model has been used for purposes of this interrogatory response and a live model has been included with this submission.

8-Staff-79 Loss Factors

Question:

Ref: Chapter 2 Appendix 2-R

The proposed Appendix 2-R has a larger value populated in row A(2) than in in A(1) for each year from 2014-2018. A(1) is supposed to be the Wholesale "higher value" reflecting the generation requirement for all power received by the distributor. A(2) is supposed to be the Wholesale "lower value" reflecting the energy received onto the distribution system.

The Supply Facilities Loss Factor has been populated with 1.0077 or 1.0078 in each year despite the instructions for the worksheet indicating that it is to be populated with A(1) divided by A(2).

a) Please explain the counter-intuitive result that A(2) has been populated with larger values than A(1). If the entries are simply reversed, please revise.
b) If Sudbury Hydro believes that the prescribed method of calculating the supply facility loss factor by dividing A(1) / A(2) is inappropriate in its case, please explain. Otherwise, would Sudbury Hydro adopt the prescribed methodology for calculating the supply facilities loss factor?
c) If Sudbury Hydro will not adopt the prescribed methodology for calculating the supply facilities loss factor, please provide a derivation of the supply facilities loss factor used.

Response:

a) GSHi intended to follow the guidance in the "Notes" of Appendix 2-R in completing this appendix. In the notes, it was indicated that A(2) should contain kWh for generation directly connected to the distributor's own network, however that same note was not included for A(1). The result was that row A(2) was higher than A(1) as generation, when added to A(2) subtotal, was high enough to cause this result.

GSHi has considered Board staff comments in this question and also considered conceptually the intended result of the calculation and has now revised Appendix 2-R to also include generation in A(1). The result is that A(1) is now higher than A(2), as expected.

The updated Chapter 2 Appendices, Appendix 2-R is submitted in live Excel format with this interrogatory response. A copy of Appendix 2-R is included as Attachment 1 to this section.

b) GSHi has adopted the prescribed method of calculating the supply facility loss factor. Please see the revised Appendix 2-R.

The updated Chapter 2 Appendices, Appendix 2-R is submitted in live Excel format with this interrogatory response. A copy of Appendix 2-R is included as Attachment 1 to this section.

c) GSHi will adopt the prescribed methodology for calculating the supply facilities loss factor.

Attachment 1 (of 1):

8-Staff-79 Attachment 1:Chapter 2 Appendix 2-R

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Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2014	**2015**	**2016**	**2017**	**2018**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	972,464,695	927,945,070	900,566,483	884,126,814	913,002,831	919,621,178
A(2)	"Wholesale" kWh delivered to distributor (lower value)	965,161,905	921,010,922	893,775,064	877,511,000	906,173,545	912,726,487
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	965,161,905	921,010,922	893,775,064	877,511,000	906,173,545	912,726,487
D	"Retail" kWh delivered by distributor	925,991,840	886,098,301	853,279,711	844,346,737	879,196,513	877,782,620
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	925,991,840	886,098,301	853,279,711	844,346,737	879,196,513	877,782,620
G	Loss Factor in Distributor's system = **C / F**	1.0423	1.0394	1.0475	1.0393	1.0307	1.0398
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0076	1.0075	1.0076	1.0075	1.0075	1.0076
	Total Losses						
I	Total Loss Factor = **G x H**	1.0502	1.0472	1.0554	1.0471	1.0385	1.0477

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**). This value should not include supply facility losses. However, the total loss factor on the tariff of rate and charges and applied to customers consumption should include the supply facility loss factor.

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

E Metered consumption of Large Use customers.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H Actual Supply Facility Loss Factor as calculated by dividing A(1) by A(2).

9-Staff-80 Lost Revenue Adjustment Mechanism Variance Account

Question:

Ref 1: Exhibit 4, Tab 10, Schedule 1, p. 1 of 4

Ref 2: LRAMVA workform, Tab 1

Sudbury Hydro is applying to dispose of its 2017 lost revenues in its 2020 COS application. However, the LRAMVA workform was completed with 2017 and 2018 lost revenue amounts, and therefore does not support the claim to dispose of 2017 LRAMVA balance only.

a) Please file an updated LRAMVA workform with 2018 amounts removed (specifically rows 75 and 76 in Table 1-b) as the 2018 lost revenue amounts are not part of the current LRAMVA claim. Based on the updated LRAMVA workform, please confirm whether the $328,035 claim amount for 2017 lost revenues in the pre-filed evidence is correct. If not, please explain why there is a difference.

b) Please confirm that all applicable models have been updated to ensure that the appropriate LRAMVA balance is reflected in the DVA continuity and bill impacts model.

Response:

a) Amounts related to 2018 have been removed from the revised LRAMVA workform (see 9-Staff-83, part a). The claim has been revised to include 2017 adjustments (see 9-Staff-81). The revision increases the LRAMVA claim to $331,260 not including carrying charges.

b) Confirmed.

9-Staff-81 LRAMVA

Question:

Ref 1: LRAMVA workform, Tab 5

Ref 2: 2019 Participation and Cost Report

In the 2019 Participation and Cost Report, it appears that there are 2017 unverified adjustments which were not included in Table 5-C of the LRAMVA workform.

a) Please explain why the unverified 2017 savings adjustments were not included in the LRAMVA claim.
b) Please confirm that Sudbury Hydro wishes to forgo the recovery of 2017 unverified adjustments in this claim.

Response:

a) Unverified 2017 savings adjustments were not included because the adjustment values were not specifically identified by the IESO in the last Participation and Cost Report. The revised LRAMVA workform includes 2017 adjustments. The adjustments were calculated as the difference between 2017 savings as per the 2017 Verified Results Report and the April 2019 Cost and Participation Report.

b) Not confirmed, GSHi wishes to recover these amounts, please see above.

9-Staff-82 LRAMVA

Question:

Ref 1: LRAMVA workform, Tab 5

Ref 2: Tariff Schedule and Bill Impact Model, Tab 6

a) Please confirm accuracy of the rate class allocations for the 2016 retrofit program savings, specifically accuracy of the allocation of 2016 retrofit savings to the Sentinel Lighting class.
b) Please discuss whether Sudbury Hydro believes it is necessary to consider extending the disposition period of the LRAMVA balance to address rate mitigation for certain customer classes that have exceeded a 10% total bill change from the previous year:

- Residential non-RPP at 10.7%
- Residential at 10^{th} consumption percentile (219 kW) at 13.3%
- Sentinel Lighting at 11.4%

Response:

a) With the following update, the rate class allocations are correct. The 0.2% 2016 retrofit allocation to the sentinel class is related to a project that was completed for a customer with a GS < 50 kW account and a sentinel account. The related savings were erroneously attributed to the sentinel light class instead of the GS < 50 kW class. This has been revised in the updated LRAMVA workform and the CDM figures used in the load forecast.

b) As per part a), the sentinel allocation in 2016 is an error and there should be no LRAMVA claim attributable to the sentinel class.

The LRAMVA workform and resulting LRAMVA rate riders included 2018 savings, which are not being disposed of as part of this proceeding. The LRAMVA claim is now approximately half of the previous balance, with similar impacts to the rate riders. Furthermore, the rate transitions that cause rate increases to the sentinel and residential classes have been extended to 5 years. Accounting for these changes the bill impacts of the customer groups listed above no longer exceed 10% so additional rate mitigation is not necessary.

9-Staff-83 LRAMVA

Question:

Ref 1: LRAMVA workform

a) If Sudbury Hydro made any changes to the LRAMVA workform as a result of its responses to the LRAMVA interrogatories, please file an updated LRAMVA workform, and confirm the revised LRAMVA balance requested for disposition, the disposition period, and the revised rate riders.
b) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

Response:

a) Please see the updated LRAMVA workform.
The revised balance reflects the removal of amounts related to 2018 and the addition of 2017 savings adjustments. The revised claim is $349,899, including carrying charges. The principal, carrying charges, and resulting rate rider for each class is detailed in the following table.

Rate Class	Billing Unit	Principal	Carrying Charges	Total LRAMVA	Load Forecast	Proposed Rate Rider
		A	B	C = A + B	D	E = C / D
Residential	kWh	$110,537	$6,220	$116,757	367,560,506	$0.0003
GS < 50 kW	kWh	$81,254	$4,572	$85,825	136,403,467	$0.0006
GS > 50	kW	$139,259	$7,836	$147,095	857,773	$0.1715
USL	kWh	$0	$0	$0	1,109,725	$0.0000
Sentinel Lighting	kW	$0	$0	$0	1,010	$0.0000
Street Lighting	kW	$210	$12	$222	20,807	$0.0107
Total		**$331,260**	**$18,639**	**$349,899**		

b) The changes are detailed in Table A-2 of tab 1-a of the revised LRAMVA workform.

9-Staff-84 Accounts 1595 (2017)

Question:

Ref 1: DVA Continuity Schedule

In the DVA Continuity Schedule, Sudbury Hydro is proposing to dispose Account 1595 (2017). Per the *Addendum to Filing Requirements for Electricity Rate Distributions – 2020 Rate Applications* issued July 15, 2019, page 11 states "Account 1595 sub-accounts are eligible for disposition when one full year has elapsed since the associated rate riders' sunset date have expired and the residual balances have been externally audited." The rate rider for Account 1595 (2017) ended April 30, 2018 and is therefore, not eligible for disposition. Please revise the DVA Continuity Schedule to remove this from disposition.

Response:

GSHi has revised the DVA Continuity Schedule to remove this from disposition, and the updated model has been filed with this submission. GSHi has also revised the DVA Continuity Schedule to remove 1595 (2018) from disposition. Both the 2017 and 2018 sub-accounts contained balances pertaining to two years of tax variance, totalling $62,240, ordered disposed of to account 1595 by the Board in IRM rate proceedings. GSHi will seek disposition of these sub-accounts in future IRM years.

9-Staff-85 Account 1508 - IFRS Transition Costs

Question:

Ref 1: Chapter 2 Appendix 2-YA

In Appendix 2-YA, $41,598 was incurred in 2016 for staff salaries. Please provide additional details on the type of work performed and why it was incurred in 2016, after the adoption of IFRS in 2015.

Response:

These salaries were incurred to perform IFRS transition tasks not limited to: the creation and implementation of A2 (GSHi's capital asset module, which interfaces with its general ledger), componentization of assets, analyzing historical asset data, calculating one-time adjustments to re-value assets and establish new useful lives for substations, programming changes required with the system, and preparing one-time IFRS transition notes for financial statements. The salaries were incremental as one additional Accountant was hired temporarily as a full-time staff was off-desk working on IFRS transition matters.

These staff salaries pertain to IFRS transition work associated with activities performed in both 2015 and 2016. Of the balance deferred, $14,608 pertained to salaries incurred in 2015 and $26,990 pertained to salaries incurred in 2016. GSHi acknowledges that the $14,608 was incurred in 2015 but deferred in its general ledger in 2016, however it was immaterial from a financial statement perspective and therefore acceptable to flow this adjustment through in fiscal 2016.

9-Staff-86 Account 1508 - Energy East Pipeline

Question:

Ref 1: Exhibit 9 – Tab 1 – Schedule 4, p. 2

Sudbury Hydro is proposing to dispose $9,519 recorded in Account 1508 – Other Regulatory Assets, Energy East Pipeline. The March 2015 *Accounting Procedures Handbook Guidance* #4 states that materiality thresholds apply to the amounts recorded for the account. Please explain why Sudbury Hydro is proposing disposition of the account when it does not meet the materiality threshold of $115,000. Please revise the DVA Continuity Schedule as needed.

Response:

Considering the OEB's guidance in this question, GSH has written off this account balance in its general ledger in its 2019 fiscal year-end and has updated the DVA Continuity Schedule to reflect this removal.

9-Staff-87 Account 1508 - Pole Attachment Revenue Variance

Question:

Ref 1: Exhibit 9 – Tab 1 – Schedule 4, p. 3

Sudbury Hydro is proposing to dispose $39,778 in Account 1508 – Other Regulatory Assets, Pole Attachment Revenue Variance.

a) Please confirm that this balance is the balance as at the 2018 year-end.

b) In the *Orientation Session for Electricity Distributors Rebasing in 2020/2021,* July 17, 2019, slide 10 of the Accounting Matters – Review of Filing Requirements & Models indicated that the OEB may consider final disposition and discontinuance of the account in the current application if a reasonable forecast of balances made up to April 30, 2020. Please provide an estimate of the balance in the account up to April 30, 2020. Please discuss whether Sudbury Hydro plans to dispose of this balance in the current application. If yes, please revise the DVA Continuity Schedule.

Response:

a) GHSi confirms that $39,778 is the balance in Account 1508 – Other Regulatory Assets, Pole Attachment Revenue Variance as at the 2018 year-end.

b) GSHi has forecasted the balance for the Incremental Pole Attachment Revenue Variance to April 30, 2020. The results are included in table 1 below. GSHi would like to dispose of this balance with this application and discontinue the use of this variance account. GSHi has updated the DVA continuity and reflected the additional balance in the 2018 Principal Adjustment column and the interest in the projected interest columns.

Table 1 – Pole Attachment Revenue Variance to April 30, 2020

	Principal Balance	Carrying Charge	Total
2018	38,524.97	104.50	38,629.47
2019	507,988.99	5,970.08	513,959.07
2020	174,698.87	4,447.39	179,146.26
Total to dispose	721,212.83	10,521.97	731,734.79

9-Staff-88 Accounts 1534 and 1535 - Smart Grid

Question:

Ref 1: Exhibit 9 –Tab 1 – Schedule 4, p.p.5-6

Sudbury Hydro is proposing to dispose Account 1534 Smart Grid Capital for $573,467and Account 1535 Smart Grid OM&A for $265,296.

a) In Account 1534, $476,028 pertains to a demonstration project. In Sudbury Hydro's 2013 approved settlement proposal, section 9 states "The Green Energy Act Plan will only include planned expenditures to a maximum of $500,000, for a Demonstration Project, relating to the mitigation of sustained localized high voltages caused by renewable connections." Please confirm that this amount referenced in the settlement proposal is for smart grid and pertains to the $476,028 recorded in the account. If not confirmed, please explain what the $500,000 is for and how it relates to the amounts recorded in the account.
b) Please compare the amounts recorded in Accounts 1534 and 1535 to the amounts that were proposed in Sudbury Hydro's 2013 cost of service rate application by activity type.
c) Please confirm that Sudbury Hydro has never received recovery for any amounts relating to the items recorded in Accounts 1534 and 1535 (via the 2013 revenue requirement or any other application). If not confirmed, please explain how much was recovered and/or included in rate base, depreciation expense and OM&A.
d) Please confirm that the amount recorded in Account 1534 is the gross cost of the capital expenditures. If not, please explain what the amount represents.
e) If part d is yes, please provide the revenue requirement calculation pertaining to the capital recorded in Account 1534 from the date the assets went into service to 2019.
f) Please confirm that no amount related to the capital recorded in Account 1534 and OM&A in Account 1535 has been recorded in rate base, depreciation expense and OM&A of the current rate application. If not confirmed, please explain what and how much has been included in rate base, depreciation expense and OM&A.
g) In Sudbury Hydro's 2013 approved settlement proposal, section 9 states "Greater Sudbury will make available the results of its Demonstration Project to the Board as required by the Board's Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence". Please file results of the Demonstration Project.

Response:

Preamble: GSHi has examined this account (1534 Smart Grid Capital) and the accounting around it and has made changes since its initial application. In its initial application, GSHi had the costs of the capital assets included in 1534 and OM&A costs in 1535. With respect to 1534, upon further research and analysis, GSHi realized this resulted in a classification error on its balance sheet (and also led to an incorrectly calculated rate rider). The assets sitting in account 1534 were used and useful at different points over the years since 2012 and should have been included in the capital asset accounts. For its year ended 2019, GSHi has moved the assets from account 1534 to their respective asset accounts (see revised 2019 Appendix 2-BA included in the live model included with this submission as well as Attachment 1 to this interrogatory response (Tab 1, Interrogatory 88, Attachment 1). GSHi then calculated the revenue requirement associated with these assets, included as a live model filed with this submission and as Attachment 2 to this interrogatory response (Tab 1, Interrogatory 88, Attachment 2) and booked the total return on capital, amortization expenses and grossed-up pils portions of the revenue requirement to account 1534. GSHi left the OM&A portion of the revenue requirement in account 1535. It is GSHi's understanding, that these entries should have been occurring over the years so not to have been causing classification errors on its balance sheet and GSHi should have been recognizing the revenue requirement in the years it was earned, with the offsetting asset (the revenue requirement) to be collected from rate payers in account 1534. The depreciation expenses, revenue requirement and associated IFRS transactions have all been booked in GSHi's 2019 Financial Statements (subject to audit). GSHi also requests that these balances to the end of 2019 be recovered, with carrying charges calculated to April 30th, 2020 and discontinue the use of this account. GSHi has calculated a revised rate rider on this basis.

a) GSHi confirms the $476,028 included in account 1534 in its initial application does pertain to the demonstration project referenced in section

9 of its 2013 approved settlement proposal. Please see preamble above for a description of the revised balance in account 1534.

b) GSHi has prepared the following tables that detail the expenditures for the Smart Grid accounts (both Capital and OM&A) for expenditures recorded in that account that pertain to the demonstration project discussed in settlement and other smart grid expenditures. GSHi has prepared two different sets of tables, Table 1 reconciles to the amounts recorded in the initial application and Table 2 presents the amounts recorded in the application, based on the changes discussed in the preamble to this response.

Table 1 – Detailed Smart Grid Accounts – Initial Application

Initial Application	
Capital 1534	
Smart Grid Capital	$63,683.80
Smart Grid Demonstration Project Capital	$881,028.25
Smart Grid Demonstration Project Contributed Capital	($405,000.00)
Carrying Charges (to April 30th, 2020)	$33,754.94
1534 - Smart Grid Capital Deferral Account Initial Application	$573,466.99
OM&A 1535	
Smart Grid OM&A	$107,530.65
Demonstration Project OM&A	$138,609.48
Smart Grid OM&A Interest (to April 30th, 2020)	$19,155.51
1535 - Smart Grid OM&A Deferral Account Initial Application	$265,295.64

Table 2 – Detailed Smart Grid Accounts – Updated for Smart Grid Entries

Revised based on 2019 Smart Grid Entries	
Capital 1534	
Smart Grid Capital Revenue Requirement (excl OM&A)	$19,383.10
Smart Grid Demonstration Project Revenue Requirement (excl OM&A)	$79,407.42
Carrying Charges	$1,820.64
1534 - Smart Grid Capital Deferral Account @ December 31 2018	**$100,611.16**
Smart Grid Capital Revenue Requirement 2019 (excl OM&A)	$4,707.94
Demonstration Project Revenue Requirement 2019 (excl OM&A)	$51,525.36
Smart Grid Capital Revenue Requirement Jan - Apr 30, 2020 (excl OM&A)	$1,110.93
Demonstration Project Revenue Requirement Jan 1 - Apr 30, 2020 (excl OM&A)	$15,880.59
Carrying Charges to April 30, 2020	$3,958.14
Total 1534 Claim	**$177,794.12**
OM&A 1535	
Smart Grid OM&A	$107,530.65
Demonstration Project OM&A	$138,609.48
Smart Grid OM&A Interest	$11,834.89
1535 - Smart Grid OM&A Deferral Account @ December 31 2018	**$257,975.02**
Smart Grid OM&A	$13,834.47
Demonstration Project OM&A	$4,252.88
Carrying Charges to April 30, 2020	$7,452.01
Total 1535	**$283,514.38**
Total Smart Grid Claim (OM&A and Capital)	**$461,308.49**

c) GSHi confirms that it has never received recovery for any amounts relating to the items recorded in Accounts 1534 and 1535 (via the 2013 revenue requirement or any other application).

d) GSHi confirms that in the initial application the amounts recorded in account 1534 were the gross cost of the capital expenditures. GSHi has revised those figures as discussed in the preamble to this response. The amounts recorded in 1534 now relate to the revenue requirement calculated for each year (excluding OM&A costs which are recorded in 1535). The calculations are included as Attachment 2 to this interrogatory response (Tab 1, Interrogatory 88, Attachment 2).

e) The revenue requirement calculations are included as Attachment 2 to this interrogatory response (Tab 1, Interrogatory 88, Attachment 2).

f) As discussed in the preamble to this response, GSHi confirms that in the initial application, no amounts related to the capital recorded in Account 1534 and OM&A in Account 1535 was recorded in rate base or depreciation expense. However, as a result of the entries GSHi recorded for its 2019 year end, the Capital assets that were previously in account 1534 have now been recorded in their respective Capital Asset accounts and therefore are included in rate base in the adjusted models.

With respect to OM&A costs, it is GSHi's interpretation, based on the "Accounting Procedures Handbook Guidance March 2015" that GSHi is to discontinue the use of these accounts following the first rate application filed underpinned by a DSP. As GSHi's 2020 application is underpinned by a DSP, it has included certain ongoing OM&A costs that were included in the deferral account, in its OM&A.

g) Please see Attachment 3 included with this interrogatory response for the report to Shareholders prepared by eCamion (a partner in the project).

Attachment 1 (of 3):

9-Staff-88 Attachment 1: 2019 Appendix 2-BA

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Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2019**

			Cost					**Accumulated Depreciation**					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Smart Grid Adj**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Smart Grid Adj**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 3,218,379	$ -			$ 3,218,379	-$ 3,172,319	-$ 30,490			-$ 3,202,810	$ 15,569
CEC	1612	Land Rights (Formally known as Account 1906)	$ 58,790	$ 6,524			$ 65,314	$ -				$ -	$ 65,314
N/A	1805	Land	$ 940,079	$ -			$ 940,079	$ -				$ -	$ 940,079
47	1808	Buildings	$ 2,954,574	$ 33,068			$ 2,987,642	-$ 1,719,546	-$ 62,057			-$ 1,781,603	$ 1,206,039
47	1820	Distribution Station Equipment <50 kV	$ 20,781,600	$ 1,988,015	-$ 354,980		$ 22,414,635	-$ 12,108,882	-$ 430,251	$ 345,190		-$ 12,193,943	$ 10,220,692
47	1825	Storage Battery Equipment	$ -			$ 881,028	$ 881,028	$ -	-$ 44,051		-$ 65,937	-$ 109,988	$ 771,040
47	1830	Poles, Towers & Fixtures	$ 27,215,982	$ 2,134,988	-$ 394,635		$ 28,956,335	-$ 10,530,145	-$ 574,888	$ 223,042		-$ 10,881,991	$ 18,074,344
47	1835	Overhead Conductors & Devices	$ 40,769,583	$ 944,617	-$ 854,127		$ 40,860,073	-$ 27,485,809	-$ 537,970	$ 799,779		-$ 27,224,001	$ 13,636,071
47	1840	Underground Conduit	$ 24,457,747	$ 433,360	-$ 12,461		$ 24,878,646	-$ 13,670,387	-$ 306,024	$ 9,811		-$ 13,966,600	$ 10,912,046
47	1845	Underground Conductors & Devices	$ 16,711,738	$ 677,149	-$ 93,442		$ 17,295,444	-$ 10,603,462	-$ 276,078	$ 61,501		-$ 10,818,039	$ 6,477,405
47	1850	Line Transformers	$ 30,251,814	$ 1,742,133	-$ 871,628	$ 48,224	$ 31,170,543	-$ 15,894,266	-$ 514,767	$ 585,212	-$ 5,425	-$ 15,829,246	$ 15,341,297
47	1855	Services (Overhead & Underground)	$ 16,347,433	$ 399,878	-$ 98,216		$ 16,649,096	-$ 7,573,633	-$ 310,715	$ 56,239		-$ 7,828,109	$ 8,820,987
47	1860	Meters	$ 9,026,088	$ 148,145			$ 9,174,233	-$ 4,956,054	-$ 517,651			-$ 5,473,705	$ 3,700,528
47	1908	Buildings & Fixtures	$ 11,731,379	$ 242,329			$ 11,973,707	-$ 4,955,683	-$ 347,134			-$ 5,302,818	$ 6,670,890
8	1915	Office Furniture & Equipment (10 years)	$ 90,616				$ 90,616	-$ 63,602	-$ 4,630			-$ 68,232	$ 22,384
10	1920	Computer Equipment - Hardware	$ 762,482				$ 762,482	-$ 744,499	-$ 10,733			-$ 755,233	$ 7,250
10	1930	Transportation Equipment	$ 6,649,937	$ 144,362	-$ 181,016		$ 6,613,283	-$ 4,398,462	-$ 433,925	$ 181,016		-$ 4,651,370	$ 1,961,913
8	1940	Tools, Shop & Garage Equipment	$ 2,535,629	$ 81,475			$ 2,617,104	-$ 2,045,113	-$ 96,629			-$ 2,141,742	$ 475,362
8	1955	Communications Equipment	$ 2,407,599	$ -			$ 2,407,599	-$ 1,821,128	-$ 91,012			-$ 1,912,140	$ 495,460
47	1980	System Supervisor Equipment	$ 2,305,222	$ 264,515		$ 29,720	$ 2,599,457	-$ 1,511,404	-$ 63,370		-$ 2,122	-$ 1,576,896	$ 1,022,561
47	1985	Miscellaneous Fixed Assets	$ 45,835	$ 1,833			$ 47,668	-$ 42,303	-$ 463			-$ 42,766	$ 4,902
47	2440	Deferred Revenue[5]	-$ 5,062,611	-$ 1,698,479			-$ 6,761,089	$ 331,231	$ 198,360			$ 529,591	-$ 6,231,498
	1330	WIP - Capital Inventory	$ 1,316,431	$ 89,473			$ 1,405,904	$ -				$ -	$ 1,405,904
	2055	Work in Process	$ 911,100	$ 567,671	-$ 793,279		$ 685,492	$ -				$ -	$ 685,492
		Sub-Total	**$ 216,427,426**	**$ 8,201,056**	**-$ 3,653,785**	**$ 958,972**	**$ 221,933,670**	-$ 122,965,465	-$ 4,454,481	$ 2,261,790	-$ 73,485	**-$ 125,231,641**	**$ 96,702,029**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	(129,739.00)				-$ 129,739	$ 129,739				$ 129,739	$ -
		Total PP&E	**$ 216,297,687**	**$ 8,201,056**	**-$ 3,653,785**	**$ 958,972**	**$ 221,803,931**	**-$ 122,835,726**	**-$ 4,454,481**	**$ 2,261,790**	**-$ 73,485**	**-$ 125,101,902**	**$ 96,702,029**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**-$ 4,454,481**				
		Net of WIP and Cap Inv 1330 and 2055	**$ 214,070,156**	**$ 7,543,913**			**$ 219,712,535**						**$ 94,610,633**

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 433,925
8		Stores Equipment	Stores Equipment	-$ 96,629
	2440	Less Deferred Revenue included in 4245 Other Revenue		$ 198,360
			Net Depreciation	-$ 4,122,287

Attachment 2 (of 3):

9-Staff-88 Attachment 2: SG Revenue Requirement Calculation

Revenue Requirement Calculation
Smart Grid Accounts

	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Other Smart Grid Assets	3,852.00	3,852.00	52,076.41	52,076.41	52,076.41	63,683.80	63,683.80	77,943.93	77,943.93	
Other Smart Grid Assets Acc Amort	(96.30)	(288.90)	(1,084.31)	(2,482.52)	(3,880.73)	(5,569.12)	(7,547.70)	(9,882.78)	(12,574.37)	
Demonstration Project						878,227.75	881,028.25	881,028.25	881,028.25	
Demonstration Project Acc Amort						(21,955.69)	(65,937.09)	(109,988.51)	(154,039.92)	
Demonstration Project Contributions						(405,000.00)	(405,000.00)	(405,000.00)	(405,000.00)	
SN Contributions Acc Amort						10,125.00	30,375.00	50,625.00	70,875.00	
Total Net Fixed Assets	**3,755.70**	**3,563.10**	**50,992.10**	**49,593.89**	**48,195.68**	**519,511.74**	**496,602.26**	**484,725.89**	**458,232.89**	
Net Book Value										
Opening Balance	-	3,755.70	3,563.10	50,992.10	49,593.89	48,195.68	519,511.74	496,602.26	484,725.89	
Closing Balance	3,755.70	3,563.10	50,992.10	49,593.89	48,195.68	519,511.74	496,602.26	484,725.89	458,232.89	
Average Net Book Value	**1,877.85**	**3,659.40**	**27,277.60**	**50,293.00**	**48,894.79**	**283,853.71**	**508,057.00**	**490,664.07**	**471,479.39**	
Working Capital										
Demonstration Project - OM&A			3,236.82	30,883.33	52,542.13	43,843.45	8,103.75	4,252.88	-	142,862.36
Other Smart Grid - OM&A	15,408.37	30,065.13	31,797.89	20,051.48	2,734.58	7,473.20		13,834.47	-	121,365.12
Operating Expenses	15,408.37	30,065.13	35,034.71	50,934.81	55,276.71	51,316.65	8,103.75	18,087.35	-	264,227.48
Working Capital Factor	15%	13%	13%	13%	13%	13%	13%	13%	13%	
Working Capital Allowance	**2,311.26**	**3,908.47**	**4,554.51**	**6,621.53**	**7,185.97**	**6,671.16**	**1,053.49**	**2,351.36**	**-**	
Incremental Smart Grid Rate Base	**4,189.11**	**7,567.87**	**31,832.11**	**56,914.53**	**56,080.76**	**290,524.87**	**509,110.48**	**493,015.43**	**471,479.39**	
Return on Rate Base										
Capital Structure (inputs detailed below)										
Deemed Short Term Debt	167.56	302.71	1,273.28	2,276.58	2,243.23	11,620.99	20,364.42	19,720.62	18,859.18	
Deemed Long Term Debt	2,345.90	4,238.01	17,825.98	31,872.13	31,405.23	162,693.93	285,101.87	276,088.64	264,028.46	
Equity	1,675.64	3,027.15	12,732.85	22,765.81	22,432.30	116,209.95	203,644.19	197,206.17	188,591.76	
Preferred Shares	-	-	-	-	-	-	-	-	-	
Total Capitalization	**4,189.11**	**7,567.87**	**31,832.11**	**56,914.53**	**56,080.76**	**290,524.87**	**509,110.48**	**493,015.43**	**471,479.39**	
Return on										
Deemed Short Term Debt	2.23	6.27	26.36	47.13	46.43	240.55	421.54	408.22	518.63	
Deemed Long Term Debt	164.45	175.45	738.00	1,319.51	1,300.18	6,735.53	11,803.22	11,430.07	8,396.10	
Equity	134.22	271.84	1,143.41	2,044.37	2,014.42	10,435.65	18,287.25	17,709.11	16,068.02	
Preferred Shares										
Total Return on Capital	300.90	453.56	1,907.76	3,411.00	3,361.03	17,411.74	30,512.01	29,547.40	24,982.75	111,888.15
Operating Expenses (Account 1535)	15,408.37	30,065.13	35,034.71	50,934.81	55,276.71	51,316.65	8,103.75	18,087.35	-	264,227.48
Amortization Expenses										
Smart Grid Assets	96.30	192.60	795.41	1,398.21	1,398.21	1,688.40	1,978.58	2,335.08	2,691.59	
Demonstration Project Assets	-	-	-	-	-	21,955.69	43,981.40	44,051.41	44,051.41	
Demonstration Project Contributions	-	-	-	-	-	- 10,125.00	- 20,250.00	- 20,250.00	- 20,250.00	
	96.30	**192.60**	**795.41**	**1,398.21**	**1,398.21**	**13,519.09**	**25,709.98**	**26,136.50**	**26,493.00**	95,739.29

Incremental Revenue Requirement before Taxes/PILS	15,805.57	30,711.29	37,737.88	55,744.02	60,035.95	82,247.48	64,325.74	73,771.25	51,475.75		
Calculation of Taxable Income											
Incremental Operating Expenses	15,408.37	30,065.13	35,034.71	50,934.81	55,276.71	51,316.65	8,103.75	18,087.35	-		
Amortization Expense	96.30	192.60	795.41	1,398.21	1,398.21	13,519.09	25,709.98	26,136.50	26,493.00		
Interest Expense	166.68	181.72	764.35	1,366.63	1,346.61	6,976.08	12,224.76	11,838.29	8,914.73		
Net Income for Taxes/PILs	**134.22**	**271.84**	**1,143.41**	**2,044.37**	**2,014.42**	**10,435.65**	**18,287.25**	**17,709.11**	**16,068.02**		
Grossed-up Taxes/PILs (calculation included below)	(298.81)	(386.34)	(245.66)	(206.26)	(48.56)	(491.83)	0.20	549.40	(501.19)	- 1,629.06	
Revenue Requirement, including Grossed-up Taxes/PILs	**15,506.75**	**30,324.95**	**37,492.22**	**55,537.76**	**59,987.39**	**81,755.64**	**64,325.94**	**74,320.64**	**16,991.52**	436,242.82	(2020 @ 4/12 for May 1 rates)
Account 1534 Entry	**98.38**	**259.82**	**2,457.51**	**4,602.95**	**4,710.68**	**30,438.99**	**56,222.19**	**56,233.29**	**16,991.52**	**172,015.34**	
Net Movement - Amortization	96.30	192.60	795.41	1,398.21	1,398.21	13,519.09	25,709.98	26,136.50	8,831.00	78,077.29	
Net Movement - Revenue	2.08	67.22	1,662.10	3,204.74	3,312.47	16,919.90	30,512.21	30,096.80	8,160.52	93,938.05	
										-	

PILs Calculation

Income Tax									
Net Income	134.22	271.84	1,143.41	2,044.37	2,014.42	10,435.65	18,287.25	17,709.11	16,068.02
Amortization	96.30	192.60	795.41	1,398.21	1,398.21	13,519.09	25,709.98	26,136.50	26,493.00
CCA - Distribution Assets (calculation included below)	-	-	(1,928.98)	(3,703.63)	(3,407.34)	(22,063.87)	(39,339.89)	(36,304.72)	(33,400.34)
CCA - SCADA Assets (calculation included below)	(1,059.30)	(1,535.99)	(691.19)	(311.04)	(139.97)	(3,255.02)	(4,656.79)	(6,017.09)	(10,550.76)
Change in taxable income	- 828.78	- 1,071.55	- 681.35	- 572.09	- 134.68	- 1,364.14	0.55	1,523.80	- 1,390.08
Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	- 219.63	- 283.96	- 180.56	- 151.60	- 35.69	- 361.50	0.15	403.81	- 368.37
Gross Up PILS									
Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
PILs	(298.81)	(386.34)	(245.66)	(206.26)	(48.56)	(491.83)	0.20	549.40	(501.19)

Supporting Information

For PILs Calculation

UCC - Distribution Equipment and Structures (Class 47) 8%

Opening UCC	-	-	-	46,295.43	42,591.80	39,184.45	490,348.34	453,808.95	417,504.24	
Capital Additions		-	48,224.41	-	-	473,227.75	2,800.50	-	-	524,252.66
Retirements/Removals (if applicable)	-	-	-	-	-	-	-	-	-	
UCC Before Half Year Rule	-	-	48,224.41	46,295.43	42,591.80	512,412.20	493,148.84	453,808.95	417,504.24	
Half Year Rule (1/2 Additions - Disposals)	-	-	24,112.21	-	-	236,613.88	1,400.25	-	-	
Reduced UCC	-	-	24,112.21	46,295.43	42,591.80	275,798.33	491,748.59	453,808.95	417,504.24	
CCA Rate Class	47	47	47	47	47	47	47	47	47	
CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%	8%	
CCA	-	-	1,928.98	3,703.63	3,407.34	22,063.87	39,339.89	36,304.72	33,400.34	
Closing UCC	-	-	46,295.43	42,591.80	39,184.45	490,348.34	453,808.95	417,504.24	384,103.90	

UCC - SCADA (Class 50) 55%

Opening UCC	-	2,792.70	1,256.72	565.52	254.48	114.52	8,466.89	3,810.10	12,053.14	
Capital Additions	3,852.00	-	-	-	-	11,607.39	-	14,260.13	14,260.13	29,719.52
Retirements/Removals (if applicable)	-	-	-	-	-	-	-	-	-	
UCC Before Half Year Rule	3,852.00	2,792.70	1,256.72	565.52	254.48	11,721.91	8,466.89	18,070.23	26,313.27	
Half Year Rule (1/2 Additions - Disposals)	1,926.00	-	-	-	-	5,803.70	-	7,130.07	7,130.07	
Reduced UCC	1,926.00	2,792.70	1,256.72	565.52	254.48	5,918.21	8,466.89	10,940.17	19,183.20	
CCA Rate Class	50	50	50	50	50	50	50	50	50	
CCA Rate	55%	55%	55%	55%	55%	55%	55%	55%	55%	
CCA	1,059.30	1,535.99	691.19	311.04	139.97	3,255.02	4,656.79	6,017.09	10,550.76	
Closing UCC	2,792.70	1,256.72	565.52	254.48	114.52	8,466.89	3,810.10	12,053.14	15,762.51	
									Check	553,972.18
									Additions per above	553,972.18
										-

Capital Structure	**2012-2020**
Deemed Short-term Debt Capitalization	4%
Deemed Long-term Debt Capitalization	56%
Deemed Equity Capitalization	40%
Preferred Shares	
Total	100%

Cost of Capital Parameters	**2012**	**2013-2019**	**2020**
Deemed Short-term Debt Rate	1.33%	2.07%	2.75%
Long-term Debt Rate (actual/embedded/deemed)	7.01%	4.14%	3.18%
Target Return on Equity (ROE)	8.01%	8.98%	8.52%
Return on Preferred Shares			
WACC	7.18%	5.99%	5.30%

Attachment 3 (of 3):

9-Staff-88 Attachment 3: eCAMION Report to Stakeholders

Techno-Economic Analysis of Science North Microgrid
Smart Grid Fund
Milestone #5

Prepared By:

eCAMION

February 2019

Executive Summary

The purpose of this report is to conduct a techno-economic analysis of a grid-connected microgrid deployed at the Science North building, in Sudbury, Ontario. The microgrid is equipped with a 250-kWh community energy system (CES), a 175-kW photovoltaic array (PV), along with an energy management system (EMS) that uses the CES/PV to perform peak shaving and power factor correction for the overall microgrid. The data used for the analysis was collected over a 9-month period (May 2018 - January 2019), where the PV was operational during the entire period of study and the CES was operational in December and January.

The integration of the CES/PV systems significantly improved the operation of the Science microgrid with its main contributions being the ability to perform peak shaving and local power factor correction despite facing technical difficulties with respect to the operation of the CES. The main observations are listed below:

1) The CES/PV system successfully managed to shave the maximum monthly peak demand (in kW) of the Science North building in every month except November and December. As a result, the aggregate cost savings of the CES/PV system in term of monthly utility bills was $9830, which translates to an overall savings of 5% of the utility bill and an aggregate energy savings of 59 MWh. The inability to reduce **significant** peak demand in November and December was primarily due to a strict limit on the reserve capacity available for the CES to use towards peak shaving (60%), operational difficulties of the CES in December, as well as the lack of PV output in these months. To remove the presence of these aforementioned restrictions and present an unbiased report, simulations were executed with December data to include a model of the CES that was fully functional yet operating with the same reserve capacity. The results of these simulations show that the CES can indeed shave peak demand by 15-25 kW (3-5% of max peak demand) and realize monthly savings of approximately $584 (2.1%) despite limited PV output.

2) The PV system was extremely successful in realizing major cost savings for peak shaving (particularly in the summer months). From May to July, the PV system managed to shave the peak demand by an average of 42 kW (7.3% of max peak demand), and completely eliminated all peak demands exceeding 600 kW.

3) While the major cost savings related to peak shaving can mainly be attributed to the PV system, it was found that the CES can still have a major impact if it discharges in shorter bursts. Data from January shows that the CES is capable of providing between 15 to 22 kW of peak shaving ability on a daily basis (approximately 8% reduction of peak demand). Simulations on December and June data show that if the reserve limit of the CES is narrowed to 20% instead of 60%, the cost savings can be 2.16% (December) and 13.75% (June).

4) Within the economic analysis, it is found that the PV/CES system can have a major impact on the three significant line items that affect the monthly energy bill: Hourly Ontario Energy Price (HOEP, varied hourly), Delivery Charges (based on peak demand), as well as Global Adjustment (GA - varied monthly for Class B customers). The PV system has major impacts on all three-line items, particularly the GA charges. Of the 13.42% major cost savings realized in June, the majority was from GA reduction (77%). The CES can be extremely useful in further reducing delivery charges and HOEP, both of which are heavily affected by peak demand. Real-world data collected in January confirms this fact, where the CES (in tandem with the PV), was able to reduce peak demand by almost 8%. Further simulation results for the month of December show that the CES would be able to provide $584 worth of energy savings if discharged during the peak period (2.1% of the utility bill).

5) The CES significantly improved the net power factor of the microgrid by providing local reactive power compensation. Without the CES, the power factor of the microgrid ranged from 0.75 to 0.85 inductive. With the CES in operation, the power factor range has improved from 0.9 to

0.95 inductive, which resulted in a **net savings of 3.4 MVAh (1.59%)** for the month of December, **and 9.6 MVAh in January (5.36%).**

6) The addition of the CES/PV system has had minimal impact on the voltage profile of the microgrid. Even with the PV system injecting close to 150 kW of active power within the microgrid at maximum capacity, the voltage magnitude measured at the point of common coupling between the microgrid and the distribution grid fluctuates within 3% of the rated transformer voltage. The voltage at the PCC is well within the limits specified by the CSA-C22.2 NO. 257-06 standard (+/- 5% of the nominal voltage) [1].

7) The integration of the CES/PV system within the microgrid does not result in the degradation of power quality due to voltage total harmonic distortion (THD). Measurements of the voltage THD up till the 9^{th} harmonic were analyzed and the maximum level of THD is less than 3%. This satisfies the IEEE 519 standard, which specifies that the voltage THD should be less than 5%, or 3% for special facilities such as airports and hospitals [2].

Assumptions and Sources of Error

1) The dataset used for this analysis faced several issues in data collection and has resulted in incomplete datasets. For this purpose, the month of October was discarded as there was less than 3 days' worth of the data for this month.
2) The intermittency of data collection had an impact on the economic aspect of the report. The monthly energy consumption should not be compared to utility metered data due to the missing data. Rather, the intent of the economic analysis is to show **relative difference** in the energy/cost savings with and without the CES/PV system.
3) Although the PV system demonstrated its peak shaving ability consistently over the period of study, the CES faced technical difficulties. Technical issues in the form of internal faults caused the GridOS software to disconnect the CES, resulting in the CES being operational for only 12 days in December. When the CES was operational, its total reserve capacity was restricted to 65% in order to ensure that it had enough emergency backup supply. As such, the CES was limited and not utilized to its full potential towards reducing the peak demand. Although the restriction was still in place in January, the internal faults of the CES were resolved and as such, the CES was able to reduce the peak demand by 8%. Nevertheless, simulations have been added to the report to demonstrate the impact of the CES if the reserve capacity limit was relaxed.

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Table of Figures

1 Introduction

The Science North microgrid, located in Sudbury, Ontario, is an initiative of the Smart Grid Fund. It is composed of a large commercial load (Science North Building), a 250-kWh community energy storage system (CES), a 150-kW photo-voltaic array (PV), as well as an energy management system (EMS) to coordinate and control the CES and PV systems autonomously. The project features three main stakeholders that include: Greater Sudbury Utilities (utility partner), eCAMION Inc (CES provider), as well as Opus One Solutions (EMS provider). Previous to the initiation of the project, the Science North building experienced large peak demands that exceeded 700 kW. As a result, the Science North building is classified as a Class B customer and its utility energy bill is shaped in large part by the peak monthly demand as well as an exposure to the Hourly Ontario Energy Price (HOEP) and Global Adjustment charge. It is expected that both CES and PV systems would be able to perform peak shaving to realize significant cost savings on a monthly basis. In addition to peak shaving, the inverter of the CES could also provide local reactive power compensation to improve the overall power factor of the microgrid.

A screenshot of the EMS (entitled GridOS from Opus One Solutions) is provided in Figure 1, where real-time monitoring and control can be performed on the CES and PV systems. The GridOS is currently being operated by utility control room engineers. With respect to peak shaving, the two most important settings are the “Peak Shave at kW” setting (set at 370 kW), as well as the “Battery Reserve” setting (set at 75%). The “Peak Shave at kW” setting is internally calculated by the GridOS software and defines the threshold by which the CES will begin to start discharging to perform peak shaving. The “Battery Reserve” control can be set by utility engineers and defines the maximum capacity that must be reserved for the battery to deal with emergency power backup. At the current setting of 75%, only 25% of the battery capacity can be used towards peak shaving, which represents approximately 62.5 kWh of energy of the 250-kWh battery. Both settings have changed throughout the project, with the peak shaving signal being set from 285 kW to 382 kW, and the battery reserve being set from 75% to 60%.

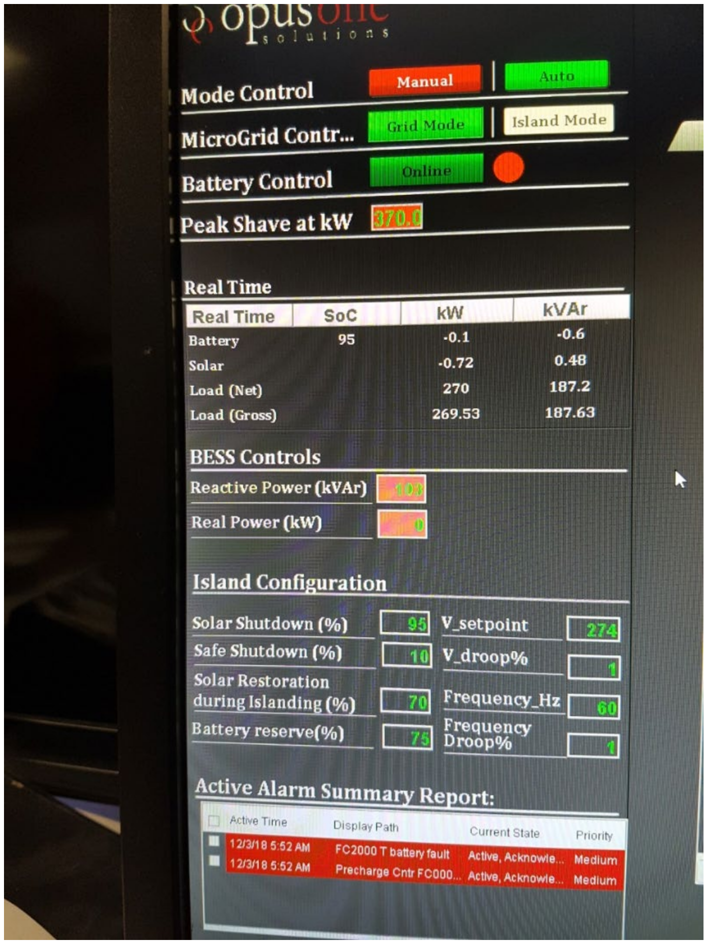


Figure 1 - Screenshot of GridOS EMS.

The structure of the report is as follows: Section 2 summarizes a deliverable map for key items that were due as part of this report. Section 3 presents an introductory analysis of the typical load profile of the Science North building and seeks to establish the off-peak and on-peak hours. Section 4 presents the results of a full technical analysis, including the impact of the CES/PV systems on peak-shaving, power factor correction, voltage magnitude, as well as harmonic distortion. Section 5 seeks to establish an economic basis for the CES/PV system and quantifies the net economic gain realized by the integration of these systems. Finally, Section 6 concludes the report with recommendations for future work.

The following conventions will be used for the remainder of the report

1) The power factor for the facility is inductive/lagging, and according to IEEE conventions, is usually represented by negative numbers. For the purpose of clarity in the figures, as well as when referenced in text, the power factor is referred to as a positive number. Correspondingly, the power factor of the battery (which is running in capacitive mode), will be denoted as negative.
2) The term “net load” will be considered to the load of the entire microgrid (Science North building, PV, as well as CES). The term “gross load” will be considered to the load of only the Science North building.
3) The active power injections from the PV as well as the CES systems are commonly represented as negative loads, however, for the purpose of clarity in the figures, as well as when referenced in text, the active power injections from both PV/CES will be referred to as a positive number.

2 Deliverable Map

The following table outlines an index that maps simulations results and analysis to key deliverables as outlined by Milestone #5 of the project.

<table>
<tr><th>Deliverable</th><th>Delivered By</th><th>Notes</th></tr>
<tr><td>5.2.2 - Control Map and Screen shot of Data Output Screen</td><td>Figure 1– Screenshot of GridOS EMS showing controllability of PV/CES Systems</td><td>On page 9</td></tr>
<tr><td>5.2.3 - Document of lessons learned</td><td></td><td>Provided by eCAMION</td></tr>
<tr><td>5.2.4.a) Control Interface with Grid OS and PV</td><td>Figure 1– Screenshot of GridOS EMS showing controllability of PV/CES Systems</td><td>On page 9</td></tr>
<tr><td>5.2.4.b) Data to prove customer load shifting demand management</td><td></td><td>Not required – submetering not available within Science North building.</td></tr>
<tr><td>5.2.4.c) Utilization of PV/CES, energy reduction/cost savings</td><td>Section 4,
<table>
<tr><td>Item</td><td colspan="2">Sept</td><td colspan="2">Nov</td><td colspan="2">Dec</td><td colspan="2">Jan</td></tr>
<tr><td></td><td>Load</td><td>Net</td><td>Load</td><td>Load</td><td>Net</td><td>Load</td><td>Load</td><td>Net</td></tr>
<tr><td>Metered Demand (MWh)</td><td>201</td><td>189</td><td>157</td><td>159</td><td>175</td><td>178</td><td>151</td><td>153</td></tr>
<tr><td>Peak Demand (kW)</td><td>606</td><td>564</td><td>431</td><td>477</td><td>445</td><td>445</td><td>469</td><td>447</td></tr>
<tr><td>HOEP ($)</td><td>6623</td><td>6195</td><td>4314</td><td>4361</td><td>5055</td><td>5126</td><td>4295</td><td>4351</td></tr>
<tr><td>GA ($)</td><td>18184</td><td>17126</td><td>16331</td><td>16540</td><td>17001</td><td>17269</td><td>10776</td><td>10924</td></tr>
<tr><td>Regulatory ($)</td><td>826</td><td>778</td><td>645</td><td>654</td><td>720</td><td>732.1</td><td>624</td><td>632</td></tr>
<tr><td>Delivery ($)</td><td>6389</td><td>5943</td><td>4544</td><td>5032</td><td>4692</td><td>4691</td><td>4944</td><td>4716</td></tr>
<tr><td>Service ($)</td><td>169</td><td>169</td><td>169</td><td>169</td><td>169</td><td>169</td><td>169</td><td>169</td></tr>
<tr><td>TOTAL ($)</td><td>32193</td><td>30213</td><td>26005</td><td>26757</td><td>27639</td><td>27989</td><td>20808</td><td>20793</td></tr>
<tr><td>Saving (%)</td><td colspan="2">6.15%</td><td colspan="2">-2.89%</td><td colspan="2">-1.20%</td><td colspan="2">0.07%</td></tr>
</table>
Table 6 -Table 8 detail the economic impact of PV/CES utilization.</td><td>On pages 25-28</td></tr>
<tr><td>5.2.4.d) Utilization of back-up power for Science North</td><td></td><td>Not required – submetering not available within</td></tr>
</table>

		Science North building.
5.2.4.5) LDC Benefits Quantification on Grid Impact	Section 3.3 – Impact on Voltage Magnitude at point of common coupling	Science North load too small to provide meaningful impact within utility distribution grid. Benefit quantification is performed for the microgrid instead in Sections 3 and 4.
5.2.4.6) Load shifting data between renewables and CES	The entirety of Section 3.1 shows the contribution of PV and CES towards load shifting and peak shaving.	On pages 14-18
5.2.4.7) Power Quality Analysis at customer site	Section 3.2 – Power Factor Correction by CES (Figure 10) and Section 3.4 – Impact of PV/CES on total harmonic distortion (Figure 14 and Figure 15)	On pages 20, 23-23, respectively.

Table 1 - Deliverable Map as Outlined by Milestone #5.

3 Analysis of the Building Load Profile

The Science North building is operational on all 7 days of the week, and as such, there is no appreciable difference in the gross load profile from weekend to weekday. A table summarizing the typical gross load profile of the building is given in Table 2, while a plot of the average day of each month is given in Figure 2. It is noted that July experiences the highest level of average and peak demand, while November through January experience the least level of demand. From Figure 2, it can be seen that the off-peak period is typically between 00:00 and 06:00 hours, where the demand usually hovers around 200 kW. Subsequently, the demand rises sharply and reaches peak periods from 10:00 to 18:00 before declining sharply again for the rest of the evening. The gross load profile of Science North is fairly typical of commercial loads, where the peak load is usually experienced in the mid-afternoon.

Metric	May	June	July	Aug	Sep	Nov	Dec	Jan
Average Daily Energy Consumption (kWh)	5195	7558	8736	7965	7447	6300	6735	5722
Average Demand (kW)	216	315	364	331	310	262	280	238
Peak Demand (kW)	549	628	722	606	606	431	445	469
Peak Demand (kVA)	618	653	766	679	646	456	466	456

Table 2 - Average Load Metrics of Science North Building.

The corresponding plot for power factor for an average day per month is shown in Figure 3. The general trend across each month is very similar, with the power factor generally being less than 0.8 (inductive) from 00:00 to 08:30. From 08:30 to 17:30, the power factor generally improves and exceeds the 0.85 mark, presumably due to heating/cooling loads being turned on due to building occupancy. December has the highest power factor amongst all months, with the power factor reaching approximately 0.88 during the peak demand periods of the day. The power factor returns to below 0.8 after 17:30.

Given the typical load profile, the CES/PV system can improve power system operation in two significant ways. The first is the utilization of PV output and strategic discharge of the CES to reduce peak demand in the on-peak hours. The second is to utilize the CES' ability to provide local reactive power injections to improve the power factor and reduce the net kVA demand of the microgrid.

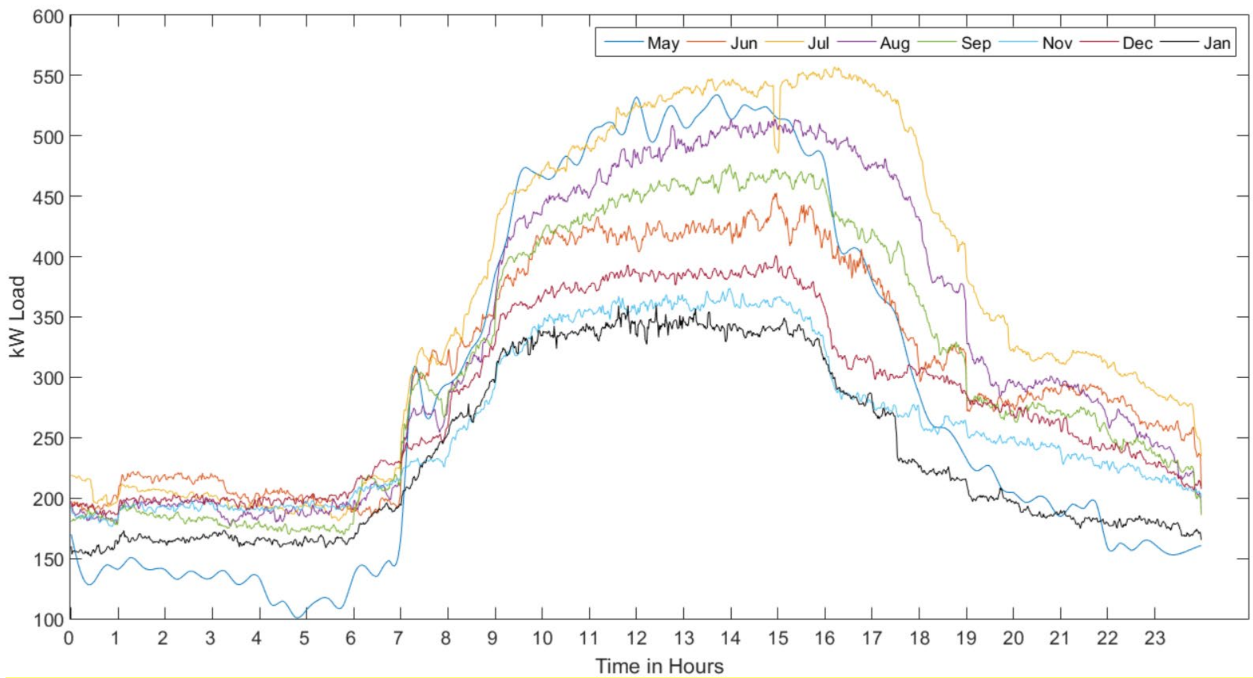


Figure 2 - Average Daily Load Profile per Month.

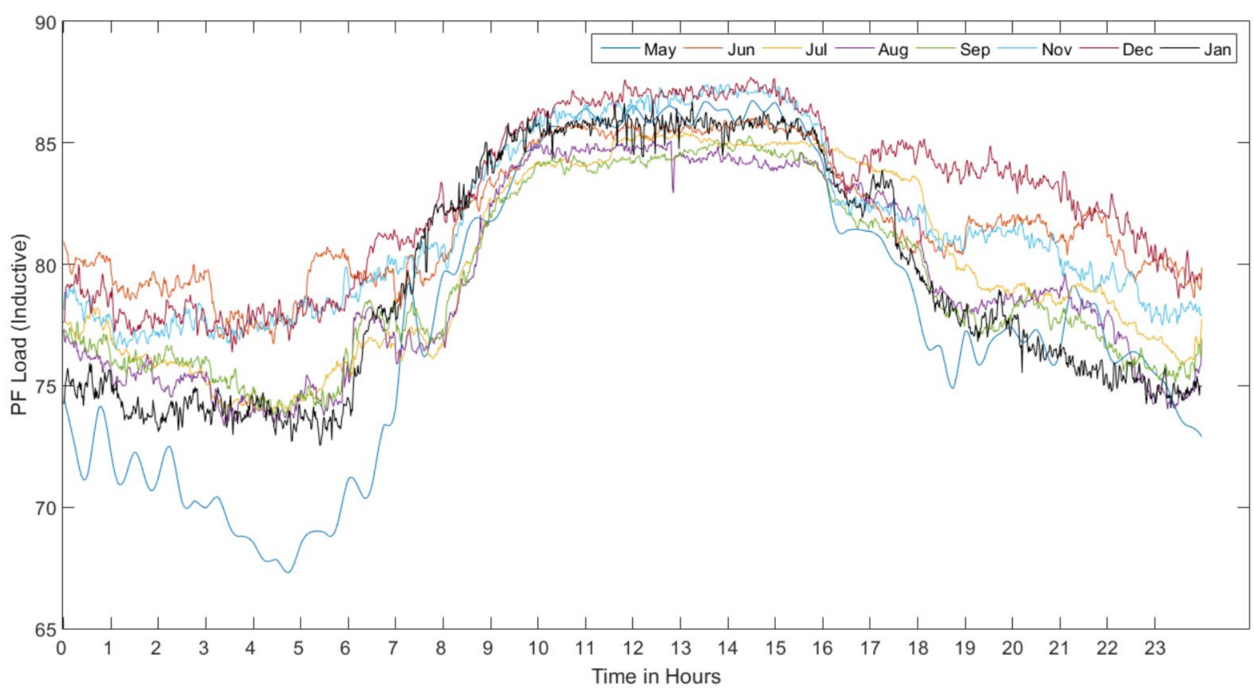


Figure 3 - Average Daily Power Factor per Month (Inductive).

4 Technical Analysis of Impact of CES/PV on Science North Building

4.1 Impact of CES/PV on Peak Shaving

To ensure that the CES responds to the control signals set by the EMS, a week-long snap shot is presented in Figure 4 that covers data collected from Dec 01 to Dec 07. During this week, the peak shaving setpoint was set at 370 kW and the battery reserve limit was set at 60%, which effectively meant that the CES was only able to utilize a maximum of 45% of its reserve energy for peak shaving (a daily total of 100 kWh). Due to these restrictions, the maximum contribution of the CES towards reducing the peak load was recorded at 13.84 kW (3.1% of the peak net load). Nevertheless, it can be seen from the figure that the CES indeed starts to discharge as the net load exceeds 370 kW and continues to discharge until it falls below 370 kW. Additionally, the CES charges at a constant rate of 10 kW during the mid-peak periods, however, it increases its rate of charge during the off-peak periods when the net load is considerably lighter (from 00:00 to 06:00).

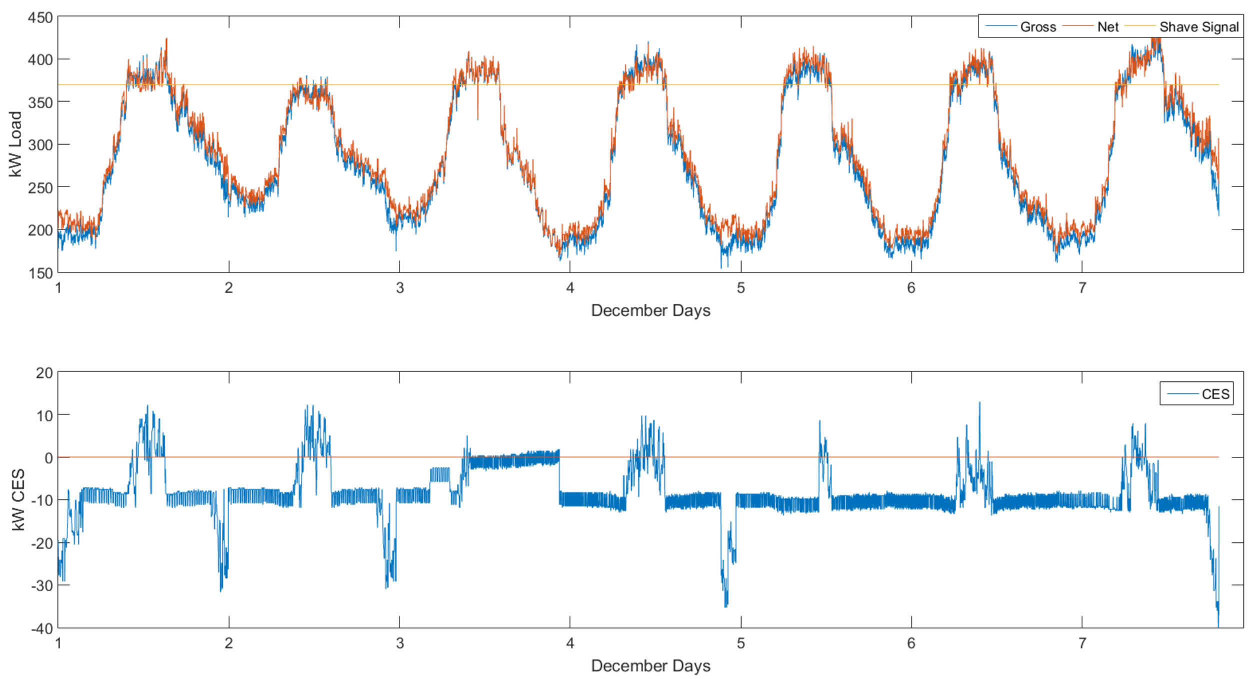


Figure 4 - CES Peak Shaving from Dec 01 - 07.

As discussed earlier, the CES faced technical issues in December that continued until January 8. Thereafter, the CES has shown consistent behavior that can be seen in Figure 5. Apart from one day (Jan 19), the CES has been able to discharge consistently during the peak periods and charge during the off-peak periods. This can be seen by analyzing the plots of the gross and net demand of the microgrid during the peak period (where the net demand is appreciably lower than the gross demand), and also during the off-peak period, where the net demand is appreciably lower than the gross demand.

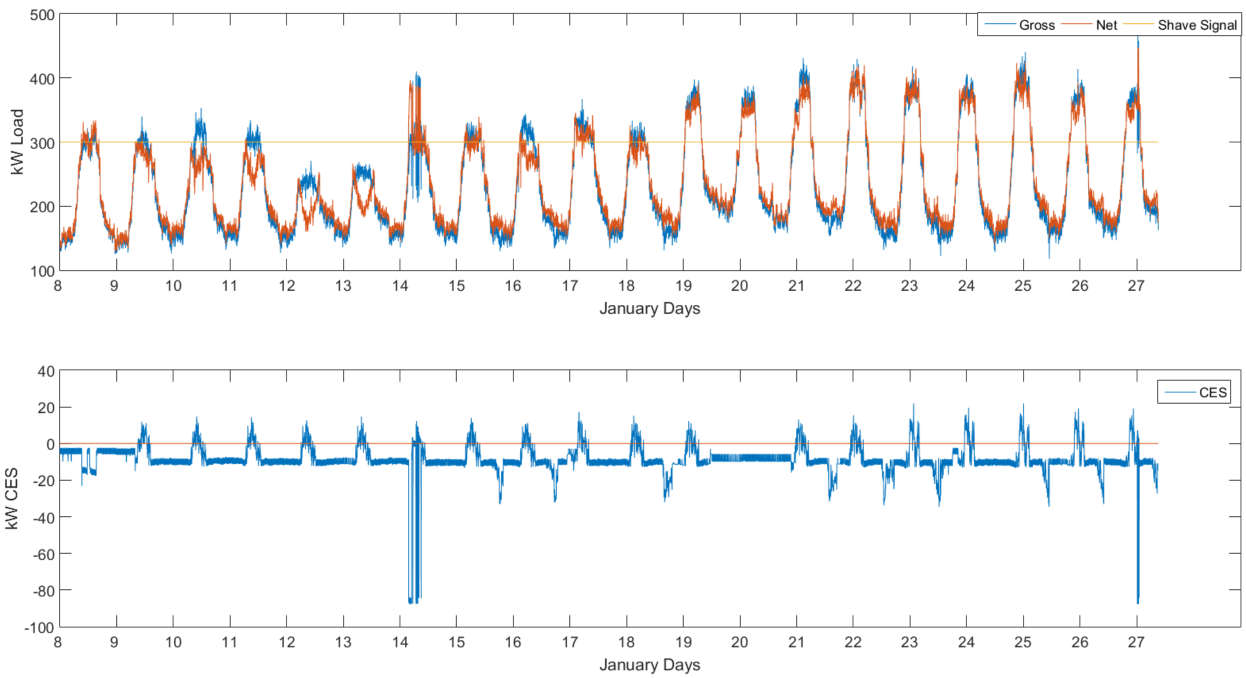


Figure 5 - Consistent Operation of the CES in January

Diving deeper into the CES contribution to peak shaving during January, a 5-day snapshot is presented in Figure 6, where the CES consistently discharges between 15 and 22 kW during the peak period. It is worth noting that during this week, the reserve capacity remained at 65%, however, the CES was commanded to discharge in shorter bursts to achieve a higher instantaneous power discharge. This resulted in the CES shaving approximately 8% of the peak load on a daily basis. This is a significant improvement over the operation of the CES in December, in which the maximum peak shaving event that could be attributed to CES was approximately 3% as seen in Figure 4.

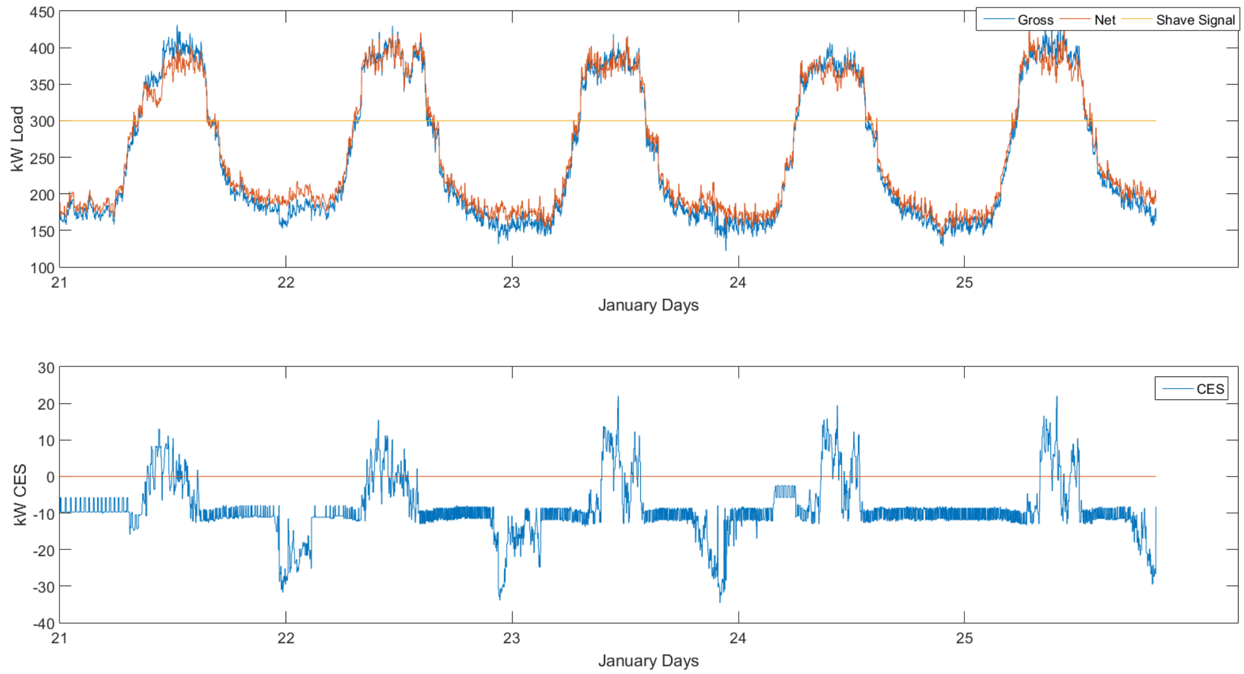


Figure 6 - CES Peak Shaving on Jan 21-25.

The ability of the CES to operate in tandem with the PV system has the potential to lead to additional peak demand reductions. This can be seen in Figure 7 **Error! Reference source not found.**, where plots of the contribution of both the CES and PV systems to peak shaving are presented during the time period of Jan 9 – Jan 13, whereas the relevant statistics are presented in

Table 3. On all five days, the plot shows a significant difference between gross and net loads, with a daily average peak demand reduction of 8.8% (or an average reduction of 65 kW from the peak load). Additionally, the CES power output is kept constant during times of intermittent production from the PV system, thereby smoothing/flattening the overall load profile of the microgrid.

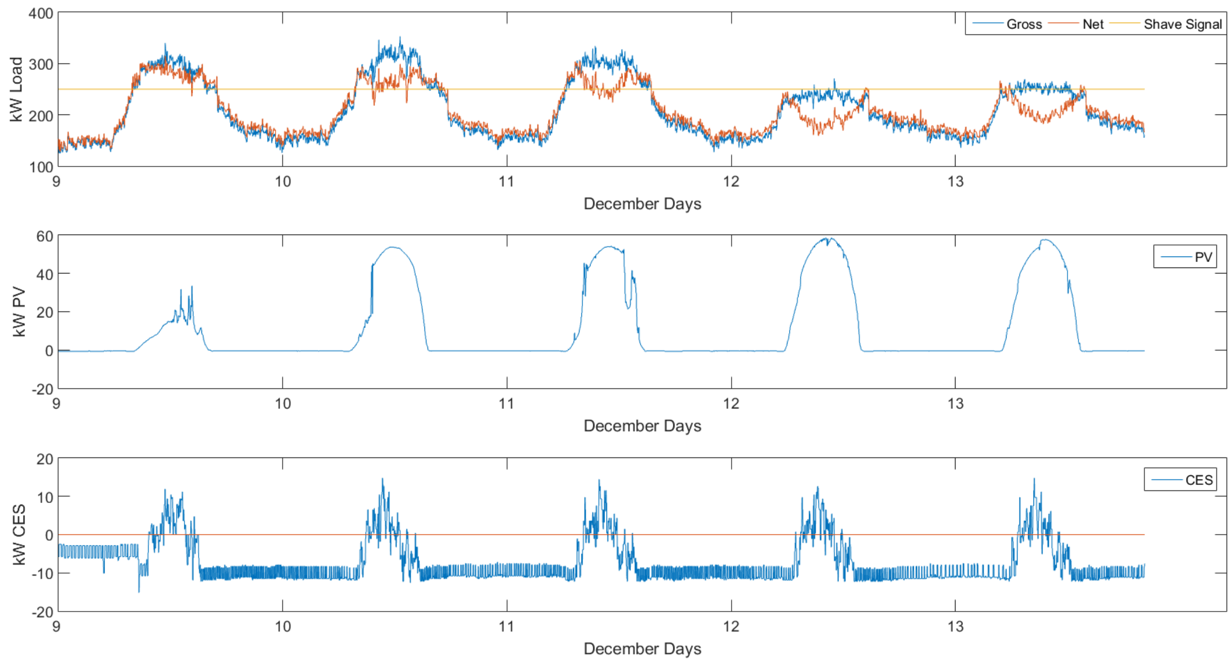


Figure 7 – CES/Peak Shaving from Jan 9-13.

	Jan 9	Jan 10	Jan 11	Jan 12	Jan 13
Peak Gross Load (kW)	339	353	334	271	268
Peak Net Load (kW)	314	298	305	253	266
Peak PV Output (kW)	33	53	54	59	58
Peak CES Output (kW)	12	15	14	13	15
% Peak Reduction	**7.9**	**18.4**	**9.5**	**7.1**	**0.7**

Table 3- Peak Shaving Statistics from Dec 15-19.

In order to demonstrate the full impact of only the PV system in reducing the peak demand, a histogram plot of the net and load consumptions for the month of July is given in Figure 8. Since the CES was not operational during this month, the difference between the net load and gross load is equal to the power generated by the PV system. As such, it can be seen that for demand exceeding 500 kW, the PV system reduces the occurrences of peak demand by almost 60%. For demand exceeding 600 kW, the PV system completely eliminates the occurrences of peak demand.

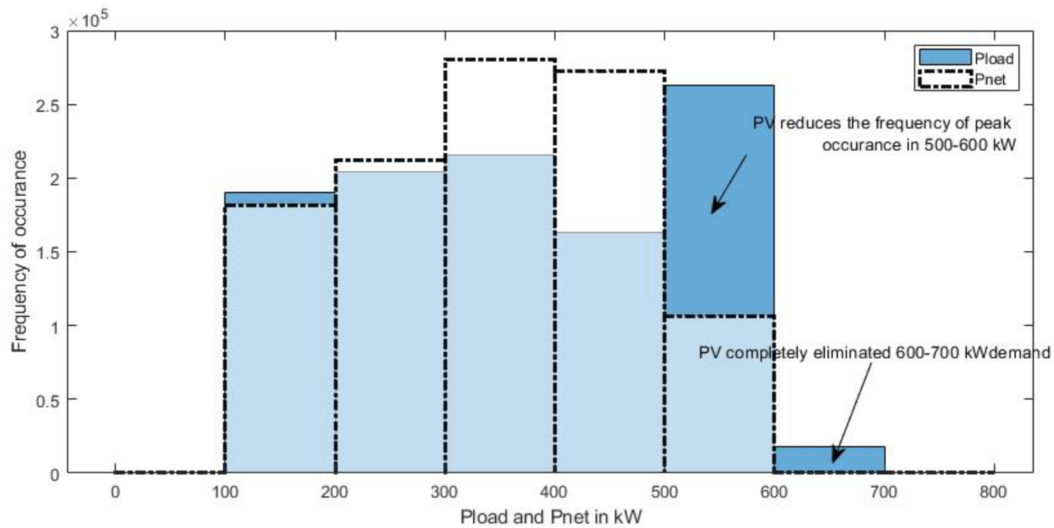


Figure 8 - PV Peak Shaving in July.

4.2 Impact of CES on Power Factor Correction

The CES has a significant impact on improving the overall power factor of the microgrid by providing local reactive power compensation. It can be seen in Figure 9 that the inverter of the CES closely follows the reactive power demand of the building, including the sudden spike in demand on the third day of December. As a result, the net reactive power demand of the microgrid is significantly lowered due to the local reactive power generation of the CES. This has significant impacts on both the power factor of the overall microgrid (Figure 10), as well as the net reduction of apparent power (kVA) that the utility must provide to the microgrid (Figure 11). Figure 10 shows the improvement in the power factor brought on by the integration of the CES, with the net power factor improving from the range of 0.75 to 0.85 lagging to the range of 0.9 to 0.95 lagging. In Figure 11, it can be seen that the net apparent demand is clearly reduced on each day by an average of 29 kVA (6.17%). The individual statistics for each day within this period can be seen in Table 4. It should be recalled that for the same time period in observing the CES contribution to peak shaving (kW) (Figure 4), there was no appreciable difference between the net and load consumption. Due to the reactive power support of the CES inverter, however, the difference in kVA can clearly be seen for the same time period in Figure 11. Throughout the month of December, the CES provided apparent energy savings of over of 3.4 MVAh (1.59% of the peak apparent demand), and an additional 9.6 MVAh in January (5.36% reduction).

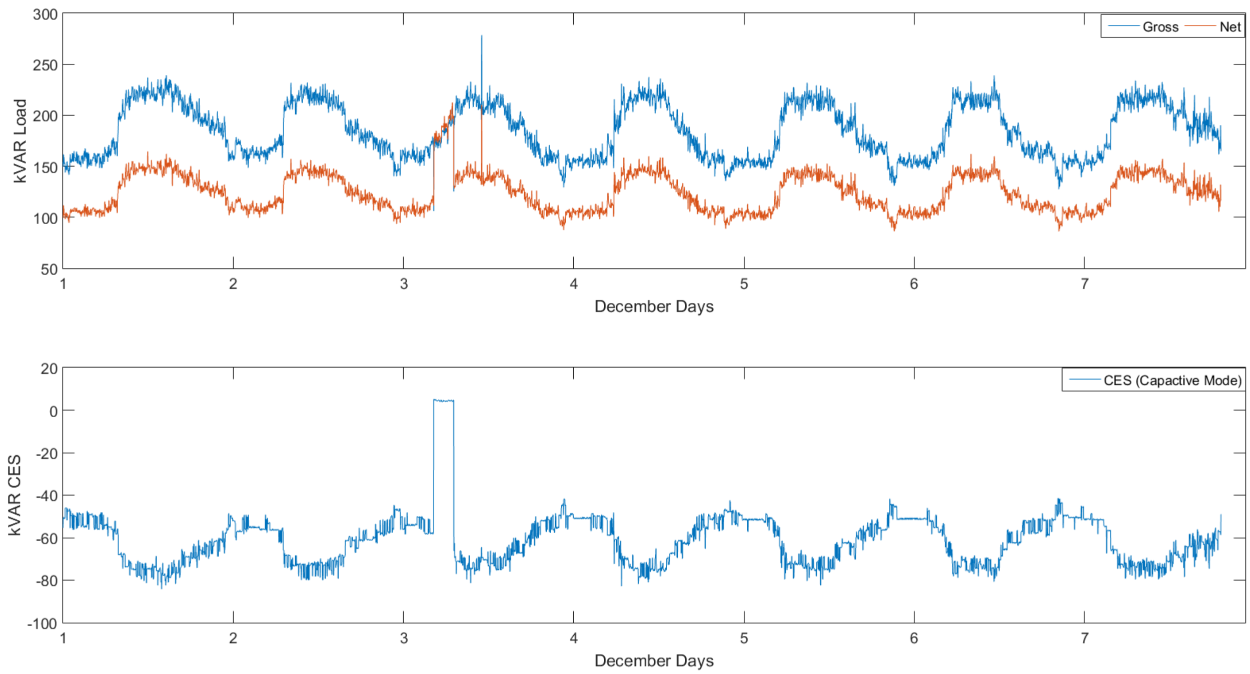


Figure 9 - Reactive Power Compensation via CES from Dec 01-07

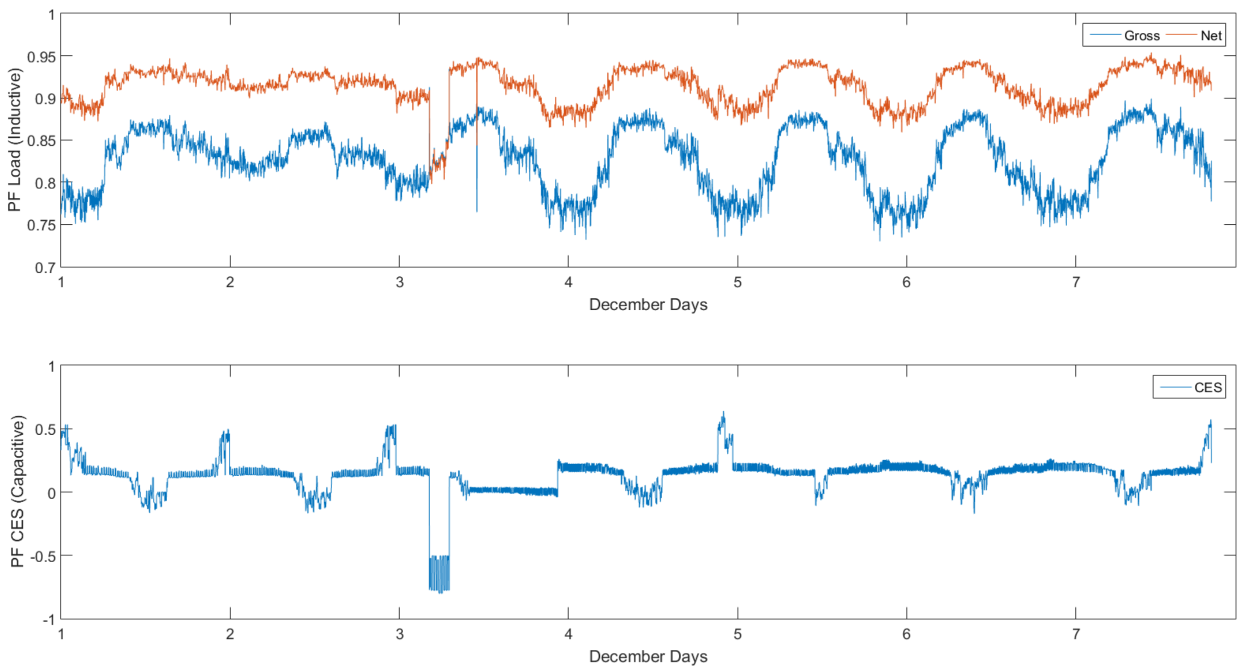


Figure 10 - Power Factor Correction by CES from Dec 01-07.

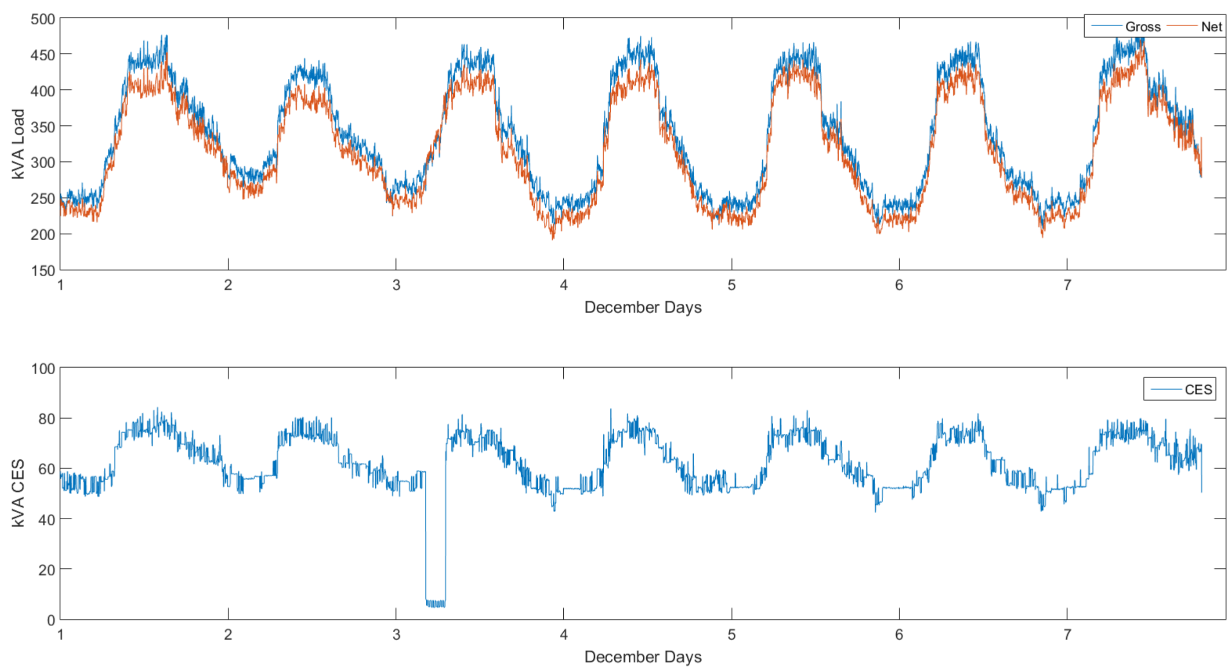


Figure 11 - Peak Reduction in kVA by CES from Dec 01-07.

	Dec 1	Dec 2	Dec 3	Dec 4	Dec 5	Dec 6	Dec 7
Peak Gross Load (kVA)	476	443	463	475	466	467	497
Peak Net Load (kVA)	452	407	435	442	442	437	469
Peak CES Output (kVA)	84	80	81	84	83	81	80
% Peak Reduction	**5.0**	**8.1**	**6.0**	**6.9**	**5.2**	**6.4**	**5.6**

Table 4 - Peak Shaving (kVA) Statistics from Dec 01-07.

4.3 Impact of CES/PV on Voltage at the Point of Common Coupling

As seen in Figure 12 and Figure 13, both the CES and PV have minimal impact on the voltage at the point of common coupling (PCC). In the first plot, the voltage at the PCC varies within 2.5% of the rated distribution transformer voltage (347 V), while in the second plot, the voltage at the PCC varies within 3.27 % of the rated voltage. In both cases, the voltage at the PCC is well within the limits specified by the CSA-C22.2 NO. 257-06 standard, which specifies that the voltage at the PCC should not exceed 5% of the nominal rated voltage (between 330 V and 365 V) [1].

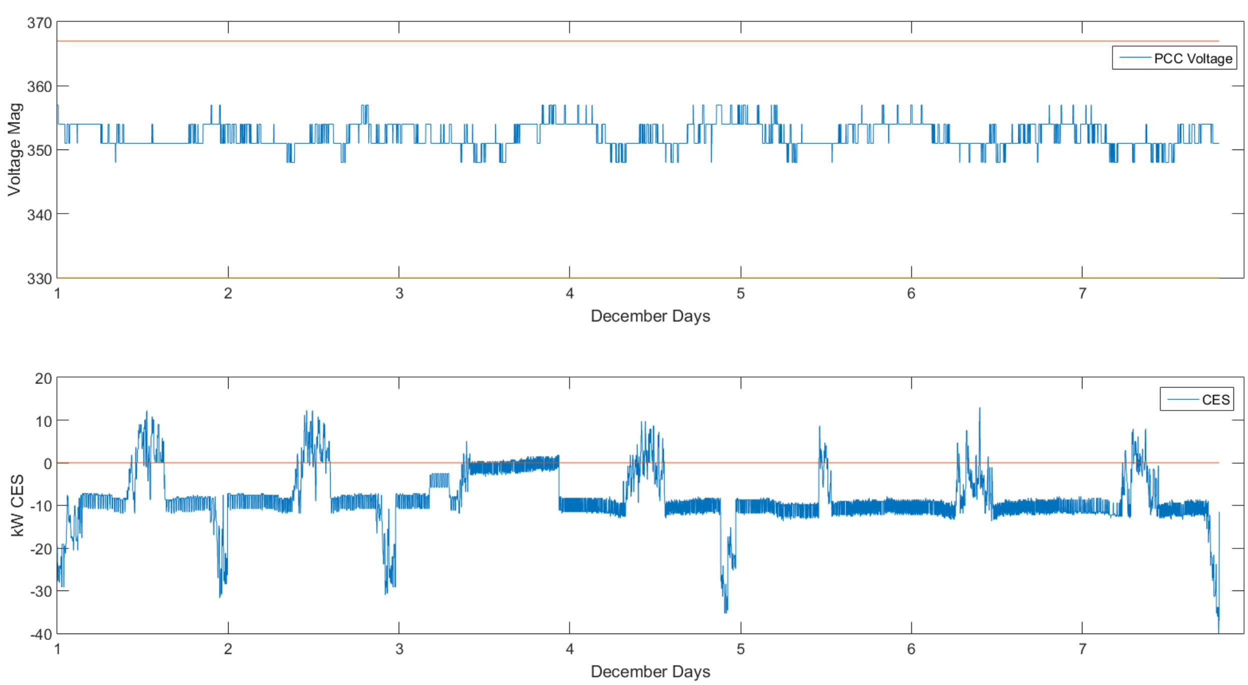


Figure 12 - Voltage Sensitivity to CES Active Power Injection from Dec 01-07.

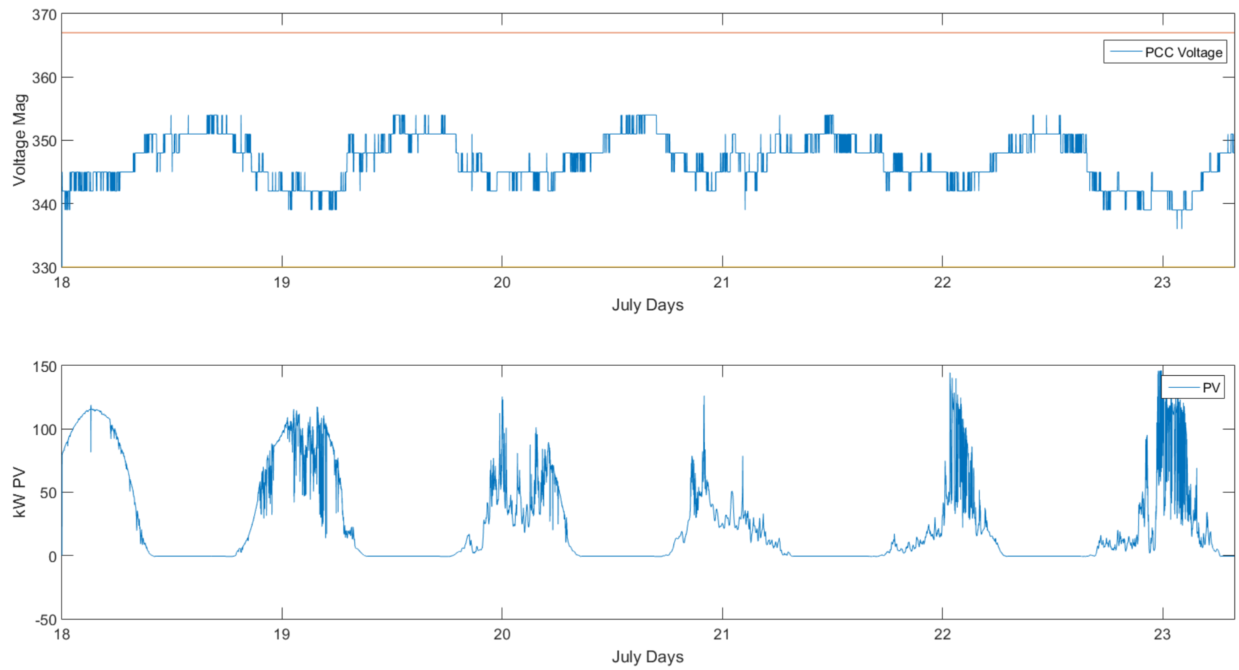


Figure 13 - Voltage Sensitivity to Active Power Injection of PV from July 18-23.

4.4 Impact of CES/PV on Total Harmonic Distortion

The presence of the CES and PV systems do not increase the voltage total harmonic distortion (THD) of the microgrid. In Figure 14, the THD and third, fifth, seventh, and ninth harmonic factors are plotted as a histogram plot, none of which exceed 2%. According to IEEE 519 standards, the voltage THD at any facility with significant power converter devices should not exceed 5% (in the case of prioritized facilities such as airports or hospitals, the limit is 3%) [2]. The results in Figure 14 show that the microgrid is well within the limits specified by IEEE 519. Expanding the study further, Figure 15 shows the probability distribution of the voltage THD from May to December. Again, the maximum THD is 3% in May, which is within the limits specified by IEEE 519.

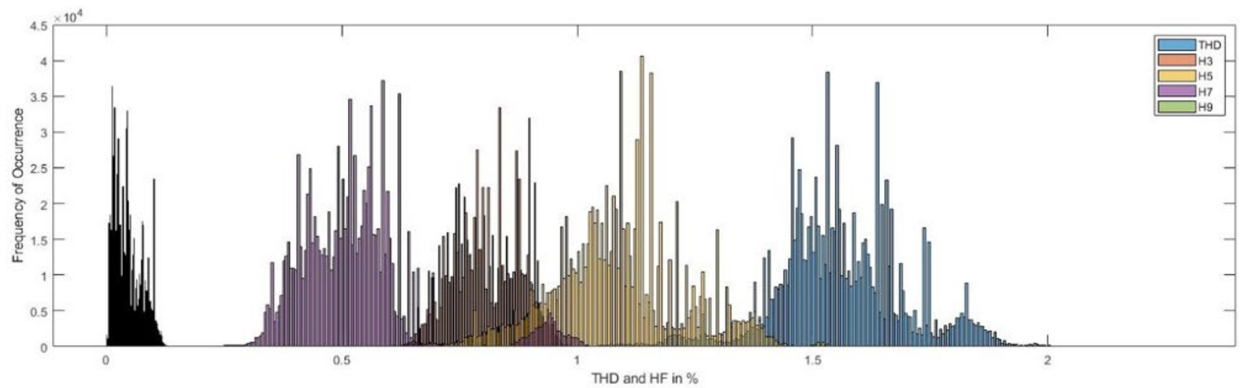


Figure 14 - Overall Microgrid THD and HF distribution in July.

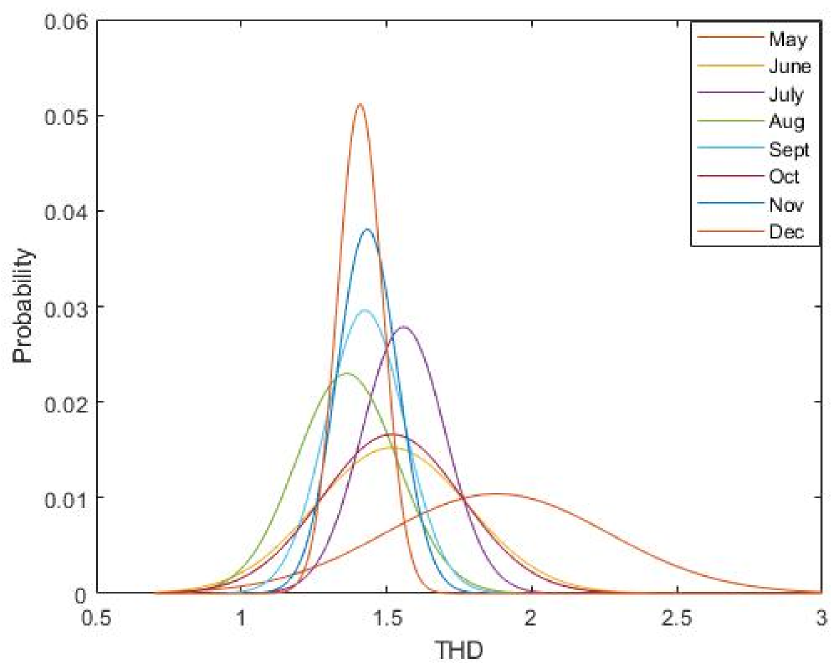


Figure 15 - THD Values from May to Dec

5 Economic Analysis of CES/PV Integration

The Science North Building is a Class B customer with peak demands between 400 kW and 750 kW. As such, its monthly energy bill consists of the following items:

Line Item	Price	Notes
Hourly Ontario Energy Price (HOEP)	Variable Hourly Rate	Subject to loss factor
Global Adjustment (GA)	Variable Monthly Rate	Subject to loss factor
Delivery Charge	$10.5375/kW	Based on peak kW or 90% peak kVA (whichever higher)
Regulatory Charges	$0.0039/kWh	Subject to loss factor
Service Charge	$169.24/month	

Table 5 - Energy Bill Line Items.

Given the above line items, there are significant incentives in place for the CES/PV systems to not only reduce overall demand to minimize GA and regulatory charges, but also to shave peak demand to leverage significant savings for HOEP and Delivery charges. The following table summarizes the performance of the CES/PV system over the entire lifespan of the installed system (May to December, with the exception of October due to missing datasets).

Note: The dataset compiled for this project has large pieces of data missing due to intermittent data collection. As such, the below table is meant to show the relative difference between the actual load and net consumption of the microgrid. By all accounts, the consumption of the building in July should be on par or higher than June, however, complete data sets were available for June and not for July.

Item	May		Jun		Jul		Aug	
	Load	Net	Load	Net	Load	Net	Load	Net
Metered Demand (MWh)	155	138	226	204	121	112	92	86
Peak Demand (kW)	549	499	628	585	722	690	606	597
HOEP ($)	2445	2116	4544	4053	4349	4001	2896	2695
GA ($)	17724	15759	28439	25634	9887	9169	7286	6842
Regulatory ($)	640	569	932	840	498	462	379	356
Delivery ($)	5785	5260	6624	6170	7611	7270	6390	6297
Service ($)	169	169	169	169	169	169	169	169
TOTAL ($)	26764	**23875**	40710	**36867**	22515	**21073**	17122	**16360**
Saving (%)	**10.8%**		**9.43%**		**6.40%**		**4.45%**	

Item	Sept		Nov		Dec		Jan	
	Load	Net	Load	Load	Net	Load	Load	Net
Metered Demand (MWh)	201	189	157	159	175	178	151	153
Peak Demand (kW)	606	564	431	477	445	445	469	447
HOEP ($)	6623	6195	4314	4361	5055	5126	4295	4351
GA ($)	18184	17126	16331	16540	17001	17269	10776	10924
Regulatory ($)	826	778	645	654	720	732.1	624	632
Delivery ($)	6389	5943	4544	5032	4692	4691	4944	4716
Service ($)	169	169	169	169	169	169	169	169
TOTAL ($)	32193	**30213**	26005	**26757**	**27639**	**27989**	20808	**20793**
Saving (%)	**6.15%**		**-2.89%**		**-1.20%**		**0.07%**	

Table 6 - CES/PV Performance in Energy Savings from May to December.

The aggregate cost savings over the 6-month period are $9829, which represents an overall savings of approximately 5% of the utility energy bill. The following conclusions can be drawn from the above data:

- The maximum monthly saving was experienced in July, which was a reduction of $3843 or 10.4% of the total energy bill.
- Presently, cost savings are primarily driven by PV output, where significant cost savings were achieved in the summer months when there was an abundance of PV output. The PV system is able to reduce both instantaneous costs (delivery charges based purely on peak demand), as well as time-varying costs (global adjustment and HOEP), whereas the CES can only majorly contribute in reducing delivery charges and minorly contribute in HOEP. This can be seen in the results for both November and December when PV production was lower. The PV/CES actually resulted in a minor economic loss due to battery acting as a significant load in off-peak hours.
- Due to the battery being restricted to a maximum of 60% of reserve capacity, it is limited in its ability to contribute to peak shaving. This can especially be seen in December, where the limited reserve capacity as well as technical difficulties resulted in a minor economic loss. In January, the CES was able to shave the maximum peak demand by 22 kW (or 5% reduction), however, the cost savings in delivery charges was nullified by the extra charges of the power consumption of the battery affecting both HOEP and GA charges.

To refine the above point, additional simulations were conducted with two varying parameters. First, the reserve capacity was altered from 60% to 20%, and second, the control settings of the CES were altered to provide shorter bursts of power discharges during peak periods. The charge efficiency of the CES is assumed to be 95%, while the charge cycle and discharge cycle are set to 6 and 8 hours, respectively. The CES discharges at a constant rate from 10:00 to 16:00, and discharges from 00:00 to 08:00, where the charge/discharge rate is a function of the total reserve capacity allotted to the CES. The simulations are conducted with the data for the month of December, and the results are shown in Table 7 below.

Item	Baseline		CES 60% Reserve		CES 40% Reserve		CES 20% Reserve	
	Load	Net	Load	Net	Load	Net	Load	Net
Demand (MWh)	175	178	175	174	175	174	175	174
Peak Demand (kW)	445	445	445	**410**	445	**385**	445	**377**
HOEP ($)	5055	5126	5055	4970	5055	4959	5055	4940
GA ($)	17001	17269	17001	16875	17001	16877	17001	16874
Regulatory ($)	720	732	720	715	720	715	720	715
Delivery ($)	4692	4691	4692	4324	4692	4061	4692	3973
Service ($)	169	169	169	169	169	169	169	169
TOTAL ($)	27639	**27989**	27639	**27055**	27639	**26783**	27639	**26673**
Saving (%)	**-1.20%**		**2.16%**		**3.09%**		**3.62%**	

Table 7 - Projections for New Control Strategy and Varying CES Battery Reserve for December.

From the simulation results in Table 7, it can be seen that the increase in reserve capacity for the CES, as well as the tuning of the control settings results in higher cost savings for the CES/PV system. Even while holding the reserve capacity to 60%, discharging the battery at a constant rate results in a net savings of over $580 (2.16%). While the difference in net power consumption is minimal (as well as the corresponding savings from global adjustment), the major cost savings come from reduction in HOEP and delivery charges, which account for over 63% of the cost savings within the month. This is achieved by the CES' ability to contribute more power towards peak shaving. The primary conclusion of this simulation is that the CES can still provide energy savings when PV output is minimal. The simulation is repeated for the month of June to observe how the PV/CES combination can further provide cost savings when there is abundance of PV output. The results are shown in Table 8.

Item	Baseline		CES 60% Reserve		CES 40% Reserve		CES 20% Reserve	
	Load	Net	Load	Net	Load	Net	Load	Net
Demand (MWh)	226	204	226	202	226	202	226	202
Peak Demand (kW)	628	585	628	513	628	504	628	496
HOEP ($)	4544	4053	4544	3980	4544	3961	4544	3941
GA ($)	28439	25634	28439	25400	28439	25403	28439	25400
Regulatory ($)	932	840	932	832	932	832	932	832
Delivery ($)	6624	6170	6624	5406	6624	5318	6624	5231
Service ($)	169	169	169	169	169	169	169	169
TOTAL ($)	40710	**36867**	40710	**35789**	40710	**35685**	40710	**35574**
Saving (%)	**9.43%**		**13.75%**		**14.08%**		**14.44%**	

Table 8 - Projections for New Control Strategy and Varying CES Battery Reserve for June.

Given that in the baseline set of data for June the CES was not operational, it is obvious that there will be significant cost savings when the CES is integrated into the simulation. The CES operating at even 60% of its reserve capacity will realize an additional $1078 in cost savings, or 4.32% more than just using the PV system. With the PV reducing overall energy demand, most of the cost savings can be attributed to GA (approximately 77% of overall savings, or $3039), while the battery further contributes to lowering the charges affected by shaving peak demand (23%, or $1882). The important conclusion that can be drawn from these two simulations is that the timing and rate of discharge are the primary drivers of cost savings with respect to the CES, even at high reserve capacities where the battery cannot discharge for long periods of time.

6 Conclusions and Future Work

Through extensive data analysis, it can be concluded that the integration of the CES/PV has been successful in performing peak shaving and power factor correction for the Science North microgrid. While peak shaving has been responsible for cost savings of over $9800 (5%) during the studied period, the net power factor of the microgrid has also improved to the range of 0.90 to 0.95 from 0.75 to 0.85 (inductive). Furthermore, the CES has provided reactive power compensation, which was realized in the reduction of apparent power with a savings of 3.4 MVAh (1.59%) for the month of December, and 9.6 MVAh in January (5.36%). Although the PV system is the primary driver of cost savings via peak shaving, the CES still contributes effectively by being utilized in constant, short bursts during extreme peak periods. Simulation results show that the CES system can still realize savings of over $500 (2.2%) when PV output is minimal for the month of December. Furthermore, if the battery reserve capacity can be relaxed to less than 50%, the CES will have the ability to realize further cost savings (up to 14.44%). The data collected as part of the report proves the concept of PES/CV peak shaving, and with a fully functioning CES, could achieve long-term financial savings for the Science North microgrid.

For future work, it is recommended that the control strategy of the CES be tuned to provide constant discharging during extreme peak periods. As the trend of the building is quite predictable, the control strategy may benefit from trialing a simple time-based approach.

7 References

[1] Canadian Standards Organization, "CSA CAN3-C235-83: Preferred Voltage Levels for AC Systems, 0 to 50 000 V", 2015

[2] IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, New York, NY: IEEE.

9-Staff-89 Accounts 2435 - Other Deferred Credit

Question:

Ref 1: Exhibit 9 –Tab 1 – Schedule 4, p.8

Sudbury Hydro previously secured funding for certain CDM programs. In 2015, Sudbury Hydro ended these programs and noted that it would propose to flow back any remaining funds after 2015 to ratepayers for amounts that were not spent. Please provide a breakdown of the ($513,952) proposed to be credited to customers by program type, showing how much was recovered and how much was spent from 2009 to 2015.

Response:

Greater Sudbury Hydro Inc's funding was approved for $2,668,587 (EB-2008-0147). Table 1 below shows by rate class, funding amount less spending by program and class.

Table 1 – EB-2008-0147 CDM Funding

	Residential	GS<50	GS>50	Streetlights	
Final Approved Funding by Rate Class	**1,011,714.00**	**319,187.25**	**862,987.75**	**474,698.00**	**2,668,587.00**
Spending by Program					
Community Awareness	56,000.16	20,000.00	20,000.00		96,000.16
Program Evaluation	14,354.23				14,354.23
Electric Thermal Storage	885,932.24				885,932.24
LED Traffic Light Conversion				59,648.94	59,648.94
Parking Lot Controller		174,261.57	306,725.09		480,986.66
Streetlight Conversion				414,530.09	414,530.09
Vending Miser		79,118.14	124,064.31		203,182.45
Total Spending					

	956,286.63	**273,379.70**	**450,789.41**	**474,179.03**	**2,154,634.77**
To Flow Back by Rate Class	**55,427.37**	**45,807.55**	**412,198.34**	**518.97**	**513,952.23**

9-Staff-90 Account 1508 - OEB Cost Assessment Variance

Question:

Ref 1: Exhibit 9 – Tab 1 – Schedule 5, p.1

Sudbury Hydro plans to continue Account 1508, Other Regulatory Assets OEB Cost Assessment Variance. In the OEB's February 9, 2016 letter regarding *Revisions to the Ontario Energy Board Cost Assessment Model*, it states "Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or custom IR) incorporating an updated forecast of cost assessments". Please explain why Sudbury Hydro plans to continue the account when there should be nothing recorded in the account going forward.

Response:

GSHi will discontinue this account going forward.

9-Staff-91 Account 1508 - OPEB Actuarial Gains & Losses

Question:

Ref 1: Exhibit 9 – Tab 1 – Schedule 5, p.p.2-5

Regarding materiality of the proposed OPEB Actuarial Gains & Losses Account, actuarial gains and losses have ranged from $2.3M loss to $6.8M gain. Please provide the annual actuarial gains and losses from 2013 to 2020.

Response:

Please find a summary table with the requested figures below. Please note - both 2019 and 2020 figures are not provided. The year 2019 is expected to be known by mid-March 2020, and the 2020 number will not be known until 2021. GSHi does not have an estimate either figure.

	2013 (Actual)	2014 (Actual)	2015 (Actual)	2016 (Actual)	2017 (Actual)	2018 (Actual)
Actuarial (Gains) Losses, before tax	$(1,603,138)	$2,345,418	$(477,626)	$(6,840,715)	$1,552,390	$(1,545,129)

9-Staff-92 Accounts 1518 and 1548

Question:

Ref 1: Exhibit 9 – Tab 2 – Schedule 2, p.p.1-2

Sudbury Hydro has quantified an estimate of what the balances in Accounts 1518 and 1548 should be as at December 31, 2019 in Table 1.

a) In Table 1, revenues have decreased from 2013 to 2019. However, retail service charges increased (typically doubled) as per the Decision and Order EB-2015-0304 in the matter of energy retail service charges effective May 1, 2019, dated February 14, 2019. Please explain whether these increases have been included in the 2019 budget numbers. If not, please revise Table 1 to reflect the increased retail service charges.

b) In Table 1, please include a forecast up to April 30, 2020.

Response:

a) These increases were not included in the 2019 budget numbers. The increases were included in the 2020 Test Year (in "Other Revenue") but not in Table 1. As a result of this interrogatory, GSHi has re-calculated the budgeted figures with more accurate inputs, including the updated rates and more accurate billing factors. The result when compared to the figures already included in the 2020 Test Year was a slightly reduced revenue budget for 4082, and slightly increased revenue budget for 4084. Please see revised Table 1 below, which fully accounts for the increased retail service charges. GSHi's updated Revenue Requirement accounts for these updated revenue figures.

1518 - Retail Cost Variance Account		2013	2014	2015	2016	2017
4082	Retail Service Revenue	(39,393.30)	(33,126.70)	(30,989.00)	(30,665.80)	(21,848.00)
5340	EBT Hub Service Fees	13,308.31	10,833.94	27,581.43	18,817.82	8,028.77
5340	Retail Service Labour	14,699.68	14,832.99	12,403.41	10,249.98	15,802.52
		(11,385.31)	(7,459.77)	8,995.84	(1,598.00)	1,983.29
1548 - Retail Cost Variance Account						
4084	Retail STR Revenue	(1,114.25)	(732.75)	(852.50)	(642.50)	(305.75)

1518 - Retail Cost Variance Account		2018	2019	2020		2020
			Estimate	**Projection**		**Full Yr Budget**
				to Apr 30/20		
4082	Retail Service Revenue	(20,810.10)	(29,914.50)	(11,972.00)		(35,916.00)
5340	EBT Hub Service Fees	11,695.50	11,280.03	6,666.67		20,000.00
5340	Retail Service Labour	15,926.77	16,894.98	5,833.47		17,500.40
		6,812.17	(1,739.49)	528.13	**(3,863.13)**	1,584.40
1548 - Retail Cost Variance Account						
4084	Retail STR Revenue	(301.75)	(496.00)	(310.08)	**(4,755.58)**	(930.24)
			Total of both 1518 & 1548		**(8,618.71)**	

b) See Table 1 above for the forecast up to April 30, 2020.

9-Staff-93 Account 1575

Question:

Ref 1: Chapter 2 Appendix 2-EA

Ref 2: Exhibit 2 – Tab 1 – Schedule 1, Attachment 2

Ref 3: Chapter 2 Appendix 2-BA

a) In Appendix 2-EA, the 2018 MIFRS closing PP&E balance is $98,676,629. In the 2018 MIFRS closing PP&E balance is $98,417,334. Please explain and reconcile the difference and revise the evidence as needed.
b) In Appendix 2-EA, the closing MIFRS PP&E balances include "WIP – Capital Inventory "and "Work in Process" (as can be seen from the PP&E breakdown from Appendix 2-BA). Please confirm that the CGAAP balances also include these items and they are for the same amount as under MIFRS, resulting in no impact to Account 1575. If not confirmed, please explain why there is a difference between CGAAP and MIFRS and why these differences should be included in Account 1575 when they do not form part of rate base.
c) In Appendix 2-EA, the additions under CGAAP and MIFRS are different each year from 2013 to 2019. Please explain what is the reason for the difference as differences are not expected given that Sudbury Hydro's 2013 rebasing application already incorporated capitalization policy changes that would affect additions.
d) In the breakdown of Account 1575 provided in Exhibit 9, Table 1 shows a column for "Loss on Disposals per App 2-BA". Please explain how these amounts agree to the disposal columns in Appendix 2-BA. Please provide an example.
e) In the breakdown of Account 1575 provided in Exhibit 9, Table 1, the "Correction of Prior Disposal" and "Depreciation Correction through RE" totals $565,450. Please explain how these amounts agree to the $946,000 adjustment to PP&E shown in 2015 financial statement note and the 2015 Appendix 2-BA.

Response:

a) While referenced in this question as 2018 figures, GSHi notes that the two dollar amounts referenced above refer to the 2019 Bridge Year MIFRS projected closing PP&E balances. The discrepancy between the two referenced figures pertained to an incorrect value included in the movement in "Work in Process" that was included in the projected balance for 2019 in Appendix 2-EA. The "Work in Process" is included in both CGAAP balances and MIFRS balances, and therefore the impact of correcting the discrepancy does not impact account 1575's balance. GSHi has updated Appendix 2-EA with the corrected 2019 projection figures and updated Chapter 2 Appendices are submitted with this response.

b) GSH confirms that "WIP - Capital Inventory" and "Work in Process" amounts are included with identical values under CGAAP and MIFRS, and therefore have no impact on the balance of account 1575.

c) The driver of the balance in account 1575 is the net book value of capital disposals. In Appendix 2-EA, capital disposals are captured by reducing the additions under MIFRS by the gross "Cost" disposed of. Similarly, the accumulated depreciation disposed of is captured by reducing the "Depreciation". Other than additions being adjusted by the gross cost of assets disposed of, the additions included in Appendix 2-EA are the same under CGAAP and MIFRS.

d) Please see below table, with an updated “Table 1” for 2019, and a reconciliation for figures that agree to Appendix 2-BA:

Updated “Table 1”:

				Difference consists of (D):				
	Loss on Disposals, Deferred in 1575	Loss on Disposals, Per App. 2-BA	Difference ("Other Adjustment" in 2-EA)	Value of items returned to inventory	Gains on Disposal	Correction of Prior Disposal	Dep'n Correction thru RE	Remaining Difference
	A	B	A - B = C					C + D
2014 & 2015	$ 990,582	$ 1,556,032	$ (565,450)			$ 72,017	$ 493,433	$ 0
2016	$ 634,172	$ 675,277	$ (41,105)	$ 41,105				$ (0)
2017	$ 461,850	$ 508,620	$ (46,770)	$ 35,710	$ 11,060			$ (0)
2018	$ 624,722	$ 651,617	$ (26,895)	$ 18,342	$ 8,552			$ (0)
2019	$ 515,799	$ 598,716	$ (82,917)	$ 82,917				$ 0
	$ 3,227,125	$ 3,990,262	$ (763,137)	$ 178,075	$ 19,612	$ 72,017	$ 493,433	$ (0)

Reconcile “Loss on Disposals, Per App. 2-BA” to Appendix Totals:

Source	Description	2015	2016	2017	2018	2019
Appendix 2-BA	Sub-Total, Cost Disposals	$ (3,193,392)	$ (3,393,707)	$ (2,479,009)	$ (4,053,171)	$ (3,653,785)
Appendix 2-BA	Sub-Total, Accum. Dep. Disposals	$ 2,058,896	$ 2,718,429	$ 1,970,389	$ 3,263,752	$ 2,261,790
Appendix 2-BA	Cost Disposals, WIP - Capital Inventory	$ 152,509	$ -	$ -	$ 137,803	$ -
Appendix 2-BA	Cost Disposals, Work in Process	$ 371,955	$ -	$ -	$ -	$ 793,279
Appendix 2-BA	Cost, Adjustment through RE	$ (1,615,330)				
Appendix 2-BA	Accum. Dep., Adjustment through RE	$ 669,330				
E09, T02, S01, Table 1	Loss on Disposals, Per App. 2-BA	$ (1,556,032)	$ (675,278)	$ (508,620)	$ (651,616)	$ (598,716)

e) Please find a reconciliation summarized in the table below:

	FS Note	OEB's Subtotal Questioned	2015 Appendix 2-BA (Note 1)
Depreciation expense adjustment @ Dec 31, 2012	$ 105,287	$ 105,287	$ 105,287
Depreciation expense adjustment @ Dec 31, 2013	$ 218,697	$ 218,697	$ 218,697
Depreciation expense adjustment @ Dec 31, 2014	$ 169,449	$ 169,449	$ 169,449
	$ 493,433	$ 493,433	$ 493,433
Disposal P&L adjustment 2013	$ 136,805	$ -	$ 136,805
Disposal P&L adjustment 2014	$ 315,762	$ -	$ 315,762
Correction of Prior Disposal	$ -	$ 72,017	$ -
	$ 452,567	$ 72,017	$ 452,567
	$ 946,000	$ 565,450	$ 946,000

Note 1: In appendix 2-BA, gross "Cost - Adjustment through RE" equals ($1,615,330) and gross "Accum. Dep - Adjustment through RE" equals $669,330. The net of these sub-totals equals $946,000.

9-Staff-94 New Accounting Guidance

Question:

Ref 1: Exhibit 9 – Tab 2 – Schedule 4, p.1

Sudbury Hydro indicated that it was in the process of implementing the full scope of the accounting guidance. It anticipates the implementation to be completed by December 31, 2019.

a) Please confirm that the accounting guidance has been fully implemented by December 31, 2019.
b) Please confirm that the accounting guidance has been implemented retroactive to January 1, 2019.
c) If part a or b above is not confirmed, please provide a status update on the implementation.

Response:

a) By December 31, 2019 GSHi had adopted the accounting guidance calculations for the initial true up, 1st true up and 2nd true up. GSH has transitioned to the Accrual basis for these submissions to the IESO beginning with December's submission.

   For 2019, given the timing of completion of this initiative, GSH does not intend to book and reverse accrual adjusting journal entries for energy sales and cost of power in line with the accounting guidance for each month throughout the year. For the calendar year GSH intends to record actual amounts for cost of energy and energy sales, with appropriate year-end accruals as necessary.

   With the above noted points in consideration, GSH has otherwise fully implemented the accounting guidance by December 31, 2019.

b) GSHi has re-calculated the true up for each month of 2019 using the "2nd True Up" methodology detailed in the OEB's accounting guidance and intends to submit a final true up for 2019 with the IESO submission for February 2020. The submission of this true-up will ensure that the 2019 year true up methodology is fully in line with the OEB's guidance.

For 2019, given the timing of completion of this initiative, GSHi does not intend to book and reverse accrual adjusting journal entries for energy sales and cost of power in line with the accounting guidance for each month throughout the year. For the calendar year GSHi intends to record actual amounts for cost of energy and energy sales, with appropriate accruals as necessary.

With the above noted points in consideration, GSHi has otherwise fully implemented the accounting guidance retroactive to January 1, 2019.

c) Not applicable, see response to a and b above.

9-Staff-95 New Accounting Guidance

Question:

Ref 1: Exhibit 9 – Tab 2 – Schedule 4, p.1

Sudbury Hydro reviewed the new accounting guidance and considered it as compared to its historical balances. It has not found any systemic issues with its RPP settlement and related accounting processes. Please provide further details on the review that was completed, and any summary reports available (e.g. how the review was done).

Response:

Beginning in 2016, GSHi invested significant time and resources in ensuring its RPP true up methodology aligned with the Board's guidance at the time. This work included engaging KPMG to review the guidance in OEB Article 490 from the Accounting Procedures Handbook and consider it against the methodology that GSH was proposing. This review was completed, and KPMG's Process Review Report, dated July 15, 2016, is included as Attachment 1 to this section.

At the time, GSHi corresponded with the OEB about the proposed change in methodology and the scope of correction. GSHi recorded an adjustment in its GL in 2016 for the 2015 year-end balances, which included a $440,808 re-classification between 1588 & 1589, and a $133,884 true up adjustment with the IESO. In 2016 and forward, GSHi used the true-up methodology that was reviewed by KPMG and in line with Article 490.

In considering the new accounting guidance, GSHi considered the conceptual differences between its 2016 historical RPP settlement methodology that was currently in use and the OEB's new guidance issued on February 21, 2019. A summary of the primary differences are as follows:

1) GSHi's historical methodology used a blended RPP rate to establish the amount collected from RPP customers in the true up calculation. The new guidance separates consumption/purchases for each RPP rate and applies the rate specific to the RPP rate (ie: Block Tier 1, Block Tier 2, TOU Off, TOU Mid, TOU On).

2) GSHi's historical methodology prorated all consumption into monthly cut-off based on the days billed. GSHi has made improvements to this partially through 2019, and its billing system is now establishing monthly cut-off more accurately as it also considers cut-off when billing quantity requests are sent with monthly cut-off throughout the year. Further improvements include the billing system separating billed consumption by month, by RPP rate. This provides more accurate data as an input to the OEB's more granular methodology.

3) GSHi's historical methodology submitted an "initial submission" on the “cash” basis, and trued up the initial submission quarterly on an "accrual" basis. The new guidance submits an initial submission on the "accrual" basis, and two further true ups in the subsequent months also on the "accrual" basis.

GSHi considers the two methods very similar from a conceptual perspective and believes that its historical method would produce a materially similar true up to the new guidance. GSHi's position that it's historical methodology is in line with expectations is supported by the GA Analysis workforms that GSHi has submitted in its 2018 & 2019 IRMs, as well as the workform submitted in this 2020 Rate Application. These workforms all reconciled the expected balance to actual, within the acceptable difference threshold.

Attachment 1 (of 1):

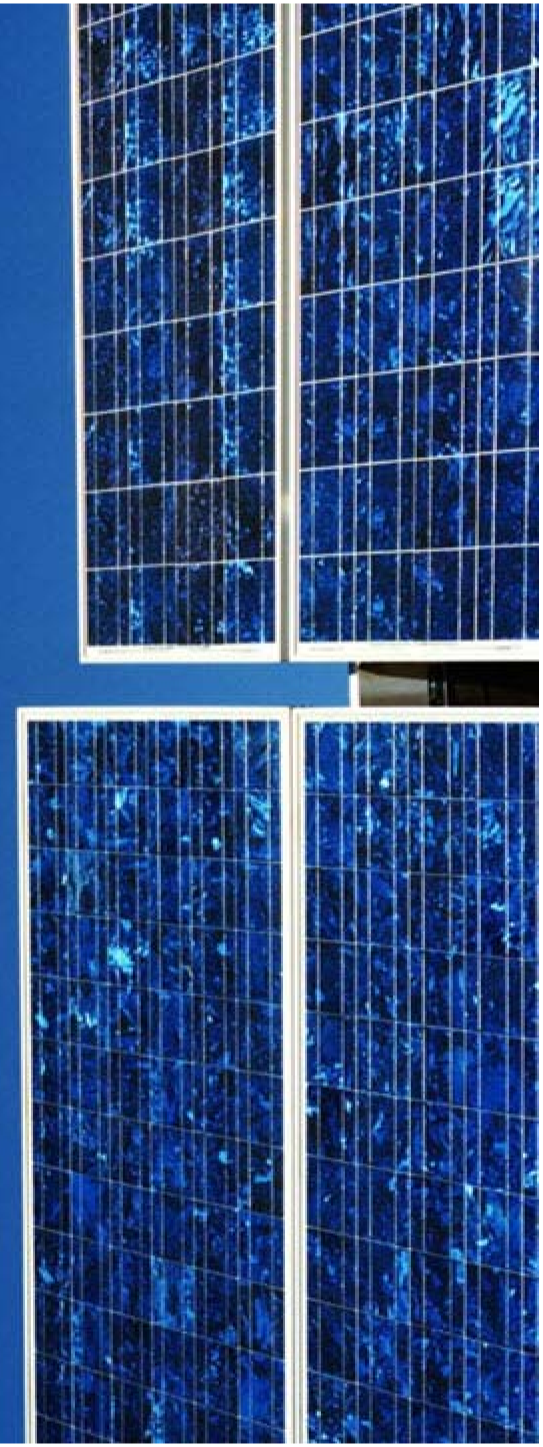
9-Staff-95 Attachment 1: KPMG Report

KPMG

Regulatory Process Review
(Form 1598 reporting)

Greater Sudbury Hydro Inc.

July 15, 2016



Scope and Limitations of Work Performed

- This report its entire contents, findings and recommendations are confidential and are intended for Greater Sudbury Hydro Inc.'s (the Entity or "GSHI") internal use only and may not be distributed, made available or relied on by other parties without KPMG LLP's ("KPMG") written consent, and is subject to the terms and conditions in our contract with the Entity dated May 26, 2016. KPMG assumes no responsibility or liability for costs, damages, expenses or losses by anyone as a result of unapproved circulation, reproduction or reliance on this report.
- In gathering information during our engagement, we relied solely on the information provided by the individuals being interviewed and, while we undertook steps to validate the information through further discussions with management, we did not independently verify or audit the information.
- KPMG did not perform an audit on the data; therefore, this presentation does not constitute an expression of opinion on the accuracy of the information presented. KPMG did not perform an audit on any of the data received from the Entity. As such, this report does not constitute an expression of audit opinion on the accuracy or achievability of the information presented.
- It must be recognized that it is not possible to predict future events with complete accuracy, or anticipate all potential future circumstances. As such, actual results achieved for the implementation of any opportunities for improvement discussed in this document will vary from the information presented, and the variations may be material.
- The scope of our engagement was by design limited, and therefore all findings and recommendations should be considered in the context of the project contract, project approach, and our limited review. In this capacity, we were not acting as auditors and accordingly our work did not result in the expression of an opinion on financial or other information. We have relied on information and representations of management for the completeness of the information provided
- The Entity and its senior management are responsible for any decisions to implement any changes as a result of this review, and for considering the impact of such changes. In performing our procedures, we acted solely as facilitators to assist the Entity in identifying opportunities for improvement for your organization. Any decisions made about the Entity's processes, controls, and systems will be made by the Entity, and the ultimate responsibility for these decisions will remain with the Entity.

Contents

Executive summary

Headlines

What were we engaged to do?

KPMG was engaged to review your existing processes, policies and procedures related to Form 1598 reporting including the methodology used to quantify the amounts reported to the IESO.

What did we find?

The work performed during this engagement resulted in noting the following areas that are done well and areas of improvement:

Areas that were done well:

1. Knowledgeable staff administer the regulatory process
2. Well thought out excel methodology is employed

Areas for improvement:

1. Data integrity checks are limited and not documented
2. Certain reconciliations completed on an annual basis only
3. Inputs to certain spreadsheets are not reconciled back to supporting documentation
4. Staff training and cross training

Objectives, Approach & Acknowledgements

Project Objectives & Approach

KPMG was engaged to review your existing processes, policies and procedures related to Form 1598 reporting including the methodology used to quantify the amounts reported to the IESO.

Our approach included the following:

Project Initiation:

- Confirm the project scope
- Confirm project deliverables
- Validate our approach and work plan
- Discuss the availability and requirements of resources

Current State Understanding:

- Review existing process and methodology and proposed revisions to gain an understanding of existing process and methodology
- Walk through spreadsheets and methodology
- Walkthrough of Article 490 (issued December 2011 by the Ontario Energy Board) with Greater Sudbury Hydro's staff

Analysis

- Assess methodology for logic errors
- Assess process to identify points of risk or error
- Identify and evaluate internal controls in place to mitigate the risk of error
- Develop and document findings, observations and recommendations

Final Report and Presentation:

- Prepare final report

Acknowledgements

The KPMG team would like to acknowledge the following personnel's participation, and for providing valuable insight into this project:

Name	Role
Lorella Hayes	Vice president of Corporate Services & Chief Financial Officer
David Chisholm	Supervisor – Regulatory Affairs and Billing
Jodie Koski	Manager, Customer Service / Regulatory Affairs

Current State Findings & Conclusions

Findings and Conclusions

This section of the report summarizes input from the Entity's Regulatory, Finance and Billing staff. We have set out our observations with the implications to the Entity. We have identified the gaps in internal control and opportunities for improvement and potential risks along with our recommendations. Where applicable we have identified best practices.

The regulatory process is supported extensively with excel spreadsheets and knowledge of these spreadsheets is limited to one or two individuals. The use of spreadsheets without robust spreadsheet protocols and policies puts the Entity at risk of error. Limiting the knowledge in one or two people increases the risk of loss of this knowledge. There are two main spreadsheets supporting the regulatory process:

- IESO spreadsheet (1588 True-Up 1598 Annual True-Up to IESO)
- RSVA reconciliation

Findings in this section of the report have been categorized under the following headings:

- Spreadsheet rigour
- Logic and methodology
- Process documentation
- Regulatory communication
- Responsibilities and training

Findings & Recommendations – Spreadsheet Rigour

Current State 1588 / 1598 Reconciliation Process (Excel workbooks)	Current Impact and Recommendations

• An excel workbook (currently the "1588 True-Up 1598 Annual True Up to IESO" – Note name may change once process is formalized) is used to quantify and support the amounts reported in regulatory filings to the IESO
• The spreadsheet is complex and made up of a number of tabs and contains inputs from a number of sources
• The spreadsheet is stored on the server, which is accessible by all finance staff
• There is currently no identifier for cells which are considered to be input cells and cells which are calculation based.
	There is an increase in the risk of error in regulatory filings since the spreadsheets are not currently protected. Formula cells are not locked to prevent inadvertent changes.
	We recommend :
	• A spreadsheet protocol be developed for spreadsheets used to support the amounts in regulatory filings
	• Such protocol should include:
	    • Locked cells for formulae
	    • Consistent colour coding to denote input cells or use of a data input tab to which formulae are referenced
	    • Policy and process for management, review and sign off of changes to spreadsheet formulae and/or logic
	    • Formal review and checking of manual data entry and cross checks, with reconciliations completed and formally documented where appropriate
	    • Formal sign off procedures for review of spreadsheet prior to filing
	    • Lockdown of final version of spreadsheet after filing is complete (prevents historic data loss)

• At the current time, as the 1598 process is currently being formalized, a process map, indicating the required steps to complete the spreadsheet is not currently available. • The required steps for the completion of the spreadsheet are complex and can be subject to interpretation	An instruction tab is considered to be a best practice for spreadsheet use. Consideration should be given to putting the list of steps in sequential order to simplify the process of populating the data in the spreadsheet, especially when someone new has to take over. In addition, the instruction tab should include where the information is obtained for the various inputs to the spreadsheets, along with the information that can be interfaced with the spreadsheet to reduce the amount of manual input.
The spreadsheet includes a number of manual input sections as well as sections which rely on the uploaded information from NorthStar	The Excel workbook includes a complicated set of interlinked tabs utilizing data downloads, manual data entry, cross checks and reconciliations to other data sources such as the general ledger and billing journal. The complexity of the spreadsheet increases the risk of error occurring. We recommend: • A comprehensive list of data integrity checks be developed • Formal review and sign off procedures be developed for completion of the integrity checks prior to filing with the IESO

Findings & Recommendations – Spreadsheet Rigour

Current State 1588 / 1598 Reconciliation Process (Excel workbooks)	Current Impact and Recommendations
• Reconciliations to other data sources are not completed on a regular basis.	Due to the complexity of the Excel workbook, there is an increased risk that a reconciliation difference goes unnoticed. We recommend the following: • Reconciliations to other data sources should be isolated in a separate tab within the workbook • The reconciliation should be automated by entering the amount from the other data sources with a formula embedded to subtract from the amount in the Excel workbook. An automated error check should be created using excel functionality so that an error or reconciliation difference is readily apparent. This could be done using an "IF" statement and having the word "ERROR" displayed when the amount does not reconcile • For data reconciled annually, accumulate monthly data each month when the Excel workbook is prepared to increase efficiency.
• The Excel workbook relies upon data downloaded from the NorthStar system for the billing data utilized in the workbooks. The downloaded data is not tested or reconciled to ensure completeness and accuracy of this data.	There is a risk of error in the IESO filing and within the regulatory accounts if the downloaded data is not complete and accurate. We recommend a formalized reconciliation process be established to ensure the downloaded data from the NorthStar billing system is complete and accurate prior to the commencement of the monthly reconciliation process.

Findings & Recommendations - Spreadsheet Rigour

Current State **1588 / 1598 Reconciliation Process (Excel workbooks)**	**Current Impact and Recommendations**
• Manual data entry is often checked by the spreadsheet preparer only with no documented review by a second individual	The preparer's familiarity with the spreadsheet and the data entered increases the risk that an error could go undetected. We recommend: • Manual data entry be checked by someone other than the preparer • Implementing this would result in the benefit of spreading knowledge of the spreadsheet over more people Segregating manually entered data in a separate tab will facilitate an efficient review of this data.
• Certain components of the data utilized in the various Excel workbooks is transferred between the various spreadsheets manually	Manual data entry increases the risk of errors occurring. We recommend: • The spreadsheet be redesigned so that this information is downloaded electronically where possible • Data integrity checks be developed and included in the spreadsheets. These checks should display an error message when an error occurs.

Findings & Recommendations - Spreadsheet Rigour

Current State RSVA Entry Spreadsheets	Current Impact and Recommendations
• Considerable effort was undertaken by the Supervisor – Regulatory Affairs and Billings in the development of the spreadsheets utilized with the RSVA reconciliation process.	• There is a risk that over time the spreadsheet logic will become compromised • Spreadsheets should be reviewed on a regular basis (eg. Annually and whenever revised) to ensure that it still does what it is supposed to do and does it correctly • This review should be formally documented and signed off
• The RPP Settlement amount is determined using amounts billed in the month rather than amount of billings for the month's electricity usage. The unbilled revenue adjustment for the month is not included in the determination of customer billings for the month. • Article 490 of the APH establishes that accrual accounting applies to the RSVA accounts. There is no specific mention of this for the determination of the RPP settlement amounts in Article 490.	• A mismatch occurs because the Global Adjustment ("GA") is based upon the amount invoiced by the IESO for the month but the amount billed do not include customer billings for electricity to the end of the month. • The methodology should be revised to include the impact of unbilled revenue on the determination of the RPP settlement amount.

Findings & Recommendations – Logic and methodology

Current State	Current Impact and Recommendations
• Article 490 of the APH requires the RPP settlement amount to be determined based upon the average weighted price from the final invoice from the IESO which is a monthly average price. GSHI uses the daily average price in its calculations of the RPP settlement amount. • This difference in the average price calculations are "trued-up" on an annual basis.	• GSHI should review the current methodology and determine if the difference in average price is significant and revise the methodology if necessary to be compliant with OEB guidance.
• The GA first estimate is used to determine the IESO reporting. On an annual basis, the GA is trued up to the final GA as provided by the IESO. • Many utilities true the GA up on a monthly basis.	• The GA can swing by a large amount owing to customers to a large amount owing from customers between the 1st estimate and final which can have a significant impact on cash flows. • GSHI should consider implementing a process to true up the GA to the final GA on a monthly basis.

Findings & Recommendations – Process Documentation

Current State	Current Impact and Recommendations
• A significant amount of time has been spent interpreting the requirements of Article 490 of the APH and developing Excel spreadsheets to facilitate the IESO reporting process. • Given the time commitment associated with the development of the spreadsheets, the process followed for the IESO reporting has not been documented.	• The complexity of this process will make it difficult for someone new to follow the process and complete the IESO reporting accurately. • There can be differences in interpretation of OEB guidance. It is critical to ensure the reconciliations are completed consistently each month in accordance with OEB guidance and GSHU's interpretation thereof. • To ensure the reconciliations are completed consistently and accurately from month to month, the process should be formally documented.
• Currently, GSHI and the IESO record meter readings of electricity usage for the month. GSHI utilizes a metering service provider to review the accuracy of the meter reads and the IESO invoice. The metering service provider compares the GSHI reads to the IESO reads and identifies differences, if any. Staff are unclear on the process that is in place if differences are identified. Differences are infrequent.	• A process to address differences in the meter reads should be formalized and circulated. This process should clearly define the magnitude of difference that would trigger filing of a notice of dispute with the IESO.

Findings & Recommendations – Regulatory communication

Current State	Current Impact and Recommendations
• Regulatory changes are monitored by the Supervisor – Regulatory Affairs and Billings, along with the Vice President of Corporate Services • Changes are disseminated to individuals within the organization based upon the nature of the change • Changes of a less specific nature are disseminated more broadly within the organization • The senior management group is advised of changes at their monthly meetings • CEO advises the Board of changes • The communication process is not formalized	The extent of change in the utility industry increases the risk that changes are not communicated to relevant individuals within the Entity. We recommend: • A formalized approach be developed for communicating and addressing regulatory changes • Regulatory changes should be a standard agenda item for senior management and Board meetings • Responsibility for identification and communication of changes should be assigned to one individual in the organization • A communication flowchart should be developed which identifies who needs to be notified depending on the nature of the change

Best practices in Regulatory Communication

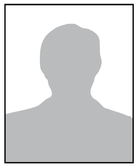
- Standing agenda item for regulatory updates to the board/committee and senior management team meetings
- Regulatory changes tied in to the Enterprise Risk Management (ERM) framework
- Regulatory risk is a specific risk category in the ERM framework
- Risk assessment and reporting to board and senior management team includes financial, operational, compliance and personnel components including training
- One individual in the organization is given responsibility for providing updates on regulatory change
- Changes impacting a specific department are communicated directly with the department
- Input is sought from directors regarding their direct reports who should be informed of a particular change

Findings and recommendations - Responsibilities & Training

Current State	Current Impact and Recommendations
• IESO submissions and underlying support is prepared by a limited number of staff members in the organization and therefore, the knowledge is centralized. • At the current time, the Supervisor of Regulatory Affairs and Billing is in a relief role, covering a maternity leave. Therefore, there are currently two individuals who are familiar with the regulatory reporting and requirements.	• To ensure this continues, we recommend the individual acting in the role currently should continue to perform the filing periodically to remain current.
• Much of the regulatory process is learned on the job as reporting and filing requirements are announced	• Consideration should be given to providing formal training to staff responsible for regulatory filings (such as the training provided by Elenchus)

Contacts

The contacts at KPMG in connection with this report are:



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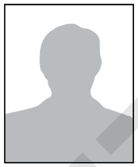

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9-Staff-96 GA Analysis Workform

Question:

Ref 1: GA Analysis Workform

In the 2018 GA Analysis Workform

a) Columns G and H are not completed under Note 4. Please explain what consumption data is used in the table in Note 4 and why columns G and H were not used.
b) There is a reconciling item for the difference in actual system loss and billed total loss factor of $542,766. Please provide a calculation for this loss difference.
c) In the 2017 and 2016 GA Analysis Workforms, there are also reconciling items for the difference in actual system loss and billed total loss factor. There is a year-over-year increasing trend in the differences from $12,703 in 2016, $295,640 in 2017 and $542,766 for 2018. Please explain year-over-year increasing trend in the differences.

Response:

a) GSHi completed a final RPP true up for 2018, where it looks at kWh billed for all months and submits a final RPP true up submission as part of the February 2019 settlement with the IESO. This true up separates the kWh billed into appropriate months. GSHi used this final true up as the source for the kWh reported on the GA Analysis Workform, and therefore no unbilled adjustments are necessary. Therefore columns G and H are not necessary to be completed.

b) Please see Attachment 1 for the supporting calculation for this loss difference.

GSHi notes that the monthly billed kWh "per RPP True Up" in this calculation differ from the GA analysis workform billed consumption kWh as submitted. GSH submitted the workform to agree to the RRR submission and its billed loss factor of 1.054, however the RPP true up methodology allocated kWh don't agree directly to 1.054. GSHi considers the "per RPP True Up" kWh to be more accurate than the kWh initially submitted in the 2018 GA Analysis Workform.

For reference, GSHi submits an updated 2018 GA Analysis Workform with the kWh matching the "per RPP True Up" kWh in Attachment 1. The total impact is considered immaterial as the "Unresolved Difference" is still well below the allowable difference.

c) The difference in a given year is expected to correlate strongly with a comparison between GSH's billed loss factor and its actual loss factor experienced. The following table, summarized from Appendix 2-R, compares the billed loss factor and the actual loss factor.

	2016	2017	2018
Billed Loss Factor	1.0540	1.0540	1.0540
Distributor's actual loss factor (Appendix 2-R)	1.0475	1.0393	1.0307
Difference	0.0065	0.0147	0.0233

Attachment 1 (of 1):

9-Staff-96 Attachment 1: Reconciling Item Calculation

		Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018
Non-RPP kWh, per RPP True Up	A	26,609,916.84	23,240,851.72	24,131,509.52	22,105,573.45	21,790,383.32	21,729,877.81	23,796,740.94	23,222,725.18	21,344,865.12	22,146,791.59	23,630,836.11	24,900,532.45
Non-RPP kWh Purchased, per RPP True Up	B	26,377,489.26	23,169,557.65	23,736,984.74	22,053,670.13	20,976,749.05	20,715,301.17	23,509,993.99	22,850,720.19	20,890,152.74	21,896,119.23	23,523,273.66	23,356,038.80
kWh overbilled	A-B=C	232,427.58	71,294.07	394,524.78	51,903.32	813,634.27	1,014,576.63	286,746.94	372,004.98	454,712.38	250,672.36	107,562.44	1,544,493.65
GA 1st estimate	D	0.08777	0.07333	0.07877	0.09810	0.09392	0.13336	0.08502	0.07790	0.08424	0.08921	0.12235	0.09198
GA $ overbilled	C*D=E	$ 20,400.17	$ 5,227.99	$ 31,076.72	$ 5,091.72	$ 76,416.53	$ 135,303.94	$ 24,379.22	$ 28,979.19	$ 38,304.97	$ 22,362.48	$ 13,160.26	$ 142,062.53
												Subtotal, E	**$ 542,765.72**

9-Staff-97 Account 1588

Question:

Ref 1: DVA Continuity Schedule

Account 1588 transactions for 2018 was ($983,175). Typically, large balances are not expected for Account 1588 as it should only hold the difference between actual and approved line losses.

a) Please provide a calculation showing Account 1588 as a percentage of Account 4705 Cost of Power annually and on a cumulative basis from 2016 to 2018.
b) Please explain the high 2018 transactions for Account 1588 in consideration of

Response:

a) GSHi understands that Account 1588 are not expected to contain large balances as it should only hold the difference between actual and approved line losses. GSHi would like to draw attention to Chapter 2 Appendix 2-R "Loss Factors" (Exhibit 8, Tab 4, Schedule 1, Page 1). This appendix has calculated a proposed loss factor of 1.0479 for GSHi, which is lower than the current loss factor of 1.054. In particular in 2017 & 2018, GSHi experienced lower line losses than billed, which drove a liability balance in account 1588 in both of those years.

   Please see the requested calculation below. GSHi has also included billed and actual loss factors from Appendix 2-R for reference.

	2016	**2017**	**2018**		**Cumulative**
1588 (Transactions)	103,058.15	(527,519.14)	(983,174.95)		(1,407,635.94)
4705	$ 66,081,128.30	$ 57,062,553.43	54,892,983.54		178,036,665.27
1588 as a % of 4705	0.16%	-0.92%	-1.79%		-0.79%
Billed Loss Factor	1.0540	1.0540	1.0540		
Distributor's actual loss factor (Appendix 2-R)	1.0475	1.0393	1.0307		

b) GSHi would like to draw attention to Chapter 2 Appendix 2-R "Loss Factors" (Exhibit 8, Tab 4, Schedule 1, Page 1). This appendix calculates the "Loss Factor in Distributor's system" of 1.0307 in 2018. This compares to GSH's billed loss factor of 1.054 and helps to explain why GSH experienced a large balance in the year.