Responses to Settlement Clarification Questions
2021 Electricity Distribution Rates Application
Niagara Peninsula Energy Inc. (NPEI)
EB-2020-0040

SEC Clarification Questions

1. [2-Staff-19(b)] In response to an IR about low DAI values, the Applicant states that, "NPEI has reviewed the data provided to Kinetrics for the ACA and identified an error in correlating asset identification numbers across data sets." Please explain what is meant by this sentence. Is the low DAI a result of this error or is this a further issue that has now been identified? If it is the latter, please explain the impact it has on the ACA results.

   It was found that the data columns did not align when some data was imported into the ACA workbook. This resulted in data fields appearing to be blank or missing data, thus causing a low DAI result. The impact that this had on the ACA results was to cause the assets with the misaligned data to have marginally higher Health Index numbers than they otherwise would have if the data had been properly imported.

2. [2-Staff-23(b)] Please provide the incremental savings (capital and OM&A) expected in 2021. Please explain how these have been built into the test year budget.

   Please see the table below.

Postage due to e-bill	28,800
48 Hour notice-IVR	44,640
Communication materials now in-house	8,000
Telephone review of Bell lines	27,600
Brinks one day	1,500
Courier	12,000
Postage Micro-fit-EFT	3,700
Vendor Cheques to EFT	16,000
These will persist into 2021	142,240
2021	
Smart Fault indicators	5,000
Expand SCADA	10,000
ACA analysis -move to in-house	15,000
Email-overdue notices	16,650
E-Bill customer growth (2500 in 2021)	33,300
Collections process automation-reduce Overtime	18,000
	97,950
Total estimated savings from efficiencies in 2021	240,190

The estimated savings of $240,190 have been built into the 2021 Test Year proposed OM&A.

The proposed pole-mount and pad-mount transformer replacement programs, as well as other voltage conversion capital projects included in the 2021 Test Year capital plan are anticipated to reduce the loss factor between 2021 and 2025 which will provide a future savings to customers' bill impacts.

3. [2-SEC-11(b)/2-Staff-38(a)] Please provide a copy of the actual business case (or similar document) that was developed before a decision to proceed with construction of the new garage facility was taken.

   No formal business case was developed before the decision to proceed with the construction of the new garage facility. Please see the response 2-Staff-98.

4. [2-SEC-19(c)] In response to an IR asking for internal guidance documents regarding how to use the risk/benefit matrix, the Applicant refers to sections of the DSP. Does this indicate that Applicant's Staff use the referenced sections of the DSP (or the information contained within) for the purposes of determining project specific risk/benefit matrix? If not, please provide a copy of the material they utilize to guide their determination of the appropriate risk/benefit score.

The risk/benefit matrix included in the DSP was developed internally as part of the update to the DSP. This matrix was developed out of the desire to implement a standardized approach to scoring potential projects. There were and are no internal guidance documents relating to either the development of or use of this matrix. The matrix was developed based on the OEB's *"Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 5 Consolidated Distribution System Plan"* Section 5.4.3.2 – Material Investments, Part B – Evaluation criteria and information requirements for each project/program.

The matrix contains a weighting for each project/program for each of the six evaluation categories identified in section 5.4.3.2: Efficiency, Customer Value& Reliability; Safety; Cyber Security & Privacy; Co-ordination & Interoperability; Environmental Benefits; Conservation and Demand Management, as well as for the type of Project Category. The matrix also aligns with the same evaluation headings contained in the Capital Project Summary document which is to be completed for each proposed project. The common link between the matrix and the project summaries is the evaluation criteria outlined in the OEB Filing Requirements document for Chapter 5 – Consolidated DSP's.

The first application of this process was in the development of the proposed 2021 Test Year capital plan as part of the Distribution System Plan and Cost of Service application processes. NPEI will be developing a "Guideline" document on the process for utilizing the risk/benefit matrix and Capital Project Summary forms early in 2021 upon availability of internal engineering department resources.

5. [4-SEC-32] Please provide a response to the IR.

   NPEI provided a response of the total cost of the three positions during the Settlement Conference.

6. [4-SEC-33] Please provide the requested information for 2019 and 2020. Specifically, for each of 2019 and 2020, please provide the actual corporate metrics and targets. For 2019 please provide the year-end actuals.

   NPEI has included in Attachment 1 as well as the Executive Pay policy that was filed with the Ontario Energy Board in confidence on August 18, 2020.

7. [4-SEC-34] Please provide the total amount of incentive pay included in the test year budget in dollars.

   NPEI has included 91% of the maximum incentive available in the 2021 Test Year.

8. [4-VECC-43(a)] When did each of the vacant positions become vacant? Are any of these vacancies included in the 2020 information contained in Appendix 2-K or any of the OM&A appendices. If so, please explain.

For each vacant position, the table below provides the date when each position became vacant and whether the vacant position is included in the 2020 information contained in Appendix 2-K.

Vacant on November 30th	# of Vacancies	Status	When Position Became Vacant	Included in 2020 Appendix 2-K
Regulatory & Financial Manager	1	Interviews November 23 & 24	New position	Yes, originally planned to hire in 1st Quarter of 2020
Key Account Co-ordinator	1	No posting as at November 6th	New position	No, plan was to hire in Jan 2021
Engineering Technician	1	Will be posted after recruitment for PLT and Reg Mgr	July 2019 retirement	Yes, originally planned to hire in 1st Quarter of 2020
Co-Op powerline apprentices	2	Will recruit from the colleges in February 2021	September 16, 2019	No, plan is to recruit in Feb 2021
Power line Technicians (PLT)	3	Interviews November 9th to 13th	1 became vacant November 27 2019; 2 became vacant October 5, 2020	2 are in 2020, 1 is in 2021
Total	8			
CDM co-ordinator	1	Moved to Accounting Supervisor position due to retirement August 31 2020 Not backfilled	August 31, 2020 (Not to be backfilled)	No, this position is not included in NPEI's rates. It is funded 100% by the IESO.
Total	9			

9. [4-Staff-64] The Applicant notes that the Accounting Supervisor and Energy Services and Metering Supervisor will still be required to do CDM work in 2021 which it has applied to the IESO to recover. Has that IESO funded portion been included in the Applicant's 2021 budget. If not, please provide the expected 2021 amount to be recovered if approved by the IESO.

NPEI's most recent CDM budget submission to the IESO includes a total of 308 hours annually for each of the Accounting Supervisor and the Energy Services and Metering Supervisor to complete the CDM work in 2021. This amounts to $46,738 in total for both positions. This $46,738, IESO funded portion, has not been included in Other Revenue in the 2021 Test Year as it was anticipated at the time the COS Rate Application was completed that all CDM work would be finalized by December 31, 2020. The $46,738 of Other Revenue is only applicable to the 2021 Test Year and not to any of the years from 2022 to 2025.

10. [5-SEC-36] As requested in the IR, please provide a summary of the responses to the RFP. (Please note: SEC does not object to the names of the unsuccessful proponents being redacted)

NPEI provided a summary of the responses to the RFP in Attachment 8 of NPEI's Interrogatory Responses. Please see 381 of 437 in NPEI's Interrogatory Responses.

11. [8-Staff-75] Under the status quo option, what would be the GS>50 MSC?

Please see the tables below.

Current Rates GS > 50 kW		% of Total
Current Service Charge-Monthly	$ 109.12	15.35%
Current Volumetric Charge- per kW	$ 3.5671	84.65%

Rate Application Proposed	Total Revenue	% of Total
Fixed Revenue	$ 1,629,488	22.01%
Volumetric Revenue	$ 5,775,021	77.99%
Total Revenue Requirement for GS > 50 kw class	$ 7,404,509	100.00%
Proposed Service Charge-Monthly	$ 168.06	
Proposed Volumetric Charge- per kW	$ 3.5321	
Sec 11 Pre-Settlement Conference	**Total Revenue**	**% of Total**
Fixed Revenue	$ 1,136,274	15.35%
Volumetric Revenue	$ 6,268,235	84.65%
Total Revenue Requirement for GS > 50 kw class	$ 7,404,509	100.00%
Sec-11 Service Charge-Monthly	$ 117.19	
Sec -11 Volumetric Charge- per kW	$ 3.8115	

VECC Clarification Questions

VECC-55

REFERENCE: 3-VECC-22 b)
Niagara_Peninsula_Energy_Inc._IRR_Weather_
Normalization_Regression_Model_20201119
Niagara_Peninsula_Energy_Inc._IRR_OEB_Appendix 2-Z
Commodity Expense 2021 Version
7-HONI-1

PREAMBLE: The response to VECC 22 b) states that NPEI has one market participant customer and that this customer is not included in the Total Power Purchased values used in the load forecast regression model.

In the Rate Class Energy Model Tab of the load forecast regression model 2021 total billed energy is derived directly from the forecast 2021 purchased power value by adjusting only for losses.

a) Please confirm what retail customer class the one market participant is in.

NPEI's one Wholesale Market Participant ("WMP") is in the GS > 50 kW class.

b) Is the market participant one of the four HONI delivery points (per HONI-1 a) and, if so, which one?

The WMP is not one of the four HONI delivery points.

c) Please confirm whether the one market participant customer is billed NPEI's monthly distribution charges and, if not, explain why.

The WMP is billed NPEI's monthly distribution charges.

d) Regardless of whether or not the market participant is billed NPEI's monthly distribution charges please indicate, for each year from 2002 to 2019, the customer's annual energy and 12-month billing demands.

Please see the table below.

Notes	Year	**KW**	**kWh**
Opened Sept 2005	2005	1,206	1,043,382
	2006	7,432	4,281,978
	2007	6,893	3,896,168
	2008	7,227	4,109,711
	2009	6,950	4,001,455
	2010	6,430	4,094,184
	2011	6,514	3,698,474
Last bill Oct 2012	2012	6,306	3,313,438
No bills	2013	-	-
No bills	2014	-	-
No bills	2015	-	-
Starts June 1 2016	2016	3,328	1,943,427
	2017	5,982	3,393,277
	2018	5,804	3,165,160
	2019	5,538	3,074,768
	2020	4,998	2,727,021

The WMP customer was a normal GS>50 kW customer of NPEI until October 2012, at which time the customer registered with the IESO to become a WMP. Since registering with the IESO as a WMP, the customer is invoiced commodity and regulatory charges directly by the IESO. NPEI issued its final bill to the customer as a normal GS>50 kW customer up to October 2012, but the account for NPEI to bill the customer as a WMP for distribution charges, transmission charges and LV was not set up. In July 2018, NPEI became aware that the customer had not been billed since becoming a WMP, and obtained permission from the IESO to establish a virtual meter point for the WMP customer in order for NPEI to bill for distribution charges, transmission charges and LV. During 2018, NPEI completed a back-billing for 24 months (i.e. back to June 1, 2016), and has been billing the WMP for distribution charges, transmission charges and LV since that time.

Therefore, the consumption and demand data for thus customer is not available for the period of November 2012 to May 2016.

e) Since the energy usage for the one market participant is not included in the purchased power values, please confirm that its energy usage is not included in the 2021 forecast billed energy values (per the Rate Class Energy Model Tab).

NPEI's confirms that the energy usage for the WMP is not included in the 2021 forecast billed energy values per the Rate Class Energy Model Tab.

f) Is the energy usage and billing demand for the one market participant included in: i) the retail energy values by customer class per the Rate Class Energy Model Tab and ii) the billing demand value by customer class per the Rate Class Load Model Tab. If yes, please provide a schedule that separates out these values for each year shown.

i. The energy usage for the WMP is not included in the energy values by customer class per the Rate Class Energy Model Tab.

ii. The billing demand for the WMP is included in the billing demand value by customer class per the Rate Class Load Model Tab for the years in which NPEI billed the WMP for distribution revenue (since June 1, 2016).

g) Based on the preceding responses, do NPEI's 2021 forecast of energy and demand billing determinants by customer class include the energy and demand associated with NPEI's market participant customer?

NPEI's forecast of energy billing determinants for the 2021 Test Year do not include the energy for the WMP, since the energy for the WMP is not included in the historical years.

NPEI's forecast of demand billing determinants for the 2021 Test Year does include the demand for the WMP. As indicated in the response to part d) above, the historical billed demand for the WMP is included in the Rate Class Load Model Tab since June 1, 2016. In the determination of the 2021 Test Year forecast of billed kW for the GS>50 kW class, NPEI utilized a 3-year average kW to kWh ratio based on 2017-2019, which includes the historical billed kW for the WMP.

i. If yes, please explain why the 2021 forecast of billing energy by customer class match (after allowing for losses) the class energy values used in the determination of commodity costs for working capital purposes (Appendix 2-Z) when such commodity costs are required to exclude market participant usage.

The 2021 forecast of billed energy by customer class matches (after allowing for losses) the energy values used in the determination of commodity costs since the WMP energy consumption is not included in either quantity.

ii. If not, what adjustments need to be made to the 2021 forecast billing energy and demand determinants by customer class so as to include the market participant customer.

In NPEI's view, no adjustments are necessary to the 2021 forecast billed energy or demand in relation to the WMP, since the 2021 Test Year forecast excludes the WMP energy (which NPEI does not bill) and includes the WMP demand (which NPEI does bill).

VECC-56

REFERENCE: 7-HONI-1 a) & b)
Niagara_Peninsula_Energy_Inc._IRR_Weather_
Normalization_Regression_Model_20201119

a) Please provide a schedule for each of the four HONI delivery points that indicates for the period 2002-2019 each of the following:

   i. Whether the customer was billed for fixed distribution delivery charges by NPEI.
   ii. Whether the customer was billed for variable distribution delivery charges.
   iii. Whether the customer was billed by NPEI for the commodity.
   iv. Whether the customer was billed by NPEI for RTSRs.
   v. Whether the customer was billed by NPEI for LV charges.
   vi. Whether the customer's "energy" is included in the purchased energy values (after LTLT adjustments) used to derive the load forecast regression model.
   vii. Whether the customer's energy values are included in the retail energy values set out in the Rate Class Energy Model Tab.
   viii. Whether customer's billing demand values are included in the Rate Class Load Model Tab.

Please see the table below. NPEI notes that the requested data is not available prior to 2009, since the bills for these accounts prior to 2009 were generated in the previous Peninsula West Utilities' Billing System. Upon conversion to NPEI's current billing system, the details of the individual charge types on each bill prior to 2009 were not converted into the new system. NPEI no longer has access to historical data prior to 2009.

The Victoria PME was installed in February 2014. Prior to that time, the Hydro One customers downstream of the PME were settled as LTLT customers, with NPEI as the physical distributor and Hydro One as the geographic distributor.

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2019	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	Volumetric distribution charges billed since May 1 2019 are being reversed
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	Volumetric distribution charges billed since May 1 2019 are being reversed
2018	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2017	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	
2016	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2015	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	
2014	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes	Victoria PME was installed in February 2014.
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No	
	iii) Billed Commodity	Yes	Yes	Yes	Yes	
	iv) Billed RTSR	Yes	Yes	No	No	
	v) Billed LV	Yes	Yes	No	No	
	vi) Energy is included in Purchased Energy	Yes	Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab	Yes	Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab	Yes	Yes	No	No	

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2013	i) Billed Fixed Distribution Charges		Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges		Yes	No	No	
	iii) Billed Commodity		Yes	Yes	Yes	
	iv) Billed RTSR		Yes	No	No	
	v) Billed LV		Yes	No	No	
	vi) Energy is included in Purchased Energy		Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab		Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab		Yes	No	No	
	ix) Billed volumetric through LTLT settlement	Yes				Prior to February 2014, the customers downstream of the Victoria PME were settled as LTLT customers.
	x) Billed fixed distribution charge through LTLT settlement	No				
2012	i) Billed Fixed Distribution Charges		Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges		Yes	No	No	
	iii) Billed Commodity		Yes	Yes	Yes	
	iv) Billed RTSR		Yes	No	No	
	v) Billed LV		Yes	No	No	
	vi) Energy is included in Purchased Energy		Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab		Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab		Yes	No	No	
	ix) Billed volumetric through LTLT settlement	Yes				
	x) Billed fixed distribution charge through LTLT settlement	No				

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2011	i) Billed Fixed Distribution Charges		Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges		Yes	No	No	
	iii) Billed Commodity		Yes	Yes	Yes	
	iv) Billed RTSR		Yes	No	No	
	v) Billed LV		Yes	No	No	
	vi) Energy is included in Purchased Energy		Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab		Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab		Yes	No	No	
	ix) Billed volumetric through LTLT settlement	Yes				
	x) Billed fixed distribution charge through LTLT settlement	No				
2010	i) Billed Fixed Distribution Charges		Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges		Yes	No	No	
	iii) Billed Commodity		Yes	Yes	Yes	
	iv) Billed RTSR		Yes	No	No	
	v) Billed LV		Yes	No	No	
	vi) Energy is included in Purchased Energy		Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab		Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab		Yes	No	No	
	ix) Billed volumetric through LTLT settlement	Yes				
	x) Billed fixed distribution charge through LTLT settlement	No				

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME	Notes
2009	i) Billed Fixed Distribution Charges		Yes	Yes	Yes	
	ii) Billed Volumetric Distribution Charges		Yes	No	No	
	iii) Billed Commodity		Yes	Yes	Yes	
	iv) Billed RTSR		Yes	No	No	
	v) Billed LV		Yes	No	No	
	vi) Energy is included in Purchased Energy		Yes	Yes	Yes	
	vii) Energy is included in Rate Class Energy Model Tab		Yes	Yes	Yes	
	viii) Billing demand values are included in Rate Class Load Model Tab		Yes	No	No	
	ix) Billed volumetric through LTLT settlement	Yes				
	x) Billed fixed distribution charge through LTLT settlement	No				

b) Please provide a schedule for each of the four HONI delivery points that indicates for the 2021 test year:

i. Whether the customer will be billed for fixed distribution delivery charges by NPEI.

ii. Whether the customer will be billed for variable distribution delivery charges by NPEI.

iii. Whether the customer will be billed by NPEI for the commodity.

iv. Whether the customer will be billed by NPEI for RTSRs.

v. Whether the customer will be by NPEI for LV charges.

Please see the table below.

		Victoria PME	Rockway PME	Port Davidson PME	Wellandport PME
2021	i) Billed Fixed Distribution Charges	Yes	Yes	Yes	Yes
	ii) Billed Volumetric Distribution Charges	Yes	Yes	No	No
	iii) Billed Commodity	Yes	Yes	Yes	Yes
	iv) Billed RTSR	Yes	Yes	No	No
	v) Billed LV	Yes	Yes	No	No

RTSR and LV are not charged by NPEI to HONI for Port Davidson and Wellandport because when HONI bills NPEI the RTSR and LV charges are removed from HONI's invoice.

c) HONI-1 indicates that the two HONI delivery points (Port Davidson and Wellandport) that are to remain GS>50 customers will not be billed for the volumetric distribution charge. Does the forecast billing demand for the GS>50 class exclude the loads for these two customers and, if yes, where/how is this adjustment made?

The forecast billing demand for the GS>50 class does exclude the kW loads for these two customers for the purpose of determining the distribution volumetric rate since the demand for these two HONI delivery points are not in the historical load. Therefore, no adjustments are required to be made.

d) Will the two HONI delivery points (Port Davidson and Wellandport) that are GS>50 customers be billed for LV and RTSR charges?

No, the Port Davidson and Wellandport delivery points are not billed RTSR and LV charges.

i. If not, why not?

RTSR and LV are not charged by NPEI to HONI for Port Davidson and Wellandport because when HONI bills NPEI the RTSR and LV charges are removed from HONI's invoice.

ii. If yes, have billing demands for these two customers been included in the determination of the LV rates and RTSRs for 2021 (i.e., different billing determinant values were used for the GS>50 class for these two charges than were used to determine the class' distribution charges)?

Not applicable.

e) Will the two HONI delivery points (Port Davidson and Wellandport) that are GS>50 customers be billed for the various rate riders applicable to the GS>50 class?
No, NPEI proposes that the Port Davidson and Wellandport delivery points should not be billed the rate riders applicable to the GS>50 kW rate class.

i. If not, why not?

Since NPEI only bills HONI for commodity and wholesale market services, the other RSVA accounts (i.e. Network, Connection and LV) would not be applicable to HONI. NPEI is unable to segregate the Group 1 accounts for the purposes of determining rate riders specific to these two customer accounts.

ii. If yes, have billing demands for these two customers been included in the determination of the GS>50 class rate riders for 2021 (i.e., different billing determinant values were used for the GS>50 class for these two charges than were used to determine the class' distribution charges)?

Not applicable.

VECC-57

REFERENCE: 3-VECC-22 a)
Niagara_Peninsula_Energy_Inc._IRR_Weather_Normalization_Regression_Model_20201119

a) For the period 2002-2019 please clarify whether the customer class energy values in the Rate Class Energy Model Tab and the customer class billing demand values in the Rate Class Load Model Tab:

i. Include or exclude LTLTs delivered to NPEI (as the geographic distributor) by a neighbouring LDC (as the physical distributor).

For all years, the customer class energy values in the Rate Class Energy Model Tab exclude the LTLT kWh delivered to NPEI (as the geographic distributor) by a neighbouring distributor (as the physical distributor).

ii. Include or exclude LTLTs delivered by NPEI (as physical distributor) to a neighbouring LDC (as the geographic distributor).

Prior to 2015, the customer class energy values in the Rate Class Energy Model Tab exclude the LTLT kWh delivered by NPEI (as the physical distributor) to a neighbouring distributor (as the geographic distributor).

For the years 2015-2019, the customer class energy values in the Rate Class Energy Model Tab include the LTLT kWh delivered by NPEI (as the physical distributor) to a neighbouring distributor (as the geographic distributor).

b) If not addressed in the response to part (a) please explain more fully the basis for the change that occurred in 2015 and specifically what was the reason for the change in the treatment of deliveries by NPEI, as physical distributor, to a neighbouring LDC, as the geographic distributor in the regression model (e.g., was it because they were excluded from NPEI's purchases from the IESO as of 2015).

As noted in the response to 3-VECC-22 a), NPEI had LTLT arrangements with 6 neighbouring LDCs. The LTLT arrangements with 5 of these neighbouring LDCs were eliminated during 2017. The elimination of LTLTs with the final LDC, Hydro One, is expected to be completed in 2021.

Therefore, after 2017, there is no quantity of LTLT kWh delivered by NPEI as physical distributor (with the exception of ongoing LTLTs with Hydro One), and the LTLT customers of the geographic distributors that were previously supplied by NPEI became NPEI customers during 2017 (with the exception of Hydro One). Accordingly, the energy sales of these customers is reflected in the Rate Class Energy Model Tab since the transfer of LTLT customers was completed (i.e. for part of 2017, 2018 and 2019). NPEI viewed it to be appropriate to treat the entire period since NPEI's last COS Rate Application consistently (i.e. 2015-2019), and therefore has included the LTLT kWh delivered since 2015 in the energy sales by customer class in the Rate Class Energy Model Tab commencing in 2015.

VECC-58

REFERENCE:	9-Staff-83 3-VECC-29 Niagara_Peninsula_Energy_Inc._IRR_2020_Filing_ Requirements_Chapter2_Appendices_11192020
PREAMBLE:	VECC 29 states that NPEI has updated the pole attachment rates to reflect the 2020 actual rate ($44.50), and has utilized the 2020 inflation factor to estimate the 2021 pole attachment rate. Staff 83 indicates that as of November 10, 2020 there were 40 poles with LDC attachments and 15,217 poles with telecom attachments – for a total of 15,257.

a) Please confirm that the 2020 inflation factor was 2%.

In the interrogatory response to 8-Staff-83 regarding the updated forecast balance for 2020 in Account 1508 – Sub-Account Pole Attachment Variance, NPEI utilized the correct OEB-approved 2020 Pole Attachment Rate of $44.50, which was set based on the 2020 OEB-approved inflation factor of 2.0%. However, in updating the forecast 2020 and 2021 Wireline Pole Attachment Revenue to be included in Appendix 2-H, NPEI only updated the rates used in the Wireline Pole Attachment accounts payable transactions to reflect the approved 2.0% increase for 2020 and the forecast 2.0% increase for 2021, but did not update the rate used in the Wireline Pole Attachment accounts receivable transactions.

Please see the response to part c) below.

b) Please confirm that there is only one telecom company with attachments to each of NPEI's poles that has such attachments (i.e., no pole as two or more telecom companies attached to it).

This is not confirmed. There are poles owned by NPEI that have two or more telecom companies attached to them. In this case, NPEI bills each company attached to NPEI's poles at the OEB-approved rate. Therefore, the reference to the number of poles in the responses to 9-Staff-83 and 3-VECC-29 actually relate to the number of attachments on NPEI poles.

c) The updated Appendix 2-H shows 2021 poles access charge revenue of $547,617. Please reconcile this value with the value obtained by multiplying the number of poles attachments NPEI currently has with the assumed 2021 poles attachment rate (i.e., 15,257 x $44.50 x 1.02 = $692,515).

As indicated in the response to part a) above, NPEI notes that the forecast 2021 Wireline Pole Attachment Rate of $44.50 * 1.02 = $45.39 was not updated correctly for the accounts receivable transactions when calculating the 2020 Bridge Year and 2021 Test Year forecast Wireline Pole Attachment Revenue in NPEI's updated Appendix 2-H submitted with NPEI's interrogatory responses.

The corrected forecast 2021 Test Year Wireline Pole Attachment Revenue is $554,608. NPEI will increase Other Revenue by $5,390 as part of the settlement process.

The Wireline Pole Attachment Revenue in Appendix 2-H represents the net revenue from other utilities for wireline attachments on NPEI poles, less what NPEI pays to other utilities for NPEI attachments on the other utilities' poles. The difference between the corrected forecast 2021 Test Year Wireline Pole Attachment Revenue of $554,608, and the value of $692,515 indicated in the question above relates to the forecast amount related to accounts payable for NPEI attachments on other utilities poles for 2021. The updated calculations for the 2020 Bridge Year and 2021 Test Year are provided in the tables below.

2020 Bridge Year

Transaction	# of Poles	OEB-Approved Pole Attachment Rate	Rate Effective in Last COS	Incremental Portion of Current Rate	Recorded in Account 1508	Recorded as Wireline Pole Attachment Revenue	Total Revenue
LDCs on NPEI Poles	40	44.50	22.35	22.15	(886)	(894)	(1,780)
Telecommunications carriers on NPEI poles	15,217	44.50	22.35	22.15	(337,057)	(340,100)	(677,157)
Subtotal (attachments on NPEI poles)	15,257				(337,943)	(340,994)	(678,937)
NPEI on Bell Poles (payable to Bell)	1,830	44.50				81,435	81,435
NPEI on Hydro One Poles (Payable to Hydro One)	609	88.29				53,769	53,769
Subtotal (NPEI attachments on other utilities poles)	2,439					135,204	135,204
Total					(337,943)	(205,790)	(543,733)

2021 Test Year IRRs

Transaction	# of Poles	Forecast OEB-Approved Pole Attachment Rate	Forecast 2021 Wireline Pole Attachment Revenue
LDCs on NPEI Poles	40	44.95	(1,798)
Telecommunications carriers on NPEI poles	15,217	44.95	(683,985)
Subtotal (attachments on NPEI poles)	15,257		(685,783)
NPEI on Bell Poles (payable to Bell)	1,830	44.95	82,256
NPEI on Hydro One Poles (Payable to Hydro One)	609	89.18	54,309
Subtotal (NPEI attachments on other utilities poles)	2,439		136,566
Total			(549,217)

2021 Test Year

Transaction	# of Poles	Forecast OEB-Approved Pole Attachment Rate	Forecast 2021 Wireline Pole
LDCs on NPEI Poles	40	45.39	(1,816)
Telecommunications carriers on NPEI poles	15,217	45.39	(690,700)
Subtotal (attachments on NPEI poles)	15,257		(692,515)
NPEI on Bell Poles (payable to Bell)	1,830	45.39	83,064
NPEI on Hydro One Poles (Payable to Hydro One)	609	90.06	54,844
Subtotal (NPEI attachments on other utilities poles)	2,439		137,908
Total			(554,608)

Difference			(5,390)

VECC-59

REFERENCE: 7-HONI- 1 & 2
OEB's 2020 Chapter 2 Filing Requirements, pages 49-50
Niagara_Peninsula_Energy_Inc._IRR_2020_Filing_Requirements_Chapter2_Appendices_11192020
Niagara_Peninsula_Energy_Inc._IRR_2020_Cost_Allocation_Model_20201119 (Tabs I3 & I4)

PREAMBLE: The Chapter 2 Filing Requirements state:

- *If the host distributor proposes to establish a new embedded distributor class, the host distributor must include that class in its cost allocation study and in the RRWF and provide rationale and supporting evidence for the establishment of an Embedded Distributor class, as applicable. The host distributor must provide the costs of serving the embedded distributor(s), load served, information regarding ownership of relevant assets involved in the connection(s), whether assets are dedicated to the embedded distributor(s) or shared to serve other customers, and the distribution charges levied.*
- *If the host distributor proposes to bill the embedded distributor(s) as if it/they were General Service Class customers, the costs and revenue must be included with that class in the cost allocation study and the RRWF. In this case, the host distributor must also complete Appendix 2-Q, which shows details on how much of the host's facilities are required to serve the embedded distributor(s), regardless of the fact that they are not treated as a distinct rate class elsewhere. The host must provide the cost of serving the embedded distributor(s), load served, information regarding ownership of relevant assets involved in the connection(s), and the distribution charges levied. Additionally, the host distributor must provide evidence supporting the continued appropriateness of the rates for the general service class for recovering the costs of providing low voltage distribution services to the embedded distributor(s).*

a) For each of the two HONI delivery points (Victoria Avenue and Rockway) that NPEI proposes to include in the new Embedded Distributor class please provide:

   i. A description of the assets used to serve the delivery point including their ownership (including the transformation station involved).

   Rockway PME
   As indicated on the attached Map (please see Attachment 2) the supply to the Rockway PME begins at the (HONI owned) Vineland DS that supplies power to the (NPEI owned) 4501F1 feeder. This feeder travels 15.5km to a

set of Stepdown Transformers (#52). After the voltage is stepped down to 8.3kV it travels 3km to the Rockway PME which measures the amount of energy consumed by HONI customers downstream of the unit. Please note HONI owns all assets downstream of the Rockway PME.

Victoria PME

As indicated on the attached Map (please see Attachment 2) the supply to the Victoria PME begins at the (Grimsby Power Inc. owned) Niagara West TS that supplies power to the (NPEI owned) 2508M5 feeder. This feeder travels 14km to supply power to the (NPEI owned) Campden MS that supplies power to the (NPEI owned) 1850F2 feeder that travels 8km to the Victoria PME which measures the amount of energy consumed by HONI customers downstream of the unit. Please note HONI owns all assets downstream of the Victoria PME.

ii. A separate version of Appendix 2-Q for the specific delivery point. In each case, please provide: i) the sources of the cost data used in columns 2, 3, 4 and 5 with cross references/reconciliation to the values in Tabs I3 and I4 of the Cost Allocation Model and ii) the basis for the kW and km values used in columns 7, 8, 9 and 10.

The sources of the cost data used in columns 2, 3, 4 and 5 in Appendix 2-Q are provided in the tables below:

	2Q Column 2				
	OM&A	Source = CA Model I3 Column D	2Q Column 11	CA Model I3 Column G	CA Model I3 Column H
5012	DS	$128,784	1.10%	1,413.49	127,370.45
	OH				
5020		$267,993	0.2410%	645.94	267,347.06
5025		$96,791	0.2410%	233.29	96,557.27
5120		$115,189	0.2410%	277.64	114,911.78
5125		$824,045	0.2410%	1,986.19	822,058.42
5130		$227,911	0.2410%	549.33	227,361.56
		$1,531,929	0.2410%	3,692.41	
	UG				
5040		$180,728	0.014%	26.08	180,701.91
5045		$382,485	0.014%	55.19	382,429.63
5145		$31,231	0.014%	4.51	31,226.16
5150		$243,981	0.014%	35.21	243,945.94
5155		$161,059	0.014%	23.24	161,036.07
		$999,484	0.014%	144.23	
		2,660,196.38		5,250.13	127,370.45

	2Q Column 3						I4 Column F				I4 Column G
Account Number		Source = Appendix 2-BA Average Fixed Asset Cost 2021	CA Model I4 Column G	Total Cost net of CC = 2Q Column 3	Per 2Q Column 11	CA Model I3 Column G	Cost after Allocation	Capital Contribution Allocated	CA Model I3 Column G	CA Model I3 Column H and I4 Column E and Column F	CC to be Allocated on I4 Column G
1820	DS	7,126,624	-	7,126,624	1.10%	78,219.63	7,048,404		78,219.63	7,048,404	-
1808		111,638	-	111,638	1.10%	1,225.31	110,413		1,225.31	110,413	-
		7,238,262	-	7,238,262	1.10%	79,444.94	7,158,817	-	79,444.94	7,158,817	-
1830	OH 1830	48,931,166	(3,371,807)	45,559,359	0.24%	117,938.74	48,813,227	(8,127.06)	109,811.68	48,821,354	(3,363,680)
		10,167,082	(700,605)	9,466,477	0.24%	24,505.71	10,142,577	(1,688.67)	22,817.04	10,144,265	(698,916)
		59,098,248	(4,072,412)	55,025,836	0.24%	142,444.45	58,955,804	(9,815.73)	132,628.72	58,965,619	(4,062,596)
	OH 1835	37,598,150	(1,691,925)	35,906,225	0.24%	90,622.79	37,507,527	(4,078.05)	86,544.74	37,511,605	(1,687,847)
		6,756,649	(304,051)	6,452,598	0.24%	16,285.54	6,740,363	(732.85)	15,552.69	6,741,096	(303,318)
		44,354,798	(1,995,976)	42,358,822	0.24%	106,908.33	44,247,890	(4,810.90)	102,097.43	44,252,701	(1,991,165)
	Total OH	103,453,047	(6,068,388)	97,384,659	0.24%	249,352.78	103,203,694	(14,626.63)	234,726.15	103,218,320	(6,053,761)
1840	UG	6,071,948	(5,314,103)	757,845	0.01%	876.22	6,071,071	(766.86)	109.36	6,071,838	(5,313,336)
		10,987,614	(9,616,241)	1,371,373	0.01%	1,585.58	10,986,029	(1,387.68)	197.90	10,987,417	(9,614,853)
		17,059,562	(14,930,344)	2,129,218	0.01%	2,461.80	17,057,100	(2,154.54)	307.26	17,059,255	(14,928,189)
1845		34,776,180	(3,956,038)	30,820,142	0.01%	5,018.42	34,771,161	(570.88)	4,447.54	34,771,732	(3,955,467)
		56,939,116	(6,477,230)	50,461,886	0.01%	8,216.67	56,930,899	(934.70)	7,281.97	56,931,834	(6,476,295)
		91,715,295	(10,433,268)	81,282,027	0.01%	13,235.09	91,702,060	(1,505.59)	11,729.51	91,703,566	(10,431,762)
	Total UG	108,774,857	(25,363,612)	83,411,245	0.01%	15,696.89	108,759,160	(3,660.13)	12,036.77	108,762,820	(25,359,952)
		219,466,165.61	(31,432,000.00)	188,034,165.61		344,494.62	219,121,671	(18,286.76)	326,207.86	219,139,958	(31,413,713)

	2Q Column 4									
Account Number		Source = Appendix 2-BA Average Accumulated Depreciation 2021	CC Before allocation	2Q Column 4	Per 2Q Column 11	Accum Deprec to be Allocated before CC	Capital Contribution Amortization Allocated	CA Model I3 Cell G183	CA Model I4 Column H	CA Model I4 Column I
1820	DS	(3,850,885)	-	(3,850,885)	1.098%	(42,266)	-	(42,266)	-	(3,808,619)
1808		(111,638)	-	(111,638)	1.098%	(1,225)	-	(1,225)	-	(110,413)
		(3,962,523)	-	(3,962,523)	1.098%	(43,491)	-	(43,491)	-	(3,919,032)
1830	OH	(23,258,073)	756,730	(22,501,343)	0.241%	(56,059)	1,824	(54,235)	754,906	(23,202,014)
		(4,832,641)	157,236	(4,675,405)	0.241%	(11,648)	379	(11,269)	156,857	(4,820,993)
		(28,090,714)	913,966	(27,176,748)	0.241%	(67,707)	2,203	(65,504)	911,763	(28,023,007)
1835		(12,928,671)	384,709	(12,543,962)	0.241%	(31,162)	927	(30,235)	383,782	(12,897,509)
		(2,323,372)	69,135	(2,254,237)	0.241%	(5,600)	167	(5,433)	68,968	(2,317,772)
		(15,252,043)	453,844	(14,798,199)	0.241%	(36,762)	1,094	(35,668)	452,750	(15,215,281)
		(43,342,756)	1,367,810	(41,974,947)	0.241%	(104,469)	3,297	(101,172)	1,364,513	(43,238,287)
1840	UG	(1,461,920)	1,870,981	409,062	0.014%	(211)	270	59	1,870,711	(1,461,709)
		(2,645,446)	3,385,672	740,226	0.014%	(382)	489	107	3,385,183	(2,645,065)
		(4,107,366)	5,256,653	1,149,287	0.014%	(593)	759	166	5,255,895	(4,106,773)
1845		(19,156,228)	850,514	(18,305,713)	0.014%	(2,764)	123	(2,642)	850,392	(19,153,463)
		(31,364,534)	1,392,549	(29,971,985)	0.014%	(4,526)	201	(4,325)	1,392,348	(31,360,008)
		(50,520,761)	2,243,063	(48,277,698)	0.014%	(7,290)	324	(6,967)	2,242,740	(50,513,471)
		(54,628,128)	7,499,717	(47,128,411)	0.014%	(7,883)	1,082	(6,801)	7,498,634	(54,620,244)
		(101,933,407)	8,867,526	(93,065,881)		(155,844)	4,379	(151,465)	8,863,147	(101,777,563)

	Depreciation expense								
	2Q Column 5								
		Source = Appendix 2-BA Depreciation Expense 2021	Amortization of Capital Contributions	2Q Column 5	2Q Column 11	Allocated Depreciation Expense	Allocation of Capital Contributions Amortization	CA Model I3 Cell G447	CA Model I4 Column L
2105-20	DS	147,029	-	147,029	1.10%	1,614	-	1,613.75	145,416
2105-30 Pr	OH Primary 82.8% per I4 Column D	621,299	79,168	542,131	0.24%	1,498	190.82	1,306.70	619,992
	OH Secondary 17.2% per I4 Column D	129,096	16,450	112,646	0.24%	311	39.65	271.51	128,824
		750,395	95,618	654,777	0.24%	1,809	230.47	1,578.21	748,817
2105-35	OH Conductor Primary 84.77% per I4 C	644,641	39,725	604,915	0.24%	1,554	95.75	1,458.03	643,183
	OH Conductor Secondary 15.23% per I4	115,846	7,139	108,707	0.241%	279	17.21	262.02	115,584
		760,487	46,864	713,623	0.241%	1,833	112.96	1,720.04	758,767
	Total Overhead	1,510,882	142,482	1,368,399	0.241%	3,642	343	3,298	1,507,584
2105-40	UG Conduit Primary	109,654	14,601	95,054	0.014%	16	2.11	13.72	109,640
	UG Conduit Secondary	198,427	81,246	117,180	0.014%	29	11.72	16.91	198,410
		308,081	95,847	212,234	0.014%	44	13.83	30.63	308,050
2105-45	UG Conductor Primary	709,819	201,210	508,609	0.014%	102	29.04	73.40	709,745
	UG Conductor Secondary	1,162,188	329,441	832,746	0.014%	168	47.54	120.17	1,162,068
		1,872,007	530,651	1,341,355	0.014%	270	76.58	193.57	1,871,813
	Total UG	2,180,088	626,498	1,553,589	0.014%	315	90	224	2,179,863
	Total Allocated Depreciation	3,837,999	768,981	3,069,018		5,570	434	5,136	3,832,863
	All other depreciation expense	4,646,004	434,755	4,211,249		-	4,646,004		
	Total Depreciation Expense	8,484,003	1,203,736	7,280,267		5,570	8,478,433		

Column 7 - DS 69,000 = capacity for all of NPEI's distribution stations

OH 1,451 = NPEI's total primary OH line length

UG 573 = NPEI's total primary UG line length

Column 8 - DS 5,000 = total capacity of Campden DS

OH 23.09 = Victoria PME = 7.9 km + Rockway PME = 15.19 km

UG 0.55 = Victoria PME = 0.25 km + Rockway = 0.3 km

Column 9 -	DS, OH, UG	44,928 = total annual demand on Campden DS
Column 10 -	DS, OH, UG	6,805 = total annual billed demand Victoria PME = 3,339 + total annual billed demand Rockway PME = 3.466

NPEI is submitting in Attachment 3, the original Appendix 2-Q submitted with its Interrogatory Responses and an updated Appendix 2-Q in pdf.

NPEI is also submitting a scenario 2-Q Excel for Victoria PME and a separate scenario 2-Q Excel for Rockway PME.

b) For each of the two HONI delivery points that NPEI proposes to continue to treat as GS>50 customers (Port Davidson and Wellandport) please provide:

   i. A description of the assets used to serve the delivery point including their ownership (including the transformation station involved).

      As indicated on the attached Map (please see Attachment 2) the supply to both the Port Davidson PME and the Wellandport PME begins at the (HONI owned) Beamsville TS that supplies power to the (HONI owned) 18M2 feeder. This feeder travels 22km to supply power to the (HONI owned) Bismark DS.
      From the (HONI owned) Bismark DS power is supplied to the (HONI owned) 1848F3 feeder that travels 7km to the Port Davidson PME which measures the amount of energy consumed by HONI customers downstream of the unit.
      From the (HONI owned) Bismark DS power is supplied to the (HONI owned) 1848F2 feeder that travels 9.5km to the Wellandport PME which measures the amount of energy consumed by HONI customers downstream of the unit.

   ii. A separate version of Appendix 2-Q for the specific delivery point. In each case, please provide: i) the sources of the cost data used in columns 2, 3, 4 and 5 with cross references/reconciliation to the values in Tabs I3 and I4 of the Cost Allocation Model and ii) the basis for the kW and km values used in columns 7, 8, 9 and 10.

As per the description in part i) and as per Attachment 2, there are no assets owned by NPEI and therefore Appendix 2-Q is zero for all of the columns.

NPEI has included an Excel version of the Cost Allocation Model where no assets are allocated and no demand is entered in Sheet I8. The minimum system with PLCC adjustment per Sheet O2 is $74.71.

c) Please explain why NPEI considers Victoria Avenue PME and Rockway PME delivery points to meet the definition of an embedded distributor but not the Port Davidson PME and Canboro Road (Wellandport PME) delivery points.

Please see IRR HONI-1 b) response.

d) Please provide an alternative cost allocation model where:

   i. There is a separate ED class for the Victoria Avenue PME and Rockway PME delivery points (as proposed by NPEI) but the allocation to the ED class is <u>not</u> based on a direct allocation using the results of Appendix 2-Q but rather uses the allocation factors established by the model.

NPEI has included an Excel version of the Cost Allocation Model with no direct allocations made on Sheet I3. On Sheet I8, NPEI has obtained NPEI's monthly system peak demands for 2019 and obtained the demand kW for Victoria PME and Rockway PME at the system peak dates and times in order to determine the CP values. Please see the table below.

2019	NPEI Total System Load	Total System Load without Embedded Generation	Date	Time	Victoria PME kW	Rockway PME kW	Total
Jan	189,815	197,346	January 31, 2019	18:30	286	317	602
Feb	183,440	186,680	February 1, 2019	18:15	242	274	516
Mar	174,285	176,665	March 6, 2019	19:00	229	308	537
Apr	151,201	152,425	April 5, 2019	19:00	179	215	394
May	151,418	154,135	May 27, 2019	16:45	173	149	322
Jun	214,095	216,857	June 28, 2019	14:45	241	197	438
Jul	251,133	256,280	July 20, 2019	17:00	331	334	665
Aug	233,187	237,907	August 20, 2019	15:45	270	226	495
Sep	212,371	213,806	September 11, 2019	16:45	237	236	473
Oct	189,818	197,009	October 1, 2019	14:30	97	229	326
Nov	168,847	169,816	November 13, 2019	17:45	193	233	426
Dec	179,068	180,118	December 19, 2019	17:15	237	282	519
			1CP				665
			4CP				2,072
			12CP				5,713

The table below determines the NCP values for the Victoria and Rockway PMEs for 2019 which have also been entered on Sheet I8 for this scenario.

Month	Victoria Billed kW	Rockway Billed kW	Total
Jan-19	330	348	678
Feb-19	294	341	635
Mar-19	264	316	580
Apr-19	224	248	472
May-19	197	225	422
Jun-19	286	267	553
Jul-19	351	368	719
Aug-19	302	286	588
Sep-19	291	263	554
Oct-19	219	232	451
Nov-19	254	267	522
Dec-19	327	306	633
1NCP			719
4NCP			2,665
12NCP			6,806

e) Please provide another alternative cost allocation model where:
   i. There are two distinct ED classes, one for the Victoria Avenue PME and Rockway PME delivery points and another for the Port Davidson PME and Canboro Road (Wellandport PME) delivery points and

   Please see VECC 59b) and d) response.

   ii. The allocation to each of the ED classes is not based on a direct allocation using the results of Appendix 2-Q but rather uses the allocation factors established by the model.

   Please see VECC 59b) and d) response.

f) Is NPEI the host distributor for any other distribution utilities besides HONI? If yes, who are they, what customer class are they currently in and what are of the assets used to serve each of the delivery points including their ownership?
NPEI is not a host distributor for any other distribution utilities other than HONI.

VECC-60

REFERENCE: Niagara_Peninsula_Energy_Inc._IRR_2020_Cost_Allocation_Model_20201119
Niagara_Peninsula_Energy_Inc._IRR_2021_RTSR_Workform_20201119
7-VECC-50

a) What is the basis for the billing and collecting weighting factor of 0.1 used for the new ED class (Tab I5.2)?

The proposed billing and collecting weighting factor for the ED class was incorrectly set at 0.1 and should be set at 1.0 whereby NPEI believes the new ED class would be similar to the Residential class weighting factor of 1.0 for billing and collecting. NPEI believes the new ED class does not have any implication related to Class A or the load review which is performed for commercial customers for rate class reclassification. Several billing and collecting activities that typically apply to other classes will be applicable to all four HONI delivery points.

b) VECC 50 asked "why for each of GS<50 and GS>50 classes the number of Line Transformer Customers is less than the number of Secondary Customers (per Tab I6.2)". The response states "The difference represents the number of customers that own their own transformers." Please describe how/why there are customers that own their own transformers but do not own the secondary assets on the "customer-side" of the transformer.

NPEI confirms that the customers that own their own transformers also own the secondary assets on the "customer-side" of the transformer. NPEI proposes to update Tab I6.2 of the Cost Allocation Model so that the number of Secondary Customers are equal to the number of Line Transformer Customers for the GS<50 kW and GS>50 kW classes.

VECC-61

REFERENCE: Niagara_Peninsula_Energy_Inc._IRR_2020_Cost_Allocation_Model_20201119
Niagara_Peninsula_Energy_Inc._IRR_2021_RTSR_Workform_20201119

a) Please confirm that in the Cost Allocation Model the cost of assets in Account 1815 (Transformer Station Equipment - Normally Primary above 50 kV) is allocated to all customer classes (except the new ED class) based on total class loads, including the load for customers not served from the NPEI-owned transformer.

NPEI confirms that the total class loads used in the Cost Allocation Model include the loads for customers not served from the NPEI-owned transformer.

b) Please confirm that in Tab 3 (RRR Data) of the RTSR Workform:

i. The load data for the GS>50 class includes the 4 HONI delivery points.

NPEI confirms that the load data for the GS>50 customer class includes the HONI delivery points for which NPEI bills volumetric distribution revenue.

ii. The load data for all customer classes includes the customer load served from the NPEI-owned transformer and the Grimsby-owned transformer.

NPEI confirms that the load data for all customer classes includes the customer load served from the NPEI-owned transformer and the Grimsby-owned transformer.

c) Is the cost of the transformation service that is provided by the Grimsby-owned transformer included in Grimsby's LV charges to NPEI or Grimsby's RTSR charges to NPEI?

The cost of the transformation service that is provided by the Grimsby-owned transformer is included in Grimsby Power's LV charges to NPEI.

d) Please confirm that the IESO transformation connection billing units used in the RTSR Workform (Tabs 5, 6 and 7) are based on 2019 actual data. If not, what year are they based on?

NPEI confirms that the IESO transformation connection billing units used in the RTSR Workform (Tabs 5, 6, and 7) are based on 2019 actual data.

e) Please provide the comparable monthly demands for the NPEI-own transformation station for the same year as the IESO transformation connection billing units used in the RTSR Workform.

The table below provides the 2019 monthly peak demands for the NPEI-owned Kalar TS.

2019 Month	Kalar TS Peak Demand (kW)
Jan	26,343
Feb	24,405
Mar	23,664
Apr	20,228
May	21,249
Jun	32,439
Jul	38,359
Aug	33,834
Sep	30,499
Oct	26,558
Nov	22,558
Dec	24,482
Total	**324,618**

f) Please provide the comparable NPEI monthly demands on Grimsby-owned transformation station for the same year as the IESO transformation connection billing units used in the RTSR Workform.

The table below provides the 2019 monthly peak demands for NPEI's supply from the Grimsby Power-owned Niagara West TS.

2019 Month	Niagara West TS Peak Demand (NPEI portion) (kW)
Jan	9,625
Feb	9,443
Mar	8,899
Apr	8,352
May	10,010
Jun	15,067
Jul	14,120
Aug	15,206
Sep	15,756
Oct	11,408
Nov	12,660
Dec	13,162
Total	**143,708**

g) Please provide an alternative Cost Allocation model which is the same as that filed with the IR responses except the costs associated with NPEI's transformer station (>50 kV) are allocated to all customer classes, including the new ED class. (Note: If NPEI is unable to determine a TCP12 values for the ED class please use the class' 12-month billing demands as a proxy)

NPEI has prepared an alternative Cost Allocation Model which includes the direct allocations from Appendix 2Q but has NCP values equaling zero and only the 12CP value has been entered as per this table below.

2019	NPEI Total System Load	Total System Load without Embedded Generation	Date	Time	Victoria PME kW	Rockway PME kW	Total
Jan	189,815	197,346	January 31, 2019	18:30	286	317	602
Feb	183,440	186,680	February 1, 2019	18:15	242	274	516
Mar	174,285	176,665	March 6, 2019	19:00	229	308	537
Apr	151,201	152,425	April 5, 2019	19:00	179	215	394
May	151,418	154,135	May 27, 2019	16:45	173	149	322
Jun	214,095	216,857	June 28, 2019	14:45	241	197	438
Jul	251,133	256,280	July 20, 2019	17:00	331	334	665
Aug	233,187	237,907	August 20, 2019	15:45	270	226	495
Sep	212,371	213,806	September 11, 2019	16:45	237	236	473
Oct	189,818	197,009	October 1, 2019	14:30	97	229	326
Nov	168,847	169,816	November 13, 2019	17:45	193	233	426
Dec	179,068	180,118	December 19, 2019	17:15	237	282	519
			1CP				665
			4CP				2,072
			12CP				5,713

HONI 4:

References:

1) Cost Allocation Model, filed on November 19th, 2020

Tabs "I9 Direct Allocation" and "O4 Summary by Class and Accounts"

Question:

As per Tab I9 of the Cost Allocation Model (Direct Allocation, Cell N32), NPEI has directly allocated costs related to Wholesale Meters (USofA 1820-3) to the Embedded Distributor class. Please confirm that, as can be seen in Tab O4 (Cell N37), the Cost Allocation Model also allocates additional Wholesale Meter related costs to the Embedded Distributor class.

NPEI has updated I4-BO Assets for account 1820 in cell D33 which is now consistent with NPEI's 2015 Cost Allocation Final Board approved model.

HONI 5:

References:

2) Cost Allocation Model, filed on November 19th, 2020

   Tab "O4 Summary by Class and Accounts"

3) Revenue Requirement Work Form, filed on November 19th, 2020

   Tab "13. Rate Design"

Question:

As per Tab O4 of the Cost Allocation Model (Cell N57), Line Transformers (USofA 1850) related costs are not allocated to the Embedded Distributor class, which accurately reflects the fact that Hydro One does not use any NPEI line transformers.

a) Please confirm that, since no transformer related costs have been allocated, the Embedded Distributor class will NOT be eligible to receive a Transformer Ownership Allowance (TOA).

Confirmed.

b) If part a) is confirmed, is it appropriate to include $4,083 related to TOA in the volumetric rates revenue used to derive the distribution volumetric rate for the Embedded Distributor class (Reference 2, Cell Y34)?

NPEI has removed the TOA for the Embedded Distributor on Sheet I6.1 Revenue.

2-Staff-92
Planned Capital
Ref 1: 2-Staff-13
Niagara Peninsula Energy showed that the planned net capital expenditure was $56.7 million in its 2015 cost of service but in its current application shows a planned net capital expenditure of $59.5 million, a variance of $2.8 million.

a) Please explain the variance of $2.8 million and why the two planned net capital expenditures do not match.

The planned capital expenditures presented in Appendix 2-AB in NPEI's 2015 COS Rate Application were based on the planned capital projects by year that were included in NPEI's DSP in its 2015 COS Rate Application. This DSP was prepared in 2014, and represents NPEI's planned capital projects for the 2015-2019 period based on the best information available at that time.

The planned capital expenditures for the 2015-2019 period that are presented in Appendix 2-AB in the current application are based on the planned capital expenditures from each of NPEI's annual budgets. NPEI's budgets are prepared each fall for the following year. For example, NPEI's 2019 budget was prepared in the fall of 2018, and therefore is a more accurate reflection of the projects that NPEI planned to complete in 2019 than the DSP plan for 2019, which was prepared in 2014.

The variance represents expenditures that were not anticipated during the previous DSP in 2014, but were incorporated into NPEI's annual budgets as the need was identified, as well as projects and programs that were included in NPEI's previous DSP, but the amounts included NPEI's annual budgets were different than the amount included in the DSP. When costs that were not anticipated in the previous DSP were included in NPEI's annual budget, other projects may have been deferred or reduced in scope. When NPEI was not able to complete a budgeted project, it may have been deferred and re-budgeted in a later year.

The tables below provide a comparison, by year, of the costs from NPEI's previous DSP with the costs included in NPEI's budget each year for the period 2015-2019. NPEI's previous DSP covered the period 2015-2019, and did not include 2020.

	2015				2016				2017		
CATEGORY	DSP	NPEI Budget	DSP vs NPEI Budget		DSP	NPEI Budget	DSP vs NPEI Budget		DSP	NPEI Budget	DSP vs NPEI Budget
	$ '000	$ '000				$ '000	$			$ '000	
System Access	2,438	2,438	-		3,024	2,683	(341)		2,596	3,005	409
System Renewal	6,743	6,743	-		4,161	3,442	(720)		5,889	6,587	698
System Service	1,028	1,028	-		3,760	4,932	1,172		2,449	1,497	(951)
General Plant	1,489	1,489	-		1,434	1,616	182		1,352	2,513	1,161
TOTAL EXPENDITURE	11,699	11,699	-		12,380	12,673	292		12,286	13,602	1,316
Capital Contributions	(827)	(827)	-		(775)	(800)	(25)		(775)	(1,537)	(762)
Net Capital Expenditures	10,872	10,872	-		11,605	11,873	267		11,511	12,065	554

	2018				2019		
CATEGORY	DSP	NPEI Budget	DSP vs NPEI Budget		DSP	NPEI Budget	DSP vs NPEI Budget
		$ '000				$ '000	
System Access	2,708	3,944	1,236		2,438	5,973	3,535
System Renewal	7,301	5,776	(1,525)		7,223	4,726	(2,497)
System Service	769	1,677	908		1,330	1,177	(153)
General Plant	1,204	2,580	1,376		1,311	3,245	1,934
TOTAL EXPENDITURE	11,982	13,977	1,994		12,303	15,122	2,819
Capital Contributions	(775)	(2,135)	(1,360)		(775)	(2,187)	(1,412)
Net Capital Expenditures	11,207	11,842	634		11,528	12,935	1,407

As can be seen from the tables above, based on actual customer demand, NPEI has increased the level of System Access projects in its annual budgets over time versus the amounts that were included in the previous DSP, which is partially offset by increased budgeted capital contributions. As a result, the level of System Renewal projects in NPEI's annual budgets have decreased versus the amounts that were included in the previous DSP.

The increase in the general plant budget over the DSP amount for 2017 mainly relates to hardware and software (See Exhibit 1, Appendix 1-5).

The increase in the general plant budgets over the DSP amounts for 2018 and 2019 mainly relates to the new garage building (See Exhibit 1, Appendix 1-4 and 1-3, IR Responses 2-Staff-38 and 2-SEC-10 and the response to Pre-Settlement Clarification Question 2-Staff-98 below).

The tables below provide the variances on a project / program level for the years where there is a difference between the previous DSP plan and NPEI's annual budget (i.e. 2016-2019),

Projects	2016 Budget	2016 DSP	Difference DSP vs Budget ($)	Difference DSP vs Budget (%)
System Access				
Customer Driven System Reinforcements for New Commercial Service Connections	1,007,500	1,007,500	-	0.0%
Metering	480,860	332,250	(148,610)	-30.9%
New Connections in Existing Subdivisions	737,004	737,004	0	0.0%
Road Relocation Projects	500,000	500,000	-	0.0%
Clifton Hill Primary Upgrade	237,796	272,874	35,078	14.8%
Sub-Total	2,963,160	2,849,628	(113,532)	-3.8%
System Renewal				
Willoughby Dr. - Main to Cattell	369,271		(369,271)	-100.0%
Willoughby Dr. - Cattell to Weinbrenner	380,290		(380,290)	-100.0%
Downtown core PILCDSTA Decomissioning	795,701	918,758	123,057	15.5%
Frederica St Rebuild - Dorchester to Drummond	671,753		(671,753)	-100.0%
NS&T ROW - Crossing the QEW	272,236	313,157	40,921	15.0%
Jordan Rd Rebuild Phase 3	335,377	429,504	94,127	28.1%
Dorchester Road Rebuild - McLeod to Dunn	531,912	672,097	140,185	26.4%
Victoria Ave South of Fly Rd - Phase 1	298,862	391,241	92,379	30.9%
Oakwood Drive - South of Smart Centre to QEW	611,940	748,101	136,161	22.3%
Dorchester Road Rebuild - Mountain to Riall	626,867	780,440	153,573	24.5%
Pole Replacements	535,930	872,112	336,182	62.7%
Kiosk Replacements	841,137	841,137	-	0.0%
Switchgear Replacements	250,002	250,002	-	0.0%
Rolling Acres OH to UG Conversion Phase 3	405,867	593,609	187,742	46.3%
Sub-Total	6,927,145	6,810,158	(116,987)	-1.7%
System Service				
Grid Modernization Program	253,000	353,000	100,000	39.5%
Glenholme to Franklin Ave - 600 MCM UG Install	133,262	153,126	19,864	14.9%
System Sustainment / Minor Betterments	780,000	780,000	-	0.0%
Sub-Total	1,166,262	1,286,126	119,864	10.3%
General Plant				
Building	87,000	-	(87,000)	-100.0%
Hardware	243,100	243,100	-	0.0%
Software	356,800	356,800	-	0.0%
Vehicles	840,000	759,440	(80,560)	-9.6%
General Equipment	89,843	74,903	(14,940)	-16.6%
Sub-Total	1,616,743	1,434,243	(182,500)	-11.3%
Total Gross Additions	**12,673,310**	**12,380,155**	**(293,155)**	**-2.3%**
Capital Contributions	(800,000)	(775,000)	25,000	-3.1%
Net Capital Additions	**11,873,310**	**11,605,155**	**(268,155)**	**-2.3%**

Projects	2017 Budget	2017 DSP	Difference DSP vs Budget ($)	Difference DSP vs Budget (%)
System Access				
Customer Driven System Reinforcements for New Commercial Service Connections	1,124,500	1,007,500	(117,000)	
Metering	543,500	332,250	(211,250)	-38.9%
New Connections in Existing Subdivisions	837,004	737,004	(100,000)	-11.9%
Road Relocation Projects	500,000	500,000	-	0.0%
Miscellaneous			-	100.0%
Sub-Total	3,005,004	2,576,754	(428,250)	-14.3%
System Renewal				
Downtown core PILCDSTA Decomissioning	292,171		(292,171)	-100.0%
Jordan Rd Rebuild Phase 4	561,614		(561,614)	-100.0%
Kalar TS Protection Equipment Refurbishment	400,000	400,000	-	0.0%
Dorchester Road Rebuild - McLeod to Dunn	359,131		(359,131)	-100.0%
Campden DS Power Tx - Replace with Former Jordan DS Tx		231,596	231,596	100.0%
GREENLANE RD AT ONTARIO TIE POINT		163,445	163,445	
Station St. DS - Power Transformer Replacement	200,000	214,865	14,865	7.4%
Station 14 Voltage Conversion - Phase 1	589,623	824,576	234,953	39.8%
Victoria Ave South of Fly Rd - Phase 1	308,719	705,385	396,666	128.5%
Oakwood Drive - South of Smart Centre to QEW	600,819		(600,819)	-100.0%
Dorchester Road Rebuild - Mountain to Riall	678,670		(678,670)	-100.0%
Chippawa Redundant Supply - Phase 1	343,719	442,690	98,971	28.8%
Station 33 Decomissioning		59,865	59,865	
Jordan DS Decommissioning		74,865	74,865	
Thorold Stone Rd Rebuild - Montrose to Kalar		671,814	671,814	
Portage Rd. Rebuild - Mountain to Church's Lane		455,289	455,289	
Pole Replacements	626,236	872,112	245,876	39.3%
Kiosk Replacements	1,001,137	841,137	(160,000)	-16.0%
Switchgear Replacements	250,000	250,002	2	0.0%
Subdivision Rehabilitation - Phase 1	245,151	490,301	245,150	100.0%
Sub-Total	6,456,990	6,697,942	240,952	3.7%
System Service				
Heartland Road Extension - Brown Rd to Chippawa Creek	114,583	137,026	22,443	19.6%
Grid Modernization Program	103,000	353,000	250,000	242.7%
Range Road 2 - East of Allen		157,759	157,759	
Brown Road Extension - Montrose to Blackburn	189,664	231,411	41,747	22.0%
System Sustainment / Minor Betterments	920,000	780,000	(140,000)	-15.2%
Sub-Total	1,327,247	1,659,196	331,949	25.0%
General Plant				
Building	492,500	-	(492,500)	-100.0%
Hardware	401,390	245,940	(155,450)	-38.7%
Software	1,120,860	265,100	(855,760)	-76.3%
Vehicles	695,250	748,152	52,902	7.6%
General Equipment	102,000	93,121	(8,879)	-8.7%
Sub-Total	2,812,000	1,352,313	(1,459,687)	-51.9%
Total Gross Additions	**13,601,241**	**12,286,205**	**(1,315,036)**	**-9.7%**
Capital Contributions	(1,537,000)	(775,000)	762,000	-49.6%
Net Capital Additions	**12,064,241**	**11,511,205**	**(553,036)**	**-4.6%**

Projects	2018 Budget	2018 DSP	Difference DSP vs Budget ($)	Difference DSP vs Budget (%)
System Access				
Customer Driven System Reinforcements for New Commercial Service Connections	1,269,425	1,007,500	(261,925)	
Metering	665,000	332,250	(332,750)	-50.0%
New Connections in Existing Subdivisions	899,004	737,004	(162,000)	-18.0%
Transfer of Expansion Facilities from Customers	1,000,000		(1,000,000)	-100.0%
Road Relocation Projects	520,813	500,000	(20,813)	-4.0%
Sub-Total	4,354,242	2,576,754	(1,777,488)	-40.8%
System Renewal				
Kalar TS Protection Equipment Refurbishment	200,000		(200,000)	-100.0%
Concession 2 Rd - Caistorville Rd to Westbrook Rd		270,368	270,368	
Thorold Stone Rd Rebuild - Montrose to Kalar	457,676		(457,676)	-100.0%
Portage Rd. Rebuild - Mountain to Church's Lane	383,291		(383,291)	-100.0%
Station 14 Voltage Conversion - Phase 1			-	100.0%
Station 14 Voltge Conversion Phase 2	971,639	1,359,726	388,087	39.9%
Victoria Ave South of Fly Rd - Phase 1	401,629		(401,629)	-100.0%
Victoria Ave South of Fly Rd - Phase 2	558,441		(558,441)	-100.0%
Oakwood Drive - South of Smart Centre to QEW	648,476		(648,476)	-100.0%
Step Down Transformer Eliminations		680,859	680,859	
MOUNTAIN RD REBUILD - DORCHESTER TO ST PAUL		392,227	392,227	
MOUNTAIN RD REBUILD - DORCHESTER TO MEWBURN		374,786	374,786	
SINNICKS AVE REBUILD - THOROLD STONE TO SWAYZE DR		1,035,102	1,035,102	
CHERRYHILL DR / CHERRYGROVE RD REBUILD		501,819	501,819	
Chippawa Redundant Supply - River Crossing	400,396		(400,396)	-100.0%
Pole Replacements	624,352	872,112	247,760	39.7%
Kiosk Replacements	100,407	841,137	740,730	737.7%
Switchgear Replacements	257,493	250,002	(7,491)	-2.9%
Subdivision Rehabilitation Phase 2	361,965	490,301	128,336	35.5%
Sub-Total	5,365,765	7,068,439	1,702,674	31.7%
System Service				
Grid Modernization Program	201,750	353,000	151,250	75.0%
Range Road 2 - East of Allen	120,655		(120,655)	-100.0%
System Sustainment / Minor Betterments	914,400	780,000	(134,400)	-14.7%
Willoughby Road Extension	280,737		(280,737)	-100.0%
Greenlane Rd at Ontario - Tie Point	160,194		(160,194)	-100.0%
Sub-Total	1,677,736	1,133,000	(544,736)	-32.5%
General Plant				
Building	1,435,000	-	(1,435,000)	-100.0%
Hardware	291,060	240,550	(50,510)	-17.4%
Software	368,500	280,500	(88,000)	-23.9%
Vehicles	343,000	605,647	262,647	76.6%
General Equipment	142,120	77,405	(64,715)	-45.5%
Sub-Total	2,579,680	1,204,102	(1,375,578)	-53.3%
Total Gross Additions	**13,977,423**	**11,982,295**	**(1,995,128)**	**-14.3%**
Capital Contributions	(2,135,000)	(775,000)	1,360,000	-63.7%
Net Capital Additions	**11,842,423**	**11,207,295**	**(635,128)**	**-5.4%**

Projects	2019 Budget	2019 DSP	Difference DSP vs Budget ($)	Difference DSP vs Budget (%)
System Access				
Customer Driven System Reinforcements for New Commercial Service Connections	1,269,425	1,007,500	(261,925)	-20.6%
Metering	401,800	332,250	(69,550)	-17.3%
New Connections in Existing Subdivisions	899,004	737,004	(162,000)	-18.0%
Transfer of Expansion Facilities from Customers	1,000,000		(1,000,000)	-100.0%
Road Relocation Projects	517,813	500,000	(17,813)	-3.4%
KM3 - Link	965,719		(965,719)	-100.0%
Kalar TS Additional Switchgear	125,000		(125,000)	-100.0%
Sub-Total	5,178,761	2,576,754	(2,602,007)	-50.2%
System Renewal				
Concession 2 Rd - Caistorville Rd to Westbrook Rd	263,333		(263,333)	-100.0%
Thorold Stone Rd Rebuild - Montrose to Kalar	427,734		(427,734)	-100.0%
Portage Rd. Rebuild - Mountain to Church's Lane	420,236		(420,236)	-100.0%
Station 14 Voltage Conversion - Phase 3	1,475,867	1,162,570	(313,297)	-21.2%
CHIPPAWA REDUNDANT SUPPLY PH 2 - WILLOUGHBY DR FROM LYONS CREEK TO WILLICK RD		561,738	561,738	
MCRAE ST AREA REBUILD		1,524,721	1,524,721	
KING ST REBUILD PH 1 - BARTLETT TO CHERRY		358,212	358,212	
POLE MOUNT STEP DOWN TX ELIMINATIONS - LINCOLN/WEST LINCOLN		664,244	664,244	
Ontario Ave Side Street Rebuild and Conversion		557,132	557,132	
Murray TS - J Bus Metering	672,623		(672,623)	-100.0%
Victoria Ave Rebuild - 7th Ave Phase 2	657,678		(657,678)	-100.0%
Pole Replacements	674,777	872,112	197,335	29.2%
Kiosk Replacements	51,200	841,137	789,937	1542.8%
Switchgear Replacements	83,000	250,002	167,002	201.2%
Subdivision Rehabilitation Phase 2	68,585		(68,585)	-100.0%
Subdivision Rehabilitation Phase 3		490,301	490,301	
Montrose - Oakwood to Biggar	794,610		(794,610)	-100.0%
Sub-Total	5,589,643	7,282,169	1,692,526	30.3%
System Service				
Grid Modernization Program	146,275	353,000	206,725	141.3%
System Sustainment / Minor Betterments	892,515	780,000	(112,515)	-12.6%
Kalar TS Power Transformer Dry Down Equipment	70,000		(70,000)	-100.0%
Sub-Total	1,108,790	1,133,000	24,210	2.2%
General Plant				
Building	1,634,373	-	(1,634,373)	-100.0%
Hardware	322,620	236,300	(86,320)	-26.8%
Software	548,649	453,302	(95,347)	-17.4%
Vehicles	600,233	527,751	(72,482)	-12.1%
General Equipment	139,200	93,693	(45,507)	-32.7%
Sub-Total	3,245,075	1,311,046	(1,934,029)	-59.6%
Total Gross Additions	**15,122,269**	**12,302,969**	**(2,819,300)**	**-18.6%**
Capital Contributions	(2,187,000)	(775,000)	1,412,000	-64.6%
Net Capital Additions	**12,935,269**	**11,527,969**	**(1,407,300)**	**-10.9%**

2-Staff-93
Road Relocation
Ref 1: 2-Staff-30
Niagara Peninsula Energy stated there has been no firm commitment from municipalities regarding their future road works.

a) Please group together all road relocation related projects and program for each year between 2015 to 2021.
b) Please provide all capital contributions related to road relocation projects for each year between 2015 to 2021.

The tables below provide the total budgeted and actual road relocation costs and capital contributions for 2015-2021.

	2015 Budget	2015 Actual		2016 Budget	2016 Actual		2017 Budget	2017 Actual
Total Road Relocation Costs	500,000	953,645		500,000	142,942		500,000	93,777
Capital Contributions	(125,000)	(496,447)		(250,000)	(94,629)		(200,000)	(61,488)
Road Relocation Net of CC	375,000	457,198		250,000	48,313		300,000	32,288

	2018 Budget	2018 Actual		2019 Budget	2019 Actual
Total Road Relocation Costs	520,813	125,864		517,813	120,412
Capital Contributions	(260,000)	(63,152)		(260,000)	(61,130)
Road Relocation Net of CC	260,813	62,712		257,813	59,282

	2020 Budget	2020 Projected		2021 Test Year
Total Road Relocation Costs	761,450	554,956		540,923
Capital Contributions	(283,087)	(151,510)		(167,711)
Road Relocation Net of CC	478,363	403,446		373,211

2-Staff-94
South Niagara Feeders Ph1

Ref 1: 2-Staff-27
Niagara Peninsula Energy stated that phase 1 of South Niagara Feeders has been deferred as Niagara Peninsula Energy considers a more efficient source of supply from adjacent utilities.

a) Please explain why the alternative of a more efficient source of supply was not originally considered.

The projected loading requirements from Niagara Health have continued to evolve over time as the design requirements for the new hospital have been firmed up. The more efficient source of supply in the current application reflects the most current information on hospital load and supply requirements and is only more efficient in this context. NPEI looks to implement the most cost effective, long term solution when servicing new customers, however, as the customer requirements evolve, NPEI must re-evaluate the plan and make necessary changes. The following paragraphs outline the history and continuously evolving plan for servicing the proposed South Niagara Hospital.

On November 20, 2017, NPEI met with the Niagara Health, Capital Redevelopment Team to discuss timelines and hydro servicing for the proposed new Niagara South Hospital. At this time, the hospital team anticipated that the peak demand for the new hospital was approximately 5.1MW. Per the hospital's requirements, two points of supply would be required. At this time, NPEI identified that the 3M30 feeder from Murray TS and the KM6 feeder from Kalar TS would be used to supply the proposed new hospital. The KM6 is presently lightly loaded and could accommodate the proposed new hospital load. This KM6 feeder presently ends on Montrose Road just North of the proposed new hospital location which is at the corner of Montrose and Biggar Roads. The 3M30 feeder presently dead ends on Oakwood Drive approximately 425m from Montrose Road, just North of the Welland River. The 3M30 feeder is more heavily loaded, but with some feeder reconfiguration and shifting of load, it was believed that the 3M30 had sufficient capacity to be utilized as the second supply point for the proposed new hospital. The southernmost 1.5km of 3M30 overhead feeder was already slated for rebuild in 2018 due to the age and condition of the circuit and poles. This work was completed in 2018 as planned. Given the loading information provided by Niagara Health, NPEI considered extending the 3M30 South along Oakwood Drive from the present day dead-end location, under the QEW overpass to join up with the KM6 at the intersection of Oakwood Drive and Montrose Road. From this point, the 3M30 would aerially cross the Welland River and the existing single circuit KM6 pole line would be rebuilt to a double circuit pole line from South of the Welland River along Montrose Road to the proposed new hospital location. The first portion of this work, being the extension of the 3M30 along Oakwood Drive to Montrose was planned for in NPEI's 2019 capital budget, however, this work was not able to be completed due to delays in obtaining MTO approval for working in proximity to the QEW crossing and ultimately due to the beginning at the end of 2019 of a planned three-year project by the MTO to rebuild the QEW bridge over the Welland River. In July of 2019, Hydro One contacted NPEI to discuss their early plans for the rebuild of their Murray TS which supplies the 3M30. Initial plans called for the replacement of the existing four power transformers with two smaller ones as well as the replacement of the Metalclad switchgear #2. Also in July of 2019, NPEI was contacted by Stantec Engineering as representatives of the Niagara Health redevelopment team regarding a kickoff meeting for the next stage in their design considerations and planning for the proposed new Niagara South Hospital. Initial discussions at this stage indicated a potential hospital loading of approximately 8.7MW. The increase in projected load as well as the, then, uncertainty around permit approval for work around the QEW and Hydro One's plans around the Murray TS were cause for NPEI to change direction on how to service the proposed new hospital.

In 2019, NPEI was in the process of planning for the design and installation of the second lineup of switchgear at the Kalar TS to utilize the remaining design capacity of the station. The revised plan at the time of developing the Rate application in 2019 was to utilize two feeder positions at Kalar TS and construct an approximately 10 km double circuit overhead pole line from the Kalar TS West along the Hydro ROW to Garner Road, then South to Brown Road, jogging West again to the continuation of Garner Road to the Welland River. The double circuit would then cross the Welland River, continue South along Morris Road to Biggar and then return East to the proposed hospital location at Biggar and Montrose. This second option for servicing the proposed new hospital location still had some uncertainty around voltage drop and crossing the Welland River as none of the road allowances are aligned on each side of the river. Further investigation into land ownership, potential easements and options for both aerial and underground river crossings were needed.

Further meetings with the hospital development team have continued throughout 2019 to present. In December of 2019, it was clarified that the design was anticipating a connected load at opening of between 7 and 8MW, however, the site was being developed with the expectation of future additional load to be added. The planned total future load would be approaching 15MW which would be the maximum load NPEI would allow on a 13.8kV feeder. NPEI continued to investigate resolutions to the issues of crossing the Welland River and managing voltage drop, given such a large load at the end of a 10km feeder. Given the problems associated with both the river crossing and voltage drop, NPEI began investigating alternate supply options in the South Niagara area. NPEI identified three options for sourcing 27.6kV supply from existing feeders with sufficient capacity in neighboring LDC's which are supplied from Hydro One owned stations, Crowland TS and Allanburg TS. This third option still requires the construction / rebuild of approximately 9km of single circuit 27.6kV overhead feeder and the installation of two primary wholesale revenue metering points along with some anticipated system expansion work on the part of the adjacent LDC(s) to facilitate connection. The total cost of this third option, while still in the preliminary design stage is anticipated to be comparable to the second option budget cost which was included in the original rate application.

NPEI continues to work with the Niagara Health team to finalize the power requirements and project timeline and is likewise continuing to work with the adjacent LDC's to formalize agreement for the additional supply points to Allanburg TS and / or Crowland TS. Work on the first phase of the South Niagara feeders is presently planned to begin in 2022 once the design has been finalized and the Offer to Connect and connection costs / capital contribution finalized. The third and final phase is anticipated to be completed by end of 2024.

b) Please confirm if this alternative will still utilize capacity at Kalar TS. If not, how does Niagara Peninsula Energy justify upgrading Kalar TS?

The present plan for servicing the proposed new Niagara South Hospital does not utilize capacity at Kalar TS. The addition of the second line-up of switchgear to Kalar TS was always anticipated in the original design of Kalar TS. This switchgear was not installed during the original construction as a means of keeping cost lower at the time with the expectation that it would be installed once growth in connected load required it. The driver for the installation of the second line-up of switchgear at Kalar TS is entirely based on customer growth within the part of NPEI's service territory supplied by Kalar TS. The proposed construction of the new Niagara South Hospital was never the main driver for this upgrade, though NPEI would not have been able to service the hospital from Kalar TS without having completed the upgrade. The need for completing the installation of the second line-up of switchgear is due to the residential and commercial customer growth in the Western portion of Niagara Falls. For additional information on the present connected load at Kalar TS, please refer to the interrogatory response to 2-Staff-25.

2-Staff-95
Non-NPEI Poles
Ref 1: 2-Staff-42

Niagara Peninsula Energy stated that it inspects third party owned poles if they support Niagara Peninsula Energy owned assets.

a) Does Niagara Peninsula Energy charge the third party for these inspections? If so, how this is recorded for the purposes of OM&A? If not, why not?

NPEI does not charge the third party for these inspections. It should be clarified that the "Pole Inspections" completed by NPEI include more than inspections of the supporting pole structure. NPEI has a duty to inspect the condition of NPEI owned assets such as brackets, transformers, insulators, down guys, grounds and arresters etc. regardless of the ownership of the supporting pole structure. For poles owned by another LDC or telecommunications company, NPEI does not deem it necessary to verify the structural integrity of the pole as this would be the responsibility of the pole owner, though if an obvious problem is identified; it will be noted by our inspectors. NPEI has a due diligence to complete regular inspections on the NPEI owned assets attached to the third part owned poles. NPEI could not charge the third party for the inspection of NPEI owned assets.

2-Staff-96
Meter Reading
Ref 1: 4-Staff-56

Niagara Peninsula Energy stated that Grimsby Power does not compensate Niagara Peninsula Energy for the base station costs and this is based on the shared services model established by Niagara Erie Power Alliance.

a) Was this shared services model used when Grimsby Power had owned the base station?
Yes.

b) The shared services model was established in 2010. Has Niagara Peninsula Energy thought about revisiting the shared services model?
The shared services model would have to be revisited with all of the NEPA LDCs, which include CNP, Welland Hydro, NOTL Hydro, Grimsby Power and NPEI.

c) Is this method of cost sharing standard in the industry?
This cost sharing method was used for the deployment of the smart meters

2-Staff-97
Stanley TS
Ref 1: Chapter 2 Appendices – 2-AA
Niagara Peninsula Energy updated the chapter 2 appendices and the project Stanley TS has now been shifted from 2020 to 2021. The costs for this project have also doubled.

a) Please provide more details on this project and explain why the costs for the project has doubled the initial forecast in 2020.

Hydro One's rebuild project consists of replacing the existing T2 with a new T4, 75MVA power transformer, replacing the existing B-Y AIS yard with a new, metalclad E-Z switchgear and removal of the old transformer and AIS yard. As a result of the new metalclad switchgear, NPEI will need to install new feeder egress cables and associated duct structure to connect the existing four distribution feeders to the four new feeder breakers. Hydro One proposed utilizing a reverse Cost Recovery Agreement with NPEI in which Hydro One would reimburse NPEI for the costs associated with the feeder egress work resulting from Hydro One's capital rebuild project at Stanley TS. NPEI's understanding is that the existing CT and VT instruments which are currently in use for both wholesale revenue metering and protection and control are to remain in service and HONI intends to continue utilizing these instruments for protection and control purposes.

Presently, the Stanley TS wholesale metering points for both the J-Q and B-Y buses use the Legacy connections to the HONI owned CT and VT instruments which are also utilized for protection and control. This is as per the Customer Wholesale Revenue Metering Agreement, (copy of this agreement is attached) which was executed between Hydro One and NPEI on June 18, 2004 for the Stanley TS. Per this agreement, as outlined in Schedule 3, NPEI and their Meter Service Provider (MSP) is responsible for any costs associated with maintaining, replacing or relocating the wholesale revenue meters and meter cabinets and associated wiring. Schedule 4, outlines the conditions for shared use of the HONI instrument transformers and under which circumstances NPEI would be required to install new instruments for the purpose of revenue metering. NPEI's interpretation of Schedule 4 is that the conditions under which NPEI would be responsible for installing new instruments are: Upon failure of the Legacy instrument transformers; in the event that the IESO deems there has been a substantial change impacting the instrument transformers or in the event that HONI removes the Legacy instruments from service.

During initial planning discussions between HONI and NPEI on July 3, 2018, HONI indicated that in their opinion, the work planned, constituted a significant change and as such, the IESO would require NPEI to install new revenue metering instruments for both the J-Q and B-Y buses. NPEI questioned this assertion, with regards to the J-Q metering and requested a follow up meeting with HONI including a representative from the IESO, which was held on September 7, 2018. Following the September 7th meeting, Barry Spencer from the IESO provided an email summary in which he indicated that the IESO did not consider the work being done by HONI to constitute a substantial upgrade of the J-Q metering and suggested that a follow up site meeting could be held to further review the scope of the project. Following the September 7th meeting, HONI proposed an alternate solution which would have allowed NPEI to continue utilizing the shared Legacy instruments. On October 5, 2018, HONI confirmed to NPEI via email that HONI would provide the VT, CT and AC sources to a new NPEI supplied metering cabinet which would replace the existing one in need of relocation. However, in a subsequent email from HONI on December 4th, HONI indicated that they did not agree with the HONI proposal of October 5th and that the only option was for NPEI to either purchase and install feeder level revenue metering for the J-Q bus feeders or to pay to have HONI install HV metering instruments in the station for NPEI to use.

During the period between December 4th, 2018 and November 25th, 2020, NPEI and HONI endeavored to resolve the impasse of responsibility for the costs associated with NPEI being mandated by HONI to stop using the Legacy shared instruments at Stanley TS for revenue metering.

For the 2020 bridge year capital budget, NPEI carried $625,765 (reference table Chapter 2: Appendix 2-AA) to cover the feeder egress and metering relocation work that was anticipated to be completed by NPEI in 2020 to facilitate the work being completed by HONI at the Stanley TS to rebuild the former B-Y bus with the new E-Z Bus. This work included the relocation of four feeders and installation of four new feeder level revenue metering points. No capital contribution from HONI was included at this time, given that no agreement had been reached with HONI on cost sharing yet. For various reasons, HONI's work on the Stanley TS rebuild project has experienced delays, which has also resulted in delays with NPEI being able to complete the relocation of feeder egress cables and former B-Y bus metering.

On November 25th, 2020, NPEI and HONI agreed to revised wording in Part C: Disputes, in the negotiated cost recovery agreement that would allow for adjustments in the final cost share agreement should the OEB subsequently determine that costs had not been allocated appropriately.

In the revised Chapter 2: Appendix 2-AA, NPEI has included updated costing for the feeder egress and meter installation for the B-Y / E-Z bus upgrade work at Stanley TS that was deferred from the 2020 Bridge Year in the 2021 Test Year capital budget. The revised estimate for the HONI initiated renewal work at Stanley TS that NPEI has now carried in the 2021 Test Year capital budget also includes the overhead pole and underground civil works necessary to accommodate the installation of four additional pole mounted primary feeder metering units and two pad mounted primary feeder metering units for the J-Q bus feeders along with the associated MSP costs for registering these new metering points. The forecasted capital cost for this project in 2021 is $1,401,148 with a projected cost recovery from HONI of $411,719 for a net cost of $989,429.

Please see Attachment 4.

b) Please provide a material project justification document for the Stanley TS project.

Capital Project Summary

Project Name:	HONI Initiated Stanley TS Renewal	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Renewal	**Service Area:**	Niagara Falls

General Information on Project (5.4.4.2.A)

Project Summary	Hydro One's rebuild project consists of replacing the existing T2 with a new T4, 75MVA power transformer, replacing the existing B-Y AIS yard with a new, metalclad E-Z switchgear and removal of the old transformer and AIS yard. As a result of the new metalclad switchgear, NPEI will need to install new feeder egress cables and associated duct structure to connect the existing four distribution feeders to the four new feeder breakers. Hydro One has also determined that they will no longer allow NPEI the continued use of the Legacy shared instruments for revenue metering purposes. As such, NPEI must install new revenue metering instruments to capture the load from all feeders supplied by either the J-Q or new E-Z buses.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$1,401,148		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$411,719		
	NPEI Estimated Cost:	$989,429		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Ten of NPEI's thirty-four 13.8kV feeders in the City of Niagara Falls are affected.			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	January 1, 2021		
	In Service Date:	December 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$200,000	$400,000	$400,000	$400,148

Images, Drawings, Maps, & Other Reference Material

See attached CCRA and CWRMA agreements signed with Hydro One for additional detail.

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The schedule risk for this program lies with Hydro One completing their portion of the work, approval of easements by Hydro One for installation of new egress manholes by NPEI as well as supply and coordination of installation / registration of new wholesale revenue meters by NPEI's MSP with the IESO.

NPEI is working closely with Hydro One in attending project planning meetings and maintaining good communications to any changes or potential project impacts. NPEI has four of the metering units on hand and has ordered the remainder with no anticipated delivery delays. Metering installations will be similar to other installation completed for several of the feeders from the Murray TS by our MSP, so no issues are anticipated with the registration of these meters with the IESO.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The Legacy metering at Murray TS for the J-Bus has instruments that are on the Measurement Canada dispensation list and are required to be replaced. NPEI and Hydro One had pursued replacement of this metering with feeder level metering, however, due to the shared bus configuration in which Hydro One also has feeders supplied out of Murray TS, the IESO would not authorize NPEI to install feeder level metering in this instance.

Pricing from Hydro One to install new metering instruments at the bus level for the Murray TS J-Bus is $720,000.

Extrapolating the above to accommodate two sets of bus metering results in an estimated install cost of $1,440,000 for Hydro One to install new bus level metering at Stanley TS.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

Not Applicable

Leave to Construct Approval (5.4.3.2.A.viii)

Not Applicable

Evaluation Criteria and Information (5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The primary investment driver is Hydro One completing the refurbishment of Stanley TS. NPEI must complete this work to continue utilizing feeders supplied by Stanley TS.

Good Utility Practice (5.4.3.2.B.1.b)

NPEI must work within the agreements with Hydro One for continued supply from the Stanley TS

Investment Priority (5.4.3.2.B.1.c)

Completion of this work is mandatory in order to continue utilizing the ten feeders supplied out of Stanley TS.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The existing feeders supplied by Stanley TS utilize bus level metering. Existing buses are J-Q and B-Y resulting in four wholesale meters. The new configuration will result in each of the ten feeders being metered individually.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Customers benefit by having NPEI having accurate wholesale revenue metering for settlement with the IESO. By relocating all of the metering outside of the Stanley TS station yard, access to the metering points is simplified from a maintenance access and coordination perspective.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

By having each feeder metered individually, the impact of one meter point is significantly reduced compared to bus level metering which would impact multiple feeders.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

Project Design Alternatives:

Two options are available for NPEI to renew the wholesale revenue metering at Stanley TS.

Option 1 is for NPEI to install individual feeder level metering at an estimated cost of $990,000.

Option 2 is for NPEI to pay Hydro One to install bus level metering instruments at an estimated cost of $1,440,000.

Safety (5.4.3.2.B.2)

Installing feeder level metering units outside of the Stanley TS yard, eliminates the need for NPEI or their contractors to work within the station in proximity to the transmission lines.

Cyber-Security and Privacy (5.4.3.2.B.3)

Not applicable

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

This work is being coordinated with both, Hydro One, NPEI's Meter Service Provider (MSP) and the IESO.

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

Not applicable.

Environmental Benefits (5.4.3.2.B.2.B.5)

Not applicable

Conservation and Demand Management (5.4.3.2.B.2.B.6)

Not applicable

Category – Specific Requirements – System Renewal (5.4.4.2.C - SR)

Asset Performance Target and Asset Lifecycle Optimization (5.4.4.2.C – SR.i.a)

Hydro One is replacing the end of life B-Y bus with new E-Z bus metalclad switchgear. Due to the new yard configuration, NPEI must install new feeder egress cables for the four affected feeders supplied from the existing B-Y bus. Hydro One is covering these costs incurred by NPEI as part of their capital project via a reverse Coat Recovery Agreement.

Hydro One has notified NPEI that they will not allow NPEI to continue utilizing the Legacy wholesale revenue metering use of shared instruments. As a result, NPEI has no option but to install new wholesale revenue metering instruments for the Stanley TS feeders.

Asset Condition Relative to Typical Life Cycle (5.4.4.2.C – SR.i.b)

Control of existing assets and deemed lifecycle is with Hydro One as they own the Stanley TS and existing Legacy Shared instruments.

Number of Impacted Customers (5.4.4.2.C – SR.i.c)

The total number of customers that are typically supplied from a Stanley TS supplied feeders is: 16,848.

Quantitative Customer Impact and Risk (5.4.4.2.C – SR.i.d)

Not applicable. – Project is driven by Hydro One station refurbishment.

Qualitative Customer Impact and Risk (5.4.4.2.C – SR.i.e)

Not applicable. – Project is driven by Hydro One station refurbishment.

Value of Customer Impact (5.4.4.2.C – SR.i.f)

Not applicable. – Project is driven by Hydro One station refurbishment.

Factors Affecting Project Timing (5.4.4.2.C – SR.ii)

Project timing is dictated by Hydro One's refurbishment project, approval of easements for installation of new feeder egress manholes by Hydro One and Certification of new metering points by the IESO.

Effect on System O&M Costs (5.4.4.2.C – SR.iii)

This project will result in higher O&M costs as the number of wholesale metering points for Stanley TS will increase from four to ten. Associated MSP costs will increase accordingly.

Impact on Reliability and Safety (5.4.4.2.C – SR.iv)

By having each feeder metered individually, the impact of one meter point failing is significantly reduced compared to bus level metering which would impact multiple feeders. With the new metering instruments being located wholly outside of the Stanley TS yard, coordination of repairs and preventive maintenance is simplified as coordination with Hydro One will no longer be required.

Analysis of Project Benefits, Costs, Alternatives, and Timing (5.4.4.2.C – SR.v)

NPEI has argued with Hydro One that the mandated installation of new wholesale revenue metering instruments at this time is outside of the intent of the executed CWRMA agreement between Hydro one and NPEI and should be at least partially covered under the same reverse Cost Recovery Agreement similar to how Hydro One is funding the new feeder egress work for the new E-Z bus feeders.

Hydro One does not agree with NPEI. Given that Hydro One owns the Stanley TS, NPEI has no option at this time but to complete the work included in this project to meet the timelines of Hydro One's refurbishment of Stanley TS in order to continue utilizing the ten feeders affected and adhering to the market rules for metering.

Like for Like Renewal Analysis, Alternative Project Design Comparisons (5.4.4.2.C – SR.vi)

Replacement of existing bus level metering with feeder level metering is anticipated to be $450,000 lower in cost that installing new bus level metering.

Project Sign-Off

Prepared By:	Shanon Wilson	Authorized By:	
Date:	December 7, 2020	Date:	
		Completion Date:	

2-Staff-98
Garage Facility
Ref 1: 2-Staff-38
Ref 2: 2-SEC-10
Niagara Peninsula Energy showed the total cost for the garage facility is $4.6 million and provided justification of the project in reference 1.

a) Please provide justification that the $4.6 million cost for the garage facility was a prudent amount.

During 2017, NPEI considered several different alternatives in relation to the new garage facility:

Outsourcing of Fleet Maintenance
Under this option, NPEI could outsource all of its vehicle maintenance and repair work to a third party vendor. NPEI determined not to pursue this option for the following reasons:

- The vehicles would have to be transported to the third party vendor's facility and back to NPEI's facility each time a vehicle required maintenance or repairs, which is not efficient and would still require an NPEI resource.
- Work would be completed based on the third party's schedule which may result in delays and would make NPEI reliant on the third party providers priorities.
- There is a risk that a third party may cease operating.
- This option would result in NPEI's vehicle technician positions becoming obsolete, with NPEI possibly having to terminate employees which could result in additional severance costs.

Increase the Roof Height of the Existing Garage Facility

NPEI's original garage facility was constructed in 1983. At that time, the fleet consisted of single axel vehicles. These vehicles would have a boom of 12.8m (42') or smaller. Currently NPEI's fleet has 8 tandem axel vehicles with booms of 16.75m (55') with the largest being 18.9m (62'). The wheel base (the distance between the steering front axle and the centre point of the driving axle) of NPEI's old single axel vehicles were 153 inches. NPEI's largest vehicles with a tandem axel has a wheel base of 254 inches. None of NPEI's tandem axel vehicles could be lifted in the existing facility with the existing hoists. If one of NPEI's large vehicles needed to be lifted, NPEI used the vehicles outriggers inside the garage limiting to only one vehicle could be worked on at one time which is inefficient due to the width of the garage floor space.

Due to the roof height of the existing garage (6.7m = 22') all boom repair and inspection work was completed outside. This included completing fine measurements with the booms for inspection purposes and fiberglass repair. Attempting to complete these tasks outside caused challenges if it is rainy, snowy or windy outside. This work cannot be done in these conditions, causing delays in these vehicles being in a condition for road-readiness.

One option that NPEI considered was increasing the roof height of the existing garage facility.

Although increasing the roof height would allow for the boom work to be completed indoors, this option does not address many of the other issues identified in NPEI's response to 2-Staff-38. This option does not increase the footprint of the existing garage facility (255.5 sq. meters = 2,750 sq. feet). Therefore, the 2 existing hoists could only be replaced with 2 new hoists of similar size or the 2 existing hosts could be replaced with only 1 larger heavy duty hoist. Further, this option would present the issue of where and how vehicle maintenance would be performed during the garage renovation. This option was not pursued since it would not provide the additional space required to safely and efficiently work on the newer larger vehicles. The cost of replacing the 2 hoists, not considering business interruption costs, was estimated to be at least $1.0 million. The cost to raise the roof of the existing garage would be very expensive as well.

Construction of a New Facility

NPEI narrowed 6 design and location possibilities for the construction of a new facility down to 3, which are as follows:

Option A2 – construct a new facility that is attached to NPEI's building located at the west side of the main building (8,800 square feet).
Option B2 – construct a new stand-alone pre-fabricated building with a peaked roof (8,100 square feet).
Option B2a - construct a new stand-alone pre-fabricated building with a flat roof (8,100 square feet).

Another option would be a stand-alone building with a traditional metal frame construction. However, NPEI decided to utilize pre-fabricated building options since they typically have a lower cost.

NPEI performed preliminary cost estimates for the 3 options listed above in July 2017. The preliminary estimates below include the total building and building services and equipment estimates, provided by NPEI's third party architect, based on information available at that time, were as follows:

Option A2 – $3.7 million
Option B2 – $3.1 million
Option B2a - $3.3 million

Option A2 – construct a new facility that is attached to NPEI's main building.

NPEI decided against this option for the following reasons:

- This option would involve renovations to the existing wall of NPEI's main building where the new building would attach.
- This option would result in traffic flow, parking and fire route issues around NPEI's main building, compared to constructing a stand-alone building further away from the main building.
- This option would result in NPEI having to relocate its diesel and gas tanks, which also have cost implications.
- This option could potentially present some snow loading issues with NPEI's existing main building.
- There were some grading issues that would have to be resolved if this option was pursued, which would incur further costs.
- There were concerns about new servicing requirements for this project from the existing main building, whether utility capacity would be an issue.
- The preliminary estimates indicated that this option had the greatest cost.
- This option limits NPEI's future ability to expand the main facility as well.

NPEI determined that option B2 was preferable to option B2a for several reasons. Option B2 had a lower estimated cost of $3.1 million, and a peaked roof design which allows for easier roof maintenance over the life of the building.

NPEI issued an RFP for the building construction of Design Option B2 to 3 proponents. The RFP was for the building construction, and did not include the costs for design, project management or some equipment. The bids were due to be received by NPEI by October 11, 2018. One of the proponents advised NPEI that they declined to bid. NPEI received 2 bids: one for $3,399,000 and one for $3,561,000. NPEI awarded the building construction to the contractor with the lowest bid.

NPEI notes that the price of concrete increased significantly between the time that the preliminary estimates were prepared by NPEI's third party architect, in July 2017, and the time that the RFP was completed in October 2018. Also, metal costs including aluminum and steel were subject to tariffs being implemented in 2018. This resulted in the cost of the project being higher than the preliminary estimates.

The new facility is 16.71m (55') high, with 974.6 sq. meter = 10,490 sq. feet gross of floor space. The repair garage and wash bay area is 732 sq. meters = 7,879 sq. feet. This is where truck repair and washing of vehicles is done. The mezzanines have 242.6 sq. meters = 2,611 sq. feet in area. This is where there is equipment like boilers, air handling units, pressure washer and compressors are stored. There is additional room for the mechanic's materials including inventory and tools to allow all mechanics materials to be kept in the same area.

The new facility has sufficient space to work on 4 vehicles simultaneously with wider doors to allow easier access for large vehicles. The facility has drive-thru bays for large vehicles to eliminate the need to back-up. The facility has 4 hoists with larger lifting capacities to sufficiently lift any of the vehicles in NPEI's fleet. It has a bulk fluid system to safely and more efficiently handle oil and hydraulic fluids. There is fireproof cabinetry to handle all of the flammable products. Pneumatic, power washing and fume exhaust equipment are in an enclosed space to reduce noise. The facility has been located further away from the Main Office to reduce traffic around the building.

The building has a roughed-in truck washing facility to accommodate future environmental friendly truck washing activities.

b) Please provide comparable project costs, if any.

NPEI has only constructed a wire building in 2013 for $1.6 million. NPEI looked for similar projects but did not find a directly relevant comparable.

c) Please explain the bidding process used for the entire garage facility project.

NPEI issued an RFP for the building construction of Design Option B2 to 3 proponents. Please see the response to part a) above.

Our project management and design consultant is a preferred vendor as they have great understanding of NPEI's facilities. This is from being involved previously in construction or renovation of NPEI's facilities. Their hourly rate is reviewed for reasonableness prior to a project commencing.

For mechanical equipment, the vendors are reviewed and the most suitable vendor was selected that provided the solutions for our buildings requirements. The vendor is then required to work with the design team to ensure that requirements are met for installation and operation of the equipment.

For the new hoist equipment, an RFP was issued. There were 2 respondents, one for $398K and one for $620K. NPEI selected the lowest bidder.

4-Staff-99
Salary
Ref 1: Appendix 2-AB
In Chapter 2 Appendix-2AB the row Wage and Benefit shows a total increase of $1.7 million.

a) Please confirm if the increase includes the costs for additional positions?

NPEI confirms in Chapter 2 Appendix 2-JB the row Wage and Benefit includes the cost for additional positions.

2-Staff-100
Amortization of Deferred Revenues and Depreciation Expense
Ref: Reponses to 2-Staff-11; updated Appendix 2-BA; updated Revenue Requirement Workform (RRWF)
OEB staff notes that the amortization of the customer contributions is to be recorded in the other revenues instead of netting against the depreciation expense. The net impact on the revenue requirement is the same.

In responding to 2-Staff-11, Niagara Peninsula Energy has updated the Appendix 2-BA by including the amortization of deferred revenues in cell K547 for ($1,203,737) but removed the amortization of deferred revenues in cell J536.

OEB staff notes that per the updated RRWF, the depreciation expense is $8,442,650 and the depreciation expense per Appendix C is $7,315,170. The depreciation expense per Appendix 2-BA is $7,280,266.

a) Please confirm that the amortization of deferred revenues $1,203,707 should be included in both cell J536 and cell K547 for the test year so that the amortization of deferred revenues is not included in the depreciation expense of the revenue requirement.

NPEI confirms the Deferred Revenues of $1,203,707 should be in both cell on Appendix 2-BA.

b) If 1) is confirmed, please update the applicable figures for other years in Appendix 2-BA.

NPEI has updated all of the years on Appendix 2-BA which has been filed with these responses for the settlement conference.

c) Please reconcile the depreciation expense figures between those used in the RRWF, Appendix 2-C and Appendix 2-BA.

Per the RRWF filed with the interrogatories the Application Depreciation Expense = $8,442,650. However, the updated Depreciation Expense for the 2021 Test year is $8,484,003. The updated Amortization of Deferred Revenues for the 2021 Test Year = $1,203,707. The net is $7,280,296. Appendix 2-C was also updated for 2020 and 2021. Cell R585 on Appendix 2-C agrees to $7,280,296. Cell Q585 on Appendix 2-C amounts to $7,315,170 which is a calculated value. Appendix 2-C is used to show the reasonability of depreciation expense.

9-Staff-101
Account 1508 Sub-account Pole Attachment Revenues Variance
Ref: Response to 9-Staff-83

Niagara Peninsula Energy has updated the forecast balance of Account 1508 Sub-Account Pole Attachment Revenue Variance to be recorded in 2020 from ($331,298) to ($337,942). OEB staff notes that the 2020 updated revenue figure of ($337,942) is based on the actual number of poles attached as of November 10, 2020.

1) Please confirm that there will be no additional pole attachments installed between November 11 and December 31, 2020.

Between November 11, 2020 and December 14th, 2020, there have been 2 attachments removed and NPEI does anticipate any new attachments between December 15th and December 31, 2020.

2) If 1) is not confirmed, please estimate the number of poles to be installed during the period of November 11 to December 31, 2020 and update the projected 2020 revenue that is recorded in Account 1508 sub-account Pole Attachment Revenues Variance.

Please see response in part 1) above.

9-Staff-102
Account 1592 sub-account CCA changes
Ref: Response to 9-Staff-87; Attachment 12

Niagara Peninsula Energy explained that the 2019 proposed balance of ($109,157) in Account 1592 sub-account CCA changes is the 2015 approved PILs expense in its 2015 CoS proceeding because there is no PILs expense. This has resulted from the regulatory tax loss when the CCA under the accelerated program is applied to the 2015 PILs model.

OEB staff notes that the 2020 proposed balance of ($109,157) in Account 1592 is calculated using the same methodology as the one in 2019.

a) Please fill out the table below and provide Niagara Peninsula Energy's position with respect to the use of this calculation method (row f) for the 2019 and 2020 balances in Account 1592. Please calculate rows (a) and (b) as the maximum claims available, without factoring any tax losses into consideration.

	2019 Balance	2020 Balance
CCA under the legacy rules using the 2015 approved capital additions (a)		
CCA under the accelerated rules using the 2015 approved capital additions (b)		
Difference in CCA (c=a-b)		
Tax rate (%) in effect of 2015 CoS (d)		
$ Impact on the revenue requirement (e=c x d)		
Grossed Up Revenue Requirement Impact $ (f= e/(1-d))		
NPEI Proposed Balance (g)		
Difference (h=f-g)		

Please see the completed table below as requested:

	2019 Balance	2020 Balance
CCA under the legacy rules using the 2015 approved capital additions (a)	9,700,584	9,700,584
CCA under the accelerated rules using the 2015 approved capital additions (b)	11,027,393	11,027,393
Difference in CCA (c= a-b)	(1,326,809)	(1,326,809)
Tax rate (%) in effect of 2015 CoS (d)	26.5%	26.5%
$ Impact on the revenue requirement (e=cXd)	(351,604)	(351,604)
Grossed-up Revenue Requirement Impact $ (f=e/1-d)	(478,373)	(478,373)
NPEI Proposed Balance (g)	(109,157)	(109,157)
Difference (h=f-g)	(369,216)	(369,216)

This table assumes there was enough Regulatory Taxable Income in 2015 to absorb the entire difference in CCA calculation. This was not the case for NPEI. Also, the impact on revenue requirement in the table above is excluding the investment tax credits that were used by NPEI to reduce the calculation of the 2015 Test Year PILS amount. The table does not include all of the components used to calculate the 2015 Test Year PILS amount.

b) Please explain the rationale and any assumptions of the method used by Niagara Peninsula Energy for the calculation its proposed balances in 2019 and 2020.

The 2015 COS rate application was approved to include $109,157 for PILS. This was based on the PILS model filed in 2015. The $109,157 total PILS was calculated using the legacy CCA rates. The Table below comes from the Test Year CCA schedule for the 2015 PILS model.

Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
Distribution System - post 1987	$ 54[illegible]	Only if election under ONTARIO		$ 54,008,997	$ -	$ 54,008,997	4%	$ 2,160,360	$ 51,848,637
Non-residential Buildings Reg. 1100(1)(a.1) election	$ [illegible]	REGULATION 162/01 ss. 5 or 7		$ -	$ -	$ -	6%	$ -	$ -
Distribution System - pre 1988	$ 3[illegible]	filed in 2001 to have ITR		$ 3,415,294	$ -	$ 3,415,294	6%	$ 204,918	$ 3,210,376
General Office/Stores Equip	$ 1[illegible]	1102(14) apply		$ 2,117,909	$ 155,313	$ 1,962,595	20%	$ 392,519	$ 1,725,389
Computer Hardware/ Vehicles	$ 2,465,289	698,878	0	$ 3,164,167	$ 349,439	$ 2,814,728	30%	$ 844,418	$ 2,319,748
Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
Computer Software	$ 326,483	368,740		$ 695,223	$ 184,370	$ 510,853	100%	$ 510,853	$ 184,370
Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
Franchise	$ -			$ -	$ -	$ -		$ -	$ -
New Electrical Generating Equipment Acq'd after Feb 27/00 Other Tha	$ 259,815			$ 259,815	$ -	$ 259,815	8%	$ 20,785	$ 239,030
Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
Computers & Systems Software acq'd post Mar 22/04	$ 1,558			$ 1,558	$ -	$ 1,558	45%	$ 701	$ 857
Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
Distribution System - post February 2005	$ 54,467,452	9,166,447		$ 63,633,900	$ 4,583,224	$ 59,050,676	8%	$ 4,724,054	$ 58,909,845
Data Network Infrastructure Equipment - post Mar 2007	$ 383,256	240,248		$ 623,504	$ 120,124	$ 503,380	55%	$ 276,859	$ 346,645
Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
Buildings acquired before 1988	$ 1,211,513			$ 1,211,513	$ -	$ 1,211,513	5%	$ 60,576	$ 1,150,937
Buildings > 18-03-07	$ 6,085,694			$ 6,085,694	$ -	$ 6,085,694	6%	$ 365,142	$ 5,720,553
Buildings > 18-03-07	$ 2,279,999	86,640		$ 2,366,639	$ 43,320	$ 2,323,319	6%	$ 139,399	$ 2,227,240
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
	$ -			$ -	$ -	$ -	0%	$ -	$ -
TOTAL	$ 126,712,633	$ 10,871,580	$ -	$ 137,584,213	$ 5,435,790	$ 132,148,423		$ 9,700,584	$ 127,883,629

Schedule S Taxable Income Test Year for 2015 on a reduced scale is shown below. The original calculation of taxable income for the 2015 COS was $608,429. If the CCA was accelerated in 2015 at the time of preparing NPEI’s 2015 CoS rate application, the CCA would have been $11,027,393. In re-creating the 2015 Test Year PILS calculation, the Test Year Taxable income would have been nil.

Taxable Income - Test Year

		Test Year Taxable Income	Test Year Taxable Income
Net Income Before Taxes		5,206,576	5,206,576

	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104		
Amortization of intangible assets 2-4 ADJUSTED ACCOUNTING DATA P490	106	5,034,074	5,034,074
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received		7,329	7,329
Change in Regulatory variance accounts		0	0
Change in Employee future benefits		101,909	101,909
Previous years Ontario apprenticeship tax credit claimed		103,699	103,699
Total Additions		**5,247,011**	**5,247,011**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	9,700,584	11,027,393
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571	63,571
Apprenticeship credits included in FS income		81,003	81,003
Total Deductions		9,845,158	11,171,967
NET INCOME FOR TAX PURPOSES		**608,429**	**(718,380)**
Charitable donations	311		
Taxable dividends received under se	320		
Non-capital losses of preceding taxat	331	-	-
Net-capital losses of preceding taxat	332		
Limited partnership losses of preced	335		
REGULATORY TAXABLE INCOME		**608,429**	**(718,380)**

The 2015 PILS calculation does not calculate a PILS amount when there is a regulatory taxable loss as shown above ($718,380).

The illustration below, shows the original calculation of NPEI's total PILS included in rates in 2015 along with a calculation illustrating the regulatory taxable income under accelerated CCA, the PILS included in NPEI's rates would have been nil.

2015 PILS					Wires Only	Revised For CCA
Regulatory Taxable Income					$608,429	0
Ontario Income Taxes						
Income	**Ontario In**	11.50%	**B**	$ 69,969 **C = A * B**		
Small bu	Ontario S	$ -	**D**			
	Rate redu	-11.50%	**E**	$ - **F = D * E**		
Ontario Income tax					$ 69,969	0
Combined	Effective Ontario Tax Rate		11.50%	**K = J / A**		
	Federal tax rate (Maximum 15		15.00%	**L**		
	Combined tax rate				26.50%	26.50%
Total Income Taxes					**$161,234**	0
Investment Tax Credits					$ 6,208	$ 6,208
Miscellaneous Tax Credits					$ 74,795	$ 74,795
Total Tax Credits					**$ 81,003**	$ 81,003
Corporate PILs/Income Tax Provision for Test Year					**$ 80,231**	$ -
Corporate PILs/Income Tax Provision Gross			73.50%	**S = 1 - M**	**$ 28,927**	0
Income Tax (grossed-up)					**$109,157**	0

If the accelerated CCA rules were in effect in the 2015 COS application the result would have been zero PILS to be included in NPEI's rates. The amount that was entered to Account 1592 is the maximum amount of PILS NPEI currently has in its rates which is $109,157. The actual accelerated CCA in NPEI's pro-rated 2018, 2019 and 2020 tax returns created actual taxable losses. These actual taxable losses are being used in the 2021 Test Year calculation of PILS which through the carryforward amounts are reducing the future PILS to be included in rates.

NPEI also notes that the $109,157 PILS that is included in its rates does not take into account the corporate minimum tax paid by NPEI in 2018 of $58,228 and in 2019 total corporate minimum tax paid was $65,891. NPEI estimates the 2020 corporate minimum tax will be similar to the 2019 amount of $65,891.

9-Staff-103
Account 1592 sub-account CCA changes
Ref: Response to 9-Staff-88; Attachment 13

Niagara Peninsula Energy has provided the calculations for the 2018 balance in Account 1592 under the two scenarios: 1) Accelerated CCA calculated using the 2015 approved capital additions prorated by the number of days that the AIIP was effective during 2018; 2) Accelerated CCA calculated using 2015 approved capital additions prorated by the 2018 Actual % of capital additions subject to AIIP

Based on the information provided in Attachment 13, OEB staff has compiled the following table:

Table 1: Summary of 2018 Balances in Account 1592 under the Two Scenarios

	Schedule 8			Schedule 1			
	Cost of Additions During the Year	**Cost of Additions Accelerated Cost**	**CCA for the year**	**Regulatory Taxable Income**	**Grossed up Income Tax**	**2015 Approved PILs expense**	**2018 balance in Account 1592**
#1	9,650,389	1,221,191	9,764,748	544,229	86,010	109,157	(23,147)
#2	9,822,473	1,049,107	9,755,707	547,423	87,162	109,157	(21,995)

For scenario #2, OEB staff also notes a discrepancy in Attachment 13 as below:

Table 2: Discrepancy of CCA between the Schedules

	CCA for the year

Attachment 13, Schedule 8, page 425	9,755,707
Attachment 13, T1, S1, Line 403, page 427	9,761,590
Difference	(5,883)

Niagara Peninsula Energy states that it proposes using the scenario #2 above to calculate the 2018 balance in Account 1592 and has revised the DVA Continuity Schedule to reflect the adjustment related to the period November 21,2018 to December 31, 2018, in the amount of ($21,995) to Account 1592.

Niagara Peninsula Energy provides the breakdown of the requested balance in Account 1592 Sub-account CCA changes as below:

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(21,995)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(240,309)
50% of Principal	(120,155)
Carrying Charges	(2,988)
Total Proposed for Disposition	**(123,143)**

a) Please confirm the accuracy of Table 1 above or revise the table as necessary.

The above table is revised to be as follows:

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(19,874)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(238,188)
50% of Principal	(119,094)
Carrying Charges	(2,988)
Total Proposed for Disposition	**(122,082)**

This is based on changing Schedule S CCA from $9,761,590 to $9,755,707. This will result in a Taxable income of $553,306 versus $547,423 as filed on page 427 of the IRR submission in Attachment 13. NPEI has included in Attachment 5 with these pre-settlement clarification questions the revised Schedule S and T. Also, please see the table below:

Impact of CCA Changes for 2018 using Prorated days					
Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA on prorated days	Recalculated Using Accelerated CCA for actual 2018 additions prorated (1,329,919/(12,447,873+1,329,919) = 9.65%	Total	Difference
Capital Additions During the Year	10,871,580	9,710,496	1,161,085	10,871,581	1
CCA for the Year	9,700,584	9,755,707		9,755,707	55,123
Regulatory Taxable Income	608,429	553,306		553,306	(55,123)
Income Tax Amount (Grossed Up)	109,157	89,283		89,283	(19,874)

b) Please recalculate the 2018 balance using the following table:

	2018 Balance under Scenario #1 (Prorated by days)	2018 Balance under Scenario #2 (Prorated by 2018 actual % claimed under the AII)
CCA under the legacy rules using the 2015 approved capital additions (a)		
CCA under the accelerated rules using the 2015 approved capital additions (b)		
Difference in CCA (c=a-b)		
Tax rate (%) in effect of 2015 CoS (d)		
$ Impact on the revenue requirement (e=c x d)		
Grossed-Up Revenue Requirement Impact $ (f= e/(1-d))		
Proration %	11.23%	10.68%
2018 Balance Calculated (g)		
NPEI Proposed Balance (h)		
Difference (i=g-h)		

Please see the OEB's requested Table below:

	2018 using Prorated Days	2018 using 2018 actual % claimed under the AII
CCA under the legacy rules using the 2015 approved capital additions (a)	9,700,584	9,700,584
CCA under the accelerated rules using the 2015 approved capital additions (b)	11,027,393	11,027,393
Difference in CCA (c= a-b)	(1,326,809)	(1,326,809)
Tax rate (%) in effect of 2015 CoS (d)	26.5%	26.5%
$ Impact on the revenue requirement (e=cXd)	(351,604)	(351,604)
Grossed-up Revenue Requirement Impact $ (f=e/1-d)	(478,373)	(478,373)
Proration %	11.23%	10.68%
2018 Balance Calculated (g)	(53,721)	(51,090)
NPEI Proposed Balance (g)	(109,157)	(109,157)
Difference (h=f-g)	(55,436)	(58,067)

NPEI does not agree with the OEB's rationale to calculate the amount that should go to account 1592 based on the tables in part a) and part b). The Tables above calculate a PILS amount that is in excess of what is currently included in NPEI's rates. Per the OEB letter dated July 25, 2019, *Under the Accounting Procedures Handbook, electricity distributors and transmitters are to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model that is used to determine the tax amount that underpins rates*. The PILS calculated by the OEB Tax Model in 2015 that is currently in NPEI's rates is $109,157. The maximum amount of PILS that can be recorded to account 1592 is as follows:

2019 - $109,157 (This is the total PILS included in NPEI's rates for 2019)

2020 - $109,157 (This is the total PILS included in NPEI's rates for 2020)

2018 – Prorated based on days = $23,147 or Prorated based on 2018 Actual % claimed under the AII = $19,874 (this is revised due to the discrepancy noted above, IRR amount was $21,995)

NPEI's revised account 1592 balance is shown below:

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(19,874)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(238,188)
50% of Principal	(119,094)
Carrying Charges	(2,988)
Total Proposed for Disposition	**(122,082)**

Using the Tables from the OEB above in part a) and part b) the OEB's Total account 1592 balance is

Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(51,090)
Impact of CCA Change for 2019	(369,216)
Impact of CCA Change for 2020	(369,216)
Total Principal	(789,522)

Table b) calculates a PILS adjustment amount to Account 1592 of $51,090 for 2018 when a total of $109,157 of PILS was included in NPEI's rates which is 46.8% of NPEI's total PILS for the year amount for 41 days of AII CCA.

This does not seem reasonable to record $789,522 in account 1592 for the period Nov. 20th, 2018 to Dec. 31st, 2020, when the total PILS included in NPEI's rates for this same period is $238,188.

c) Please confirm the discrepancy noted in Table 2 above and revise the schedule(s) as applicable.

Please see part a) above.

d) Please compare the proposed balance in Account 1592 by Niagara Peninsula Energy to the total balance of 2018 to 2020 calculated using the gross revenue requirement impact in the table provided in b) for 2018, as well as the gross revenue requirement impact in the table provided in staff follow-up question #3 a) for 2019 and 2020.

Please see the response to part a).

9-Staff-104
Loss Carry Forwards

Ref: Response to 9-Staff-88; Attachment 14; Updated PILs Expense Model

Niagara Peninsula Energy states that:

> NPEI notes that its originally filed 2021 Income Tax PILs Workform incorporates a loss carry forward. Part of the balance of loss carry forward is due to the accelerated CCA effective in 2018, 2019 and 2020. Since the impact of the accelerated CCA for 2018, 2019 and 2020 is recorded in Account 1592, in order to avoid double-counting the accelerated CCA impact, NPEI has revised the amount of loss carry forward that is included in the 2021 PILs Workform which relates to the future reduction in PILS that is to be included in the 2021 Test Year rates.

Niagara Peninsula Energy has provided a revised loss carryforward table as below:

Revised Loss Carry forward for the 2019 Historical Year						
	2015	2016	2017	2018	2019	2020
	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Bridge Year
Opening Loss CF balance				943,963	511,820	1,298,903
Non-capital losses	0	202,647	1,685,379	2,610,148	1,395,512	138,976
				3,554,111	1,907,332	1,437,879
Applied to 2013		(202,647)				
Applied to 2015			(741,416)	(1,975,729)		
Non-capital loss carry forward Balance per Tax Return	0	0	943,963	1,578,382	1,907,332	1,437,879
Loss Carry back to 2014- approved by MOF February 24, 2020				(943,963)		
2018 Non-Capital loss carry forward Balance adjusted at Februry 24 2020				634,419	1,907,332	
PILS 1592 entries for adjusted for AIIP, for 2018, 2019 and 2020				(122,599)	(608,429)	(608,429)
Revised Non-Capital loss carry forward Balance adjusted				511,820	1,298,903	829,450

Niagara Peninsula Energy also states that:

> On the PILS model being re-filed with these interrogatories, NPEI has entered $1,298,903 on Sheet H4 Sch 4 Loss Cfwd History as the 2019 Loss Carry-forward balance. On Sheet B4 Sch 4 Loss Cfwd Bridge, NPEI has entered an adjustment amount of ($583,020) to arrive at the Balance available for use post Bridge Year of $829,450.

Per the updated PILs model dated Nov 24, the regulatory tax loss generated in the 2019 historical year is $289,137 and the regulatory tax loss generated in the 2020 bridge year is $113,567. OEB staff would expect the non-capital losses for 2019 and 2020 would be updated to the updated regulatory tax loss figures in the updated PILs model of $289,137 and $113,567 respectively. However, the Non-capital losses in 2019 and 2020 in the table above (2nd row) are still the same figures as in the original filed PILs model.

OEB staff notes that the taxable loss in 2019 on sheet H1 of the updated PILs model has decreased from $1,395,512 to $289,137 because of the decrease in the "Other Deductions" line item of "Depreciation of Capital contributions" from $1,002,764 in the originally filed PILs model to $34,166.

a) Please explain the 2018 figure of ($122,599) and 2019 figure of ($608,429) for "PILs 1592 entries for adjusted for AIIP, for 2018, 2019 and 2020" in the table above and reconcile these figures to the PILs balances in Account 1592 as proposed by Niagara Peninsula Energy.

The $122,599 and $608,429 relates to the Regulatory Taxable Income associated with the PILS amounts for the pro-rated 2018 year and the 2019 that have been entered to account 1592.

The 2018 PILS entered to account 1592 was $21,995, using a % of total PILS in rates in the amount of $109,157, the % applied to the Regulatory Taxable Income from 2015 of $608,429 results in a prorated regulatory taxable income from 2015 of $122,597. See the table below.

PILS change for 2018	(21,995)
2015 PILS in rates	109,157
% of PILS related to 1592 in rates	-20.15%
PILS Regulatory Taxable Income in rates	608,429
Reduction to Regulatory Taxable Income for 2018 based on 2018 Actual AIIP expenditures as a % of total 2018 expenditures	(122,597)

The total 2015 PILS amount included in rates is $109,157 which is based on Regulatory taxable income of $608,429 from the 2015 PILS model. Also, see 9-Staff-102 above which recreates the 2015 PILS T2S1 from 2015.

This have been updated for the discrepancy noted above in 9-Staff-103 a).

Impact of CCA Changes for 2018 using Prorated days					
Description	**2015 Board-Approved Amounts**	**Recalculated Using Accelerated CCA on prorated days**	**Recalculated Using Accelerated CCA for actual 2018 additions prorated 1,329,919/12,447,873 = 10.68%**	**Total**	**Difference**
Capital Additions During the Year	10,871,580	9,710,496	1,161,085	10,871,581	1
CCA for the Year	9,700,584	9,755,707		9,755,707	55,123
Regulatory Taxable Income	608,429	553,306		553,306	(55,123)
Income Tax Amount (Grossed Up)	109,157	89,283		89,283	(19,874)
PILS change for 2018	(19,874)				
2015 PILS in rates	109,157				
% of PILS reduction for AIIP	-18.21%				
PILS Regulatory Taxable Income in rates	608,429				
Reduction to Regulatory Taxable Income for 2018 based on 2018 Actual AIIP expenditures as a % of total 2018 expenditures	(110,777)				

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(19,874)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(238,188)
50% of Principal	(119,094)
Carrying Charges	(2,988)
Total Proposed for Disposition	**(122,082)**

b) Please explain the adjustment amount of ($583,020) entered on Sheet H4 Sch 4 Cfwd Bridge.

The total Loss carry forward Table on page 139 pf 437 from the IRR responses showed a Loss Carryforward at the end of 2019 to be used for the 2021 Test Year in the amount of $829,450. In order to arrive at this opening loss carryforward for the Bridge Year on the PILS model, NPEI had to make an adjustment of (583,020) in order achieve a Balance available for use post Bridge Year on Sheet B4 Sch 4 loss cfwd Bridge of the 2021 PILS model.

c) Please verify the Non-capital loss figures for 2019 and 2020 in the revised loss carryforward table above and update the figures as applicable.

The revised Carry forward loss is $841,272 based on updating the 2018 amount of CCA from ($9,761,590 to $9,755,707)

	2015	2016	2017	2018	2019	2020
	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Bridge Year
Opening Loss CF balance				943,963	523,642	1,310,725
Non-capital losses	0	202,647	1,685,379	2,610,148	1,395,512	168,734
				3,554,111	1,919,154	1,479,459
Applied to 2013		(202,647)				
Applied to 2015			(741,416)	(1,975,729)		
Non-capital loss carry forward Balance per Tax Return	0	0	943,963	1,578,382	1,919,154	1,479,459
Loss Carry back to 2014- approved by MOF February 24, 2020				(943,963)		
2018 Non-Capital loss carry forward Balance adjusted at Februry 24 2020				634,419	1,919,154	
PILS 1592 entries for adjusted for AIIP, for 2018, 2019 and 2020				(110,777)	(608,429)	(608,429)
Revised Non-Capital loss carry forward Balance adjusted				523,642	1,310,725	871,030

PILS change for 2018	(19,874)
2015 PILS in rates	109,157
% of PILS related to 1592 in rate	-18.21%
PILS Regulatory Taxable Income in rates	608,429
Reduction to Regulatory Taxable Income for 2018 based on 2018 Actual AIIP expenditures as a % of total 2018 expenditures	(110,777)

The Loss Carry forward has been updated from $829,450 t0 $871,030 to be used for the 2021 Test Year. The loss at the end of 2019 has been updated from $1,298,903 to $1,310,725. In order to arrive at a Loss Carryforward available for use in the Test Year in the amount of $871,030 an adjustment was made on B4 Sch 4 Loss Cfwd Bridge Year in the amount of $608,429 which is the 2020 equivalent regulatory taxable income for 2020 which corresponds to the PILS amount of $109,157 for 2020 entered to account 1592. An updated Excel PILS model has been sent along with this updated response to 9-Staff-104.

d) Please explain why the “Depreciation of Capital Contribution” has decreased significantly from $1,002,764 in the originally filed PILs model to $34,166 in the updated PILs model dated Nov 24.

The Depreciation of Capital Contributions for the 2019 year should be $1,002,764 and has been updated in the PILS model sent with this updated 9-Staff-104 response.

E) ADDITIONAL CLARIFICATION REQUEST by OEB Staff on December 9, 2020.

If NPEI did not record any amounts to Account 1592 related to AII, the Loss Carryforward available for use for the 2021 Test Year would be as follows:

Revised Loss Carry forward for the 2019 Historical Year						
	2015	2016	2017	2018	2019	2020
	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Bridge Year
Opening Loss CF balance				943,963	634,419	2,029,931
Non-capital losses	0	202,647	1,685,379	2,610,148	1,395,512	168,689
				3,554,111	2,029,931	2,198,620
Applied to 2013		(202,647)				
Applied to 2015			(741,416)	(1,975,729)		
Non-capital loss carry forward Balance per Tax Return	0	0	943,963	1,578,382	2,029,931	2,198,620
Loss Carry back to 2014- approved by MOF February 24, 2020				(943,963)		
2018 Non-Capital loss carry forward Balance adjusted at Februry 24 2020				634,419	2,029,931	2,198,620
PILS 1592 entries for adjusted for AIIP, for 2018, 2019 and 2020				0	0	0
Revised Non-Capital loss carry forward Balance adjusted				634,419	2,029,931	2,198,620

The loss carry-forward amount used for the Test Year would be $2,198,800. NPEI has submitted a PILS model in PDF with this updated response that will illustrate the 2021 Test Year PILS amount would be $390,731. The $2,198,800 loss carry forward available for the 2021 Test Year is higher than the original submission in Exhibit 4 Table 4.9.1.4 in the amount of $2,029,931. The loss carry forward calculations have been updated for updated 2020 and 2021 capital additions and capital contributions as well as an updated 2020 projected net income.

NPEI's actual non-capital loss for 2019 as per the tax return in Appendix 4-13 of the originally filed application Exhibit 4 page 1077 of 1411 on the T2S1 was ($1,395,515). This taxable loss includes the CCA amount based on AII of $11,448,594. If the 2019 T2S1 was prepared using the legacy CCA rules the CCA would have been $10,162,995.

	2019 - CCA Schedule 8											
	using legacy rules	2	3	5	8	9	11	12	13	14	17	18
			Cost of Additions	Adjustments	Proceeds	UCC	djust	CC adjustme	UCC adjustment	CCA	CCA	UCC
		Balance	during the	Transfers	of	2 + 3 - 5	ccele	r accelerate	or non accelerate	%	for the year	Balance
Class		12/31/2018	year		Disposition		CCA	by factor	CCA			12/31/2019
1	Buildings	46,722,944				46,722,944	-			4%	1,868,918	44,854,026
1b	Buildings	3,001,729				3,001,729	-			6%	180,104	2,821,625
1b	Buildings > 18-03-17	4,623,306	2,037,896			6,661,202	-	-	1,018,948	6%	338,535	6,322,667
2	Electrical generating equipment	2,666,487				2,666,487	-	-		6%	159,989	2,506,498
3	Building < 1990	986,784				986,784	-	-		5%	49,339	937,445
8	Office Equipment, Tools, Other	1,308,815	307,359			1,616,174	-	-	153,680	20%	292,499	1,323,675
10	Vehicles and Equipment	2,140,091	599,766		265	2,739,592	-	-	299,751	30%	731,952	2,007,640
12	Computer Software	71,243	361,773			433,016	-		180,887	100%	252,130	180,887
14.1	Goodwill	679,344				679,344	-	-		7%	47,554	631,790
17	Roads, parking lots	186,130				186,130	-	-		8%	14,890	171,240
45	Computers	142				142	-	-		45%	64	78
47	Transmission and Dist Equipment	70,664,797	7,992,827			78,657,624	-	-	3,996,414	8%	5,972,897	72,684,727
50	Computers > 3/18/07	369,597	184,892			554,489	-	-	92,446	55%	254,124	300,365
		133,421,409	11,484,513	-	265	144,905,657	-	-	5,742,124		10,162,995	134,742,662

The difference between the AII CCA and the legacy rules for CCA are captured through NPEI's calculation of its loss carry forward that NPEI is using to calculate its 2021 Test Year PILs to be included in rates.

NPEI has adjusted its non-capital loss by the equivalent amount of regulatory taxable income that has already been adjusted to account 1592. For example, the 2015 PILS calculation of $109,157 is the result of regulatory taxable income in the amount of $608,429. For each year that the total PILs is recorded to account 1592, i.e. pro-rated 2018, 2019 and 2020, the equivalent of the regulatory taxable income must be removed from the actual non-capital loss carryforward that is being used to calculate NPEI's 2021 Test Year regulatory taxable income in order to arrive at the 2021 Test Year PILS amount to be included in future rates i.e. 2021 to 2025.

UPDATE TO CALCULATE THE AMOUNT TO BE ENTERED TO ACCOUNT 1592-December 11, 2020

Using the Actual additions for 2018, 2019 and 2020 and calculating the difference between Legacy CCA and CCA under accelerated AII the amount to be recorded in Account 1592 would be $671,045. See the Table below. Attachment 7 illustrates the detailed Schedule 8 for the CCA calculations using legacy and accelerated AII for 2018, 2019 and 2020 actual additions.

	CCA calculated usin legacy rules on Actual additions	Accelerated AII CCA using Actual Additions	CCA Difference	Tax Rate	PILS not Grossed UP on CCA Difference	PILS Grossed UP on CCA Difference
CCA 2018 using Actual additions	10,397,485	10,445,587	48,103	0.265	12,747	17,343
CCA 2019	10,410,893	11,448,593	1,037,700	0.265	274,991	374,137
2020 Bridge Year Additions	10,378,418	11,153,815	775,397	0.265	205,480	279,565
Non-capital loss using AII per tax return	31,186,796	33,047,996	1,861,200		493,218	671,045

The amount included in NPEI's revenue requirement for PILS from the 2015 Test Year for the period November 20, 2018 to December 31, 2020 is $238,188. See the Table below.

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(19,874)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal for disposition	(238,188)

Impact of CCA Changes for 2018 using Actual

Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA on actual additions	Recalculated Using Accelerated CCA for actual 2018 additions prorated 1,329,919/12,447,873 = 10.68%	Total	Difference
Capital Additions During the Year	10,871,580	9,710,496	1,161,085	10,871,581	1
CCA for the Year	9,700,584	9,755,707		9,755,707	55,123
Regulatory Taxable Income	608,429	553,306		553,306	(55,123)
Income Tax Amount (Grossed Up)	109,157	89,283		89,283	(19,874)

The difference in PILS grossed-up available to reduce the 2021 PILS is $432,857. See the table below:

PILS Grossed UP on CCA Difference	Grossed up PILS included in NPEI's Revenue Requirement	Difference in Pils grossed Up Available to reduce 2021 PILS
17,343	19,874	(2,531)
374,137	109,157	264,980
279,565	109,157	170,408
671,045	238,188	432,857

The Difference in PIL grossed-up of $432,857 is equivalent to a Loss Carryforward amount of $1,200,564. This amount was entered in the OEB PILS model on B4 Sch 4 Loss Cfwd-Bridge in Cell G15.

Difference in Pils grossed Up Available to reduce 2021 PILS	Difference in Pils NOT grossed Up Available to reduce 2021 PILS	Loss Carryforward to be used entered on B4 Sch 4 Loss Cfwd Bridge- OEB PILS model
(2,531)	(1,860)	(7,021)
264,980	194,760	734,944
170,408	125,250	472,641
432,857	318,150	1,200,564

After entering the $1,200,564 on B4 Sch 4 Loss Cfwd Bridge, the amount on T4Sch 4 Loss Cfwd Test is $1,200,564 in Cell G13. The number of years loss until next cost of service (I.e. years the loss is to be spread over) is set to 5 in Cell G14. The result is an annual amount of $240,113.

Note the original taxable loss in the amount of $168,689 on the B1 Sch1 Taxable Income Bridge was removed by way of adding to Cell F8. This is required in order to avoid double counting the loss on T4 Sch 4 Loss Cfwd Test. If this amount did not get removed the $1,200,564 would not be the amount required on T4 Sch4 Loss Cfwd Test.

Loss Carryforward to be used entered on B4 Sch 4 Loss Cfwd Bridge-OEB PILS model	# of Years Loss until next Cost of Service	Loss Carry forwardAmount to be used in 2021 Test Year on T4 Sch 4 Loss Cfwd Test
(7,021)	5	(1,404)
734,944	5	146,989
472,641	5	94,528
1,200,564		240,113

The Amount to be used to reduce the Test Year Taxable Income of $240,113 links to T1 Sch1 Taxable Income Test in Cell F118. The result is a reduction of $240,113 of taxable income in the 2021 Test Year.

The $240,113 reduction to the 2021 Taxable Income equates to PILS of $63,630. On a Grossed-Up PILS basis the amount of 2021 Test Year PILS reduction is $86,571. See the table below.

Loss Carry forwardAmount to be used in 2021 Test Year on T4 Sch 4 Loss Cfwd Test	Tax Rate	Reduction to 2021 Test Year PILS not Grossed UP	Reduction to 2021 Test Year PILS Grossed UP
(1,404)	0.265	(372)	(506)
146,989	0.265	38,952	52,996
94,528	0.265	25,050	34,082
240,113		63,630	86,571

The $86,571 PILS reduction over five years equates to (86,571 X 5) of $432,857. Therefore, the PILS reduction is similar to a rate rider being refunded over five years.

In Summary:

Account 1592 Disposition of PILS in the amount of $238,188 (This is on the DVA continuity) to be refunded to customers between January 1, 2021 and December 31, 2021

Reduction to 2021 PILS amount to be included in the 2021 Test Year Revenue Requirement of $86,571 over five years for a total of $432,857.

Total PILS refunded to customers = $238,188 + $432,857 = $671,045. Account 1592 will be subject to carrying charges during the five-year period on the amount of $432,857. The total carrying charges related to the $238,188 is $6,389 which is included on the DVA.

All other non-taxable actual losses relate to the timing differences of net movement in regulatory assets and liabilities. These time differences reverse upon the disposition of Group 1 and Group 2 regulatory deferral and variance accounts as well the net position of Group 1 variance accounts will change as a result of the market changes.

9-Staff-105,
Line Loss Variances in Account 1588 and Account 1589
Ref: Response to 9-Staff-91

In confirming that there is no line loss variance recorded in Account 1589, Niagara Peninsula Energy states that:

NPEI has not accounted for the unaccounted-for energy (UFE) variance (i.e. line loss variance) related to the Class B Non-RPP global adjustment billing in Account 1589.

NPEI bills all Class B non-RPP customers, and accrues for unbilled revenue, using the actual GA rate each month. When allocating Charge Type 148 on the IESO invoice and the Class B Global Adjustment charges billed to NPEI by its host distributor, Grimsby Power Inc., NPEI allocates the amount of the Class B GA charges to Account 1589 that exactly offsets the Class B GA revenue each month, so that no variance accumulates in Account 1589. The remainder of the Class B GA charges are booked to Account 1588. As a result, all of the UFE variance related to Class B Non-RPP GA accumulates in Account 1588.

Niagara Peninsula Energy further states that:

Using NPEI's method of recording all UFE variances relating to Class B global adjustment charges in Account 1588 (both RPP and Non-RPP), RPP and Non- RPP customers with equal consumption and equal power sales revenue will be allocated an equal amount of the overall UFE variance.

Niagara Peninsula Energy then provides an illustrative example showing the equal allocation of the overall UFE variance between RPP and Non-RPP customers.

OEB staff notes that the illustrative example provided by Niagara Peninsula Energy assumes no RPP variance (i.e. average TOU rate of $0.10 = Average WAP cost of power of $.02 + Actual average GA Rate = $.08).

a) Please confirm that Niagara Peninsula Energy's method of recording all UFE variances in Account 1588 does not conform to the approach prescribed in the OEB's accounting guidance for commodity accounts.[1]

NPEI confirms that the OEB's accounting guidance for commodity accounts states: *"Total Loss Factor (TLF) will not be the same as purchased volumes from the IESO. Differences exist between actual system losses and TLF billed to customers. The resulting differences are defined as unaccounted for energy (UFE) and such differences will be tracked in Account 1588 – RSVA Power and Account 1589 – RSVA GA."*

b) Please provide the line loss variances (in dollars) associated with Non-RPP GA in accordance with the table below:

2019 Metered Non-RPP kWh excluding Class A customers	
OEB Approved TLF %	
2019 Calculated TLF %	
Loss kWh difference (kWh)	
2019 Average GA rate ($/kWh)	
2019 Line Loss Variance (in dollars) pertaining to Non-RPP customers' GA	

Please see the populated table below:

2019 Metered Non-RPP kWh excluding Class A customers	478,260,401
OEB Approved TLF %	1.0479
2019 Calculated TLF %	1.0396
Loss kWh difference (kWh)	(3,989,917)
2019 Average GA rate ($/kWh)	0.1084
2019 Line Loss Variance (in dollars) pertaining to Non-RPP customers' GA	(432,513)

[1] The Accounting Guidance Related to Commodity Pass-Through Account 1588 and 1589, February 21, 2019, page 9.

i) Please confirm that the 2019 line loss variance dollars calculated in the table above is currently recorded in Account 1588 and allocated to all ratepayers.

NPEI confirms that the 2019 line loss variance dollars calculated in the table above is currently recorded in Account 1588 and allocated to all customers.

ii) Please confirm that based on the APH and the accounting guidance, the above 2019 line loss variance dollars associated with Non-RPP GA is to be recorded in Account 1589 and disposed to all Non-RPP customers.

Please see the response to part a) above.

iii) Please provide the DVA rate rider and GA rate rider under the scenario that the line loss variance dollars for Non-RPP GA is transferred from Account 1588 to Account 1589 in 2019.

NPEI will provide updated rate rider calculations during the settlement process.

c) Please update an illustrative example by using the following data where a price variance in the RPP is assumed instead:

- Average RPP Price: $0.090
- Average GA rate: $0.108
- Average Electricity Price: $0.02

i) Using the scenario above, where a non-RPP customer is billed the energy price of $0.11 (GA rate + electricity) and an RPP customer is billed the RPP price of $0.09. please explain whether Niagara Peninsula Energy's method still results in an equal allocation of volume variance.

As indicated in the question above, the illustrative example provided by NPEI in the response to 9-Staff-91 assumes no RPP variance. NPEI notes that RPP variances are settled monthly with the IESO as Charge Type 142 – Regulated Price Plan Settlement Amount, which is recorded in Account 1588 RSVA Power.

The updated illustrative example requested above is provided below.

- Average RPP Price: $0.090
- Average GA rate: $0.108
- Average Electricity Price: $0.02

Scenario 1 – UFE recorded in Account 1588 only

Account for all UFE Variance in Account 1588	**RSVA Power - 1588**	**RSVA GA - 1589**	**Total**
Bill RPP Customer on TOU- 10,000 kWh * 1.05 @ $0.09	(945.00)		(945.00)
Bill non-RPP Customer Power - 10,000 kWh *1.05 @ $0.02	(210.00)		(210.00)
Bill non-RPP Customer GA - 10,000 kWh *1.05 @ $0.108		(1,134.00)	(1,134.00)
Total Revenue	(1,155.00)	(1,134.00)	(2,289.00)
CT 101 - 20,000 kWh *1.04 @ $0.02	416.00		416.00
CT 148 - 20,000 kWh *1.04 @ $0.108 = $2,246.40	1,112.40	1,134.00	2,246.40
CT 142 - 10,000 kWh *1.04 @ ($0.09 - $0.02 - $0.108)	(395.20)		(395.20)
Total Charges	1,133.20	1,134.00	2,267.20
RSVA Balance	(21.80)	-	(21.80)

Allocation for Disposition	kWh	RSVA Power - 1588	RSVA GA - 1589 (Non-RPP only)	Total
Non-RPP	10,000	(10.90)	-	(10.90)
RPP	10,000	(10.90)		(10.90)
	20,000	(21.80)	-	(21.80)

Scenario 2 – UFE recorded in Account 1588 for RPP and Account 1589 for Non-RPP

Account UFE Variance in Account 1588 for RPP and Account 1589 for Non-RPP	RSVA Power - 1588	RSVA GA - 1589	Total
Bill RPP Customer on TOU- 10,000 kWh * 1.05 @ $0.09	(945.00)		(945.00)
Bill non-RPP Customer Power - 10,000 kWh *1.05 @ $0.02	(210.00)		(210.00)
Bill non-RPP Customer GA - 10,000 kWh *1.05 @ $0.108		(1,134.00)	(1,134.00)
Total Revenue	(1,155.00)	(1,134.00)	(2,289.00)
CT 101 - 20,000 kWh *1.04 @ $0.02	416.00		416.00
CT 148 - 20,000 kWh *1.04 @ $0.108 = $2,246.40	1,123.20	1,123.20	2,246.40
CT 142 - 10,000 kWh *1.04 @ ($0.09 - $0.02 - $0.108)	(395.20)		(395.20)
Total Charges	1,144.00	1,123.20	2,267.20
RSVA Balance	(11.00)	(10.80)	(21.80)

Allocation for Disposition:	kWh	RSVA Power - 1588	RSVA GA - 1589 (Non-RPP only)	Total
Non-RPP	10,000	(5.50)	(10.80)	(16.30)
RPP	10,000	(5.50)		(5.50)
	20,000	(11.00)	(10.80)	(21.80)

9-Staff-106
Ref: LRAMVA workform, Tab 1 – Nov 19, 2020
Ref: 2021 Tariff Schedule and Bill Impact – Nov 19, 2020

In the “LRAMVA workform” (tab 1), the LRAMVA balance is proposed to be disposed of over a 3-year period, but in the “Tariff Schedule and Bill Impact” model (tab 6), the rate riders for Account 1568 are calculated based on a 1-year disposition period.

a) As the bill increase for the streetlighting class is 20.5% with a 1-year disposition period for the LRAMVA balance, please confirm whether NPEI intended to dispose of the LRAMVA balance for this specific rate class by more than 1 year to mitigate rate impacts.

   In the LRAMVA Workform (Tab 1), NPEI entered a value of 3 for the recovery period in error. NPEI notes that this value has no impact, as the actual LRAMVA rate riders are calculated in the DVA WorkForm. NPEI confirms that it is proposing a 1-year disposition period for the LRAMVA balance. NPEI will address rate mitigation, if any, as part of the Settlement process.

b) If there is no change required to the proposed disposition period for the LRAMVA balance, please confirm.

   NPEI confirms that no change is required to the proposed disposition period for LRAMVA.

8-Staff-107
Ref: 2021 Tariff Schedule and Bill Impact (Tab 3) – Nov 19, 2020

Please update tab 3 of the “Tariff Schedule and Bill Impact” model with the approved inflation factor noted in the recently issued Decision and Rate Order (EB-2020-0285) Inflation Adjustment for Energy Retailer Service Charges.

NPEI will update the Tariff Schedule and Bill Impact model to reflect the updated Retailer Service Charges as part of the Settlement process.

9-Staff-108

Line Loss Variances in Account 1588 and Account 1589

Ref: Response to 9-Staff-105

Based on the updated illustrative example provided by Niagara Peninsula Energy, OEB staff has recalculated the line loss variance $ attributable to the RPP customer and Non-RPP customer as below:

Table 1: the UFE $ attributable to RPP customer and Non-RPP customer

	kWh	RPP Customer	Non-RPP Customer	Total
Bill RPP Customer on TOU	10,000	(945.00)		(945.00)
Bill Non-RPP Customer Energy	10,000		(210.00)	(210.00)
Bill Non-RPP Customer GA			(1,134.00)	(1,134.00)
Total Revenues		**(945.00)**	**(1,344.00)**	**(2,289.00)**
CT101	20,000	208.00	208.00	416.00
CT148	20,000	1,123.20	1,123.20	2,246.40
CT142	10,000	(395.20)		(395.20)
Total Charges		**936.00**	**1,331.20**	**2,267.20**
UFE Variance $		**(9.00)**	**(12.80)**	**(21.80)**

OEB staff has compared the UFE $ allocation calculated in Table 1 above to the UFE $ provided in the response to 9-Staff-105 under the two scenarios as below:

Table 2: Comparison of the UFE Allocation $ in Table 1 to the Allocation $ under the two Scenarios

Allocation Comparison	The UFE $ Allocation from above	Scenario 1- UFE recorded in Account 1588 Only (NPEI's proposal)	Scenario 2 - UFE recorded in Account 1588 and Account 1589 (APH)
RPP Customers	(9.00)	(10.90)	(16.30)

Non-RPP Customers	(21.80)	(10.90)	(5.50)

a) Please confirm the Table 1 and Table 2 and revise the tables as necessary.

NPEI confirms that Table 1 above represents the UFE allocation to the RPP and Non-RPP customer, without regard to which accounts the revenue and charges are actually recorded in.

NPEI notes that, in Table 2, the UFE allocation to the Non-RPP customer from Table 1 should be $12.80, not $21.80. Also, the allocation under Scenario #2 is ($5.50) to RPP and ($16.30) to Non-RPP.

The revised Table 2 is provided below:

Allocation Comparison	The UFE $ Allocation from Above	Scenario 1 - UFE Recorded in Account 1588 Only (NPEI's proposal)	Scenario 2 - UFE Recorded in Account 1588 and Account 1589 (APH)
RPP Customers	(9.00)	(10.90)	(5.50)
Non-RPP Customers	(12.80)	(10.90)	(16.30)

b) Please confirm that based on the comparison in Table 2, neither of the allocation $ under Scenario #1 and Scenario #2 results in an allocation of the UFE $ that should be attributable to RPP customer and Non-RPP customer.

NPEI confirms that, based on the comparison in Table 2, neither of the allocated dollar amounts under Scenario #1 or Scenario #2 results in the UFE allocation from Table 1.

The difference between the Table 1 scenario, and Scenario #2 in Table 2, is that the power sales revenue and CT 101 relating to the Non-RPP customer is actually recorded in Account 1588, which is allocated to both RPP and Non-RPP customers for disposition.

Attachment 1 – Pre-Settlement Clarification Questions

Balanced Scorecard 2019 Plan and Actual Balanced

Scorecard 2020 Plan and Executive Pay Policy

#	2019	Planned Weighting %	Performance Rating 0,1,2,3	Achieved Weighted Rating %
#	**Growth & Sustainability**			
	LDC Profitability			
1	EBITDA Margin > 40%	10%	2.00	10.00%
2	Return on Assets > 1.12%	5%	2.00	5.00%
3	OM&A (Exclude Depreciation) Cost/Customer < $345	7%	2.00	7.00%
4	Preparation of 2021 COS Application	10%	2.00	10.00%
5	Debt Service Coverage > 1.75	2%	2.00	2.00%
6	Debt capitalization < 0.6	3%	2.00	3.00%
7	Annual Calendar for Internal Departments-All Regulatory Filing Accurate & On Time	3%	2.00	3.00%
		40%		40.00%
	Customer & Community			
1	Conduct 3rd Party Customer Satisfaction Survey-Results meet or exceed 2017 results (87%)	4%	3.00	4.80%
2	Scheduled appointments 100% on time	2%	2.00	2.00%
3	Calls answered on time > 89%	2%	2.00	2.00%
4	Billing Accuracy > 99%	2%	2.00	2.00%
5	First Contact Response > 94%	1%	2.00	1.00%
6	New Residential/Small Business Services connected on time > 92%	1%	2.00	1.00%
7	Prepare Customer Engagement Plan	3%	1.50	2.25%
		15%		15.05%
	Operational Excellence			
1	95% Capital Budget Expended Annually	10%	1.86	9.30%
2	SAIDI < 2.50 (excluding significant events)	7%	2.20	7.28%
3	SAIFI < 1.25 (excluding significant events)	7%	1.80	6.30%
4	Safety Level of Public Awareness > 83%	1%	1.90	0.95%
		25%		23.83%
	Public Policy			
1	Optimize CDM Programs	1%	1.00	0.50%
2	Achieve 5 year Target (74.44 GW)	1%	1.00	0.50%
3	Renewable Generation Connection Impact Assessments 100% on time	2%	2.00	2.00%
4	New Micro Embedded Generation Facilities connected 100% on time	1%	2.00	1.00%
		5%		4.00%
	People & Information Systems			
1	Pro-Active Safety & Wellness Culture	1%	2.00	1.00%
2	Zero Workplace Injuries	1%	1.00	0.50%
3	Increase the # of hours without a reportable loss time injury by 2%	1%	1.00	0.50%
4	Develop an Attendance Management Program	1%	2.00	1.00%
5	2 Improvements to Management Safety System	2%	1.90	1.90%
6	Enhanced Leadership Development Program Initiatives	2%	2.00	2.00%

	2019	Planned Weighting %	Performance Rating 0,1,2,3	Achieved Weighted Rating %
7	Develop and implement a Communication program to provide enhanced communication between Supervisor and Employee	1%	1.10	0.55%
8	100% of Performance Assessments completed before January 31st of the following year	2%	2.00	2.00%
9	Achieve 5-year target-Cyber Security WISP program	2%	2.00	2.00%
10	Annual Hardware and Software capital budgets completed within 5% of total respective budget dollars	1%	2.00	1.00%
11	Develop Corporate Mobile App as part of NPEI's innovation program	1%	1.00	0.50%
		15%		12.95%
	Total Weighting	100%		95.83%

Corporate % Achieved Weighted			
CEO Weighting	80%	95.83%	76.66%
Executive Weighting	70%	95.83%	67.08%

Rating Opportunity		
	3	120.0%
	2	100.0%
	1	50.0%
	0	0.0%

Legend
3 = 120%
2.5 = 110%
2 = 100%
1.5 = 75%
1 = 50%
0.5 = 25%
0 = 0 %

#	2020	Planned Weighting %	Performance Rating 0,1,2,3	Achieved Weighted Rating %
#	**Growth & Sustainability**			
	LDC Profitability			
1	EBITDA Margin > 40%	10%		#N/A
2	Return on Assets > 1.39%	3%		#N/A
3	OM&A (Exclude Depreciation) Cost/Customer < $332	10%		#N/A
4	Complete the 2021 COS Rate Application process	10%		#N/A
5	Debt Service Coverage > 1.75	3%		#N/A
6	Debt capitalization < 0.6	3%		#N/A
7	Annual Calendar for Internal Departments-All Regulatory Filing Accurate & On Time	1%		#N/A
		40%		#N/A
	Customer & Community			
1	Conduct 3rd Party Electrical Safety Survey-Results meet or exceed 2017 results (83%)	4%		#N/A
2	Scheduled appointments 100% on time	2%		#N/A
3	Calls answered on time > 89%	2%		#N/A
4	Billing Accuracy > 99%	2%		#N/A
5	First Contact Response > 96%	1%		#N/A
6	New Residential/Small Business Services connected on time =100%	1%		#N/A
7	Analyze and report on Customer Service Survey results quarterly	3%		#N/A
		15%		#N/A
	Operational Excellence			
1	90% Capital Budget Expended Annually	10%		#N/A
2	SAIDI < 1.79 (excluding significant events and loss of power)	7%		#N/A
3	SAIFI < 1.53 (excluding significant events and loss of power)	7%		#N/A
4	Number of Serious Electrical Public Incidents = 0	1%		#N/A
		25%		#N/A
	Public Policy			
1	Prepare a Customer Engagment Plan	1%		#N/A
2	Design and implement new website	1%		#N/A
3	Develop Crisis Communications Plan	1%		
4	Renewable Generation Connection Impact Assessments 100% on time	1%		#N/A
5	New Micro Embedded Generation Facilities connected 100% on time	1%		#N/A
		5%		#N/A

	2020	Planned Weighting %	Performance Rating 0,1,2,3	Achieved Weighted Rating %
	People & Information Systems			
1	Pro-Active Safety & Wellness Culture	1%		#N/A
2	Zero Workplace Injuries	2%		#N/A
3	Increase the # of hours without a reportable loss time injury by 2%	1%		#N/A
4	Implement new recruitment program to be more efficient	1%		#N/A
5	Conduct Employee Engagement survey	2%		#N/A
6	Update the Accident & Incident Reporting Program	2%		#N/A
7	Achieve 5-year target-Cyber Security WISP program	2%		#N/A
8	Annual Hardware and Software capital budgets completed within 5% of total respective budget dollars	1%		#N/A
9	Increase customer presence on the customer portal and website by 5%	1%		#N/A
10	Re-engineer Customer Contact Management	2%		#N/A
		15%		#N/A
	Total Weighting	100%		#N/A

Corporate % Achieved Weighted			
CEO Weighting	80%	#N/A	#N/A
Executive Weighting	70%	#N/A	#N/A

Rating Opportunity		
	3	120.0%
	2	100.0%
	1	50.0%
	0	0.0%

Legend
3 = 120%
2.5 = 110%
2 = 100%
1.5 = 75%
1 = 50%
0.5 = 25%
0 = 0 %

Niagara Peninsula Energy Corporation ('NPEI')
Executive Total Compensation Pay Policy

Introduction

NPEI pursues a total compensation strategy, which ensures its Executives are paid at market competitive rates. The organization engages, from time-to-time, the services of an independent external compensation consultant who works with the VP Human Resources and President & CEO to analyze the competitive markets and to establish total compensation that will attract, retain and motivate employees.

The Governance Committee of the Board of Directors, reviews compensation levels of members of NPEI's executive team, evaluates the President & CEO's individual performance and considers Executive management succession and related matters. All decisions relating to the compensation of the Executive team are reported and shared with the full Board of directors.

The President & CEO is accountable to manage, review and approve compensation matters as they relate to NPEI's non-executive management team.

Pay Philosophy Statement

NPEI recognizes the alignment of the contributions of its Executives to the success of its business. The organization strives to pay competitively and equitably for performance, yet is cognizant of the budgetary and business constraints of operating in a regulated environment.

NPEI bases its total compensation philosophy on its desire to attract, retain and motivate top talent and high-performing Executives. NPEI provides a total compensation program that establishes and maintains competitive salary levels within relevant markets and available resources, which is consistent with job content, responsibilities and expectations. The Program emphasizes and encourages excellence by rewarding individual contributions, including performance that supports NPEI's core values of ***Integrity, Fairness, Responsibility, Respect and Transparency.***

In addition to total cash compensation opportunities, NPEI provides a comprehensive benefit plan designed to address its Executives health and wellness, and encourages continuous professional development and career advancement through its performance management system and supporting programs.

Guiding Principles

In developing and administering its total compensation Program, NPEI considers that the outputs should:

- Support the Strategic Goals and Core Values of the organization
- Maintain fair and equitable compensation practices
- Maintain market-driven competitiveness
- Support a performance and results driven culture
- Be simple to administer and understand
- Be openly communicated to Executive team members
- Be flexible to meet the unique needs that may exist within the organization

Market Position

NPEI regularly monitors, analyzes and determines the market competitiveness of its Executive total compensation Program. A comprehensive external market-comparator analysis is conducted at a minimum, once every three years. In the off years, the organization undertakes an external review against a set of benchmark positions, both executive and management to determine relativity and identify any substantive changes driven by market and/or environmental conditions.

Market Comparators

NPEI attracts and recruits Executives from both the LDC and the private sector markets, with particular emphasis on the LDC market. The organization reviews and analyzes its competitiveness against three market comparators to provide a robust and comprehensive review. Over and above the private and LDC markets, the organization recognizes the importance and community sensitivity of monitoring its position against the public sector.

Data Sources

NPEI reviews, analyzes and determines its Executive level market position against the following market compensation data bases:

Broader Public Sector (BPS) Ontario – excluding GTA

- Includes public sector and non-profit organizations

Industrial Sector (Industrial) Ontario – excluding GTA

- Includes private organizations in a variety of industries

Local Distribution Corporation (LDC) Sector

- Includes LDC's of similar size and scope, and those that NPEI considers its market competition for talent

Competitive Positioning

NPEI considers its primary competition for talent its LDC market, yet recognizes the requirement to maintain a balanced review and approach against both the private and public sector markets.

The organization strives to maintain a 50^{th} percentile position against the public and private sectors, with a primary focus on maintaining a 50^{th} percentile position against its LDC market competition.

Total Compensation Elements

NPEI maintains and executes on a performance management system that aligns its Executives performance to total compensation. The organization has developed and maintains a **Balanced Scorecard** ('BSC') and supporting documentation to help guide, direct and authenticate its position on merit and incentive pay for its Executives.

Base Salary – Merit Pay

Merit pay is the portion of total compensation that is added to an individual's base salary. Merit pay rewards individuals for the growth, commitment, drive and achievement in the performance of their role in the organization. Job rate (100%) is the rate at which a fully experienced and competent individual achieves or is expected to operate at. Below job rate, the individual is considered developing. Achieving above job rate is possible for individuals who have demonstrated mastery or consistent superior performance in one or more roles.

NPEI maintains a 'formal' base salary band of 80% to 100%. In addition the CEO has discretion to utilize an additional 105% which:

- Provides sufficient opportunity to reward, retain and attract top talent beyond 100%
- Provides opportunity to mitigate compression issues
- Is consistent with best practice and its LDC market comparators
- Provides opportunity to place individuals new to the position in a developmental salary range, as well as recognize the need to go beyond 100% in a tight or aggressive market for certain talent

CEO Confidential 105% Policy
NPEI maintains a separate and confidential Policy that outlines the CEO's ability to progress Executives beyond 100% comp-ratio, to a maximum of 105% The Policy provides guidelines, and perimeters to assist the CEO when applying his/her discretion. The CEO relies on the VP Human Resources' insight and expertise when considering application of the Policy.

Incentive Opportunity
NPEI's incentive pay is a lump-sum payment, not compounded or added to an individuals base salary. Incentive pay rewards individuals for objectives met, stretch target goals achieved and for adding value beyond the expected performance of their role in the organization.

Incentive Pay Plan

Incentive pay is available to those individuals who contribute materially to the success of the organization through their direct ability to impact the business, their ingenuity, drive and leadership. Incentive pay is paid out through actual achievement of weighted objectives set out and clearly defined at the beginning of the performance year. The Board & President & CEO determines and directs the payout opportunity criteria of achievement, as follows:

	Achievement *
Outstanding Opportunity	120%
Target Opportunity	100%
Threshold Opportunity	50%
Below Threshold	0%

* Payout is linear and includes incremental achievement between Threshold and Outstanding percentages.

Pay Plan Mix
NPEI's pay mix reflects the differences in the individual roles and responsibilities of the Executive team. The most senior positions maintain a greater emphasis placed on variable pay in recognition of their ability to directly impact the organization's overall performance and drive results. Conversely, these individual's have less impact on the BSC Corporate Objectives, normally operationalized below the Executive level.

Position	Incentive Pay Mix	
	Corporate	**Individual**
President & CEO	20%	80%
CFO, SVP, VP Positions	30%	70%

Corporate vs. Individual Objectives

Corporate Objectives

Annually NPEI develops organizational objectives aligned to it longer-term Strategic Plan and Strategy Map. The annual objectives are defined within the five perspectives of NPEI's Balanced Scorecard.

Growth & Sustainability	*Customer & Community*	*Operational Excellence*	*Public Policy*	*People & Information Technology*

Objective within the BSC are focused on those substantive projects and initiatives the organization needs to achieve within the performance year. Objectives should be as quantifiable as possible, to allow for more robust evaluations of actual results.

Individual Objectives

Each Executive team member will identify 3 to 5 objectives that are substantive, strategic and require his/her personal interaction, support, direct and focus. It is not expected that individuals will have an objective from each of the five BSC perspectives. Each will have more area of control, influence and ability to achieve results relative to their areas of expertise and accountability.

Evaluating and Managing Performance

NPEI places considerable emphasis on a results-driven, performance-based system, which achieves success through the development of SMART (Specific, Measurable, Achievable, Relevant, Time-bound) objectives. Goals are intended to challenge the organization to consider how it can improve overall and individual skills to maximize its potential and further enhance its contribution to the shareholder and community.

The program and supporting practices (succession planning, talent management, career & leadership development and recruitment) are influenced and directed by NPEI's set of behavioural core competencies. NPEI's Performance Management System assesses individuals in four major components:

Behavioural Core Competencies	*Annual Performance Evaluations*	*Merit & Incentive Pay*	*Professional & Career Development*

Accountability

1. The President & CEO is accountable to interpret NPEI's BSC incentive program, and may amend and/or cancel the program at any time, subject to the approval of the Board of Directors.

2. The President & CEO and the Vice President Human Resources are responsible to administer the Program, undertake regular market driven reviews and support recommendations to the Board of Directors where required.

3. The Vice President Human Resources is responsible to review, recommend and develop a total compensation Program and Performance Management System that aligns with the organizations core competencies and values, reflects best practice and maintains the organizations compensation principles relative to its market position and competitive total compensation.

4. The Vice President Human Resources is responsible to recommend modifications or program changes consistent with the strategic needs of the business, the evolving regulated environment and the challenges the organization may encounter relative to its talent management strategy.

5. Vice President Human Resources is responsible to ensure the accuracy of the financial calculations and that individual payments are made as soon as possible after the approvals are given.

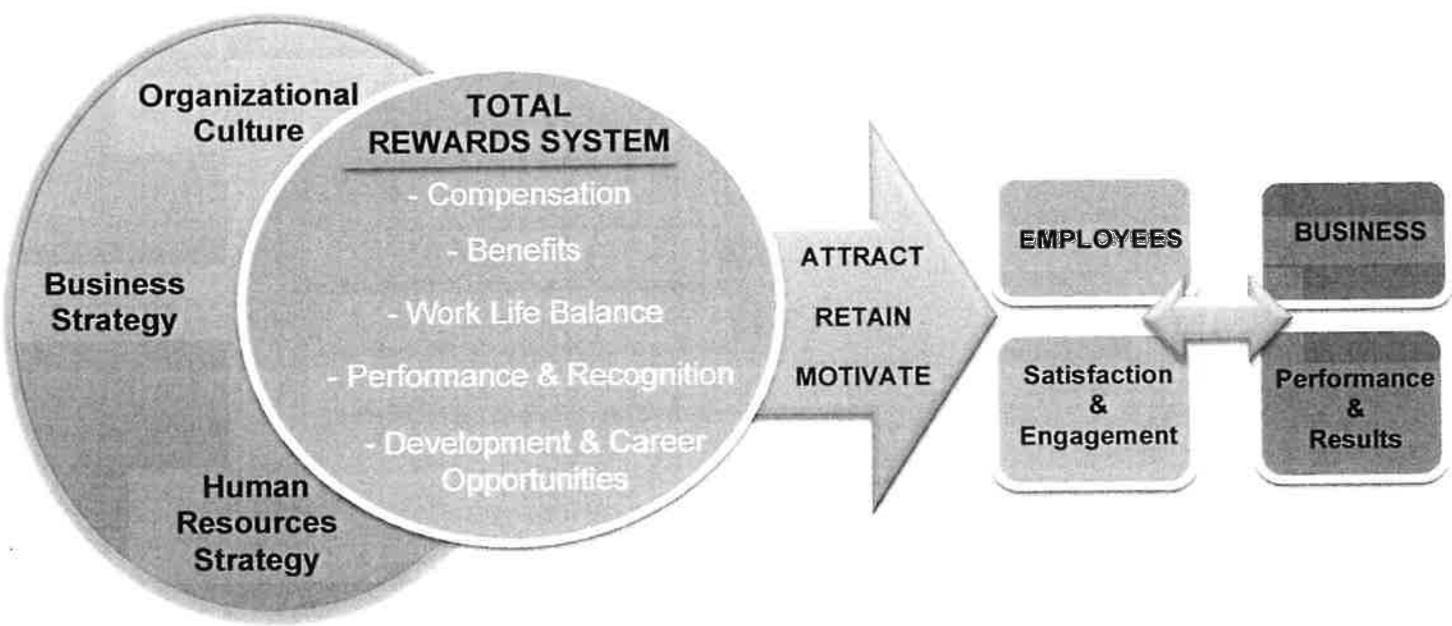
6. Each Executive member has the responsibility to support the total compensation program criteria, align their team efforts with NPEI's strategic goals, vision and core values and motivate their employees to achieve corporate and individual success (where eligible).

7. Each individual eligible under the program has the responsibility to follow the procedures and expectations as outlined in the Performance Management System guidelines and tools, as defined with their position of responsibility.

NPEI's Total Compensation Model

The following model provides the elements required to feed into and support NPEI's total rewards and compensation system. The organization will be better positioned to achieve its business goals, drive its short and long-term strategies and support an engaged and evolving employee culture operating within an aligned and integrated program.

Success will improve the organizations talent management and succession planning practices, while improving employee satisfaction and company performance.



NIAGARA PENINSULA ENERGY INCORPORATED (NPEI)

EXECUTIVE INCENTIVE PAY PLAN

niagara peninsula energy inc.

I. Purpose of the Plan

Niagara Peninsula Energy Incorporated ('the Company') seeks to encourage and reward a performance-driven culture by aligning its Executive's achievements with the corporate vision and its short and long-term strategic goals.

The Executive Incentive Program provides for a variable compensation component, over and above annual base salary. The purpose of the Plan is to focus the Executive's efforts, attention and achievement against those goals that advance the organization and drive its strategic vision.

II. Plan Objectives

The objective of the Plan is to:

- Provide a financial reward that is directly related to performance in support of executing on NPEI's business plans
- Focus and reward individual achievement that supports the Company's strategic plans
- Motivate exceptional performance over and above day to day expectations
- Incent and enhance rewards for above average financial and operational results that move the business forward

III. Guidelines for Participation

Nothing contained herein shall be construed that participation in the Program is a contract of employment which confers upon the participant the right to continue in the employ of the Company nor does it obligate the Company to allow the employee to participate in the Program in future years.

IV. Eligible Participants

In order to be eligible for an incentive, the individual must be actively employed by the Company on its fiscal year-end of December 31st. If the individual leaves the organization prior to year-end, his/her incentive pay shall be pro-rated for the time he/she was actively employed. However, they will not be eligible if he/she is terminated for cause prior to the date the incentive payment is issued.

If the individual experiences a change in incentive percentage during the year he/she will be eligible for a pro rata incentive award. The pro rata award will be based on the portion of the year at each respective incentive percentage, with the appropriate salary level applied.

Incentive pay is a percentage based on the individual's current annual base salary.

The eligible Executive incentive for the current year (2019) is:

	Threshold 50%	Target 100%	Outstanding 120%
CEO	12.5%	25.0%	30.0%
Executive	10.0%	20.0%	24.0%

V. Non-Payout Threshold

The Company requires appropriate financial stability and viability to pay out an incentive to its Executive. In the event the organization does not achieve a positive EBIT less the annual incentive pay, in any given year – an incentive shall not be paid out.

VI. Termination of Employment

The Executive shall be considered for an incentive pro-rata payout for the period of active employment in the event of the death, retirement or not for cause termination during the performance period. In the event of death, the payment will be made to the individual's estate.

No incentive payout in respect of the current year will be payable in the event of termination for cause during the performance period. Nor is the individual eligible if he/she chooses to leave the Corporation's employ during the current calendar year.

VII. Corporate Goals

The Company annually sets out its Balanced Scorecard (BSC) objective aligned to its long term Strategy. These objectives are supported by the Governance Committee of the Board and align to the Company's success and continued growth.

Financial success and continued enhancement to Shareholder value is the cornerstone of the Company remaining a profitable. As such, and as evidenced in the Company's BSC objectives, continuous improvement, productivity improvements, cost control and new revenue growth support a healthy Balance Sheet that provides value to Customers by keeping rates reasonable and value to the Shareholder by providing a profit on its investment.

VIII. Executive Objectives

Annually, the Company shall identify critical and substantive activities and objectives for the upcoming year and will document these objectives in its Annual BSC. Each Executive shall develop his/her individual objectives, aligned to the BSC – which are to be reviewed and approved by- for the CEO by the Governance Committee and for the Executive by the CEO.

The CEO thereby directs his management team to set organizational objectives, which are cascaded appropriately within each department and supported through comprehensive Work Plans. The Work Plans provides departmental initiatives and measures that support the organizations objectives.

IX. Performance & Payout Periods

The individual's performance will be assessed annually and payment will be made as soon as practical after the end of December and after the Corporation has received its annual audited financial statements.

The incentive payout will be calculated as a percentage of the individual's annual base salary earnings. The payout is subject to applicable taxes and deductions. As such, incentive payouts are eligible to be included as income for OMERS purposes at these payouts.

X. Incentive Pay is Re-Earnable Income

The incentive payout is "re-earnable" each year and does not form part of the individual's base salary.

XI. Amendment and Termination

The Company reserves the right at any time to amend or terminate this Plan in whole or in part by resolution of the directors of the Governance Committee of the Board.

XII. Administration, Determinations and Interpretation

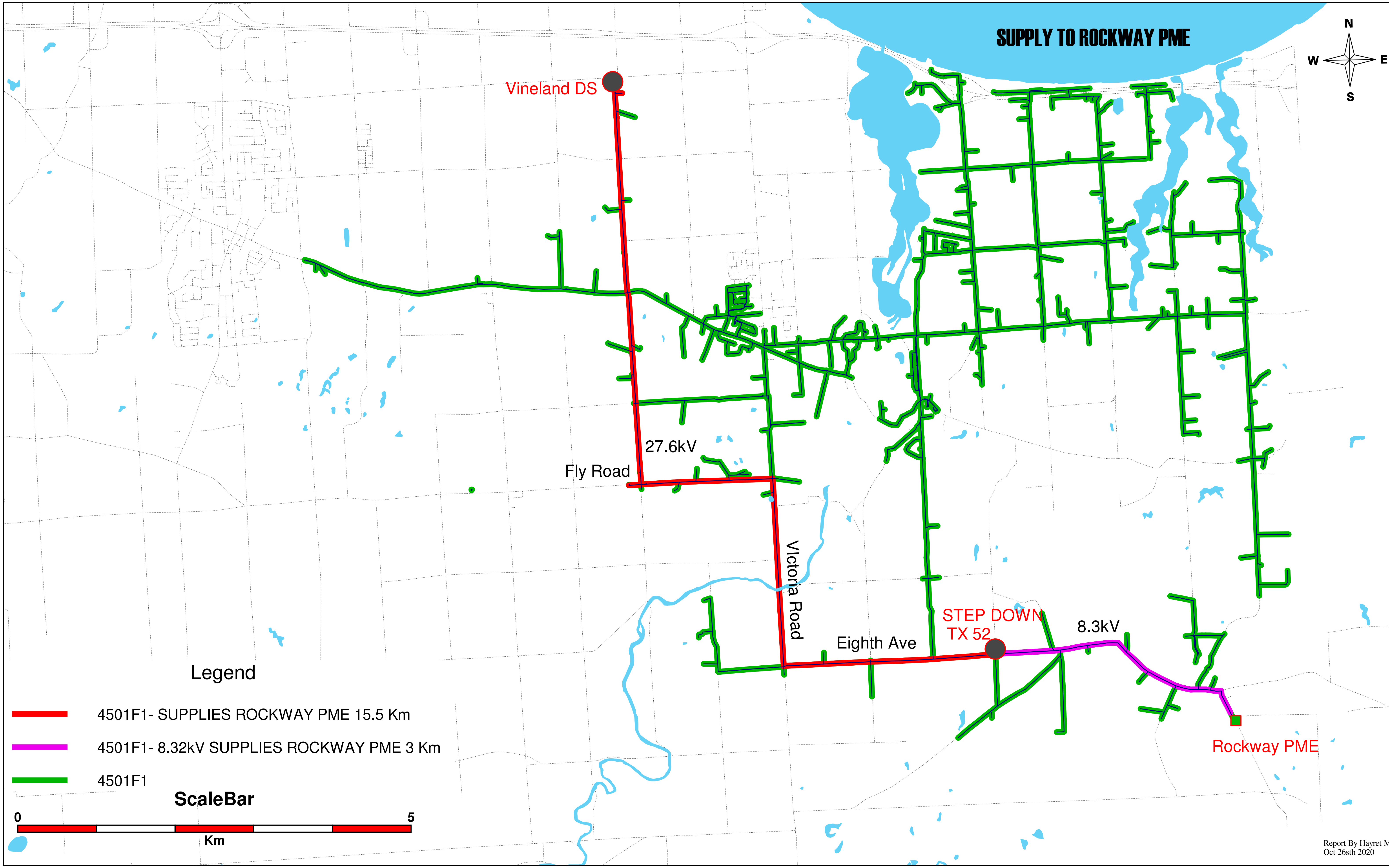
Any determination required to be undertaken by the Company pursuant to this Plan, shall be properly determined or done by the Corporation.

Any disputes or disagreements which arise under or as a result of or in any way related to the interpretation, construction or application of this Plan shall be determined by the Corporation, and any such determinations shall be final, binding and conclusive for all purposes.

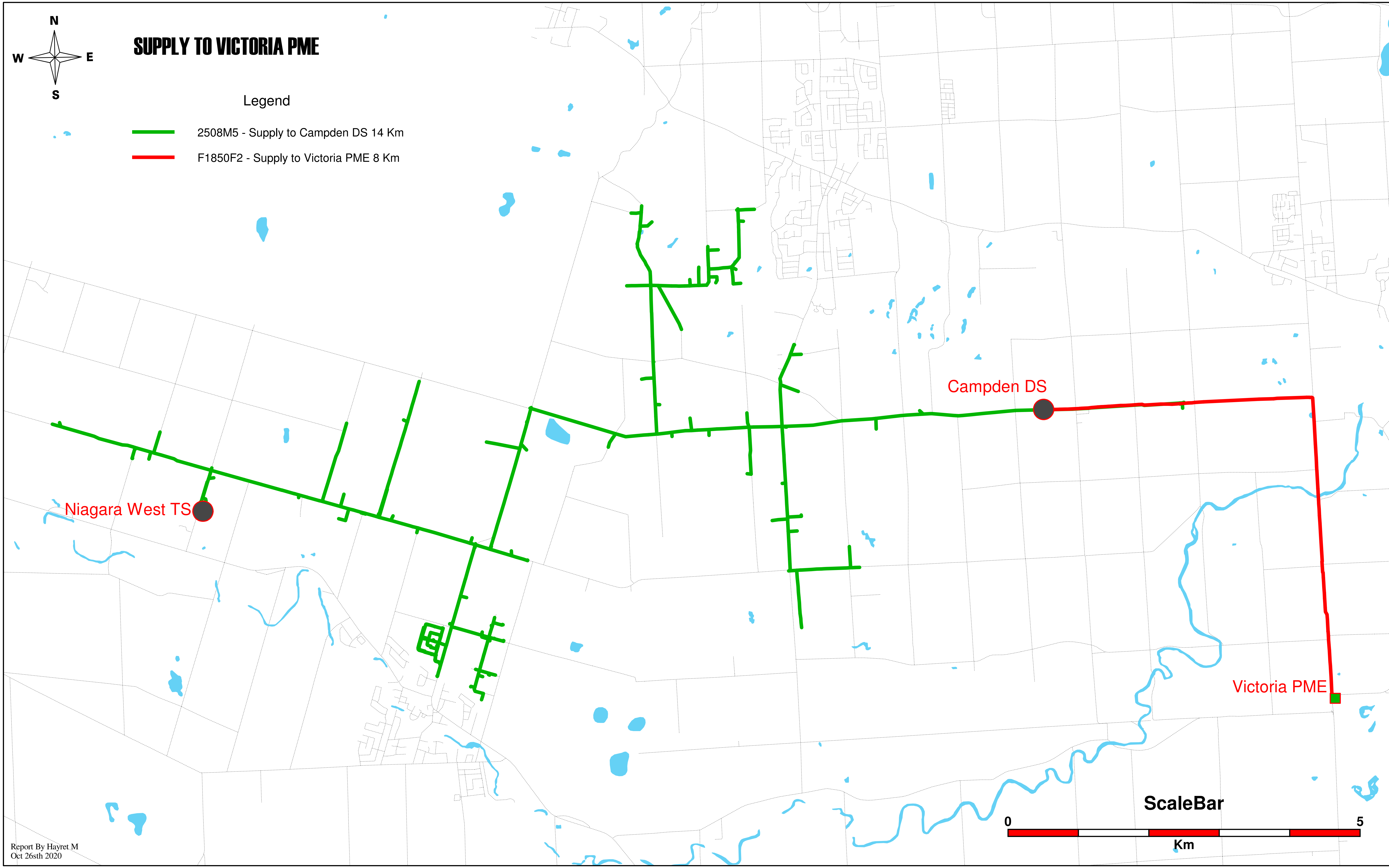
This Plan and all matters to which reference is made herein shall be governed by and interpreted in accordance with the laws of the Province of Ontario and those of Canada insofar as the latter may be applicable.

Attachment 2

HONI Delivery Points Maps



SUPPLY TO ROCKWAY PME
N
W
E
S
Vineland DS
27.6kV
Fly Road
Victoria Road
Eighth Ave
STEP DOWN
TX 52
8.3kV
Rockway PME
Legend
4501F1- SUPPLIES ROCKWAY PME 15.5 Km
4501F1- 8.32kV SUPPLIES ROCKWAY PME 3 Km
4501F1
ScaleBar
0
5
Km
Report By Hayret M
Oct 26th 2020



N
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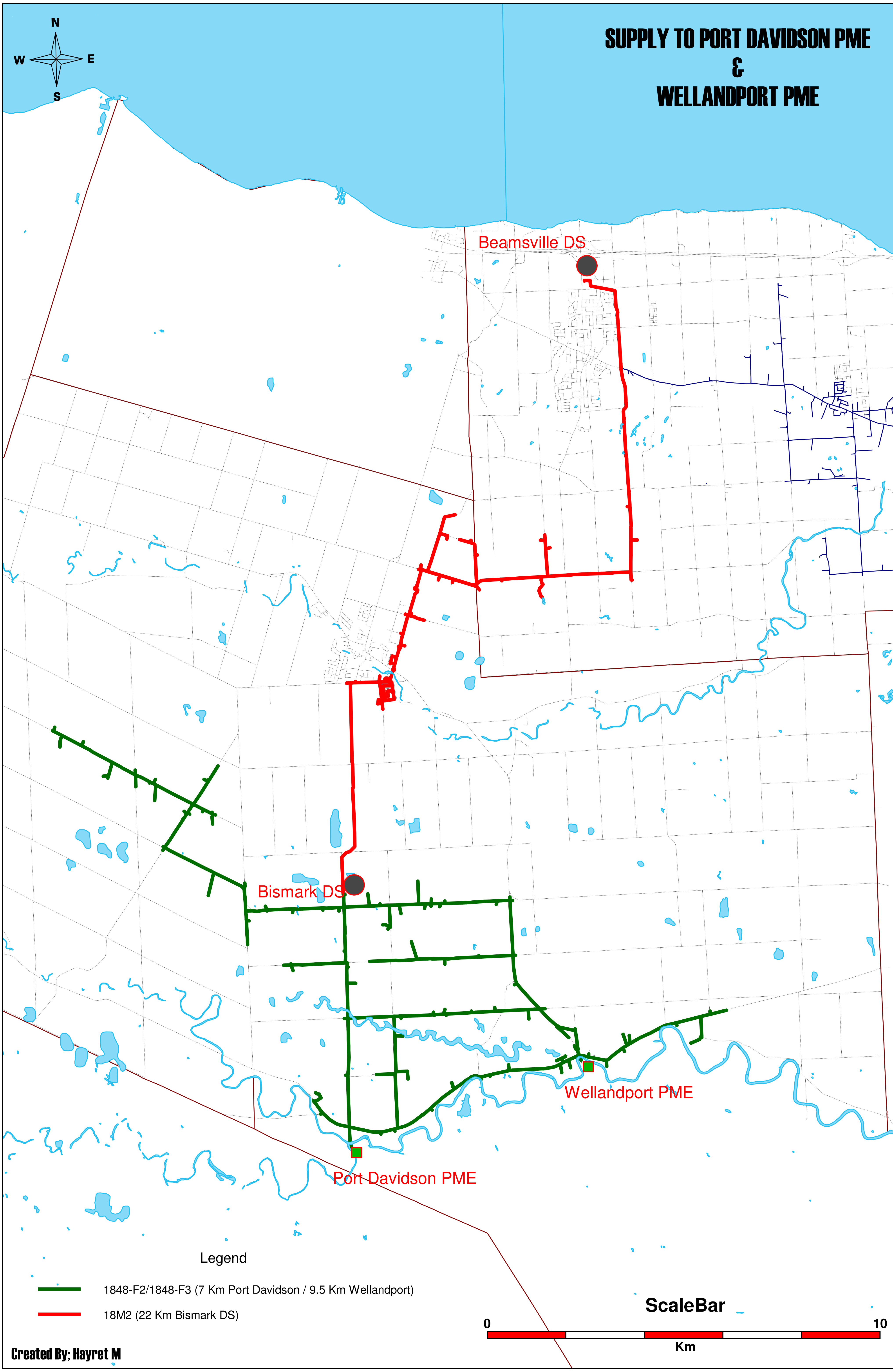
E
S
SUPPLY TO VICTORIA PME
Legend
2508M5 - Supply to Campden DS 14 Km
F1850F2 - Supply to Victoria PME 8 Km
Campden DS
Niagara West TS
Victoria PME
ScaleBar
0
5
Km
Report By Hayret M
Oct 26sth 2020



SUPPLY TO PORT DAVIDSON PME
&
WELLANDPORT PME
N
W
E
S
Beamsville DS
Bismark DS
Wellandport PME
Port Davidson PME
Legend
1848-F2/1848-F3 (7 Km Port Davidson / 9.5 Km Wellandport)
18M2 (22 Km Bismark DS)
ScaleBar
0
10
Km
Created By; Hayret M

Attachment 3

Appendix 2-Q

Pre Settlement and IRR

File Number:	EB-2020-0040
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-Q
Cost of Serving Embedded Distributor(s)

To be completed by Host Distributors ONLY
(Not required if Host Distributor has an Embedded Distributor rate class, i.e. a separate row on Sheet 11 of the RRWF.)

Proposed Rate Class for Billing Embedded Distributor(s)

Host's Distribution Facilities used by Embedded Distributor(s)

(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6) = '(3) + (4)**
Asset Class	**Total OM&A costs asociated with asset class**	**Original cost of asset class**	**Accumulated amortization of asset class**	**Annual amortization of asset class**	**Net Book Value of asset class**
Totals for Host Distributor:	($)	($)	($)	($)	
Distribution Stations	$ 128,783.95	$ 7,238,261.82	-$ 3,962,523.27	-$ 147,029.43	$ 3,275,738.55
Low Voltage Line					$ -
LV Line category # 2 (if applcable)					$ -
OH	$ 1,531,928.50	$ 97,384,658.64	-$ 41,974,946.61	-$ 1,368,399.41	$ 55,409,712.02
UG	$ 999,483.93	$ 83,411,245.16	-$ 47,128,410.95	-$ 1,553,589.35	$ 36,282,834.21
					$ -
					$ -

(1)	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**
Asset Class	**Total line length or station capacity in asset class**	**Line length or capacity required to provide LV service to Embedded Distributor(s)**	**Annual total demand on station/line providing LV services (sum of 12 monthly peaks)**	**Annual billed Embedded Distributor demand on station/line providing LV services**	**Embedded Distributor(s)' Responsibility Share**
Embedded Distributor's share:	kW or kVa; km	kW or kVA; km	kW or kVA	kW or kVA	percent
Distribution Stations	69,000.00	5,000.00	44,928	6,805	1.10%
Low Voltage Line					0.00%
LV Line # 2 (if applicable)					0.00%
OH	1,451.00	23.09	44,928	6,805	0.24%
UG	573.00	0.55	44,928	6,805	0.01%

(1)	(12)	(12a)	(13)	(14)	(15)	(16)
Asset Class	**Return on Assets used to Provide LV services**	**Taxes/PILs**	**Annual amortization on assets used to provide LV services**	**OM&A costs with burden associated with assets used to provide LV services**	**Total annual cost associated with assets used to provide LV services**	**Monthly cost associated with the delivery of LV services**
	($)	($)	($)	($)	($)	$/kW or $/kVA
Distribution Stations	$ 1,801.2725	$ 432.1083	-$ 1,613.75	$ 1,413.49	$ 2,033.1240	0.30
Low Voltage Line	$ -	$ -	$ -	$ -	$ -	0.00
LV Line # 2 (if applicable)	$ -	$ -	$ -	$ -	$ -	0.00
OH	$ 6,685.2242	$ 1,611.3421	-$ 3,298.25	$ 3,692.41	$ 8,690.7204	1.28
UG	$ 262.0851	$ 63.1702	-$ 224.19	$ 144.23	$ 245.2944	0.04
Total					**$ 10,969.1388**	**1.61**

(17)	(18) Capital Structure (%)	(19) Cost Rate (%)	(20)	(21) (%)
Long-Term Debt	56.00%	2.84%	Weighted Average Cost of Capital	5.00%
Short-term Debt	4.00%	1.75%		
Common Equity	40.00%	8.34%	Tax/PILs Rate	26.5%
Preferred Shares				
Total	100.00%		Working Capital Allowance Factor	7.5%

File Number:	EB-2020-0040
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-Q
Cost of Serving Embedded Distributor(s)

To be completed by Host Distributors ONLY
(Not required if Host Distributor has an Embedded Distributor rate class, i.e. a separate row on Sheet 11 of the RRWF.)

Proposed Rate Class for Billing Embedded Distributor(s)

Host's Distribution Facilities used by Embedded Distributor(s)

(1)	(2)	(3)	(4)	(5)	(6) = '(3) + (4)
Asset Class	**Total OM&A costs asociated with asset class**	**Original cost of asset class**	**Accumulated amortization of asset class**	**Annual amortization of asset class**	**Net Book Value of asset class**
Totals for Host Distributor:	($)	($)	($)	($)	
Distribution Stations	$ 128,783.95	$ 7,230,422.00	-$ 3,962,523.00	-$ 147,029.00	$ 3,267,899.00
Low Voltage Line					$ -
LV Line category # 2 (if applcable)					$ -
OH	$ 1,531,928.50	$ 97,384,658.00	-$ 41,974,947.00	-$ 1,368,399.00	$ 55,409,711.00
UG	$ 999,483.93	$ 83,411,245.00	-$ 47,128,412.00	-$ 2,336,712.00	$ 36,282,833.00
					$ -
					$ -

(1)	(7)	(8)	(9)	(10)	(11)
Asset Class	**Total line length or station capacity in asset class**	**Line length or capacity required to provide LV service to Embedded Distributor(s)**	**Annual total demand on station/line providing LV services (sum of 12 monthly peaks)**	**Annual billed Embedded Distributor demand on station/line providing LV services**	**Embedded Distributor(s)' Responsibility Share**
Embedded Distributor's share:	kW or kVa; km	kW or kVA; km	kW or kVA	kW or kVA	percent
Distribution Stations	69,000.00	5,000.00	44,928	6,805	1.10%
Low Voltage Line					0.00%
LV Line # 2 (if applicable)					0.00%
OH	1,451.00	23.09	44,928	6,805	0.24%
UG	573.00	0.55	44,928	6,805	0.01%

(1)	(12)	(12a)	(13)	(14)	(15)	(16)
Asset Class	**Return on Assets used to Provide LV services**	**Taxes/PILs**	**Annual amortization on assets used to provide LV services**	**OM&A costs with burden associated with assets used to provide LV services**	**Total annual cost associated with assets used to provide LV services**	**Monthly cost associated with the delivery of LV services**
	($)	($)	($)	($)	($)	$/kW or $/kVA
Distribution Stations	$ 1,796.9743	$ 431.0734	-$ 1,613.75	$ 1,413.49	$ 2,027.7956	0.30
Low Voltage Line	$ -	$ -	$ -	$ -	$ -	0.00
LV Line # 2 (if applicable)	$ -	$ -	$ -	$ -	$ -	0.00
OH	$ 6,685.2241	$ 1,611.3421	-$ 3,298.25	$ 3,692.41	$ 8,690.7212	1.28
UG	$ 262.0851	$ 63.1702	-$ 337.20	$ 144.23	$ 132.2849	0.02
Total					**$ 10,850.8017**	**1.59**

(17)	(18) **Capital Structure** (%)	(19) **Cost Rate** (%)	(20)	(21) (%)
Long-Term Debt	56.00%	2.84%	Weighted Average Cost of Capital	5.00%
Short-term Debt	4.00%	1.75%		
Common Equity	40.00%	8.34%	Tax/PILs Rate	26.5%
Preferred Shares				
Total	100.00%		Working Capital Allowance Factor	7.5%

Attachment 4

2-Staff-97

Stanley TS Details

November 25, 2005

Mr. Cliff Ballinger
Meter Foreman
Niagara Falls Hydro Inc.
7447 Pine Oak Drive
P.O Box 120
Niagara Falls, Ont.
L2E 6S9

Dear Mr.Ballinger:

Enclosed are signed and executed copies of the Customer Wholesale Revenue Metering Agreement for Niagara Stanley TS and Niagara Murray TS.

Please call me at 416-345-5455 if you have any questions regarding this agreement.

Regards,

Derek Reynolds

Derek Reynolds
Senior Customer Business Officer
Customer Business Relations
Hydro One
483 Bay Street, TCT 15
Toronto, ON
M5G 2P5

Cc: Robert Davidson, Account Executive, Hydro One Networks Inc.

BINDER DOCUMENT FOR

CUSTOMER WHOLESALE REVENUE METERING AGREEMENT

BETWEEN:

HYDRO ONE NETWORKS INC.
A corporation organized and existing under the laws of Ontario
("Networks")

and

NIAGARA FALLS HYDRO INC.
A corporation organized and existing under the laws of Ontario
("MMP")

For valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, Networks and MMP (collectively, the "Parties") agree as follows:

1. MMP and Networks each hereby acknowledges having received and reviewed the Customer Wholesale Revenue Metering Agreement, dated June 18, 2004, including all Schedules and Exhibits attached thereto and referenced therein (collectively, the "CWRMA").

2. MMP and Networks each covenants and agrees to all of the terms, conditions, and any other provisions of the CWRMA.

3. For purposes of Section 6.2(a) of the CWRMA, the MMP's contact and address information is as follows:

   Contact Name
   NIAGARA FALLS HYDRO INC.
   Address 1
   Address 2
   City, Ontario
   Postal Code

THE PARTIES, by their duly appointed representatives who each have the authority to bind the parties, agree to be bound by all of the provisions of this Binder Document, including the Customer Wholesale Revenue Metering Agreement.

NIAGARA FALLS HYDRO INC.	**HYDRO ONE NETWORKS INC.**
By:________________	By:________________
Print Name:____________	Print Name: Jim Patterson
Title:_______________	Title: Manager, Customer Business Relations
Date:_______________	Date:_______________
I have authority to bind NIAGARA FALLS HYDRO INC.	**I have authority to bind the corporation**

INSTRUCTIONS:

1. **MMP to sign two copies of Binder Document;**
2. MMP to return two originally signed Binder Documents to Hydro One Networks Inc., **Attention Derek Reynolds TCT15**, by mail or courier; and
3. Networks to sign two copies and return one signed copy of Binder Document to MMP for its records; and
4. No additions, deletions, or other alterations or modifications to this document are permitted; in case any such changes made, they shall have no force or effect. See Section 6.12 of CWRMA.

CUSTOMER WHOLESALE REVENUE METERING AGREEMENT

This Customer Wholesale Revenue Metering Agreement is used in conjunction with the Document Binder executed by the MMP, identified in the Document Binder, and by Hydro One Networks Inc. ("Networks").

WHEREAS:

A Ontario law requires the registration of participants in the Ontario Electricity Market;

B The MMP is registered as a Metered Market Participant and has entered into an agreement with a Metering Service Provider that is qualified and registered under the Market Rules established for the Ontario Electricity Market in respect of the registered Metering Installations described in Schedules 1 and 2 herein;

C The MMP has one or more Metering Installations situated on property that is either owned, operated, or controlled by Networks; and,

D In accordance with the applicable regulations and rules, the Parties wish to enter into this Customer Wholesale Revenue Metering Agreement ("CWRMA") and to describe the terms and conditions applicable to the metering of the supply of electricity to the MMP.

NOW THEREFORE, in consideration of the mutual covenants set forth herein and of other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereto covenant and agree as follows:

ARTICLE 1: EFFECT OF RECITALS

Each of the Parties acknowledges and agrees that each of the foregoing recitals is true and that the other Party has relied on those recitals in entering into this CWRMA.

1.1 Definitions

In this CWRMA, unless something in the subject matter or context is inconsistent therewith, the word or phrase has the meaning set out below. If a term of this CWRMA is not otherwise defined herein, the definitions listed in Chapter 11, Definitions, of the Market Rules shall apply:

"**Business Day**" means a day other than a Saturday, Sunday, or statutory holiday in Ontario.

"**Confidential Information**" means information designated by either Party as being confidential, and further includes any other information not in the public domain, supplied by one Party to the other in confidence implicitly or explicitly, where disclosure could reasonably be expected to prejudice the competitive position of the disclosing Party; interfere with the contractual or other negotiations of the disclosing Party or another person; or result in loss or gain to the disclosing Party or to another person.

"Customer Wholesale Revenue Metering Agreement" or **"CWRMA"** means this agreement including all schedules and exhibits attached hereto or referenced hereto.

"**Execution Date**" means the date the Binder Document for this CWRMA is signed by the later of both Parties.

"**Force Majeure**" means events or circumstances, or combination of events or circumstances, that are beyond the reasonable control of a Party including, without limiting the generality of the foregoing, "Acts of God", flood, earthquake, fire, explosion, epidemic, war, riot, civil disturbance, labour trouble, strike, sabotage, invasion, lightning, lock-out, vandalism, storm, and restraint by court or public authority, all of which by exercise of due diligence and foresight a Party could not be expected to avoid.

"**IMO**" means the Independent Electricity Market Operator established under Part II of the *Electricity Act, 1998*, or any similar body that may succeed the Independent Electricity Market Operator.

"**Market Rules**" means those rules for the Ontario Electricity Market made under Section 32 of the *Electricity Act, 1998*, and the forms, policies, guidelines or other documents adopted by the IMO Board pursuant to the provisions of the *Electricity Act, 1998*, that are in force at any date when Work is performed. Section and appendix numbers referred to herein are those current in the December 5, 2002, issue of the Market Rules, and may be subject to change by IMO.

"**Metering Installation**" has the meaning attributed to such term under the Market Rules, and for purposes of this CWRMA, are more particularly identified in Schedules 1 and 2 herein;

"**Metered Market Participant**" or "**MMP**" has the meaning attributed to such term under the Market Rules.

"**Metering Service Provider**" or "**MSP**" has the meaning attributed to such term under the Market Rules.

"**Party**" means a party to this CWRMA, and "**Parties**" means both Parties.

"**Site**" means the locations of the Metering Installations through which the MMP's electricity is measured at which part of the work shall be performed.

"**Site Conditions**" means the physical and climatic conditions, applicable at any Site, together with the obligatory site instructions that regulate access and security, health and safety, work protection codes and environmental protection at a Site.

"Substantial Performance" is as defined in the *Construction Lien Act*, R.S.O. 1990. If such definition is not in force or is not applicable, Substantial Performance shall have been reached when the work is ready for use or is being used for the purpose intended.

1.2 Interpretations

The expressions "hereof", "herein", "hereto", ""hereunder", "hereby" and similar expressions refer to this CWRMA and not to any particular Article, section or portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and sections are to Articles and sections of this CWRMA.

A reference to any statute, regulation, rule, order or directive includes amendments thereto.

Words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

ARTICLE 2: SCOPE

The MMP acknowledges and agrees:

2.1 that the IMO will determine the seal expiry date of any new Meter for purposes of determining the earliest seal expiry date of any Meter forming part of the Metering Installation;

2.2 that the MMP will continue paying the regular rates under the Ontario Energy Board ("OEB") approved tariff for metering services until such rates are unbundled and a new tariff is approved by the OEB;

2.3 to the terms and conditions of the following additional schedules, which are schedules to, and form part of, this herein CWRMA:

Schedule 1 – Wholesale Revenue Metering Exit Option Selection
Schedule 2 – Metering Installation Information
Schedule 3 – Licence Terms and Conditions
Schedule 4 – Shared Use of Networks Instrument Transformers
Schedule 5 – Communications and Electrical Supply

ARTICLE 3: FEES FOR EXITING WHOLESALE METERING INSTALLATIONS

3.1 The MMP covenants and agrees to pay Networks an exit fee of five thousand two hundred dollars ($5,200) plus applicable taxes thereon per Metering Point ("Uniform Exit Fee"). The MMP hereby authorizes and directs Networks to set-off the Uniform Exit Fee against any amounts that may be payable by Networks to the MMP in connection with annual rebates under Rate Order No. RP-2003-0188/EB-2003-0233 and this shall be Networks' good and sufficient authority to do so.

ARTICLE 4: LIMIT OF LIABILITY AND INDEMNIFICATION

4.1 Liability and Indemnification

(a) Notwithstanding any other provision of this CWRMA, Networks' total, cumulative, and aggregate liability (except for personal injury or death) to MMP (or any other party or parties claiming through MMP) in connection with this CWRMA shall not exceed twenty-five thousand dollars ($25,000) per occurrence and in the aggregate for any calendar year ("Overall Annual Aggregate Limit"), whether Networks' liability is based in contract, tort, equity, at law, and/or upon any other theory of liability, howsoever arising; Networks' shall only be liable if it has acted in a manner that is grossly negligent or committed an act of wilful misconduct. Each provision of this CWRMA, even if inconsistent or conflicting with this provision, shall be subject to the Overall Annual Aggregate Limit, except to the extent that such inconsistent or conflicting provision(s) further restrict Networks' liability. MMP agrees that Networks would not have entered into this CWRMA without the inclusion of this Section 4.1.

(b) MMP shall indemnify, defend and hold harmless Networks, its affiliates, subsidiaries and shareholders, and each of their respective officers, directors, partners, general partners, limited partners, employees, shareholders and agents (each a "Networks Indemnitee") from and against a loss, claim, or damages, asserted against or suffered by any Networks Indemnitee relating to, or in connection with, or resulting from, or arising out of any negligence or wilful misconduct of MMP, its employees or any authorized representatives, including any of its third party contractors, consultants, agents or advisors, in connection with this CWRMA.

(c) Networks shall be deemed to hold the provisions of Section 4.1(b) that are for the benefit of Networks Indemnitees that are not party to this CWRMA in trust for such persons as third party beneficiaries under this CWRMA.

(d) MMP is liable for the acts and omissions of its employees, agents, and contractors when any one of them is on property that is owned, operated, or controlled by Networks.

4.2 Limit of Liability

(a) In no event shall Networks be liable to MMP or anyone claiming through MMP (pursuant to Section 4.1(a) or otherwise in relation to or as a consequence of this CWRMA) for any loss of profits or revenues, business interruption losses, loss of contract, cost of capital, loss of business opportunity, or loss of goodwill, or for any indirect, consequential, incidental, or special damages, including, but not limited to, punitive or exemplary damages, whether any of the said liability, loss, or damages arise in contract or tort.

(b) Neither Party shall be liable to the other for loss, damage, delay in the work or non-performance of any CWRMA obligation caused by Force Majeure. In such event both Parties shall be prompt in restoring normal conditions, re-establishing schedules, and resuming operations as soon as the event causing the Force Majeure has ceased. The duty to be prompt in restoring normal conditions, re-establishing schedules, and resuming operations shall not apply in the case where the Force Majeure is declared as a result of a strike, lockout or other labour dispute.

(c) Notwithstanding anything else in this CWRMA, the Parties agree that Networks shall not be responsible for:

(i) any sanctions, fines, penalties, or similar obligations imposed on MMP by the IMO or any similar or successor body, and MMP agrees to indemnify and hold harmless Networks from any such sanctions, fines, penalties, or similar obligations; or

(ii) any loss of the monitoring data specified in Chapter 4 of the Market Rules due to Meter unavailability.

(d) The Parties acknowledge that this Article 4, in conjunction with all of the other provisions of this CWRMA, fairly and reasonably allocate the risks between Parties, and that the fees and other financial arrangements reflect this allocation of risk. The Parties further agree and acknowledge that the exclusions and limitations of liability set out in this Article 4 are fair and reasonable in the commercial circumstances, such that the exclusions and limitations have been, in part, an inducement to each Party, and that neither Party would have entered into this CWRMA but for such exclusions and limitations.

ARTICLE 5: DISPUTE RESOLUTION

5.1 Resolution

In the event of a dispute regarding this CWRMA, the Parties shall attempt, in good faith, to resolve the dispute amicably and promptly within ten (10) Business Days, through the appointment, if required, of a senior representative of each Party.

5.2 Arbitration

(a) If, pursuant to Section 5.1, the Parties cannot come to a resolution within ten (10) Business Days, then the dispute shall be submitted to arbitration conducted pursuant to the *Arbitration Act, 1991* of Ontario, then in effect, to the extent not inconsistent with the provisions herein specified.

(b) Such arbitration shall be held in Toronto, Ontario and the dispute shall be heard by one arbitrator who has not previously been employed by either Party, does not have a direct or indirect interest in either Party, and shall be disinterested in the subject matter. Such arbitrator shall either be mutually agreed by the Parties within ten (10) calendar days after agreeing to arbitration, or failing agreement, shall be selected under the rules of the *Arbitration Act, 1991* of Ontario.

(c) The judgement rendered by the arbitrator may be enforced in any court of competent jurisdiction. All costs of the arbitration shall be paid equally by the Parties, unless the award shall specify a different division of the costs. Each Party shall be responsible for its own expenses, including counsel's fees unless the award shall specify differently. Both Parties shall be afforded adequate opportunity to present information in support of its position on the dispute being arbitrated. The arbitrator may also request additional information from the Parties.

(d) Should the Parties commence arbitration pursuant to this Article 5, then the following arbitration rules shall apply:

(i) The arbitrator shall be bound by the terms of the CWRMA and may not detract from or add to its terms.

(ii) The Parties may by mutual agreement specify the rules that are to govern the arbitration proceedings and limit the matters to be considered.

(iii) The arbitrator, any Party, any witness and any other participant in the arbitration proceeding shall not disclose, transmit or disseminate (a) anything said or done in the arbitration, (b) any documents disclosed or provided during or in connection with the arbitration, (c) any information disclosed during or in connection with the arbitration, and (d) the existence or result of the arbitration, including without limitation arbitration settlement, and the arbitration award and any explanations or reasons for the award; however, the preceding shall not apply to the extent that it is legally necessary for the purposes of a court challenge of the arbitration or in respect of an action to enforce the arbitration award.

(iv) Each Party agrees that it will not bring a lawsuit concerning any dispute covered by the arbitration provision.

ARTICLE 6: MISCELLANEOUS

6.1 Confidentiality

Other than as required by the Market Rules and permitted by this CWRMA, the Parties shall hold in confidence and not disclose to others or use, except as required for the proper performance of the work, any Confidential Information disclosed by one Party to the other, its successors, assigns, agents, employees, or affiliates pursuant hereto, or acquired or generated by a Party in the course of performance of the work. Each Party shall obtain the same obligation from its agents and vendors.

6.2 Notices

(a) Any notice, demand, consent, or request required or permitted to be given or made under this CWRMA shall be addressed and delivered to the address shown below:

To MMP:
As indicated in Document Binder

To NETWORKS:
Hydro One Networks Inc.
Attention: Manager, Customer & Business Relations
483 Bay Street
15th floor, North Tower
Toronto, Ontario M5G 2P5

with copy to:
Hydro One Networks Inc.
Director, Network Strategy
483 Bay Street
15th floor, North Tower
Toronto, Ontario M5G 2P5

(b) Changes to the above addresses shall be communicated to the other Party in writing within 30 days thereof. The change of address notification shall be deemed to be incorporated into this CWRMA without further action.

6.3 Assignment

(a) Neither party shall assign this CWRMA, or any portion thereof, without the prior written consent of the other Party, such consent not to be unreasonably withheld. Notwithstanding the foregoing, Networks may assign the agreement to an affiliate, as defined by the Ontario *Business Corporations Act*, without the MMP's consent, provided that written notice is given to the MMP.

(b) Subject to the above, this CWRMA shall be binding upon and enure to the benefit of, the Parties hereto and their respective successors, assigns, personal representatives and estates.

6.4 Term and Early Termination

(a) The initial term of this CWRMA shall be for a period of five (5) years from the date of signature of the Party last signing the Document Binder for this CWRMA ("Initial Term"), subject to any renewals, which renewals shall coincide exactly with any renewals pursuant to Schedule 3 hereof.

(b) Notwithstanding anything else herein,

(i) either Party may terminate this CWRMA if the other Party:

A becomes insolvent, bankrupt, or unable to pay its debts as they fall due, or pursuant to any bankruptcy, reorganization, debt arrangement, or other proceeding under any bankruptcy or insolvency law being instituted by or against it; or

B fails to pay the other Party any amount due under this CWRMA.

(ii) this CWRMA shall automatically expire or terminate when the Licence (described in Schedule 3 hereof) expires or terminates.

6.5 Delivery of Notice

(a) Any written notice required by this CWRMA shall be deemed properly given and delivered if either sent by registered mail, facsimile or delivered to the address specified in Section 6.2(a), above. Notices shall be deemed to have been received upon the earlier of:

(i) the date indicated on the delivery receipt if sent by registered mail;

(ii) the date indicated on the delivery receipt or transmission slip if sent by courier or facsimile, if delivered during normal business hours. If not delivered during normal business hours, delivery shall be deemed to have occurred on the next Business Day.

(b) The designation of the person to be so notified or the address or facsimile number of such person may be changed at any time by either Party by written notice.

6.6 Change in Business

Either Party shall immediately notify the other Party by registered delivery upon the occurrence of any change in business circumstance (including, but not limited to insurance coverage), a registration, or a licence having a material effect on its ability or qualification to meet the requirements of the Market Rules or otherwise perform the work or any of its obligations hereunder, or permit the work to be performed hereunder.

6.7 Law

The CWRMA shall be governed by and interpreted in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, and subject to Article 5 herein, all disputes shall be heard in a court of competent jurisdiction in the City of Toronto.

6.8 Entire Agreement

This CWRMA constitutes the entire agreement between the Parties hereto with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the Parties with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the Parties other than as expressly set forth in this agreement. Except as expressly provided herein, no amendment, modification or supplement to this CWRMA shall be valid or binding upon Networks unless set out in writing and executed by the Manager, Customer Contracts and Business Relations Department of Networks. Any inconsistent or conflicting terms in any related purchase order, order acknowledgement/request, confirmation, or similar form or document, even if signed by the Parties either before or after the date of this CWRMA shall have no force or effect.

6.9 Waiver

No wavier of any breach of any provision of this CWRMA shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

6.10 Severability

If any provision of this CWRMA is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect unless such invalidity or unenforceability renders the operation of this CWRMA impossible.

6.11 Amendments

No amendments will be made to this CWRMA without the express written approval of both parties.

6.12 No Alterations

Any addition, deletion, or other alteration or modification to any pre-printed agreement documentation, even if signed or initialled by both Parties, shall have no force or effect. No employee or representative of Networks has the right to alter, vary, waive any provision of this CWRMA, or to undertake any liability whatsoever on behalf of Networks, unless such be in writing and signed by the Manager, Customer Business Relations.

End of Document

Schedule 3

LICENCE TERMS AND CONDITIONS

RECITALS:

1. Networks is the owner of certain property located in Niagara Falls, Ontario, being legally described in the attached Exhibit "A" and shown outlined on the attached Exhibit "B" (the "Property");

2. MMP seeks permission to locate on the Property certain of its metering equipment and the routing of cables therein that are related to or incidental to wholesale metering in respect of the operation of the MMP's electricity transmission or distribution system on the terms and conditions contained herein.

3. Definitions/Interpretation

"Emergency" means any abnormal condition that requires immediate remedial action to prevent or limit loss of the Networks facilities or the MMP's Works that could adversely affect the reliability of the Networks electricity transmission or distribution system, the integrity of the Networks facilities or the MMP's Works, public safety, life, property, or the environment.

"Initial Term" means the period defined in the Customer Wholesale Revenue Metering Agreement ("CWRMA").

"MMP's Works" means any equipment, apparatus, work, utilities or facilities used by the MMP for the Permitted Use.

"Networks' Works" means any equipment, apparatus, work, utilities or facilities owned, operated, or controlled by Networks on the Property from time to time.

"Permitted Use" means use of the Property for anything related or incidental to wholesale metering in respect of the operation of the MMP's electricity transmission or distribution system.

"Representatives" means the directors, officers, employees, contractors, agents and other representatives of the MMP or Networks.

(a) Each capitalized term used herein shall have the meaning ascribed to it herein. All capitalized terms used in these Licence Terms and Conditions and not defined herein shall have the meanings ascribed thereto pursuant to the CWRMA, and all schedules thereto.

2. Permission

(a) Networks hereby gives permission to the MMP on a limited and non-exclusive basis to locate on the Property certain of its metering equipment and the routing of cables therein that are related to or incidental to wholesale metering in respect of the operation of the MMP's electricity transmission or distribution system ("Licence") upon and subject to the terms and conditions herein.

(b) Provided that the MMP is not in default of any terms and conditions contained herein, and provided that the MMP provides Networks with six (6) months prior written notice before the end of the Initial Term, the MMP shall have a right to renew this Licence for three (3) consecutive terms of ten (10) years each, and each on the same terms and conditions save and except only for the (i) Renewal Fee (as later defined) payable, and (ii) a corresponding reduction of any further option(s) to renew. The lump sum fee payable by the MMP for each renewal term shall be determined by Networks on or before the commencement of any subsequent period by using the Networks then current formula for calculating such fees

(c) The terms within this schedule, and any exhibits referenced herein, shall permit the MMP and its Representatives to enter on, over, along and through the Property at any time and from time to time for the purpose of constructing, installing, maintaining, inspecting, patrolling, altering, repairing, removing, protecting, reconstructing, replacing, moving, using and/or operating the MMP's Works together with access rights necessarily ancillary thereto.

(d) This Licence is subject to any of Networks' Works, and the MMP covenants and agrees not to interfere or cause any damage to any such Networks' Works.

(e) This License is subject to a subsurface easement over the Property (the "Easement"). The Easement is owned by Hydro One Telecom Inc., and may be a registered or unregistered Easement.

3. Fees and Other Payments

(a) The MMP covenants to pay Networks a lump sum fee for the Initial Term in the amount of $10.00 (the "Initial Fee") the receipt and sufficiency of which is hereby acknowledged, plus the fees for each renewal term (each a "Renewal Fee").

(b) In addition to any other monies payable hereunder during the term of these Licence Terms and Conditions, or any extension thereof, the MMP agrees to pay any increase in taxes, additional taxes, grants, rates, fees or other assessments or payments in lieu thereof (collectively, the "Taxes") levied as a result of the MMP's Permitted Use that Networks, in its sole and absolute discretion, but acting reasonably, determines to represent the reasonable allocation or assessment of such Taxes, including but not limited to any administrative costs incurred in determining such allocation or assessment.

(c) The MMP agrees to make all payments Networks pursuant to these Licence Terms and Conditions within thirty (30) days of receipt of any invoice.

4. MMP's Covenants

The MMP also covenants and agrees:

(a) to maintain and keep in good order, condition, and repair the Property, the MMP's Works and all equipment, fixtures, chattels and improvements therein or thereon, and upon notice in writing from Networks to repair the Property as Networks may so require.

(b) at the expiration or sooner termination of the Initial Term or any renewal thereof, to peaceably surrender and yield up unto Networks its interest in the Property, and to restore the Property to its condition immediately prior to the location of MMP's Works;

(c) to comply with all statutes, by-laws, rules, regulations, orders, ordinances, protocols, codes, guidelines, policies, notices, directions, and judgments of every governmental or other competent authority, including a court or another body having the power to render decisions, relating in any manner to the MMP's Works or the exercise of any of the rights granted herein;

(d) that if an Emergency arises in connection with the MMP's Works, Networks may (but shall not be required to) take such appropriate measures, as it reasonably believes under the circumstances then prevailing, to attempt to remedy such Emergency without thereby terminating this Licence and without any prior notice (verbal or written) to the MMP and MMP shall reimburse Networks for Networks reasonable costs and expenses in so doing; in connection therewith.

(e) to observe and perform the additional terms and conditions contained in Exhibit "C" attached hereto.

5. MMP's Breach

(a) In the event:

(i) the MMP does not observe, perform and keep each and every of the covenants, stipulations, provisions and conditions contained in these Licence Terms and Conditions and fails to proceed to diligently remedy such default within fifteen (15) days following written notice thereof to the MMP (or no notice in the event of an Emergency); or,

(ii) any of the MMP's Works shall be at any time seized or taken in execution or attachment by any creditor of the MMP; or,

(iii) the MMP commits an act of bankruptcy or shall become an insolvent person (within the meaning of the *Bankruptcy and Insolvency Act Canada)* or a petition shall be filed against the MMP and not be discharged or bona fide disputed within three (3) days from the filing thereof; or,

(iv) a receiving order should be made against the MMP, or if a receiver is appointed by private instrument or by any court of competent jurisdiction for all or a portion of the MMP's property; or,

(v) the MMP makes a sale in bulk or gives any bill of sale, or if any proceeding for a composition with creditors under any federal or provincial law is instituted by or against the MMP;

then, in every such case, except as provided in 5(c) herein, at the option of Networks, all payments then due and owing under the provisions of this Licence shall immediately become due and payable and, at the option of Networks, this Licence shall cease and be determined, and the Initial Term or any renewal thereof shall then become forfeited and void, in which event Networks may remove all MMP persons or property from the Property at the MMP's expense.

(b) If the MMP fails to pay Networks any amounts required to be paid pursuant to the provisions of this Licence, then Networks may, at its option, make all such payments on behalf of the MMP who shall forthwith reimburse Networks for all costs and expenses so incurred. All arrears of fees and other sums to be paid by the MMP to Networks shall bear interest at the rate per annum equal to the prime bank rate quoted by The Royal Bank of Canada from time to time plus five per cent (5%) calculated and payable weekly, not in advance, from the due date for the payment with interest on overdue interest at the aforesaid rate until such amounts owing are paid in full by the MMP. The prime bank rate shall be determined on each interest payment date, to be applicable to all amounts then owing as aforesaid.

(c) If the MMP fails to observe or perform any of its obligations and has not cured such default pursuant to Section 5(a)(i) then Networks may, but shall not be obligated to, attempt to remedy such default without thereby terminating this Licence and the MMP shall reimburse Networks for its costs and expenses in so doing (plus an administration fee equal to fifteen per cent (15%) of such costs and expenses). Networks shall not be liable for anything done or omitted to be done by Networks in attempting to remedy such default.

Schedule 3

hydro one

6. Networks' Covenants

Subject to the due performance by the MMP of its obligations herein, Networks agrees with the MMP as follows:

(a) that the MMP shall peaceably and quietly hold and enjoy this non-exclusive Licence of the Property for the Initial Term or any renewal thereof, subject nevertheless to;

(i) Networks' Works and/or facilities existing on the Property from time to time;
(ii) any easements, leases, licences, or any right or use of occupation, in connection with the Property existing from time to time;
(iii) the terms and conditions of this Schedule ; and

(b) that it will perform all of the obligations of Networks described in this Licence.

7. Use

The Property shall be used by the MMP only for the Permitted Use and for no other purpose.

9. Assignment and sublicensing

(a) This Licence is personal to the MMP and the MMP shall not assign this Licence or these Licence Terms and Conditions in whole or in part, directly or indirectly, nor sub-Licence or part with, or share the possession of all or part of the Property, or mortgage or encumber this Licence or the MMP's interest herein or otherwise transfer its interest, directly or indirectly, by way of change of control, or otherwise, without the prior written consent of Networks and such consent in each case may be arbitrarily or unreasonably withheld.

(b) If the MMP attempts to assign, sub-Licence, sublet, share possession, mortgage or encumber or transfer all or part of the Property without first having obtained the consent of Networks as aforesaid, then Networks may, at its option, terminate this Licence without prejudice to any rights of Networks in respect of any breach of the MMP's obligations set forth in these Licence Terms and Conditions.

10. Relocation

(a) Notwithstanding any of the rights granted herein, Networks may use the Property for any and all purposes of its undertaking including landscaping and installation of berms; and if at any time or times, in the opinion of Networks, acting reasonably, the presence or use of the MMP's Works interferes with Networks' use or intended use of the Property, Networks may require the MMP to relocate the MMP's Works or any part or parts of the MMP's Works in another location or locations on the Property within six months from the time of such request, and all the provisions of this Schedule shall then apply to the MMP's Works in their new location or locations and the cost of such relocation shall be borne as follows:

(i) if the request is made during the initial five-year period of the Initial Term of the grant of this Permission Networks shall pay only the full direct labour cost of such relocation;

(ii) if the request is made after the initial five-year period of the Initial Term of this Permission, but before the initial ten-year period of the Initial Term of this Permission, Networks shall pay only fifty per cent of the direct cost of labour of such relocation and the MMP shall pay the balance of costs;

(iii) if the request is made after the expiration of the initial ten-year period of the Initial Term of this Permission, the MMP shall pay the full cost associated with such relocation.

(c) If at any time or times during the Initial Term or any renewal thereof, any of the rights granted herein should in the opinion of Networks, acting reasonably, directly or indirectly increase the cost or expense of any of Networks works and/or facilities now existing at the date hereof or hereinafter constructed on the Property, including the cost to Networks of acquiring any additional lands or easements because of the existence of the rights under this Licence, the increase in cost or expense reasonably attributable thereto shall be born as follows:

(i) if the increase occurs during the initial one-year period of the Initial Term of this Licence, Networks shall pay the full costs;

(ii) if the increase occurs after the initial one-year period of the Initial Term of this Licence, but before the initial two-year period of the Initial Term of this Licence, the direct costs shall be divided equally between Networks and the MMP; and

(iii) if the increase occurs after the expiration of the initial two-year period of the Initial Term of this Licence, the MMP shall pay the full costs.

11. Net Licence Agreement

It is the express intent of the parties that the Licence is absolutely net and carefree to Networks during the Initial Term and all renewals thereof, free and clear of all payments, charges, taxes and obligations of any nature whatsoever with respect to the Property, except as may be expressly set forth in these Licence Terms and Conditions.

12. Registration

The MMP agrees that it will not register these Licence Terms and Conditions on title to the Property. Breach of this provision shall entitle Networks, at its option, to terminate these Licence Terms and Conditions.

16. Removal

Upon the expiration or sooner termination of the Initial Term or any renewal thereof or if at any time the MMP shall abandon the MMP's Works, the MMP shall remove the MMP's Works from the Property at its sole cost and expense within six (6) months of the termination of this Permission or abandonment of the MMPs Works, or within six (6) months of the date of written notice in case of Early Termination, as defined below, and restore the Property, to the reasonable satisfaction of Networks , to the condition at the time this Permission was granted.

17. Early Termination

Notwithstanding any other provision to the contrary, either party may terminate these Licence Terms and Conditions for any reason upon at least six (6) months written notice to the other party ("Early Termination") without any penalty. In the event that Networks invokes this Early Termination provision, it shall make reasonable inquiries of any facilities in the vicinity of the Property that are owned or operated by Networks with the view to accommodating the MMP's Works on similar terms and conditions.

Schedule 3

18. Miscellaneous

(a) These Licence Terms and Conditions and any agreements contemplated herein or therein, including any schedules thereto, constitute the entire agreement among the parties pertaining to the subject matter hereof and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, between the parties. There are no warranties, representations or other agreements between the parties in connection with the subject matter hereof except as specifically set forth herein.

(b) Each party will from time to time hereafter and upon any reasonable request of any other party, execute, make or cause to be made, all such further acts, deeds, assurances, certificates and things as may be required to more effectually implement the true intent of these Licence Terms and Conditions.

(c) If any provision of this Permission shall be held invalid, illegal or unenforceable by any court of competent jurisdiction, governmental authority or otherwise, to the extent permitted by law, such invalidity, illegality or unenforceability shall not affect the legality, validity or enforceability of any of the other provisions herein.

19. Force Majeure

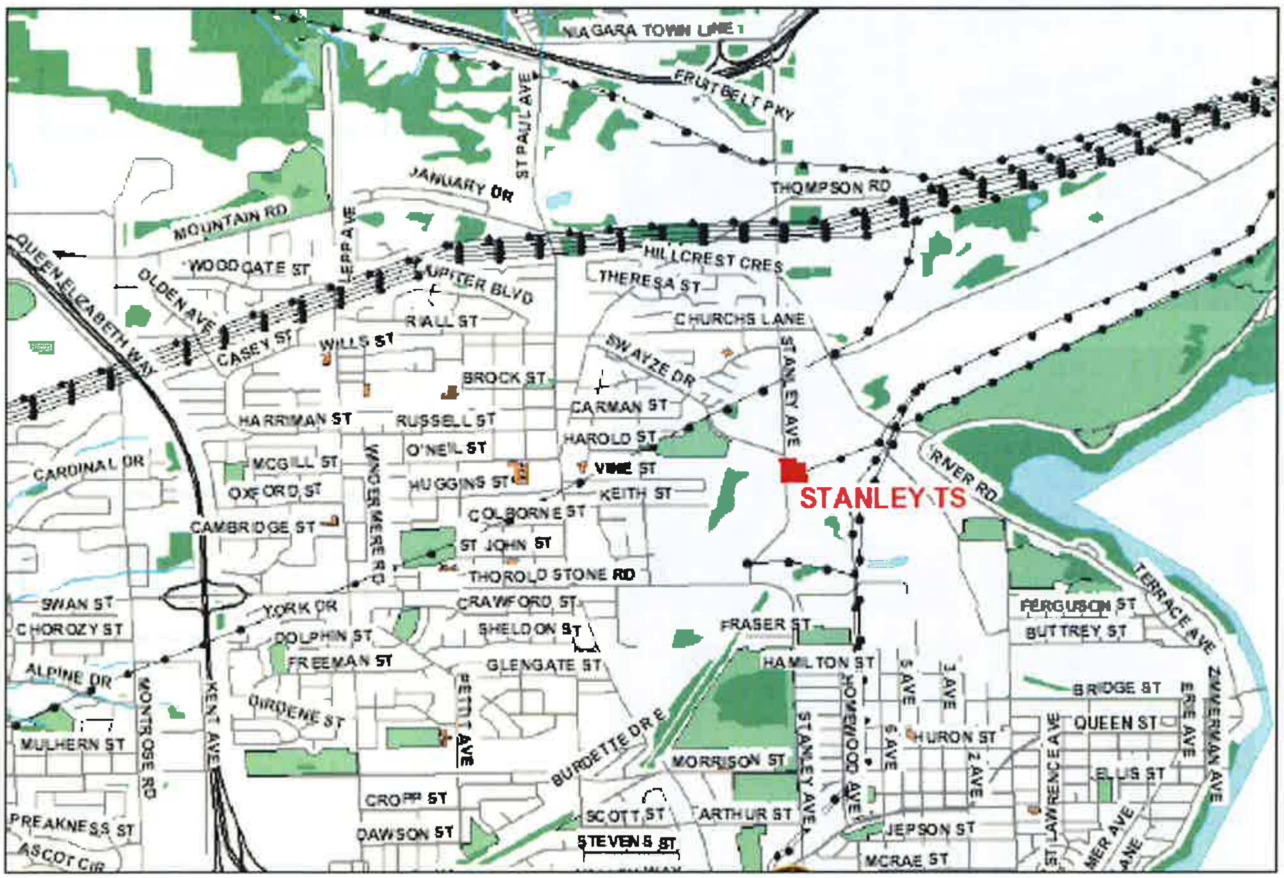
Neither party shall be responsible for damages caused by delay or failure to perform its obligations under these Licence Terms and Conditions when such delay or failure to perform is due to conditions or causes beyond its reasonable control, including, without limitation, fires, floods, acts of God, war, acts of public authorities, or inability to obtain necessary labour or materials due to any of the foregoing causes ("Force Majeure"). In the event of an event of Force Majeure, the party delayed or unable to perform its obligations due to the event of Force Majeure shall be allowed a reasonable period of time to fulfill its obligations hereunder having regard to the applicable circumstances.

Schedule 3

EXHIBIT "A"

The lands shown on the sketch attached hereto and marked as Exhibit "B", and legally described as:

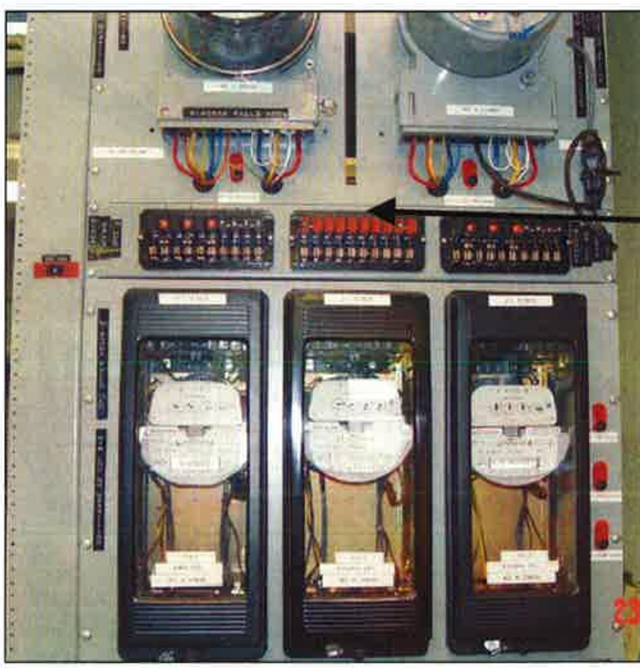
Part of Lot 59, (Stamford Twp), now City of Niagara Falls, Region of Niagara, further described as Parts 35-39, 45-58, 66 on R.Plan 59R-10609 consisting of an area of approximately 100 sq. ft.



Schedule 3

EXHIBIT "B"

Upper portion of Rack 310 where new main and alt meter for 12T1B+T2Y will be installed.



Middle portion of rack 311 where new main and alt meter for 12T1J-T2Q will be installed

Schedule 3

EXHIBIT "C"

In addition to the provisions contained in the body of Schedule 3, the MMP covenants and agrees to the additional terms and conditions contained in this Exhibit "C"

1, Access to the Property

Prior to any access to the Property, the MMP shall have entered into Networks' standard MMP Station Access Agreement.

2. Indemnification

(a) In addition to any amounts payable pursuant to Section 3 of the Licence Terms and Conditions, the MMP agrees to indemnify and save harmless Networks from and against all costs and expenses resulting from or relating to the MMP's Works on the Property, including but not limited to:

(i) the cost of having the Networks' Representative accompany the MMP and its Representatives when accessing the Property;

(ii) subject to Section 10 of the Licence Terms and Conditions, any incremental costs and expenses incurred by Networks as a result of the installation, removal, relocation, upgrading of the MMP's Works;

(iii) any incremental costs and expenses incurred by Networks as a result of the MMP's Works related to regular maintenance charges related to site usage including but not limited to snow plowing, grass cutting, or any other work associated with the MMP's Works, including but not limited to, all costs associated with protection and tele-metering facilities;

(iv) and incremental costs and expenses incurred by the MMP related to the Networks' normal activities in managing the Networks' assets including operation, maintenance and future asset investments.

3. Compensation

(a) The Licencee agrees to compensate Networks for the following:

(i) any loss of revenue resulting from Networks having to operate its facilities in departure from its normal operation due to any additional constraints caused by the presence of the MMP's Works, save and except when the gross negligence or willful misconduct of Networks, its servants or agents, contributes to such loss;

(ii) the consumption of energy and applicable tariffs when power is taken from Networks service. If metered values are not available, the consumption shall be billed based on an estimate of monthly demand;

4. Liability

(a) The MMP agrees that it shall be liable for the following:

(i) any forced outages of Networks' equipment which are originated by failures in the MMP's Works and any penalties that Networks may be subject to, due to these failures, save and except when the gross negligence or willful misconduct of Networks, its servants or agents, contributes to such loss.

(ii) all of the MMP's Representatives and property at any time on the Property shall be at the MMP's sole risk and Networks shall not be liable for any loss, damage or injury (including loss of life) to them or it however occurring, except as provided for in Section 4.1(a) in the main section of the Customer Wholesale Revenue Metering Agreement.

(iii) ensuring that there are no liens registered against the Property with respect to the supply of services or materials to or in respect of the MMP's Works and the MMP shall promptly cause any liens so registered to be discharged at its own expense.

5. Environment

The MMP covenants and agrees to ensure that no contaminants, pollutants, or toxic, dangerous or hazardous substances or materials as defined under any applicable statutes, regulations, by-laws, ordinances, requirements or orders imposed by any competent authority, or guidelines shall be used, emitted, discharged, stored or disposed of on the Property except in strict compliance with such statutes, regulations, by-laws, ordinances, requirements or orders, or guidelines.

6. Technical requirements

Any equipment, owned by the MMP, shall be technically compatible with Networks' existing and planned facilities, and meet the Electricity Safety Authority requirements and all other standards and regulations.

7. Maintenance and Construction

The MMP shall ensure that (i) its Representatives do not interfere with any of Networks facilities or property; and (ii) maintenance of the MMP's Works requiring outages to Networks' facilities are coordinated in such a manner to coincide with Networks' outage plans. At the same time, maintenance work on MMP's Works shall not interfere with Networks' Works.

8. Regulatory and Legislative Obligations

The Land Usage Permission shall comply with all relevant regulatory and legislative obligations including, but not limited to, the Transmission System Code, the Market Rules and Exemption Order OH-27 made under the Environmental Assessment Act.

9. Staff Qualifications

(a) The MMP and its Representatives shall at all times, while on the Property, exercise all due skill and diligence in the performance of its work. In the instances where the MMP's Works interfaces with Networks' equipment, the MMP's Representatives must be certified and deemed qualified as stated in the Hydro One Safety Rules;

(b) All training, testing and certification required by the MMP's Representatives must comply with Hydro One Safety Rules, and such training, testing and certification shall be at the MMP's expense.

10. Miscellaneous

(a) The MMP will attend safety and coordination meetings at its own costs, as required, for the purpose of informing their Representatives of health & safety hazards at the Property;

(b) The MMP will not enter into subcontracts with respect to the Property without prior written approval from Networks;

(c) In the event that any work on the Property is being performed in an unsafe manner, the MMP agrees to take additional actions to ensure the work is performed in safe manner, which actions may include, but not limited to, additional training or appointment of additional supervision, stop the work or terminate the contract with its contractor if work is not being performed safely by the contractor.

(d) The MMP shall properly document the qualifications of its Representatives required to access the Property or use the Property facilities;

(e) The MMP shall maintain the MMP's Works including, where applicable, all facilities and equipment required in order for the MMP's Works to be incorporated/interfaced into the Networks operational system.

Schedule 4

hydro one

Shared Use of Networks Instrument Transformers

Station: Niagara Stanley TS
MMP: Niagara Falls Hydro Inc.

Conditions for the use of Networks-owned Legacy* Instrument Transformers located in Networks-controlled facilities by parties other than Networks for Wholesale Revenue Metering.

(* in service prior to May 1, 2002)

- Ownership of the Instrument Transformers remains with Hydro One.
- Hydro One staff, in accordance with standard maintenance practices, will perform maintenance and repair of the Instrument Transformers.
- The MMP may be accountable for a portion of maintenance and repair costs above and beyond compliance with the Market Rules.
- Hydro One shall not be responsible for the Emergency Instrument Transformer Restoration Plan (EITRP) under the Market Rules requirement, nor does Hydro One have any obligation to comply with the EITRP.
- Hydro One shall not allow the use of other Hydro One-owned equipment for use in complying with the EITRP.
- Hydro One does not guarantee the availability of, nor is Hydro One obligated to maintain, a stock of spare Instrument Transformers.
- Hydro One shall not be required to restore an Instrument Transformer within the time period stipulated under the Market Rules.
- Hydro One has the right, at its sole and absolute discretion, not to repair or replace a damaged Instrument Transformer.
- Hydro One does not warrant or guarantee any existing or continued Measurement Canada accuracy requirements of the Instrument Transformers.
- Hydro One may have to connect additional burdens to the Instrument Transformer. If the connection of additional burden results in the rated burden to be exceeded, the MMP may be required to make alternative arrangements for metering instrument transformers. Market Rule approvals associated of the required instrument transformers shall be the responsibility of the MMP.
- Tests required after seal expiry by the Market Rules or Measurement Canada to determine the accuracy of an Instrument Transformer and other Measurement Error Correction (MEC) requirements will be arranged by Hydro One at the MMP's request. The MMP will be responsible for the costs.
- The MMP shall require its MSP to be responsible for Market Rule required routine Instrument Transformer inspections, shall coordinate such inspections with Hydro One staff if required and shall pay all costs. The MMP shall ensure that its MSP not make physical contact with the Instrument Transformers and adjacent equipment.
- The MMP shall install a complete set of compliant Instrument Transformers should a change to the Instrument Transformers be considered substantial in the IESO's opinion or if Hydro One decides not to repair or replace an Instrument Transformer. Currently the IESO considers the replacement of two or more Instrument Transformers, for any reason, to be substantial. In this regard, Hydro One does not guarantee the availability of space on equipment or land for the installation of standalone dedicated Instrument Transformers.

Schedule 4

1. **Shared Use**
   Hydro One agrees to allow the MMP to share the use of the Instrument Transformers associated with the B, Y, J and Q buses (T1 and T2).

2. **Description**
   The Instrument Transformers associated with the B, Y, J and Q buses (T1 and T2), listed in Schedule 2, shall be used by the MMP only for wholesale revenue metering.

3. **Licensing Agreement**
   The MMP will be exempt from the licensing costs associated with the Instrument Transformers.

4. **Obligation**

Hydro One is not obliged to sustain the shared use equipment and may remove this equipment from service at its discretion. Hydro One will use best efforts to inform the MMP in advance of any such removal of shared use equipment to allow the MMP to make alternative arrangements for Wholesale Revenue Metering.

Schedule 5

hydro one

Communications and Electrical Supply

Station: Niagara Stanley TS
MMP: Niagara Falls Hydro Inc.

1. Communications:

Neutralizing Transformer
Bell Canada owns the neutralizing transformer ("NT") terminal pairs at Niagara Murray TS; therefore, MMP shall contact Bell Canada regarding their use.

MMP must relinquish the use of the NT pairs within three (3) months notification from Networks.

No liabilities are to be imposed on Networks for the use of the NT pairs and Network's does not guarantee quality of service or continuity of service.

Any ongoing lease cost for the NT's is the responsibility of the MMP

Communications Circuit

The MMP is responsible for transferring lease of the existing communications channel for on going use. MMP agrees to pay the cost for the ongoing lease of the communications channel for their wholesale revenue metering installation.
Electrical Supply:

The MMP is the Market Participant for the entire load measured by the primary wholesale revenue meter. The primary wholesale revenue meter captures the station service load. The MMP is therefore responsible for the station service load.
The MMP shall be allowed to connect to the station service to supply its metering installation.

Main meter is externally powered from 120 VAC station service power and alternate meter will be self powered (from the PTs). This will comply with the Market Rules requirements regarding the power supply from the different sources.

3. Meters and Metering Equipment:

Networks will provide and MMP will pay for one (2) 120 VAC cable from the AC distribution panel to the existing rack, four (4) duplex receptacle outlets for 120 VAC, four (4) blocking switches, one (1) telephone line sharing device, two (2) IESO conforming 3-element main meter and base, two (2) IESO conforming 3-element alt meter and base and one (1) dedicated phone line for the metering point from the property line to the neutralising transformer.

Schedule 1

Hydro One Networks Inc. ("Networks") - Metered Market Participant ("MMP")
Wholesale Revenue Metering Exit Option Selection

Please fill in one form per Metering Installation
Fax signed and completed form to 416-345-5977 or mail to address on next page

If you have any questions, please send us an e-mail at tx.meterexitprogram@hydroone.com

Company Information

Date:	Janaury 19, 2004	**Hydro One ID #:**	540547
Market Participant Name:	Niagara Falls Hydro Inc.		
MMP Name:	Niagara Falls Hydro Inc.		

Contact Information
(All meter exit issues will be through this contact)

Name:	Cliff Ballinger				
Position/Title:	Meter Foreman				
Address:	7447 pin oak drive, P.O BOX 120				
City:	NIAGARA FALLS	**Province:**	ON	**Postal Code:**	L2E6S9
Telephone:	(905) 353-6025	**Fax:**			
E-mail:	cliffballinger@niagarafallshydro.on.ca				

Meter Installation Information

Grid Connected Station Name:	Niagara Stanley TS		
Main Meter ID #:	**0244117100**	**Earliest Seal Expiry:**	2004

1. Exit Option Selection (please check ONLY one)

Existing Wholesale Metering Location			
Inside Networks Station		Outside Networks Station	
Abandon (*)	☐	Abandon	☐
Use Existing ITs	☒	Purchase	☐
De-register	☐	De-register	☐

(double click on appropriate box and select "Checked" then OK)

2. (*) Inside Networks Station – Abandon

- preferred location for new installation: Inside Station ☒ Outside Station ☐

3. Timing of Exit (please check one)

Upon Seal Expiry ☒ Early Exit ☐

Origianl Signed copy in file – John Compostella	January 20, 2004
Signature	Date

Name (please print): John Compostella

Instructions →

3 Steps to Complete the Exit Process:

Step 1 – MMP:

- ⇒ Verify Contact and Meter Installation Information and make corrections where required.
- ⇒ Select **ONE** of the exit options.
- ⇒ If Abandoning existing meter located inside station, do you wish to construct a new meter installation inside OR outside the station?
- ⇒ Select "timing of exit".
- ⇒ Sign the form and return the form by fax to 416-345-5977, or mail to:

  Hydro One Networks Inc.
  Attn: Lee Collins
  483 Bay Street, 15^{th} Floor North Tower
  Toronto, Ontario, M5G 2P5
- ⇒ Hire a Meter Service Provider

Step 2 – Networks:

- ⇒ Will confirm your selected option and update any discrepancies.
- ⇒ Prepare the appropriate agreement and send to you for signature.
- ⇒ Arrange for a project manager to contact you regarding any required regulated work (i.e. make ready work associated with connection of your metering equipment to Networks equipment).

Step 3 – MMP:

- ⇒ Return signed agreement as required.

Schedule 2

hydro one

Metering Installation Information

Delivery Point Location (TS orDS)	**STANLEY TS**
Site Location Name:	**12T1B-T2Y**
MMP Name:	
Metering Installation I/S Date:	**1958**

Location Number (10 Digits):	**0244117100**	**Type (Bus/Feeder/Trans):**	**BUS**
Earliest Seal Expiration Date:	**2004**	**Voltage Level (KV):**	**13.8**
Equipment Category:	**LV Outdoor**	**Located in Customer Site?**	**No**

Recorder:

Test No.	Serial No.	Make	Model	Built	Seal Date	Com
J058741	3507	PSI	S200C	1995	7/13/2001	Land

Meter(s):

Measures**	Test No.	Serial No.	Make	Model	Elements	Role*	Built	Seal
KWhDEL	J018030	5034548	WHSE	D4A3	3	STD	1980	9/18/1997
KVARhDEL	J025942	5065599	WHSE	D4A3	3	STD	1985	9/18/1997
KVARhREC	J025449	5064383	WHSE	D4A3	3	STD	1985	9/18/1997

* MAIN or ALT or STD (standalone)
** kWh /kVARh, received/delivered

Current Transformers:

Phase	Shared*	Serial No	Make	Model	Type	Acc	Ratio	MC Appr**
WHITE		2234957	FERR	RU15		0.3B0.5	2000 : 5	YES
RED		2234956	FERR	RU15		0.3B0.5	2000 : 5	YES
BLUE		2415740	FERR	RU15		0.3B0.5	2000 : 5	YES

Voltage Transformers:

Phase	Shared*	Serial No	Make	Model	Type	Acc	Ratio	MC Appr**
W-N		2-418117	FERR	MP-15		0.3Z	8400 : 120	YES
R-N		2-418116	FERR	MP-15		0.3Z	8400 : 120	YES
B-N		2-418113	FERR	MP-15		0.3Z	8400 : 120	YES

* Is the IT embedded (E) in Hydro One Network Inc. equipment or does the revenue meter share (S) the IT with other functions such as protection or SCADA or standalone dedicated (D) for Revenue Metering.
ND No drawing
S (1) Shared with PUC

Schedule 2

Metering Installation Information

Delivery Point Location (TS orDS)	**STANLEY TS**
Site Location Name:	**12T1J-T2Q**
MMP Name:	**Niagara Falls Hydro Inc.**
Metering Installation I/S Date:	**1958**

Location Number (10 Digits):	**0244117100**	**Type (Bus/Feeder/Trans):**	**BUS**
Earliest Seal Expiration Date:	**2004**	**Voltage Level (KV):**	**13.8**
Equipment Category:	**LV Indoor**	**Located in Customer Site?**	**No**

Recorder:

Test No.	Serial No.	Make	Model	Built	Seal Date	Com
J058752	3533	PSI	S200C	1995	7/13/2001	Land

Meter(s):

Measures**	Test No.	Serial No.	Make	Model	Elements	Role*	Built	Seal
KWhDEL	H803617	5035252	WHSE	D4B3F	3	STD	1981	3/15/1996
KVARhDEL	H805048	5087871	WHSE	D4B3F	3	STD	1987	7/3/1997
KVARhREC	H802598	5097383	WHSE	D4B3F	3	STD	1900	7/3/1997

* MAIN or ALT or STD (standalone)
** kWh /kVARh, received/delivered

Current Transformers:

Phase	Shared*	Serial No	Make	Model	Type	Acc	Ratio	MC Appr**
RED		309585	NONE	BHK-22M		0.3B1.8	2400 : 5	YES
BLUE		309588	NONE	BHK-22M		0.3B1.8	2400 : 5	YES
WHITE		309587	NONE	BHK-22M		0.3B1.8	2400 : 5	YES

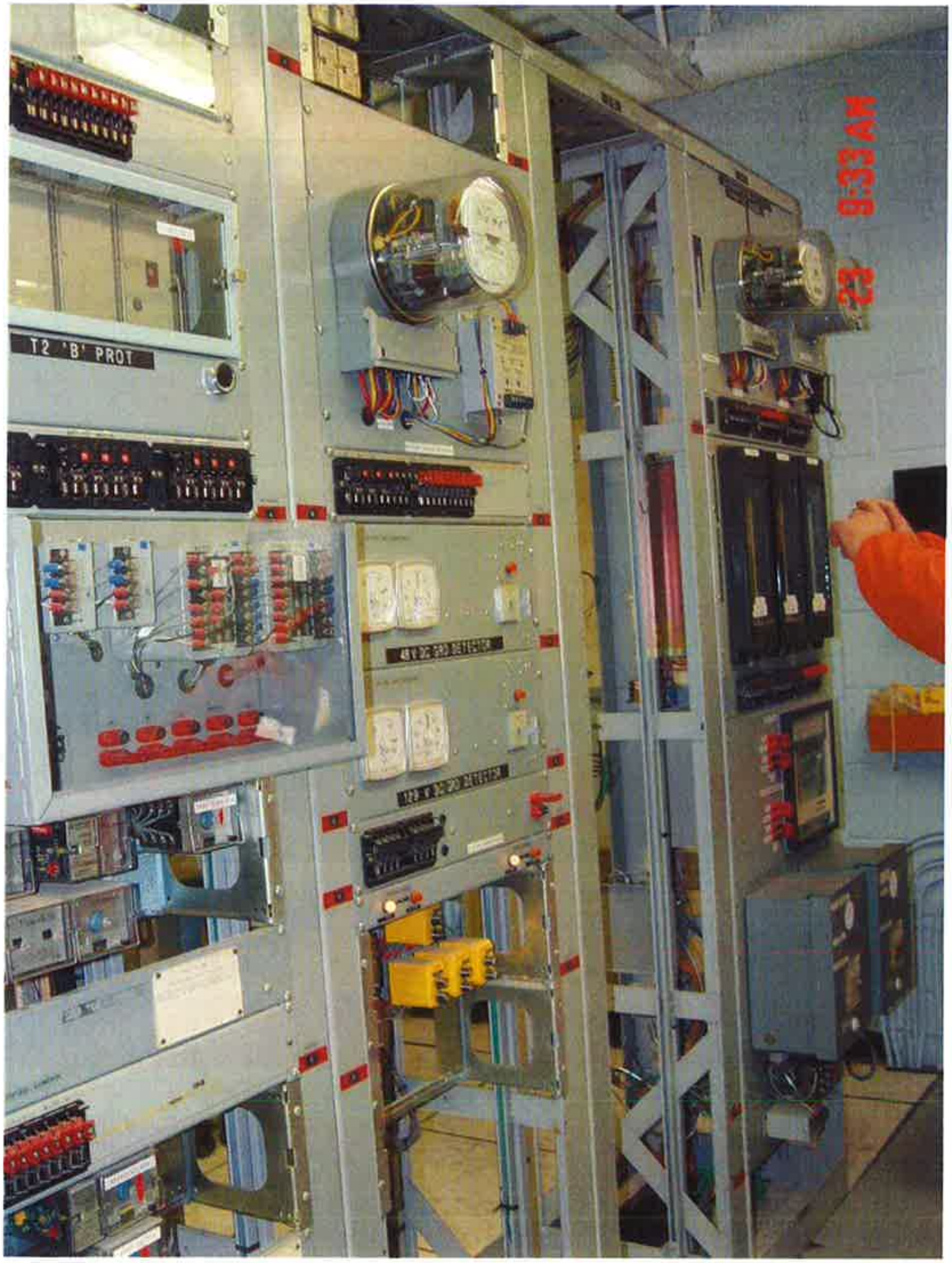
Voltage Transformers:

Phase	Shared*	Serial No	Make	Model	Type	Acc	Ratio	MC Appr**
R-N		76981	NONE	PTD-15		0.6Z-0.6Z	8400 : 120	YES
B-N		76982	NONE	PTD-15		0.6Z0.6Z	8400 : 120	YES
W-N		76980	NONE	PTD-15		0.6Z0.6Z	8400 : 120	YES

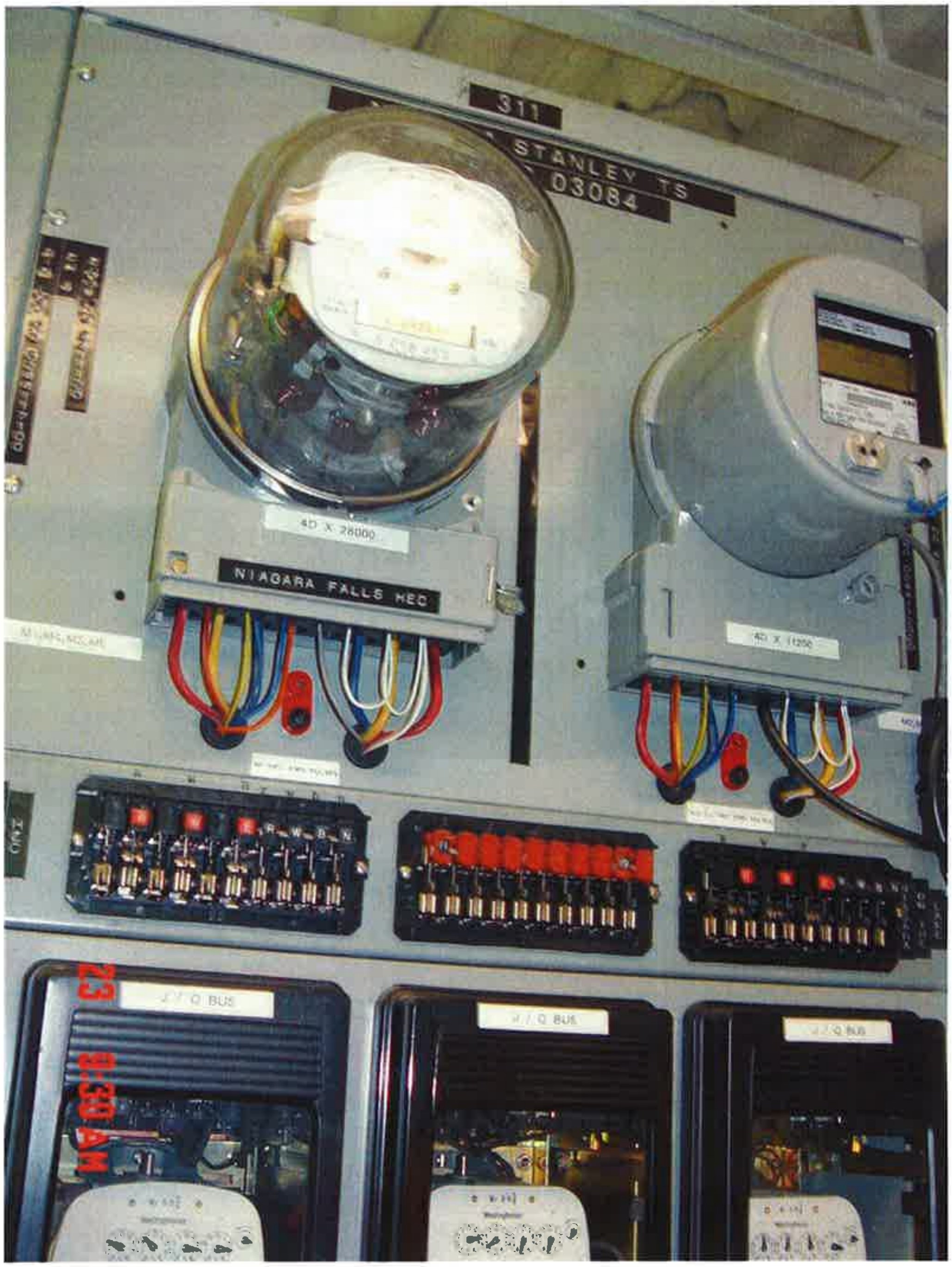
* Is the IT embedded (E) in Hydro One Network Inc. equipment or does the revenue meter share (S) the IT with other functions such as protection or SCADA or standalone dedicated (D) for Revenue Metering.
ND No drawing
S (1) Shared with PUC

Niagara Stanley TS (NF12) – 12T1B+T2Y and T1J-T2Q

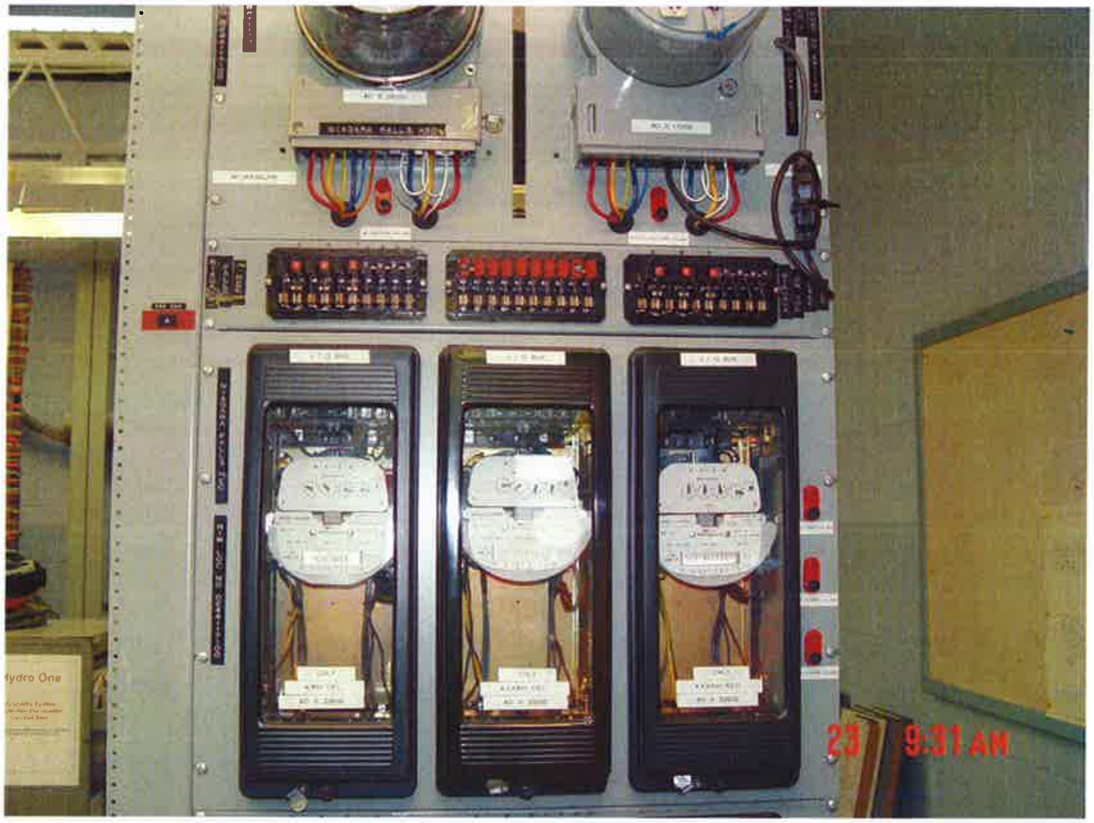
Stanley TS



Rack Linup

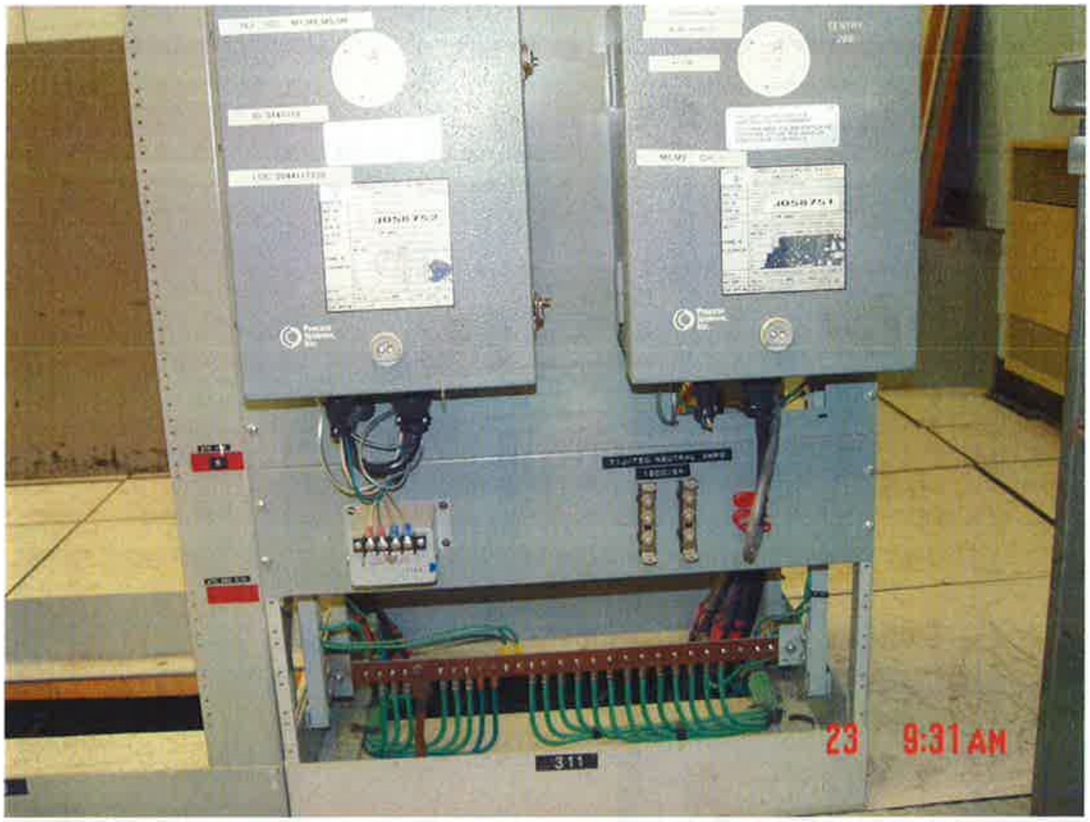


Rack 311 Upper Portion



Rack 311 Middle Portion

Rack Lower Portion



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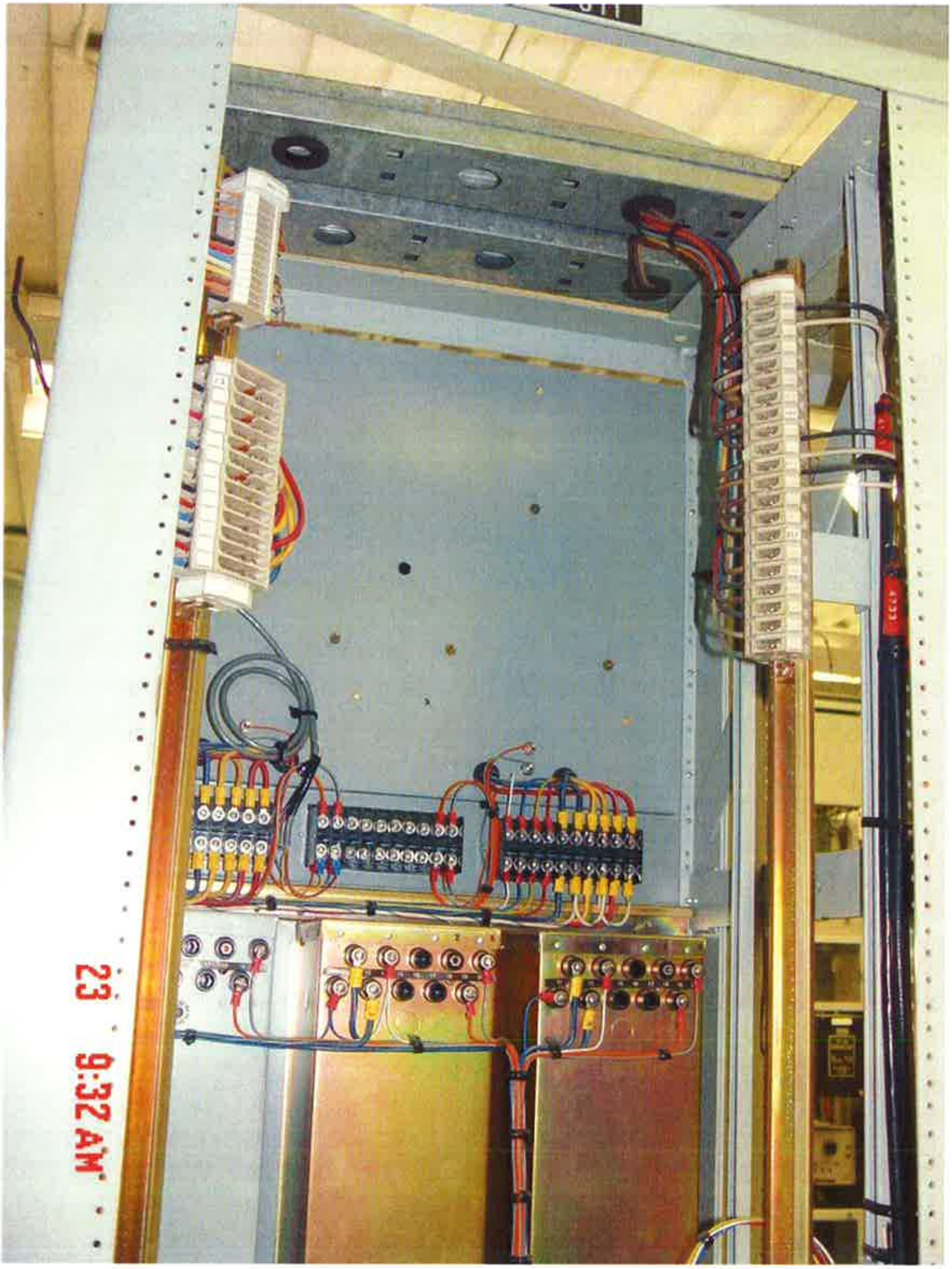
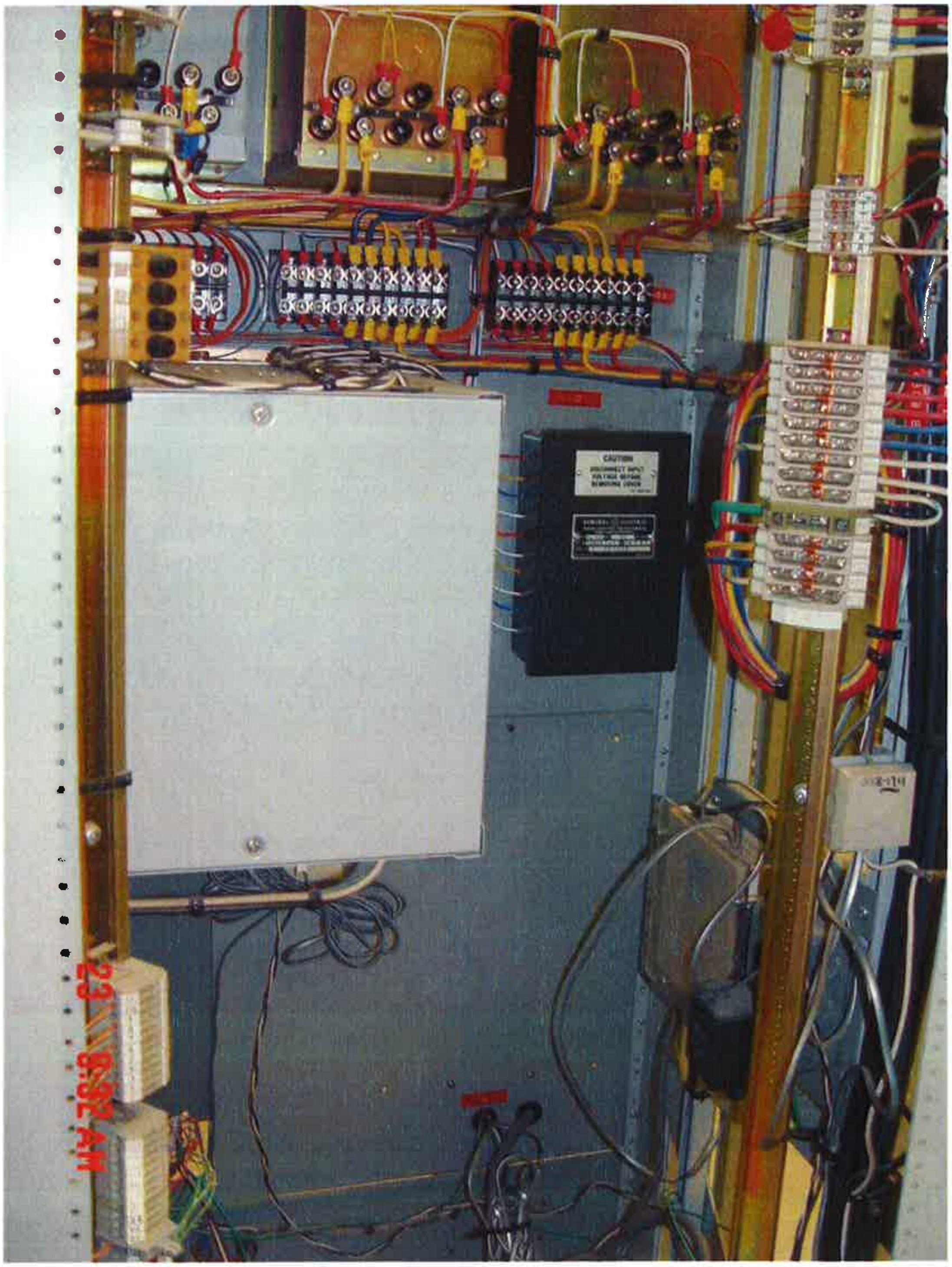
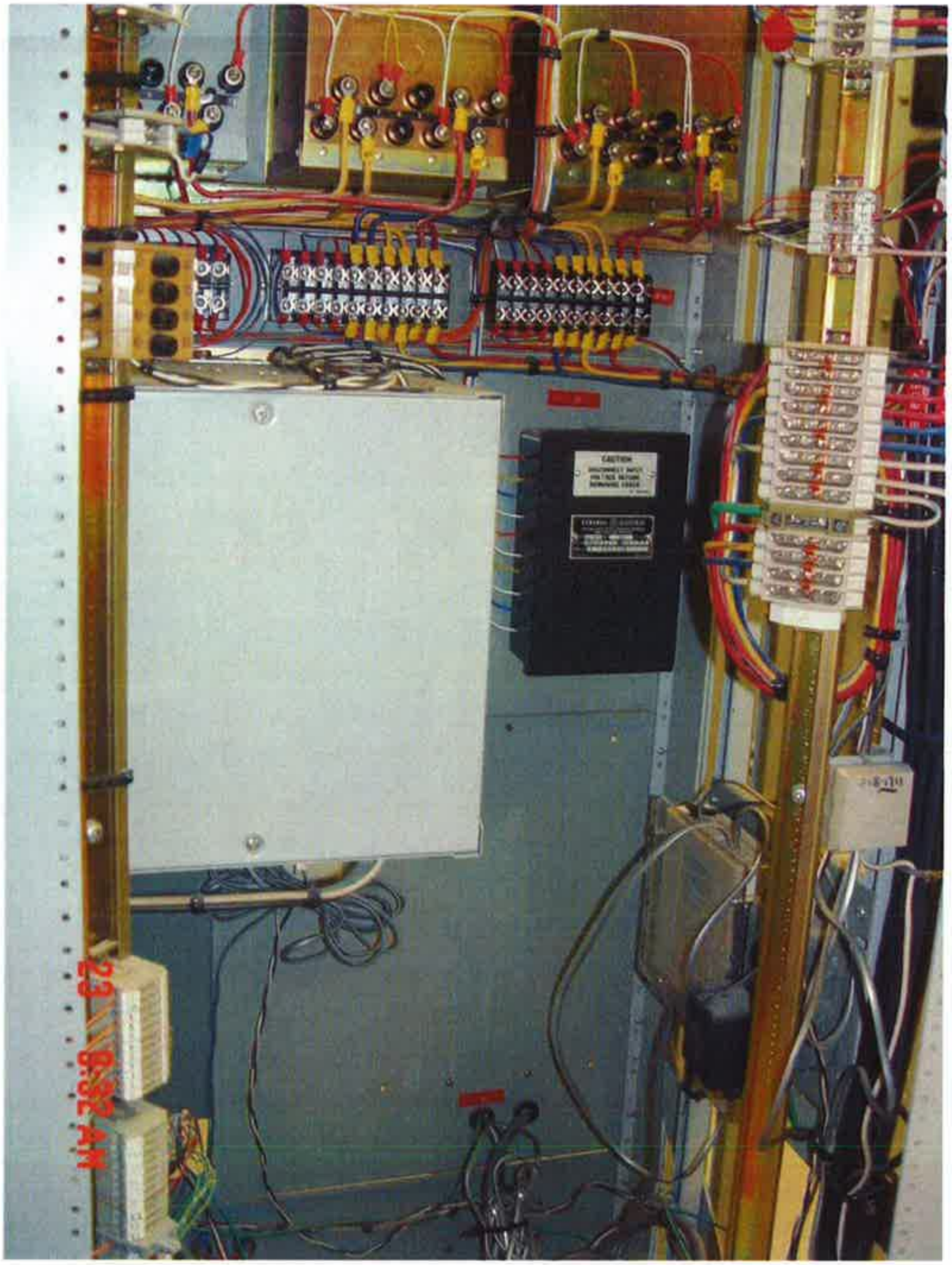


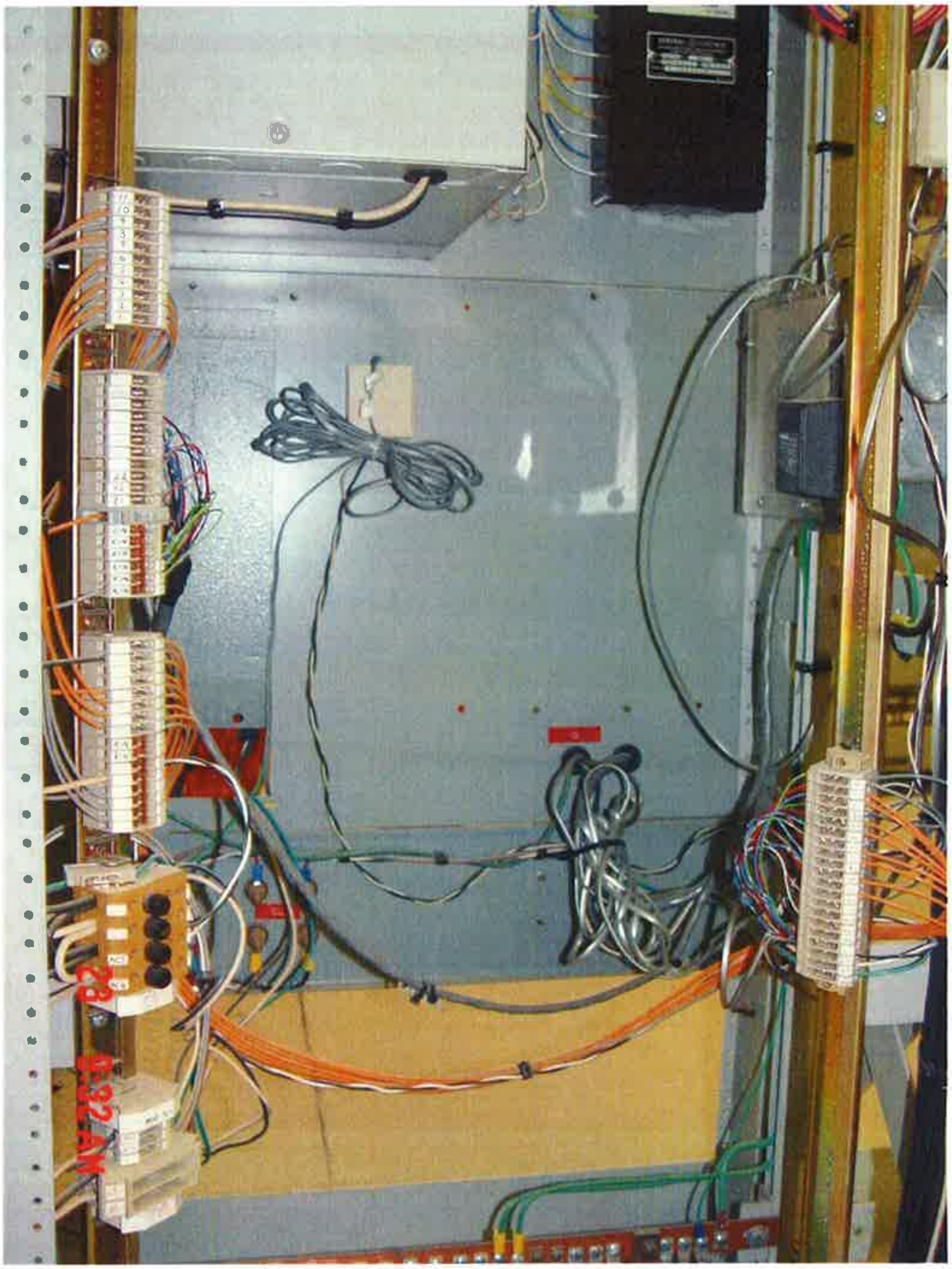
Rack 311 Upper Back Portion



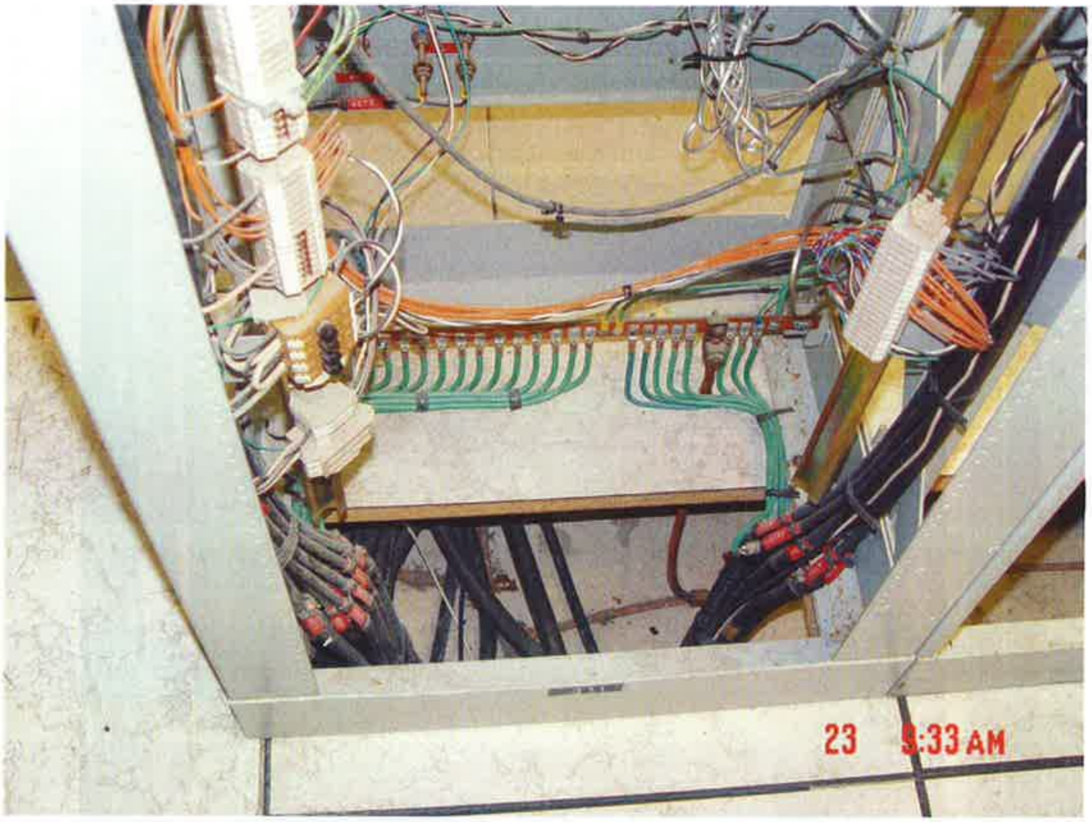
Rack 311 Middle Portion Back



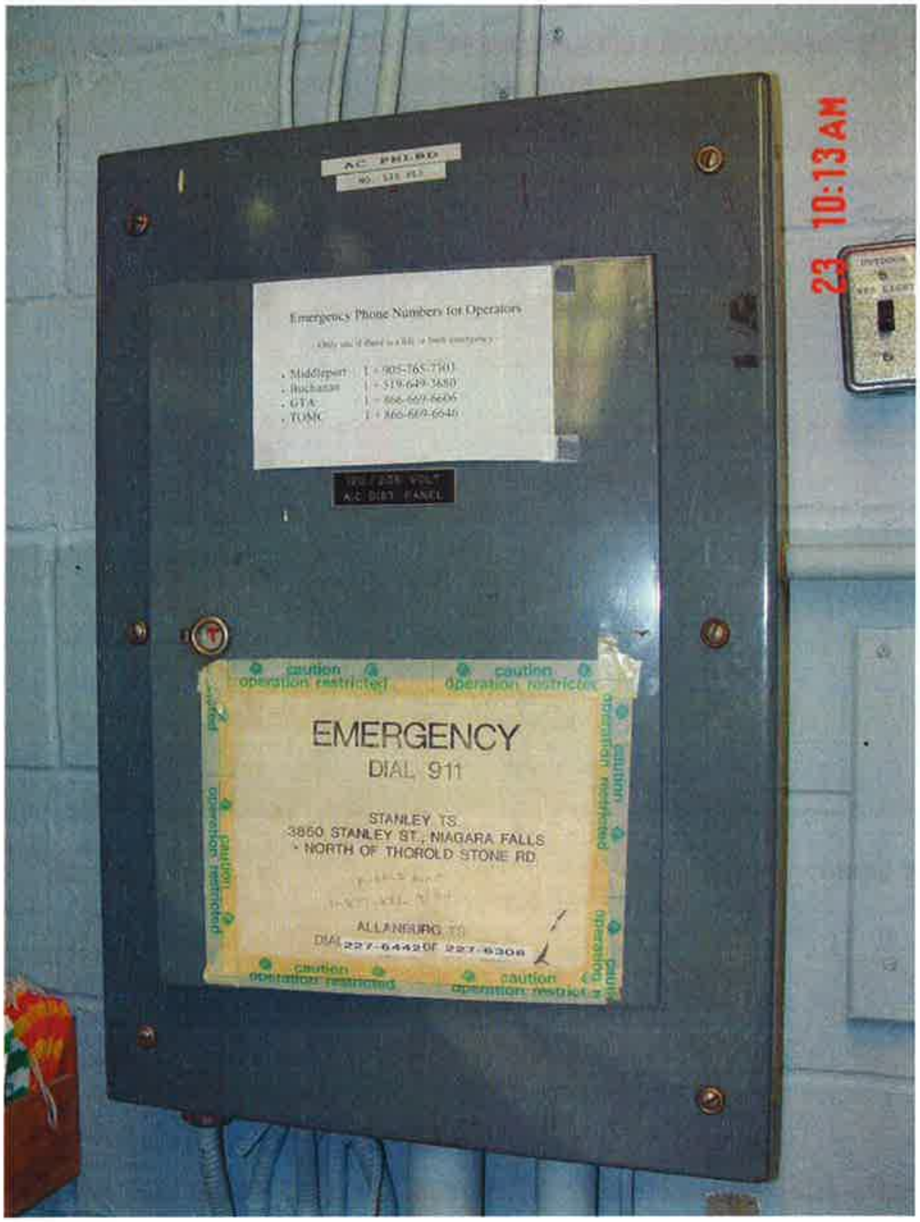
Rack 311 Middle Portion Back



Rack 311 Lower Portion Back



Rack 311 Bottom



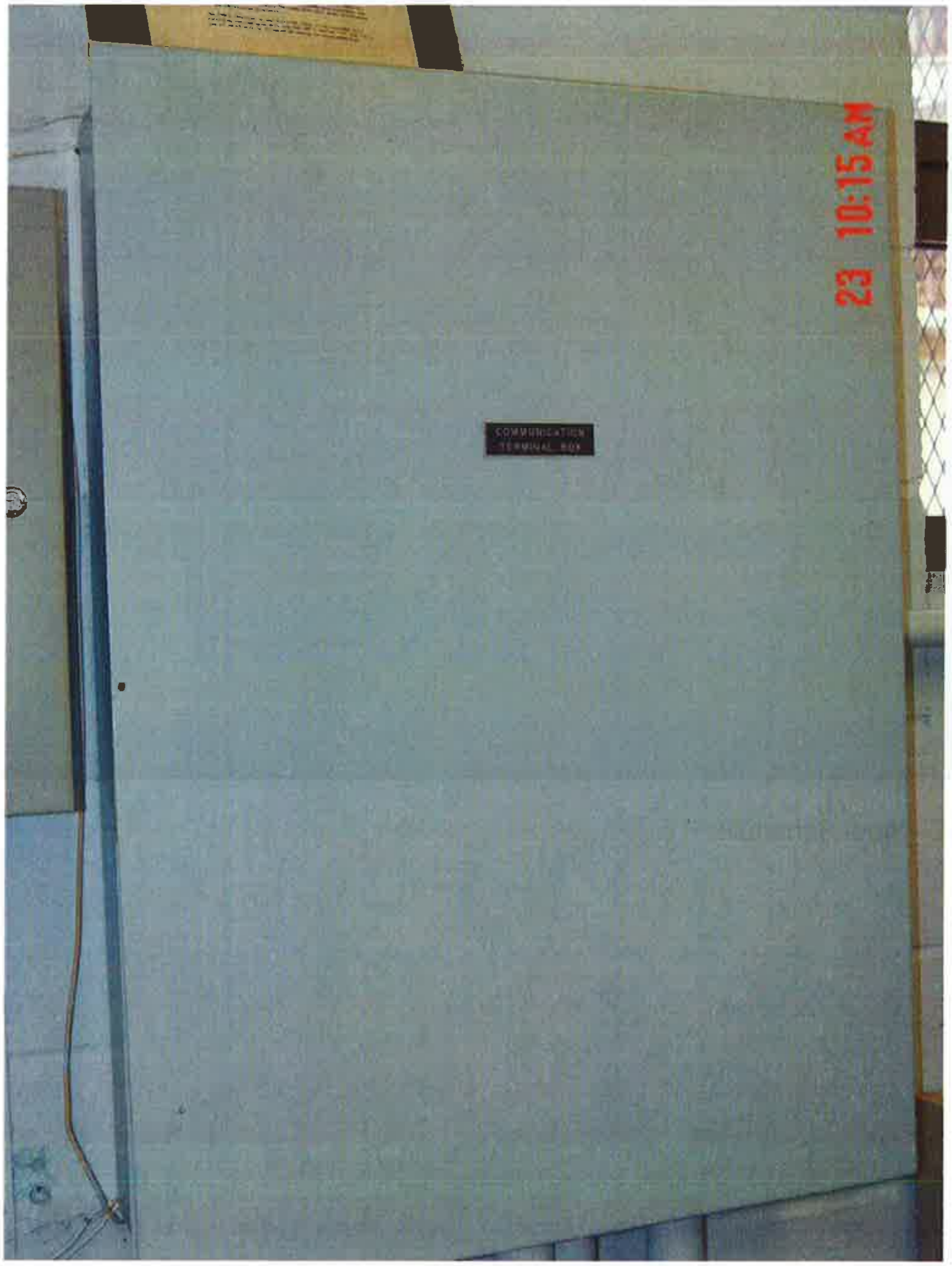
120VAC Panel

120VAC Door Open

120VAC Panel Schedule

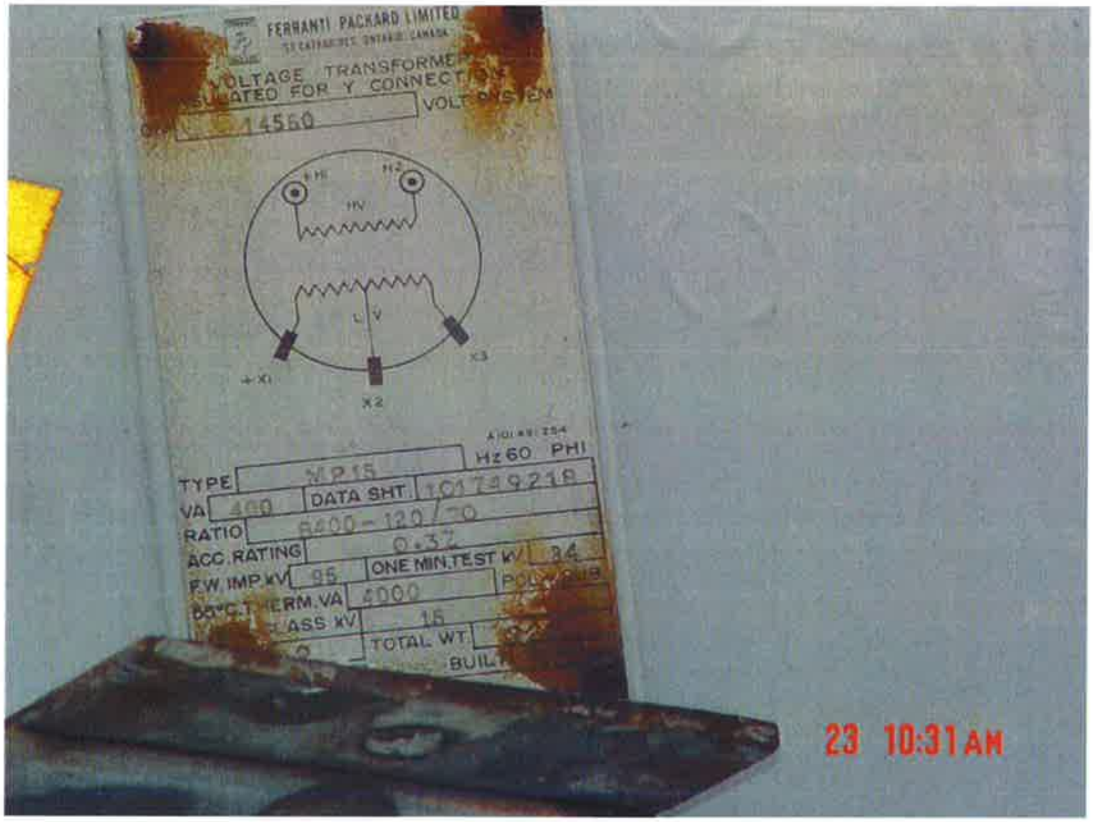
120VAC Panel

120VAC Panel Schedule



Comm. Terminal Block

T2


FERRANTI PACKARD LIMITED
VOLTAGE TRANSFORMER
FOR Y
14560
HV
LV
X2
X3
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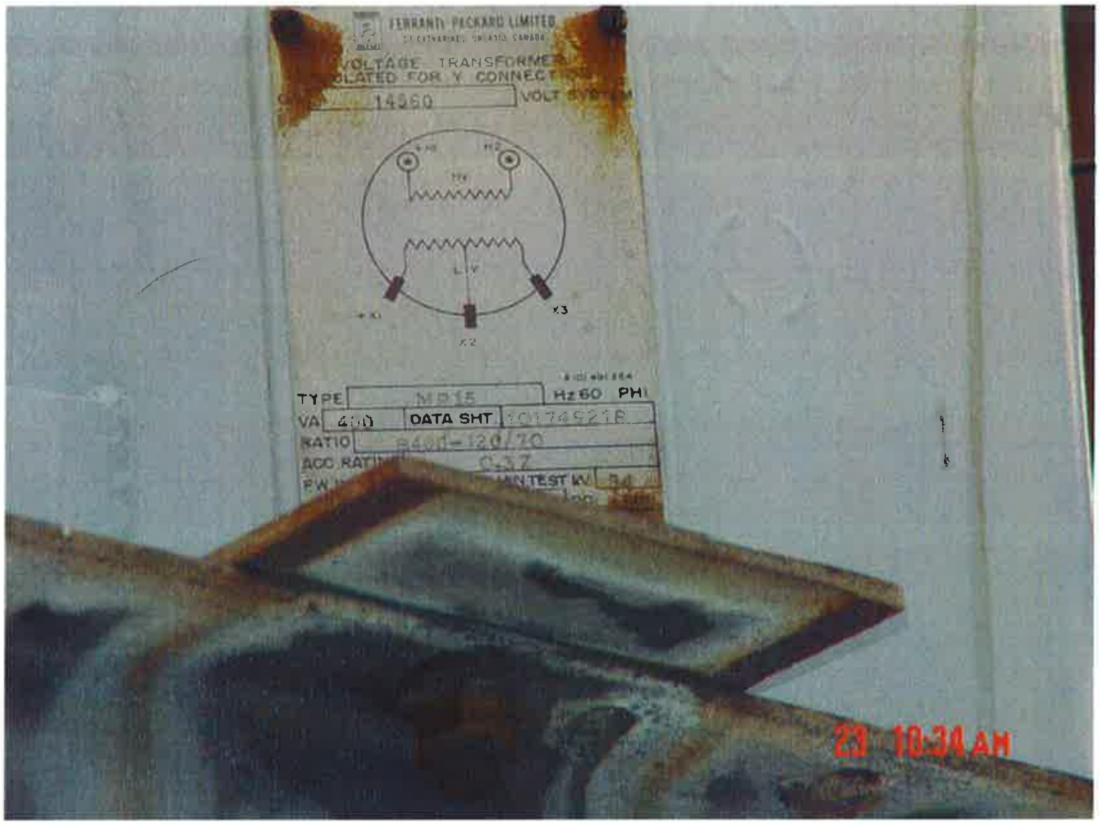
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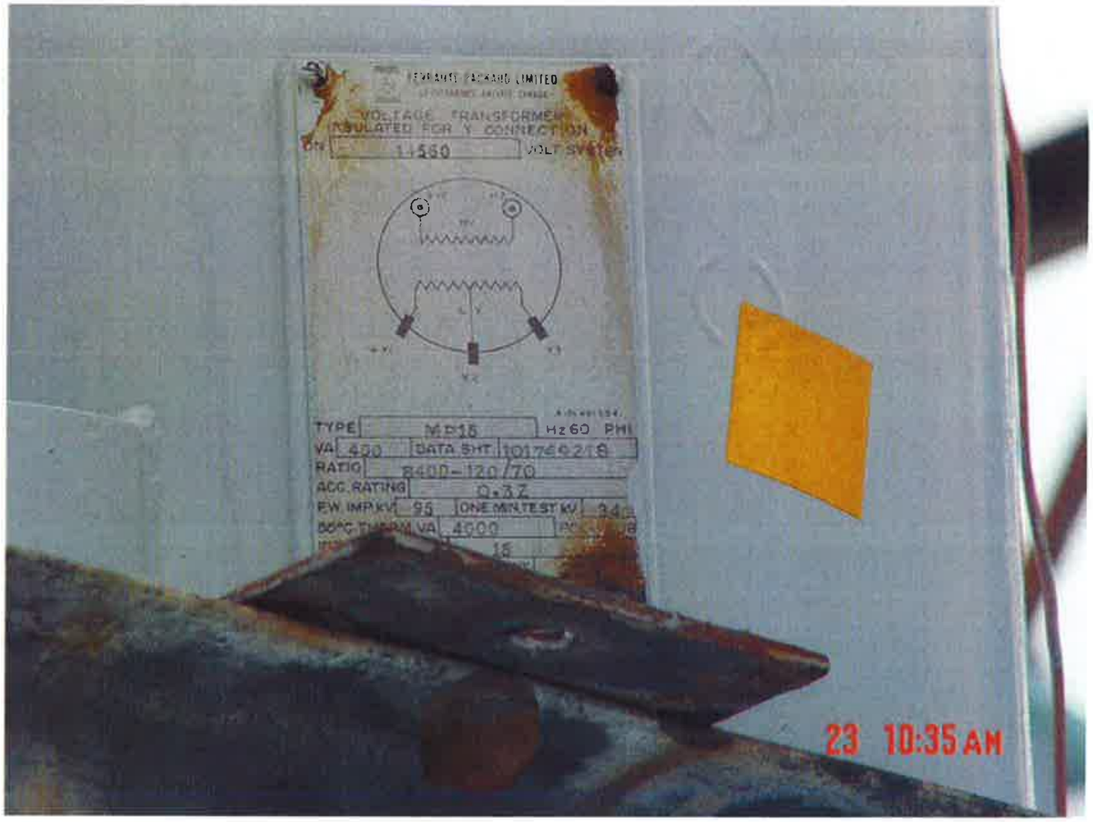
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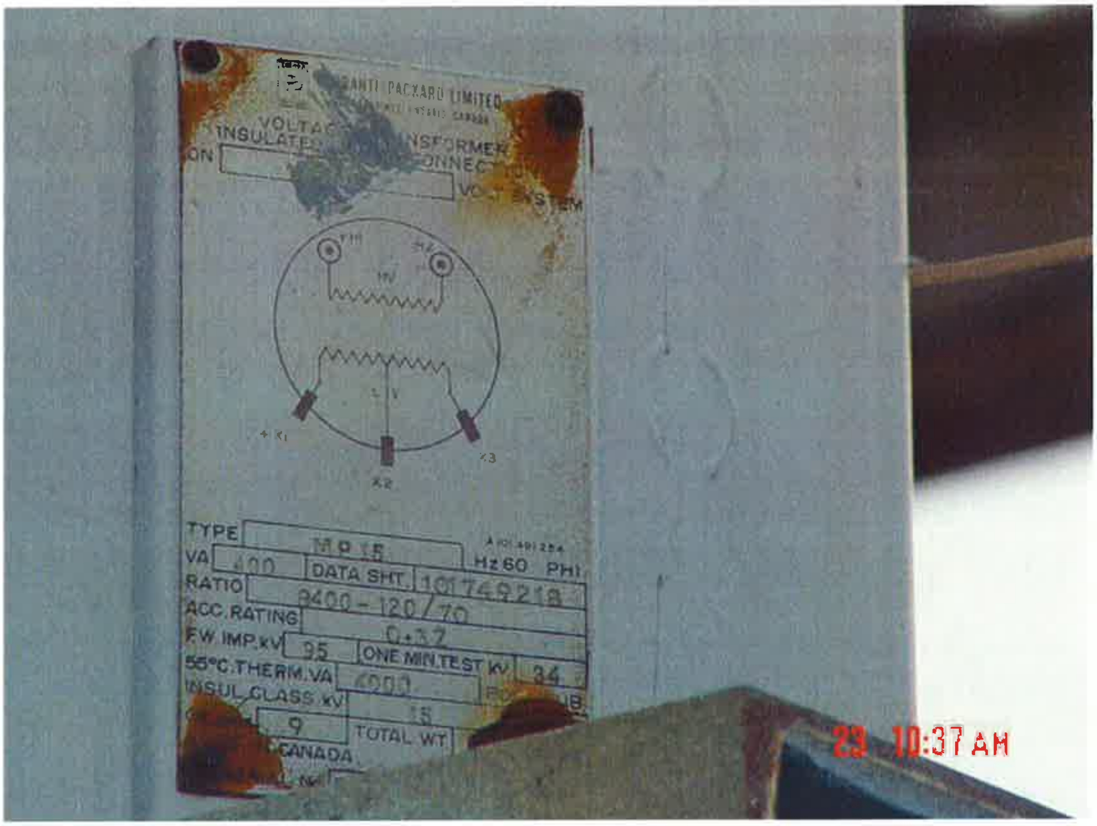

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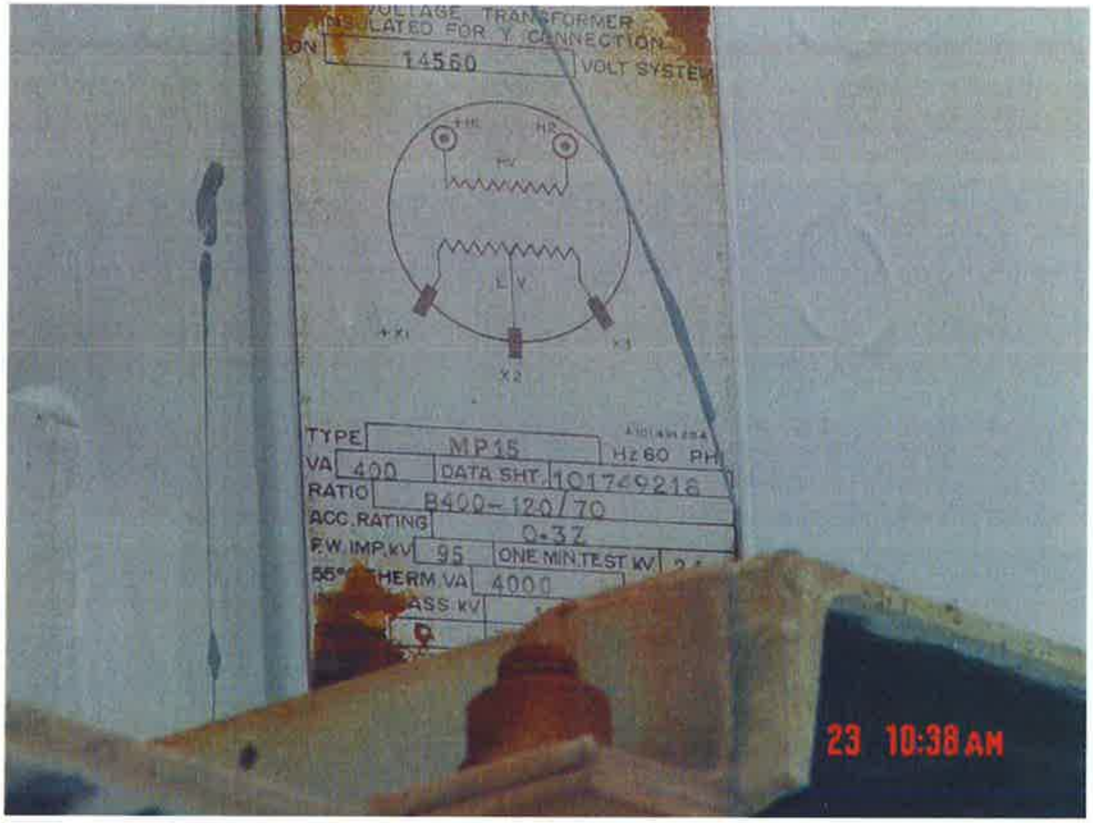
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CT and Transformer Secondary

CTs on the Structure

T2

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Transformers Secondary Side


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BPTs

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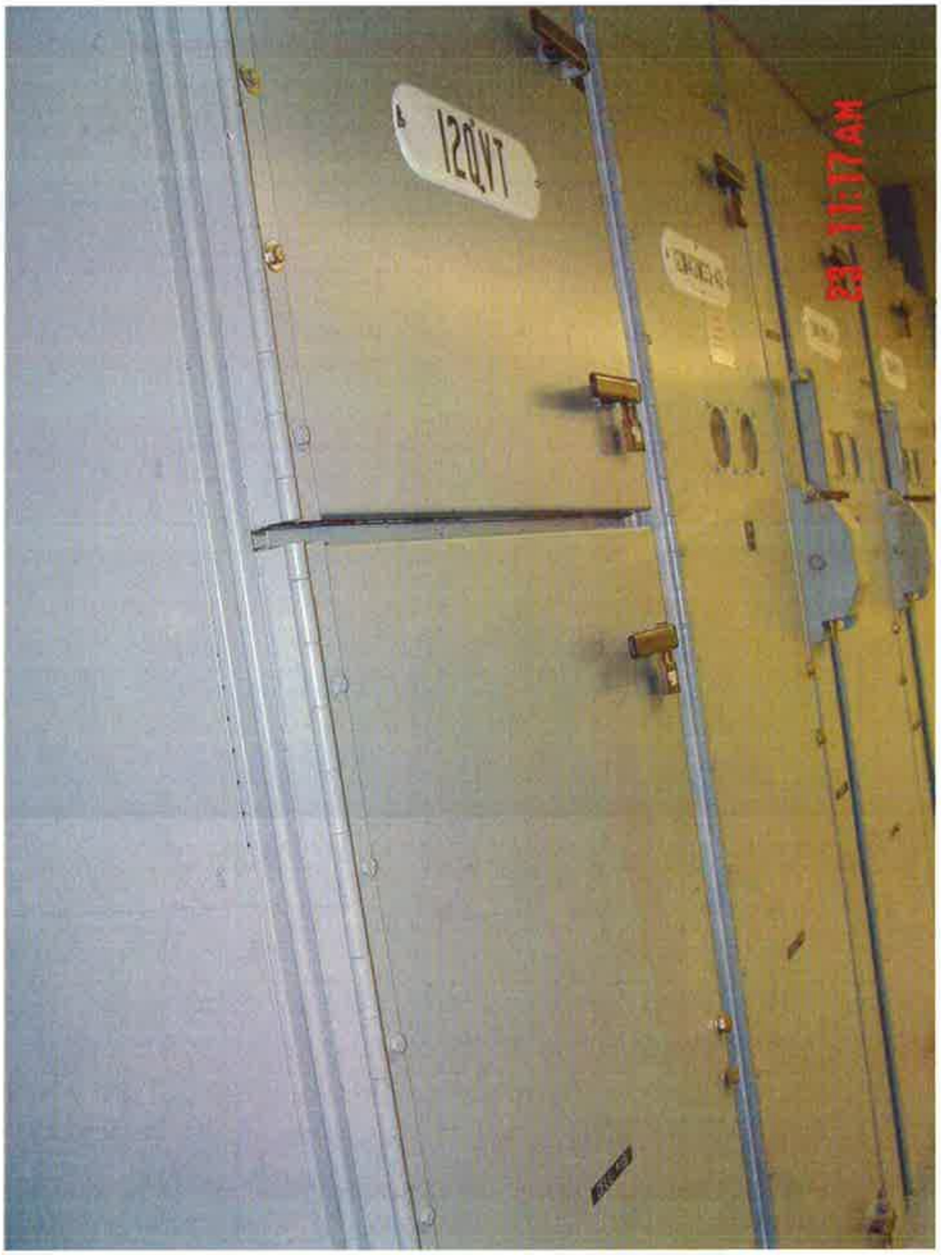

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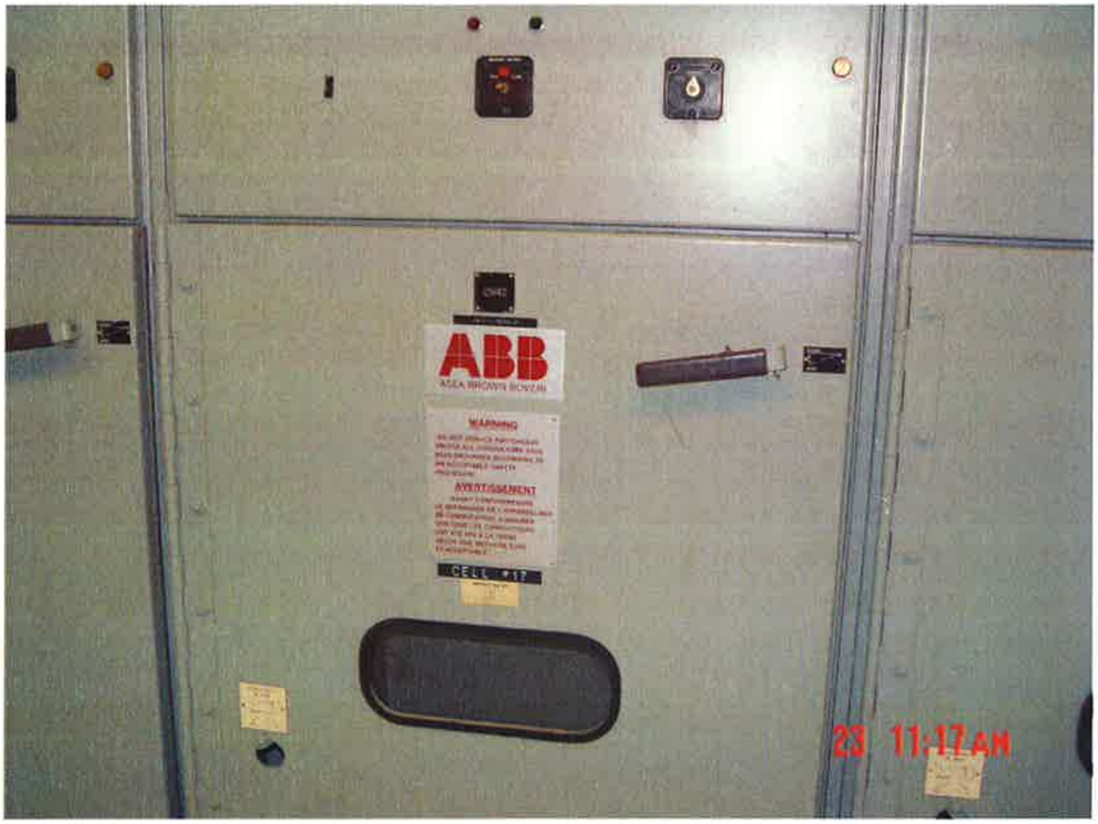

Switchgear S/N

CUSTOMER FACILITY UPGRADE CONTRIBUTION AGREEMENT
Stanley TS Refurbishment – BY bus Feeder Egress

THIS CUSTOMER FACILITY UPGRADE AGREEMENT made between Niagara Peninsula Energy Inc. (the **"Customer")** and Hydro One Networks Inc. **("Hydro One")** dated this 26th day of November, 2020.

WHEREAS:

(a) Hydro One proposes to: (i) carry out modifications to certain of its transmission facilities at Stanley TS that serve the Customer via the Stanley B/Y switchyard for the purposes of replacing assets that are at end of life; build a new B/Y Switchyard in a green field location; and once the B /Y Switchyard is placed in service, the BY Bus will be named the EZ bus (collectively, the "**Hydro One Project**");

(b) the Customer will incur costs (including without limitation planning, coordination, engineering, materials and equipment, switching, construction, commissioning, labour and administrative costs) to define, design and execute certain modifications of the Customer facilities at Stanley TS, which are required to interface with the Hydro One Project (the "**Project**").

(c) the Customer is agreeable to performing the work required for the Project, in accordance with the Project Scope, and on the following terms and conditions, including but not limited to the Project Costs and the Project schedule (as set out in Schedule "C" hereof), subject to Hydro One executing and delivering this Agreement to the Customer by no later than the 30th day of June, 2020 (the "**Execution Date**").

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:

1. Each of the parties hereto confirms the truth and accuracy of the recitals and agrees that the recitals form part of this Agreement. In the Agreement, terms which appear herein without definition shall have the meanings ascribed thereto in Appendix "A".

2. Subject to Section 13 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date that the Customer executes the Agreement (the "**Effective Date**") and shall expire on the date that Hydro One pays the Customer the final invoice in full for Work Chargeable to Hydro One or the Customer issues a refund to the Hydro One in accordance with Section 10 hereof (the "**Term**").

3. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any Applicable Laws;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) it is registered for purposes of Part IX of the Excise Tax Act (Canada) and its registration number is set out in Schedule "C"; and

(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Work Chargeable to Hydro One

4. Hydro One and the Customer shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice, in compliance with all Applicable Laws, including, but not limited to the provisions of the Transmission System Code applicable to the Customer Facilities, and using duly qualified and experienced people. Furthermore, the Customer shall ensure that the Customer's Facilities which are being modified or replaced by the Customer as part of the Work Chargeable to Hydro One and/or the Excluded Work meet the requirements set out in Sections 24.1 and 24.2 of the Connection Agreement.

5. the Customer acknowledges and agrees that:

(a) Hydro One has the right to witness the commissioning and testing of the Connection of the Customer's Facilities which are being modified or replaced by the Customer as part of the Work Chargeable to Hydro One and/or the Excluded Work;

(b) the Customer shall use the services of a professional engineer(s) appropriately licensed in Ontario to design and commission the Customer's Facilities which are being modified or replaced by the Customer as part of the Work Chargeable to Hydro One and/or the Excluded Work and such that they will not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system; and

(c) where applicable, the Customer's submissions to Hydro One shall be signed and stamped by a professional engineer appropriately licensed in the province of Ontario.

6. The parties acknowledge and agree that:

(a) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Work Chargeable to Hydro One, at Hydro One's sole expense. The Customer shall provide copies of such permits, certificates, reviews and approvals to Hydro One upon Hydro One's written request.

(b) Hydro One shall provide the Customer with data required by the Customer to execute the Project;

(c) Hydro One may participate in the commissioning, inspection or testing of the Work Chargeable to Hydro One and/or the Excluded Work at a time that is mutually agreed by Hydro One and the Customer to confirm satisfactory performance of such systems;

(d) the Customer's responsibilities under this Agreement shall be limited to the performance of the Work Chargeable to Hydro One and/or Excluded Work in accordance with the terms of this Agreement. For greater certainty, Hydro One is solely responsible for connection of the Project to Hydro One's Facilities and Hydro One's transmission system;

(e) if the Customer requires access to Hydro One's Facilities or Hydro One's Property(ies) for the purposes of performing the Work Chargeable to Hydro One and/or the Excluded Work, or Hydro One requires access to the Customer's facilities for the purposes described in subsections (c), (e) or (f) above, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 of the Connection Agreement shall be deemed to be a reference to this Agreement, all references to "the Transmitter" shall be deemed to be a reference to Hydro One, and all references to "the Customer" shall be deemed to be a reference to the Customer;

(f) the Customer shall provide Hydro One with copies of the documentation specified in Schedule "C" of the Agreement under the heading "Documentation Required", within 120 calendar days after the Ready for Service Date. Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's facilities and shall provide copies to Hydro One upon receiving written request from Hydro One. For greater clarity, ownership of such documentation shall at all times remain vested in the Customer; and

(g) Hydro One and the Customer shall amend the Connection Agreement, as may be required to reflect the changes being made to the Customer's Facilities as part of the Work Chargeable to Hydro One and/or the Excluded Work, at least 30 days prior to the re-Connection of the Customer's Facilities which are being modified or replaced by the Customer as part of the Work Chargeable to Hydro One, and/or the Excluded Work, to Hydro One's transmission system.

7. The Customer shall use reasonable efforts to complete the Work Chargeable to Hydro One by the Ready for Service Date, subject to any changes contemplated in Schedule "C" of this Agreement, and provided that:

(a) Hydro One is in compliance with its obligations under the Agreement;

(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of the Customer, acting reasonably;

(c) there are no delays resulting from the Customer not being able to obtain outages from the IESO that are required for: (1) the Work Chargeable to Hydro One, or (2) making changes to the Work Chargeable to Hydro One or the scheduling of all or a portion thereof;

(d) there are no delays resulting from the Customer not being able to obtain any permits, certificates, reviews or approvals required under any Applicable Laws with respect to the Work Chargeable to Hydro One, acting reasonably;

(e) there are no delays resulting from the Customer being unable to obtain materials or equipment required from suppliers in time to meet the Project schedule for any portion of the Work Chargeable to Hydro One provided that such delays are beyond the reasonable control of the Customer;

(f) the Customer does not have to use its employees, agents and contractors performing the Work Chargeable to Hydro One elsewhere on its facilities, where such work is determined to be of higher priority than the Project by the Customer acting reasonably;

(g) there are no delays resulting from a Force Majeure Event; and

(h) Hydro One executed the Agreement on or before the date specified as the Execution Date in the recitals.

8. Hydro One's rights and requirements hereunder, including, but not limited to Hydro One's:

(a) specifications of the protection equipment on the Customer's side of the Connection Point;

(b) review and acceptance of power system components on the Customer's side of the Connection Point;

(c) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities; and

(d) participation in the commissioning, inspection and testing of the Customer's Facilities;

are solely for the purpose of Hydro One ensuring that the Customer's Facilities which are being modified or replaced by the Customer as part of the Work Chargeable to Hydro One and/or the Excluded Work and will not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, in accordance with Hydro One's obligations under Applicable Laws.

9. Upon completion of the Work Chargeable to Hydro One, the Customer shall own, operate and maintain all equipment and facilities installed by the Customer as part of the Work Chargeable to Hydro One and/or the Excluded Work (the "**Equipment**") in, under, on, over, along, upon, through and crossing the Customer's property(ies).

For greater certainty, the parties acknowledge that:

(a) ownership and title to the Equipment shall throughout the Term and thereafter remain vested in the Customer, and Hydro One shall have no right of property therein; and

(b) any portion of the Equipment that is located on Hydro One's Property(ies) shall be and remain the property of the Customer and shall not be or become fixtures and/or part of Hydro One's Property(ies).

the Customer will be liable for maintaining, repairing and replacing the Equipment at its own expense. Nothing in this Agreement or otherwise, including, but not limited to Hydro One paying for the Work Chargeable to Hydro One under the terms of this Agreement, shall have the effect of passing title to or responsibility for the Equipment to Hydro One, unless otherwise agreed to in writing by the parties.

10. Hydro One shall pay the Project Costs, plus applicable Taxes, for the Work Chargeable to Hydro One in accordance with the terms of this Agreement. These amounts shall be paid by Hydro One to the Customer in the manner specified in Schedule "C" of this Agreement or as otherwise agreed to in writing by the parties.

Within 180 calendar days after the Ready for Service Date, the Customer shall provide Hydro One with an invoice or a credit memorandum specifying the actual Project Costs, for the Work Chargeable to Hydro One (plus applicable Taxes) and providing the same breakdown for the actual Project Costs as the breakdown of the estimated Project Costs in Schedule "C". Subject to section 15, any difference between the Project Costs for the Work Chargeable to Hydro One (plus applicable Taxes) and the amount already paid by Hydro One on account of the Cost Estimate of the Project Costs for the Work Chargeable to Hydro One, as described in Part 2 of Schedule "C", shall be paid within 60 calendar days after the issuance of the invoice or credit memorandum by:

(a) the Customer to Hydro One, if the amount already paid by Hydro One exceeds the Project Costs, or the Maximum Contribution Amount if applicable, for the Work Chargeable to Hydro One (plus applicable Taxes); or

(b) Hydro One to the Customer, if the amount already paid by Hydro One is less than the Project Costs, or the Maximum Contribution Amount if applicable, for the Work Chargeable to Hydro One (plus applicable Taxes).

the Customer acknowledges and agrees that Hydro One has informed the Customer that Hydro One intends to record in a regulatory deferral or variance account the Project Costs, or where applicable, Maximum Contribution Amount, to be paid to the Customer under the terms of this Agreement, for purposes of demonstrating the reasonableness of the Project Costs, or where applicable, Maximum Contribution Amount, to the OEB in a future Hydro One rate proceeding (the "**Purpose**"). As such, the Customer shall maintain complete and accurate records for Work Chargeable to Hydro One for a period of at least seven (7) years. the Customer, using commercially reasonable efforts, shall determine which records must be retained for purposes of assisting Hydro One in substantiating the Project Costs. the Customer shall file the records with the OEB or provide such records to an OEB inspector at the written request of Hydro One where Hydro One determines that such records are necessary to satisfy the Purpose, or where the OEB or and OEB inspector requires Hydro One to obtain such records to satisfy the Purpose (collectively, the "**Requested Information**").

Hydro One understands and acknowledges that the Customer may request that the OEB hold the Requested Information in confidence in accordance with the OEB's "Practice Direction on Confidential Filings" as may be amended or replaced from time to time by the OEB (the "**Practice Direction**"). Hydro One shall, using all reasonable efforts, cooperate with and support the Customer in respect of such a request, including any decision by the Customer to appeal or seek review of the Board's decision denying confidential treatment of the Requested Information (the "**Final Decision**"), as permitted by the Practice Direction. If the Customer's request for confidential treatment of the Requested Information is refused by the OEB in its Final Decision, and withdrawal of such Requested Information would result in Hydro One not being able to meet the Purpose, the Customer shall file on the public record such Requested Information.

Part B: Events of Default

11. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by Hydro One to pay any amount due under this Agreement, including any amount payable pursuant to Section 10 within the time stipulated for payment;

(b) Material breach by Hydro One or the Customer of any term, condition or covenant of the Agreement; or

(c) the making of an order or resolution for the winding up of Hydro One or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against Hydro One.

For greater certainty, a dispute will not be considered an Event of Default under the Agreement. However, a party's failure to comply with the terms of a settlement will be considered an Event of Default under the Agreement.

12. Upon the occurrence of an Event of Default by Hydro One hereunder (other than

those specified in Section 11(c) of this Agreement, for which no notice is required to be given by the Customer), the Customer shall give Hydro One written notice of the Event of Default and allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to the Customer under the terms of the Agreement, at law or in equity: deem the Agreement to be repudiated and, after giving Hydro One at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by Hydro One pursuant to Section 9.

13. Upon the occurrence of an Event of Default by the Customer hereunder, Hydro One shall give the Customer written notice of the Event of Default and shall allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

14. All rights and remedies of the Customer and Hydro One provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to the Customer and Hydro One respectively at law or in equity, and any one or more of the Customer's and Hydro One's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy the Customer or Hydro One may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part C: Disputes

15. All disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;

(b) the cost and the allocation of costs for the Work Chargeable to Hydro One;

(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's Facilities; and

(d) the Excluded Work;

shall be dealt with in accordance with the dispute resolution procedure set out in the Connection Agreement.

Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any amounts, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement. This obligation shall survive the termination of this Agreement.

Part D: Incorporation of Liability and Force Majeure Provisions

16. PART THREE: LIABILITY AND FORCE MAJEURE and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART THREE: LIABILITY AND FORCE

MAJEURE to "this Agreement" shall be deemed to be a reference to the Agreement, all references to "the Transmitter" shall be deemed to be a reference to Hydro One, and all references to "the Customer" shall be deemed to be a reference to the Customer.

For the purposes of this Section 16, the parties agree that the reference to:

(a) the Transmitter in lines 3 and 4 of Section 15.1 means Hydro One or any party acting on behalf of Hydro One such as contractors, subcontractors, suppliers, employees and agents; and

(b) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

The parties agree that the aggregate liability of each party under this Agreement and in particular under this Section 16 shall at no time exceed the actual Project Costs for the Work Chargeable to Hydro One.

Part E: General

17. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right 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 the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

18. Other than as provided in this Agreement, no amendment, modification or supplement to the 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 the Agreement.

19. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Sr. VP of Asset Management, Shanon Wilson, Niagara Peninsula Energy Inc, 7447 Pin Oak Drive, Niagara Falls, Ontario, L2E 6S9 on behalf of the Customer and to the Secretary, Hydro One Networks Inc., 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario, M5G 2P5, fax no: (416) 345-6972 on behalf of Hydro One.

A notice delivered by fax or email will be deemed to be received on the date of the fax if received before 3 p.m. or on the next Business Day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

20. The 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 laws of Canada applicable therein, and, subject to Section 15, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

21. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same Agreement.

22. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amount due under Section 10

and Part 2 of Schedule "C" shall survive the termination of the Agreement.

23. **Invoices and Interest.** Invoiced amounts are due 30 calendar days after invoice issuance. All overdue amounts, including but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

24. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Appendix A attached hereto and Schedules "A", "B" and "C" are to be read with and form part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Customer Facility Upgrade Contribution Agreement to be executed by the signatures of their proper authorized signatories, as of the date written below.

NIAGARA PENINSULA ENERGY INC.

Name: BRIAN WILKIE
Title: PRESIDENT + CEO
Date: NOVEMBER 25, 2020
I have the authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Name: Susan Wylie
Title: Director, Large Customer Account Management
Date: November 26, 2020
I have the authority to bind the Corporation

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the Transmission System Code and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Agreement" means this agreement, including Appendix "A" and Schedules "A", "B" and "C" attached hereto.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission board, court authority or agency.

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" means the connection agreement between the Customer and Hydro One dated May 2008 in respect of the connection of the Customer's facilities at Stanley TS to Hydro One's transmission system, and where applicable, as amended by Section 3.0.7 of the Transmission System Code.

"Connection Point" means the point where the Customer's facilities are connected to Hydro One's Facilities.

"Customer" for purposes of this Agreement, means the Customer.

"Customer's Facilities" has the meaning set forth in the Transmission System Code and any reference in this Agreement means the Customer's the Customer Facilities.

"Electricity Act, 1998" means the *Electricity Act, 1998* being Schedule "A" of *the Energy Competition Act*, S.O. 1998, c.15, as amended.

"**Equipment**" has the meaning set forth in Section 9 of this Agreement.

"**Excluded Work**" means the work relating to the Project described in Schedule "B" to this Agreement, to be performed by the Customer at no cost to Hydro One, in accordance with the terms of this Agreement.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"Good Utility Practice" has the meaning ascribed thereto in the Transmission System Code.

"Hydro One's Facilities" means the "facilities" (as defined in the Transmission System Code) that are owned or operated by Hydro One.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One has easement rights.

"IESO" means the Independent Electricity System Operator continued under the Electricity Act, 1998.

"Market Rules" rules made under section 32 of the *Electricity Act, 1998* (Ontario), including, but not limited to Chapter 6 thereof.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Maximum Contribution Amount" means the lower of the actual Project Costs or the amount set out in Schedule "C" payable by Hydro One in accordance with Section 10 of this Agreement.

"OEB" means the Ontario Energy Board.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "C" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Project Costs" means the costs incurred by the Customer for engineering, materials and equipment, construction, commissioning, administrative, labour (including overhead) and other related costs for the Work Chargeable to Hydro One as well as interest during construction using the Customer's capitalization rate in effect during the construction period, and as set out on a preliminary basis in Schedule "C" of this Agreement.

"Project Milestone Date" means those milestone dates specified in Schedule "C" of this Agreement.

"Project Scope" means the work to be performed by the Customer described in Schedule "A" of this Agreement.

"Purpose" has the meaning ascribed thereto in Section 10 of this Agreement.

"Ready for Service Date" means a date to be agreed upon by the parties acting reasonably, upon which the Work Chargeable to Hydro One is fully and completely constructed, installed, commissioned and energised to the Connection Point. If Hydro One intends to install new disconnect switches, Hydro One's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Requested Information" has the meaning ascribed thereto in Section 10 of this Agreement.

"Taxes" means any and all applicable federal, state, provincial, local or foreign taxes and duties including, but not limited to, sales, use, excise, value added, gross receipts, privilege or other non-recoverable taxes that are mandated or imposed on the Customer by any jurisdiction or governmental entity in relation to the Work Chargeable to Hydro One under this Agreement (other than taxes that are imposed upon the income, property, payroll or capital of a person).

"Transmission System Code" means the code of standards and requirements originally issued by the OEB on July 14, 2000, as it may be amended, revised or replaced in whole or in part from time to time in accordance with the Section 70.2 and 70.3 of the *Ontario Energy Board Act*.

"**Transmitter**" for purposes of this Agreement, means Hydro One.

"Work Chargeable to Hydro One" means the work to be performed by the Customer described in Schedule "A" in accordance with the terms described in Schedule "C" of this Agreement. For greater clarity, Work Chargeable to Hydro One shall not include the Excluded Work.

Schedule "A"

PROJECT SCOPE - WORK CHARGEABLE TO HYDRO ONE

The Customer will perform the following work:

For the four feeders (12M1, 12M4, 12M5 and 12M6) that will be fed off new EZ bus:

- install 2 cable manholes outside station fence (per the Customer's specifications);
- install feeder riser poles for M1, M4, M5 and M6 outside of the station fence;
- perform switching operations;
- perform cable pulling, testing & ready for termination/connection to final connection point;
- perform pole replacement work (framing, transfers and removals); and
- submit completed COVER documents to Hydro One.

For greater certainty, the following work will not be performed by the Customer as it will be performed by Hydro One:

- termination of completed feeder cables to the load side of the breaker potheads; and
- installation of the cable duct bank between the new building to the two (2) cable manholes installed by the Customer.

Schedule "B"

PROJECT SCOPE – EXCLUDED WORK

Any and all revenue metering related work.

Hydro One vs NPEI Milestones-AR24221-Stanley TS Upgrade Project: As of 2020-11-05 (Rev 01).

No	Hydro One Milestone Activities	Start Date	Finish Date	No	NPEI Milestone Activities	Start Date	Finish Date	Notes
1	New Building Construction		8/19/2020	1	Submit Doc. to process Easement		??????	
2	CKT Q3N (All Terminals), Stanley T2, T2-Q3N, T2Y, BY, T2Q, JQ, Q Bus, M41, M42, M43, T2Z, Y-Bus, M4, M6. Requires Supporting Gaurantees from NPEI.	9/6/2021	10/1/2021	2	Obtain Easement from Hydro One		??????	
2-1	In case of T1 failure during this period, Hydro One will restore T2 Zone within: Recall time of 4 Hours during the day time, during evening 6 Hours			3	Submit Manhole and Feeder Metering Design to Hydro One for Review / comment		??????	Hydro One requires minimum four (4) weeks for comments.
2-2	During this period NPEI is expected to transfer "Y" Bus (M4 and M6) loads to alternate supply.			4	Install 15KV cable manholes and foundations for feeder metering equipment		??????	Once installed, Hydro One will install connecting cable trenches between the new building and NPEI's Cable Manholes.
2-3	During this period protectionss for NPEI's M41, M42, M43, M4 and M6 Feeder will be transffered from the old relays to the new PCT in the new building. For Zone Test Trip for feeder protections, coordination between Hydro One and NPEI needed.			5	Install, pre-test and register new feeder metering equipment		09/302021	If NPEI need extra day to finish this activity, please advise Hydro One.
	Blank			6	Install new feeder poles, pull new 15KV cables, test and ready to terminate to Breakers by Hydro One		9/30/2021	If NPEI need extra day to finish this activity, please advise Hydro One.
	Blank			7	Connect NPEI's new M1 cables to the new breaker in "E" Bus. Hydro One EMD will terminate with NPEI's presence.	11/3/2021	11/3/2021	Refer to Hydro One activity 4-1.
3	CKT Q4N (All Terminals), Stanley T1, T1B, BY, T1J, JQ, J Bus, M31, M32, M33, T1E, B-Bus, M1, M5. Requires Supporting Gaurantees from NPEI.	10/4/2021	10/29/2021	8	Connect NPEI's new M4 cables to the new breaker in "Z" Bus. Hydro One EMD will terminate with NPEI's presence.	11/4/2021	11/4/2021	Refer to Hydro One activity 4-2.
3-1	In case of T2 failure during this period, Hydro One will restore T1 Zone within: Recall time of 4 Hours during the day time, during evening 6 Hours			9	Connect NPEI's new M5 cables to the new breaker in "E" Bus. Hydro One EMD will terminate with NPEI's presence.	11/5/2021	11/5/2021	Refer to Hydro One activity 4-3.
3-2	During this period NPEI is expected to transfer "B" Bus (M1 and M5) loads to alternate supply.			10	Connect NPEI's new M5 cables to the new breaker in "Z" Bus. Hydro One EMD will terminate with NPEI's presence.	11/8/2021	11/8/2021	Refer to Hydro One activity 4-4.

3-3	During this period protectionss for NPEI's M31, M32, M33, M1 and M5 Feeder will be transffered from the old relays to the new PCT in the new building. For Zone Test Trip for feeder protections, coordination between Hydro One and NPEI needed.				11	Hydro One to take T2 out of service to disconnect old 15KV cables from T2 Secondary Winding and old T2Y breaker.	11/9/2021	11/9/2021 (Last activity involving NPEI). Declair all new equipment fully in-serviced.	Refer to Hydro One activity 5 and 5-1.
	Blank				11-1	OGCC and NPEI to arrange / set up power supply to "Q" Bus (M41, M42 and M43) and "Z" Bus (M4 and M6).			
	Blank								
4	Connect NPEI's new M1, M4, M5 and M6 cables to the new breaker in "E" Bus. Hydro One EMD will terminate with NPEI's presence. NPEI to provide supporting gaurantees during this period.	11/1/2021	11/5/2021						
4-1	Connect NPEI's new M1 cables to the new breaker in "E" Bus. Hydro One EMD will terminate with NPEI's presence.	11/3/2021	11/3/2021						
4-2	Connect NPEI's new M4 cables to the new breaker in "Z" Bus. Hydro One EMD will terminate with NPEI's presence.	11/4/2021	11/4/2021						
4-3	Connect NPEI's new M5 cables to the new breaker in "E" Bus. Hydro One EMD will terminate with NPEI's presence.	11/5/2021	11/5/2021						
4-4	Connect NPEI's new M5 cables to the new breaker in "Z" Bus. Hydro One EMD will terminate with NPEI's presence.	11/8/2021	11/8/2021						
	Blank								
	Blank								
5	Hydro One to take T2 out of service to disconnect old 15KV cables from T2 Secondary Winding and old T2Y breaker.	11/9/2021	11/9/2021 (Last activity involving NPEI). Declair all new equipment fully in-serviced.						
5-1	OGCC and NPEI to arrange / set up power supply to "Q" Bus (M41, M42 and M43) and "Z" Bus (M4 and M6).								
	Blank								
	Blank								

Shanon Wilson

From:	Zach Lindley
Sent:	Tuesday, November 17, 2020 2:53 PM
To:	Shanon Wilson
Subject:	RE: Tentative schedule for HONI Stanley work
Attachments:	AR24221-Hydro One-NPEI Schd-Rev01-2020-11-05.xlsx

Hi Shanon,

Attached is HONI's tentative schedule for the project.

Their project team has reviewed our proposed design and given us the okay to proceed with the easement application. We are planning to complete our plan and profile drawings and submit them to Hydro One's Real Estate Department next week when Mario is back in the office.

We've been advised that the easement application process can take up to 4 months, so we're planning to start construction around May 1st. Meter commissioning will be late September and we'll swing the feeders over to the new bus in November.

Let me know if you need any other info.

Thanks,

Zach

Zach Lindley | Engineering Systems Manager
Tel: (905) 356-2681 ext 6237 | Email: zach.lindley@npei.ca

Schedule "C"

Part 1: Estimate of Project Costs of the Work Chargeable to Hydro One:

The estimate of the Project Costs of the Work Chargeable to Hydro One (excluding harmonized sales tax (HST) is $ 280,207.66 + 131,511.74 and is summarized as follows:

Project Description Feeder egress work - construction	**Estimated Project Costs($)**
Labour	77,363.20
Trucks/Equipment	50,280.00
Civil Contractor	61,000.00
Engineering	11,188.80
Overhead (62%) **	54,902.24
Sub-Total	254,734.24
Contingency (10%)	25,473.42
Total Price ($)	280,207.66

Project Description Materials	**Estimated Project Costs ($)**
Underground *(cables, terminations)*	56,528.35
Duct Banks	31,844.58
Overhead *(poles, framing)*	7,271.97
Overhead (25%)	23,911.23
Sub Total	119,556.13
Contingency (10%)	11,955.61
Total Price ($)	131,511.74

**** Overhead is applied to Engineering and Construction Labour total. [NTD: Labour cost is based on hours worked x fully burdened rate]**

Maximum Contribution Amount: $280,207.66 + $131,511.74 = $411,719.40 (excluding HST).

Part 2: Manner of Payment

Payment Milestone Date	Work Chargeable to Hydro One ($)
Ready for service date	$411,719.40 plus HST in the amount of $53,523.52

Part 3: Project Schedule

To be negotiated by Hydro One and the Customer.

Part 4: Scope and Schedule Change

For the purpose of this Part 4 of Schedule "C", the term "Non-Hydro One Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as a result of any one or more of the following:

- any environmental assessment(s);
- requirement to obtain approval under Section 92 of the *Ontario Energy Board Act*;
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the *Ontario Energy Board Act;* and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope whether initiated by Hydro One or are Non-Hydro One Initiated Scope Changes, may result in a change to the Project Costs estimated in Schedule "C" of this Agreement and the Project schedule, including the Ready for Service Date.

All Hydro One initiated scope changes to the Project must be in writing to the Customer.

The Customer will advise Hydro One of any cost and schedule impacts of any Hydro One initiated scope changes. The Customer will advise Hydro One of any Material cost and/or Material schedule impacts of any Non-Hydro One Initiated Scope Changes.

The Customer will not implement any Hydro One initiated scope changes until written approval has been received from Hydro One accepting the new pricing and schedule impact.

The Customer will implement all Non-Hydro One Initiated Scope Changes until the estimate of the Non-Hydro One Initiated Scope Changes reaches **10%** of total Project Costs. At that point, no further Non-Hydro One Initiated Scope Changes may be made by the Customer without the written consent of Hydro One accepting new pricing and schedule impact. If Hydro One does not accept the new pricing and schedule impact, the Customer will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

Part 5: Miscellaneous

Hydro One's HST Number: 87086-5821 RT0001

Customer's HST Number: 87196-9127 RT0001

Shanon Wilson

From:	Barry Spencer [barry.spencer@ieso.ca]
Sent:	Wednesday, September 19, 2018 11:48 AM
To:	Zach Lindley; 'Meifeng.Lian@HydroOne.com'; 'Ardalan@HydroOne.com'; 'TMcConnell@pui.ca'; Metering Installations
Cc:	'AWatts@pui.ca'; 'DSharpe@pui.ca'; Shanon Wilson; 'Nimesh.Mistry@HydroOne.com'; 'petar.saravolac@HydroOne.com'
Subject:	RE: Stanley TS J/Q scope of work

Hi everyone,

Thank you all for the conference call on September 7th. As discussed, would Hydro One please provide two drawings: the "as is" and the "proposed" configurations of the J/Q yard at Niagara Stanley TS.

To summarize IESO's understanding, Hydro One will be performing the following power system changes:

- replacing the T2 power transformer
- replacing all feeder breakers
- replacing all transformer LV breakers (revenue metering CTs are independent and will remain)
- replacing all protection and control equipment (inside new building) and new switchgear cabling
- retaining use of existing CTs and VTs

At this time, we believe the above items are not considered substantial, however in order to better understand what changes will be made to the metering installation (secondary cabling, VT auto transfer scheme, CT summation, VT sharing) and any implications, Hydro One will arrange an on-site meeting including:

- MMP: Niagara Peninsula Energy Inc. (Zach Lindley/Shanon Wilson)
- MSP: Meter Services Peterborough Inc. (Terry McConnell/Dave Sharp/Andrew Watts)
- IESO (Richard Zaworski/Zahir Gohgari/Robert Stancu/Barry Spencer)

This on-site meeting will help the IESO reach a conclusion as to whether the new station configuration will trigger the substantial upgrade of the J/Q metering installation. Please propose a few dates so all parties can identify their availability.

If I have missed anything, or any items above require correction/clarification, please let me know.

Regards,

Barry Spencer – Revenue Metering
Independent Electricity System Operator (IESO) | T: (905) 855-6482
Station A, Box 4474, Toronto, ON M5W 4E5

From: Barry Spencer
Sent: August 24, 2018 11:55 AM
To: 'Zach Lindley'; 'Meifeng.Lian@HydroOne.com'; Ardalan@HydroOne.com; TMcConnell@pui.ca; Metering Installations

Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; petar.saravolac@HydroOne.com
Subject: RE: Stanley TS J/Q scope of work

Hi Zach,

As discussed on our phone call, I will set up a conference call between IESO Metering, yourself and Shanon from NPEI, Hydro One and Peterborough MSP. I will forward an invite for somewhere between September 5th and 7th.

Regards,

Barry

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: August 21, 2018 1:18 PM
To: 'Meifeng.Lian@HydroOne.com'; Ardalan@HydroOne.com; Barry Spencer; TMcConnell@pui.ca; Metering Installations
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; petar.saravolac@HydroOne.com
Subject: RE: Stanley TS J/Q scope of work

CAUTION: This email originated from outside of the organization. Exercise caution when clicking on links or opening attachments even if you recognize the sender.

Hi Barry,

Do you have enough information to advise us on whether or not we need to upgrade the JQ Bus metering? Should we setup a call?

Thanks,

Zach

From: Meifeng.Lian@HydroOne.com [mailto:Meifeng.Lian@HydroOne.com]
Sent: Friday, August 10, 2018 2:33 PM
To: Ardalan@HydroOne.com; Zach Lindley; barry.spencer@ieso.ca; TMcConnell@pui.ca; MeteringInstallations@ieso.ca
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; petar.saravolac@HydroOne.com
Subject: RE: Stanley TS J/Q scope of work

Ardy,

As shown in the attached drawing, the existing JVT and QVT's 120V secondary windings are used for LDC revenue meters. On each winding, the existing loads include Auto Voltage Transfer (~8VA), Phase Shifter

(~6.9VA) and some analog transducers (~0.1VA). Therefore, the total is ~15VA. Based on our plan, the new load on the 120V winding will be SEL351-7 relay for the LV bus 'B' protection (~0.06VA).

Best Regards,

Meifeng Lian
(416) 345-5188

From: DERAKHSHANIAN Ardalan
Sent: Friday, August 10, 2018 9:27 AM
To: Zach Lindley; 'Barry Spencer'; TMcConnell@pui.ca; Metering Installations
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; LIAN Meifeng; MISTRY Nimesh; SARAVOLAC Petar; LIAN Meifeng; DERAKHSHANIAN Ardalan; SARAVOLAC Petar
Subject: RE: Stanley TS J/Q scope of work

Zack,

I am in touch with our planning department to provide response to Barry's question. Allow us to get back to you earlier next week, and I believe it would be very beneficial to have conference call after.

Thanks

Ardy

Ardalan Derakhshanian, P.Eng.
PM, Project Delivery, TCT-12
Hydro One Networks Inc.
Tel: (416) 345-4217
Cell: (416) 768-4217
Email: Ardalan@HydroOne.com

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From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Thursday, August 09, 2018 3:37 PM
To: 'Barry Spencer'; DERAKHSHANIAN Ardalan; TMcConnell@pui.ca; Metering Installations
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; LIAN Meifeng; MISTRY Nimesh; SARAVOLAC Petar
Subject: RE: Stanley TS J/Q scope of work

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Ardy, can you answer the questions about non-metering devices connected to the VT secondary windings? I am not sure what other devices are connected.

Barry, we do not have plans to upgrade the 12T1J-T2Q metering. Our involvement in this project is being driven by Hydro One's upgrade, we have not budgeted for upgrading these metering points.

Let me know if you would like to schedule a call.

Thanks,

Zach

From: Barry Spencer [mailto:barry.spencer@ieso.ca]
Sent: Thursday, August 09, 2018 10:47 AM
To: Zach Lindley; 'Ardalan@HydroOne.com'; TMcConnell@pui.ca; Metering Installations
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Meifeng.Lian@HydroOne.com; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com
Subject: RE: Stanley TS J/Q scope of work

Hi Zach/Ardy/Terry,

We are looking for additional details regarding the scope's final bullet, *"Both secondary windings of J/Q Bus VTs will be used for protection as per HONI standard (no dedicated winding for metering)."* for our assessment of the existing AMIS 12T1J-T2Q metering installation.

Please provide the following information:

- Are there presently any non-metering devices connected to any of the revenue metering VT secondary windings on the J or Q bus? If yes, what devices are connected and what are their rated load?
- What future non-metering devices will be connected and to which of the revenue metering VT secondary windings on the J or Q bus? What are their rated load?
- Are there any plans for upgrading the 12T1J-T2Q metering to a DOC status? (given that the B/Y yard will require new compliant metering installations)

Based on the responses, we may need to coordinate a call to discuss. The IESO's guiding principle regarding modifications to metering installations under the Alternative Metering Installation Standard (AMIS) is that the MMP should be making an effort to move towards a Declaration of Compliance (DOC) metering installation, not further away from it.

Thank you,

Barry

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: August 09, 2018 8:36 AM
To: 'Ardalan@HydroOne.com'; Barry Spencer; Metering Installations
Cc: AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Meifeng.Lian@HydroOne.com; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; TMcConnell@pui.ca
Subject: RE: Stanley TS J/Q scope of work

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Thanks Ardy.

Barry, please let me know if any other info is needed to determine whether or not upgrades are required on the JQ metering.

Regards,

Zach

From: Ardalan@HydroOne.com [mailto:Ardalan@HydroOne.com]
Sent: Tuesday, August 07, 2018 3:53 PM
To: Zach Lindley; TMcConnell@pui.ca; barry.spencer@ieso.ca
Cc: MeteringInstallations@ieso.ca; AWatts@pui.ca; CMcBride@pui.ca; DSharpe@pui.ca; Shanon Wilson; Meifeng.Lian@HydroOne.com; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; Ardalan@HydroOne.com
Subject: RE: Stanley TS J/Q scope of work

Zach,

Sorry for delay, The scope of work specific for J/Q switchyard at Stanley TS is as follow:

- T2 will be replaced
- All J/Q breakers will be replaced (roll in replacement)
- J/Q bus VTs and breaker CTs inside the metalclad will be retained
- New PCT equipment will be installed for the entire station and will be located inside the new building.
    - The existing cables between J/Q CTs & VTs and old control building will be removed; install new cables from J/Q CTs & VTs to the fuse and link rack inside the new building.
    - The existing HONI transducers connected to the J/Q RM CT circuit will be removed.
    - The existing HONI Auto Transfer Scheme connected to the J/Q RM VT circuit will be removed.
    - Both secondary windings of J/Q Bus VTs will be used for protection as per HONI standard (no dedicated winding for metering).

Thanks

Ardy

Ardalan Derakhshanian, P.Eng.
PM, Project Delivery, TCT-12
Hydro One Networks Inc.
Tel: (416) 345-4217

Cell: (416) 768-4217
Email: Ardalan@HydroOne.com

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From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Thursday, August 02, 2018 8:27 AM
To: 'Terry McConnell'; Barry Spencer; DERAKHSHANIAN Ardalan
Cc: Metering Installations; Andrew Watts; Cory McBride; David Sharpe; Shanon Wilson
Subject: RE: Stanley TS

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Thanks Terry,

The M2 and M3 feeders will not be used. Hydro One will not be installing cells for these feeders.

Ardy, can you confirm the scope of work to be competed on the JQ bus?

Thanks,

Zach Lindley
Niagara Peninsula Energy Inc.
Engineering Systems Manager
Phone: 1-877-270-3938 ext. 6237
Email: zach.lindley@npei.ca

From: Terry McConnell [mailto:TMcConnell@pui.ca]
Sent: Wednesday, August 01, 2018 12:22 PM
To: Barry Spencer; Zach Lindley
Cc: Metering Installations; Andrew Watts; Cory McBride; David Sharpe; Terry McConnell
Subject: RE: Stanley TS

Thanks Barry:

Zach: Per below, please confirm with Hydro One the scope of work to be completed on JQ Bus. If only breaker replacements and existing CT's and PT's will not be altered, we believe no upgrades to the metering will be required at this time.

For BY Bus, please confirm M2 and M3 are not used and will be locked off by HONI. If we go ahead with 4 new feeder meter installations for BY, we will need to do a station service estimate as it is presently captured by the bus metering. We can facilitate this with HONI at time of upgrade.

Regards,

Terry McConnell
Manager, Metering Services
Meter Services Peterborough,
a Division of Peterborough Utilities Inc.
tel (705) 748-9301 ext 1279
fax (705) 743-5988
email tmcconnell@pui.ca

>>> Barry Spencer <barry.spencer@ieso.ca> 2018-08-01 10:59 AM >>>

Hi Terry,

As discussed on the phone, replacing the T1B+T2Y summed metering installation with four NPEI feeder metering installations would leave 2 unmetered feeders and station service exposed. These items would need to be addressed before proceeding.

Regarding the JQ equipment, changes to a facility should be checked with the IESO. Minor changes or changes not related to electrical power will not trigger the substantial upgrade or refurbishment clause. However, major changes to a facility that relates to the transmission, distribution or generation may trigger the clause. The intent is that the metering upgrade would be included in any substantial work on the facility where it is applicable to the wholesale market.

Hydro One changing breakers in and out should not trigger the upgrade clause, but it's possible they could be doing other work.

Please confirm with Hydro One the full details of the JQ changes, or have them submit the scope of work to meteringinstallation@ieso.ca and we can assess.

Regards,

Barry Spencer – Metering Installations
Independent Electricity System Operator (IESO) | T: (905) 855-6482
Station A, Box 4474, Toronto, ON M5W 4E5

From: Terry McConnell [mailto:TMcConnell@pui.ca]
Sent: July 30, 2018 12:43 PM
To: Barry Spencer; Metering Installations
Cc: Terry McConnell
Subject: Stanley TS

Hi Barry:

Attached is the current SLD for NPEI, Stanley TS.

HONI is working on upgrading the BY yard and we are looking at options for upgrading the BY Bus metering. Probably NPEI will install 4 new metering units outside the fence on their feeders as this is most cost effective solution for them.

NPEI also mentioned that HONI was going to replace all breakers on the JQ Bus, but I don't believe they are touching the metering PT's and CT's which are summated. HONI says that since the breakers are being replaced, the JQ Bus metering will need to be upgraded, however, I don't believe this to be the case.

Can you provide clarification on JQ metering requirements?

Please let me know if any questions.

Regards,

Terry McConnell
Manager, Metering Services
Meter Services Peterborough,
a Division of Peterborough Utilities Inc.
tel (705) 748-9301 ext 1279
fax (705) 743-5988
email tmcconnell@pui.ca

Disclaimer

Shanon Wilson

From:	Ardalan@HydroOne.com
Sent:	Friday, September 28, 2018 4:16 PM
To:	Zach Lindley; Stefanie.Pierre@HydroOne.com; petar.saravolac@HydroOne.com; rreyes@burnsmcd.com; bmpietrzyk@burnsmcd.com
Cc:	AWatts@pui.ca; TMcConnell@pui.ca; CMcBride@pui.ca; Shanon Wilson; Jim Sorley; Mario Rosano; Vince Morinello; Nimesh.Mistry@HydroOne.com; petar.saravolac@HydroOne.com; Meifeng.Lian@HydroOne.com
Subject:	RE: Stanley TS
Attachments:	NPEI Stanley TS-Install Preliminary Manhole Locations Sept 25, 2018.pdf

Zack,
Thank you for your timely response. I am planning to have a meeting in last week of October with our field and outage planning at site to walk everyone through the design and also discuss the outages. It most likely would be a half a day site visit, so maybe we can combine this with IESO meeting? Your thoughts?

Ragner & Co.
Please see Zack's comments on the attached sketch regarding the manhole. Also, note Zack's response regarding the J/Q metering and provide response to his questions.

Thanks
Ardy

Ardalan Derakhshanian, P.Eng.
PM, Project Delivery, TCT-12
Hydro One Networks Inc.
Tel: (416) 345-4217
Cell: (416) 768-4217
Email: Ardalan@HydroOne.com

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Friday, September 28, 2018 2:25 PM
To: DERAKHSHANIAN Ardalan; PIERRE Stefanie
Cc: Andrew Watts; 'Terry McConnell'; Cory McBride; Shanon Wilson; Jim Sorley; Mario Rosano; Vince Morinello; MISTRY Nimesh; SARAVOLAC Petar; LIAN Meifeng
Subject: Stanley TS

Hi Stefanie and Ardy,

Here is the sketch showing our proposal for the manhole locations.

Our preference for the JQ metering is to move forward with the solution that you proposed, reusing the existing ITs and installing a new metering cabinet complete with voltage transfer scheme. Can we follow up with a site visit with the IESO to get their approval?

Would you be able to provide us with any wiring diagrams you have showing the existing voltage transfer scheme and CT summation? Also, would you be able to suggest a relay that we could use for the voltage transfer scheme?

Have a great weekend,

Zach Lindley
Niagara Peninsula Energy Inc.
Engineering Systems Manager
Phone: 1-877-270-3938 ext. 6237
Email: zach.lindley@npei.ca

For Niagara Peninsula Energy Customers please Click Here to participate in our online customer service survey! (powered by SurveyMonkey)

Shanon Wilson

From:	Stefanie.Pierre@HydroOne.com
Sent:	Friday, October 05, 2018 2:17 PM
To:	Zach Lindley
Cc:	Shanon Wilson
Subject:	Stanley TS-feedback to NPEI question regarding metering of J/Q bus
Attachments:	NF12-65185-0008-D.PDF; NF12-65002-0004-D.PDF

Zach,

See attached for the existing drawings that we found for the PT throw-over scheme.

HONI will provide the VT, CT, and AC sources to the new metering cabinet. The metering cabinet to also include the new voltage transfer scheme. Since HONI would not be sharing station DC with the customer's metering, NPEI could replace the 125VDC operated RXMA-1 relay with a 115VAC operated RXMA-1 relay (would require a different relay part number for 115V AC application, but similar application of the relay). The AC wetting voltage for the RXMA-1 relay could come from a circuit on an AC distribution panel, which would be behind the ATS so they should have reliable AC for use. The undervoltage relays could stay as CSJ types. There are certainly other options that they could look at, but this is just one that we thought of quickly that wouldn't require 125VDC.

Please consider this information *CONFIDENTIAL* and is an FYI for NPEI as you will be responsible for design.

Stefanie S Pierre, MSc, P.Eng
Account Executive
Key Account Management
Hydro One Networks Inc
6975 Kenderry Gate
Mississauga, ON L5T 2Y1
Mobile: 647.261.9575

Stefanie.pierre@hydroone.com
www.hydroone.com

Shanon Wilson

From: Zach Lindley
Sent: Wednesday, February 13, 2019 4:29 PM
To: Shanon Wilson
Subject: RE: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Sounds good. Have a good night.

From: Shanon Wilson
Sent: Wednesday, February 13, 2019 3:18 PM
To: Zach Lindley
Subject: Re: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

It sounds like they really dont want us having any meetering in the station. We should budget for feeder metering for next year.

Regards,

Shanon

Sent from my Samsung Galaxy smartphone.

-------- Original message --------
From: Zach Lindley <zach.lindley@npei.ca>
Date: 2019-02-13 3:01 PM (GMT-05:00)
To: Shanon Wilson <Shanon.Wilson@npei.ca>
Subject: FW: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Hi Shanon,

Here's Hydro One's response to my inquiry about the accuracy of their estimate for HV metering at Stanley TS.

Let me know your thoughts. Should we move forward with a request for a class 3 estimate?

Thanks,

Zach

From: Ishankumar.Vyas@HydroOne.com [mailto:Ishankumar.Vyas@HydroOne.com]
Sent: Wednesday, February 13, 2019 2:11 PM
To: Zach Lindley
Cc: johanhak@HydroOne.com; Stefanie.Pierre@HydroOne.com; Ardalan@HydroOne.com; Nimesh.Mistry@HydroOne.com; travis.iwamoto@HydroOne.com; petar.saravolac@HydroOne.com
Subject: FW: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Zach,

We had a chance to look into below concern. Our team cannot have one transformer to have LV metering and other HV metering. This is because these units supply both yards so metering is on yard basis and not transformer basis. That being said, the choice for NPEI should be between either PME on all feeder or HV metering on HV side of each transformer. Also NPEI has accepted the PME on the feeders for B/Y yard and so it'd be easiest for NPEI to do the same for the other yard. In any case, the HV metering for $700K is an **Class 5 Estimate ranging -50%/+100%.**

The estimate would include Engineering, Procurement, Construction and Management of installing 2Ea. 3-element, IESO compliant meters on 115kV HV side of T1 and T2 transformers at Stanley TS. This would also include procurement and installation of instrument transformers (including the foundations, support structures, and instrument transformers), Revenue Metering CT/VT junction boxes, Equipment and wiring in metering panel and communication with IESO regarding the transfer of the metering point once the new installation has been checked out and accepted by HONI. Communication would be the responsibility of NPEI, as well as design and procurement of metering cabinets would be responsibility of NPEI. Please note that the scope has been identified based on previous project and does not reflect what needs to be done in this specific situation. NPEI can go for DETL estimate for class 3 Estimate (Range -20 / +30%) on HV metering. Stefanie would be able to assist you with this if you decide to go with this option.

Please note that due to tight space at Stanley TS, SF6 Instrument transformers might be required.

Regards,
Ishan Vyas

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Wednesday, January 30, 2019 2:43 PM
To: JO Han
Cc: Shanon Wilson; PIERRE Stefanie; DERAKHSHANIAN Ardalan; MISTRY Nimesh
Subject: RE: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Hi Han Jo,

We're still looking for more info on the cost of HV metering at Stanley TS. An estimated cost of $700k was provided to us in the minutes of our July 3rd meeting. Can you advise us on the accuracy of that number and what those costs include?

Best Regards,

Zach Lindley
Niagara Peninsula Energy Inc.
Engineering Systems Manager
Phone: 1-877-270-3938 ext. 6237
Email: zach.lindley@npei.ca

From: Zach Lindley
Sent: Friday, December 14, 2018 11:27 AM
To: 'johanhak@HydroOne.com'
Subject: RE: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Thanks Han Jo. We'll wait for your clarifications.

From: johanhak@HydroOne.com [mailto:johanhak@HydroOne.com]
Sent: Friday, December 14, 2018 7:10 AM
To: Zach Lindley
Cc: johanhak@HydroOne.com; Stefanie.Pierre@HydroOne.com
Subject: RE: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings.

Good Morning Zach,

As You already are aware of, I have been assigned to this project as a new PM and would like to advise NPEI that I'm still waiting for clarifications from Hydro One Planning Dep't. As soon as I receive up to dated info. I will forward / reply to NPEI's questions.
Kind Regards,
Han Jo, PENG / PMP.
Project Manager, Project Delivery, Transmission & Stations, Hydro One Networks Inc.
Office (416) 345 - 1341, Mobile (647) 628 - 8677
E mail; johanhak@HydroOne.com

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Monday, December 10, 2018 11:48 AM
To: DERAKHSHANIAN Ardalan; JO Han; PIERRE Stefanie
Cc: SARAVOLAC Petar; MISTRY Nimesh; bmpietrzyk@burnsmcd.com; 'Terry McConnell'; Shanon Wilson
Subject: AR24221_NPEI_Metering & SCC_RE: Stanley TS relay settings

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Ardy and Johan,

Would you be able to share with me the reason why we can't continue to use the JQ ITs?

Also, Stefanie provided us with an estimate of around $700k for the two high side metering points in the minutes from our July 3rd meeting. Ardy had mentioned that there would likely be some additional engineering costs since the project's design was so far along. Can you comment on how accurate we could expect the $700k estimate to be if we went in that direction?

Thanks,

Zach

From: Ardalan@HydroOne.com [mailto:Ardalan@HydroOne.com]
Sent: Tuesday, December 04, 2018 2:08 AM
To: Zach Lindley
Cc: petar.saravolac@HydroOne.com; Nimesh.Mistry@HydroOne.com; Stefanie.Pierre@HydroOne.com; Ryan Claussen; johanhak@HydroOne.com; Ardalan@HydroOne.com; bmpietrzyk@burnsmcd.com
Subject: Re: Stanley TS relay settings

Nimesh,
Please provide response to Zack's email below. We provided the short cct study from scope.

Zack,
Jo Han has taken over this project as the PM. Please make sure to include him in communications. Also regarding the J/Q metering we had several internal discussion and HONI basically does not agree with proposed installation that ee discussed in our last site visit. The only visble options are

The HV metering or feeder metering out of the fence. You already have the estimate for HV metering from earlier this year. Let the team know what would be NPEI preference.
Thanks
Ardy

Sent from my iPhone

On Dec 3, 2018, at 12:01 PM, Zach Lindley <zach.lindley@npei.ca> wrote:

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Ardy,

We need to confirm a couple of things before we move forward with the feeder relay settings study. Was the attached short circuit study done using new T2's impedance? Also, can you confirm that the study uses a 100 MVA base?

Thank you,

Zach

From: Zach Lindley
Sent: Monday, November 26, 2018 11:44 AM
To: Nimesh.Mistry@HydroOne.com
Cc: Ryan Claussen; Ardalan@HydroOne.com; 'petar.saravolac@HydroOne.com'
Subject: RE: Stanley TS relay settings

Hi Nimesh,

We are looking to move forward with the feeder relay settings study. Can you confirm that the attached short circuit study was done using new T2's impedance?

Thanks,

Zach

From: petar.saravolac@HydroOne.com [mailto:petar.saravolac@HydroOne.com]
Sent: Saturday, November 17, 2018 6:48 AM
To: Zach Lindley; Nimesh.Mistry@HydroOne.com
Cc: Ryan Claussen; Ardalan@HydroOne.com
Subject: RE: Stanley TS relay settings

Hi Zach,

I am not sure, maybe Nimesh can confirm. What I can say is that looking at the test values of old and new T2 the impedances seem to be within 0.6-0.7% or so within each other (new T2 being the higher one).

Regards,
Petar

Petar Saravolac, P.Eng.

Project Engineering, E&C
Hydro One Networks Inc.
483 | Bay Street | 14th Floor
Toronto, ON | M5G 2P5
Tel: 416.345.5265
Cell: 416.575.7664
Email: petar.saravolac@HydroOne.com
www.HydroOne.com

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Friday, November 16, 2018 11:15 AM
To: SARAVOLAC Petar
Cc: Ryan Claussen
Subject: RE: Stanley TS relay settings

Hi Petar,

Can you confirm that the SC study was done using new T2's impedances? I'm assuming old T2 and new T2 have the same impedances?

Thanks,

Zach

From: petar.saravolac@HydroOne.com [mailto:petar.saravolac@HydroOne.com]
Sent: Tuesday, November 13, 2018 6:18 PM
To: Ardalan@HydroOne.com; Zach Lindley; Stefanie.Pierre@HydroOne.com; azook@burnsmcd.com; bmpietrzyk@burnsmcd.com; ameekhoff@burnsmcd.com; Nimesh.Mistry@HydroOne.com
Cc: Ryan Claussen
Subject: RE: Stanley TS relay settings

Zach,

Please see attached SC study that we received from Nimesh a while ago. I believe this was going to be added to the minutes of meeting by Stefanie but not sure if I ever saw it directly attached to the file she sent out.

I believe all the info you are after is in there since you guys probably don't really care about transformer nameplates but rather SC levels and thevenin impedances, which are all shown there, but please let us know if there is anything else you require.

Regards,
Petar

p.s. Ardy, I think the question below was for the main transformers not SS. Station service transformers should have no impact on feeder settings study performed by NPEI.

Petar Saravolac, P.Eng.
Project Engineering, E&C
Hydro One Networks Inc.
483 | Bay Street | 14th Floor
Toronto, ON | M5G 2P5

Tel: 416.345.5265
Cell: 416.575.7664
Email: petar.saravolac@HydroOne.com
www.HydroOne.com

From: DERAKHSHANIAN Ardalan
Sent: Tuesday, November 13, 2018 4:10 PM
To: Zach Lindley; PIERRE Stefanie; SARAVOLAC Petar; Adam Zook; Bryan M Pietrzyk; Alexander Meekhoff; MISTRY Nimesh
Cc: Ryan Claussen
Subject: Re: Stanley TS relay settings

Nimesh,
Can you help us with short cct.

Alex,
I guess you team can help with the name plate of existing SS transformer and the standard nameplate drawing for new SS transformer?

Sent from my iPhone

On Nov 13, 2018, at 2:47 PM, Zach Lindley <zach.lindley@npei.ca> wrote:

> *** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***
>
> Hi Ardy,
>
> Can you provide a couple of other items to assist with our relay setting study?
>
> - 13.8kV supply bus short circuit levels.
> - Transformer nameplate data for the existing and new station transformers.
>
> Thanks,
>
> Zach
>
> ---
>
> **From:** Ardalan@HydroOne.com [mailto:Ardalan@HydroOne.com]
> **Sent:** Thursday, November 01, 2018 2:57 PM
> **To:** Stefanie.Pierre@HydroOne.com; Zach Lindley
> **Cc:** Ardalan@HydroOne.com; petar.saravolac@HydroOne.com
> **Subject:** FW: Stanley TS relay settings
>
> Zach,
> Please see attached. By the way, I am curious as these are your feeder settings, are you sure it is not available to you internally?
> Thanks
> Ardy
>
> **Ardalan Derakhshanian, P.Eng.**
> PM, Project Delivery, TCT-12
> Hydro One Networks Inc.
> Tel: (416) 345-4217
> Cell: (416) 768-4217

Email: Ardalan@HydroOne.com

PURPOSE-LED | **VALUES**-DRIVEN
SAFETY COMES FIRST | **STAND** FOR PEOPLE | **EMPOWERED** TO ACT | **OPTIMISM** CHARGES US | **WIN** AS ONE

From: Zach Lindley [mailto:zach.lindley@npei.ca]
Sent: Wednesday, October 31, 2018 11:20 AM
To: DERAKHSHANIAN Ardalan
Cc: SARAVOLAC Petar; PIERRE Stefanie
Subject: Stanley TS relay settings

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Ardy,

Do you have copies of the existing relay settings for the feeders and bus protections that you could share with me?

Thanks,

Zach Lindley
Niagara Peninsula Energy Inc.
Engineering Systems Manager
Phone: 1-877-270-3938 ext. 6237
Email: zach.lindley@npei.ca

<StanleyTS IESO 2018.doc>

Attachment 5

Revised pages 425-427 of Attachment 13 from IR Responses

Schedule S & T

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		5,206,576

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,755,707
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,900,281**
NET INCOME FOR TAX PURPOSES		**553,306**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**553,306**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 553,306	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	B	$	63,630	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D					
	Rate reduction	-11.50%	E	$	-	F = D * E		
Ontario Income tax							$ 63,630	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				11.50%	K = J / A		
	Federal tax rate (Maximum 15%)				15.00%	L		
	Combined tax rate						26.50%	M = K + L
Total Income Taxes							**$ 146,626**	N = A * M
Investment Tax Credits							$ 6,208	O
Miscellaneous Tax Credits							$ 74,795	P
Total Tax Credits							**$ 81,003**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							**$ 65,623**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	S = 1 - M	**$ 23,660**	T = R / S - R
Income Tax (grossed-up)							**$ 89,283**	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Attachment 6

PILS model with Tax Loss

at $2,198,620

Ontario Energy Board

Income Tax/PILs Workfor

Utility Name	Niagara Peninsula Energy Inc.
Assigned EB Number	EB-2020-0040
Name and Title	Suzanne Wilson Senior VP Finance
Phone Number	905-353-6004
Email Address	suzanne.wilson@npei.ca
Date	31-Aug-20
Last COS Re-based Year	**2015**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the appl data and the results.

rm for 2021 Filers

Version **1.20**

or the purpose of filing your rate application. You may use and copy this
assisting you in that regard. Except as indicated above, any copying,
r other use or dissemination of this model without the express written
person that is advising or assisting you in preparing the application or
o the restrictions noted above.

lications, the onus remains on the applicant to ensure the accuracy of the

Instructions

Purpose
The purpose of this workb
calculation of PILs for the

Tab S Summary is a sumr
Workform.

Tab S1 Integrity Checks n

Methodology
To calculate the PILs for t

1) input the balances fro
2) input the balances for
Inputs should include:
- non-deductible expe
- loss carryforward (S
- capital cost allowanc
- non-deductible rese

3) make any other adjus
reasonable.

Other Notes
Tabs H0 to H13 relate to t
Tabs B0 to B13 relate to t
Tabs T0 to T13 relate to t

The amounts on tabs H0 t
adjustments or correction

It is assumed the net inco
calculated on tab A.

On tab "A. Data Input She

ɔook is to calculate the estimated Payment in Lieu of Taxes (PILs) for the Test Year. The
Test Year is on tab T0 and is based on the inputs on the other tabs.

mary of the amounts to be transferred to the Data Input Sheet of the Revenue Requirement

nust be completed after the completion of the PILs calculation in this workbook.

he Test Year:

m the income tax return of the Historical Year in tabs H1 to H13.
the Bridge Year and the Test Year.

enses (Schedule 1 - B1 and T1)
chedule 4 - B4 and T4)
ce (Schedule 8 - B8 and T8)
rves (Schedule 13 - B13 and T13)

tments and inputs required so that the PILs amount calculated for the Test Year on tab T0 is

the Historical Year.
he Bridge Year.
he Test Year.

to H13 should agree to the tax return filed with the Canada Revenue Agency. Any CRA audit
s should also be reflected.

me before tax for the Test Year is equal to the Return on Equity. Return on Equity is

eet", input the "Rate Base" amount and "Return on Rate Base" amounts.

Ontario Energy Board

Income Tax/PILs Workform f

rical Year

al

e Year

ear

ear

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

No inputs required on this worksheet.

Integrity C

The applica

1
2
3
4
5
6
7
8
9

ne Tax/PILs Workform for 2021 File

hecks

ant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or

Item
The depreciation and amortization added back in the application’s PILs model agree with the numbers disclosed in
The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge
Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts
The CCA deductions in the application’s PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application
Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application
A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized
CCA is maximized even if there are tax loss carry-forwards
Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission
The income tax rate used to calculate the tax expense is consistent with the utility’s actual tax facts and evidence file

ers

r provide an explanation i

Utility Confirmation (Y/N)
Y
Y
Y
Y
Y
Y
Y
Y
Y

f this is not the case:

Notes

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 168,112,586**	**$ 161,680,323**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$ 6,724,503	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 94,143,048	*X = S * U*	
Deemed Equity %	40.00%	V	$ 67,245,035	*Y = S * V*	
Short Term Interest Rate	1.75%	Z	$ 117,679	*AC = W * Z*	
Long Term Interest	2.84%	AA	$ 2,671,774	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.34%	AB	**$ 5,608,236**	*AE = Y * AB*	T1
Return on Rate Base			**$ 8,397,689**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Tax Rates **Federal & Provincial** **As of MMM XX, 2019**	**Effective January 1, 2015**	**Effective January 1, 2016**	**Effective January 1, 2017**	**Effective January 1, 2018**	**Effective January 1, 2019**	**Effective January 1, 2020**
Federal income tax						
General Corporate Rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal Tax Abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted Federal Rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate Reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined Federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000
Federal Small Business Rate	11.00%	10.50%	10.50%	10.00%	9.00%	9.00%
Ontario Small Business Rate	4.50%	4.50%	4.50%	3.50%	3.50%	3.20%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	-$ 1,395,511	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	**B**			
	Federal tax rate (Maximum 15%)	15.00%	**C**			
	Combined tax rate (Maximum 26.5%)				26.50%	**D = B+C**
Total Income Taxes					**-$ 369,810**	**E = A * D**
Investment Tax Credits					$ 13,589	**F**
Miscellaneous Tax Credits						**G**
Total Tax Credits					**$ 13,589**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year					**$ -**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations
Income before PILs/Taxes	**(A + 101 + 102)**	3,311,849	
Additions:			
Interest and penalties on taxes	103	38,282	
Amortization of tangible assets	104	7,818,837	
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107		
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111	74,145	
Charitable donations and gifts from Schedule 2	112	74,036	
Taxable capital gains from Schedule 6	113		
Political contributions	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120	0	
Non-deductible meals and entertainment expense	121	18,655	
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125		
Reserves from financial statements – balance at the end of the year	126	4,780,183	
Soft costs on construction and renovation of buildings	127		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))		5,462,680	
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Inducement under 12(1)(x)ITA		22,166	

Total Additions		**18,288,984**	**0**
Deductions:			
Gain on disposal of assets per financial statements	401		
Non-taxable dividends under section 83	402		
Capital cost allowance from Schedule 8	403	11,448,713	
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413		
Reserves from financial statements - balance at beginning of year	414	4,020,821	
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Net movement in regulatory balances		1,061,366	
Depreciation of capital contributions		1,002,764	
Capital contributions received 13(7.4)		5,462,680	
Total Deductions		**22,996,344**	**0**
Net Income for Tax Purposes		**-1,395,511**	**0**
Charitable donations from Schedule 2	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		**-1,395,511**	**0**

Historic Wires Only
3,311,849
38,282
7,818,837
0
0
0
0
74,145
74,036
0
0
0
0
0
0
18,655
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4,780,183
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5,462,680
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22,166

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18,288,984
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11,448,713
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4,020,821
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22,996,344
-1,395,511
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0
-1,395,511

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	2,029,931		2,029,931	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns
1	Buildings, Distribution System (acq'd post 1987)	$ 44,854,026
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	$ 9,022,018
2	Distribution System (acq'd pre 1988)	$ 2,506,498
3	Buildings (acq'd pre 1988)	$ 937,445
6	Certain Buildings; Fences	$ -
8	General Office Equipment, Furniture, Fixtures	$ 1,262,204
10	Motor Vehicles, Fleet	$ 1,827,789
10.1	Certain Automobiles	$ -
12	Computer Application Software (Non-Systems)	$ -
13_1	Lease # 1	$ -
13_2	Lease # 2	$ -
13_3	Lease # 3	$ -
13_4	Lease # 4	$ -
14	Limited Period Patents, Franchises, Concessions or Licences	$ -
14.1	Eligible Capital Property (acq'd pre 2017)	$ 631,790
14.1	Eligible Capital Property (acq'd post 2016)	$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	$ 171,240
42	Fibre Optic Cable	$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	$ 78
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -
47	Distribution System (acq'd post Feb 22/05)	$ 72,045,301
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	$ 198,675
95	CWIP	$ -
	SUB-TOTAL - UCC	133,457,063

r 2021 Filers

Less: Non-Distribution Portion	UCC Regulated Historical Year
	$ 44,854,026
	$ 9,022,018
	$ 2,506,498
	$ 937,445
	$ -
	$ 1,262,204
	$ 1,827,789
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
	$ 631,790
	$ -
	$ 171,240
	$ -
	$ -
	$ -
	$ 78
	$ -
	$ 72,045,301
	$ 198,675
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
	$ -
0	**133,457,063**

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital gains reserves ss.40(1)			0
Tax reserves not deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & share issue expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General reserve for inventory obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:	4,780,183		4,780,183
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**4,780,183**	**0**	**4,780,183**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILS Tax Provision - Bridge Year

							Wires Only
						Reference	
Regulatory Taxable Income						B1	-$ 168,689
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate			
Ontario (Max 11.5%)	11.5%	11.5%	-$ 19,399	11.5%	**B**		
Federal (Max 15%)	15.0%	15.0%	-$ 25,303	15.0%	**C**		
Combined effective tax rate (Max 26.5%)							26.50%
Total Income Taxes							**$ -**
Investment Tax Credits							$ 17,315
Miscellaneous Tax Credits							
Total Tax Credits							**$ 17,315**
Corporate PILs/Income Tax Provision for Bridge Year							**$ -**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

A

D = B + C

E = A * D

F
G
H = F + G

I = E - H

Ontario Energy Board

Income Tax/PILs Workform for 2

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**(A + 101 + 102)**		3,679,003
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		8,163,410
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107	B8	0
Income inclusion under subparagraph 13(38)(d)(iii)	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations and gifts from Schedule 2	112		70,387
Taxable capital gains	113		
Political contributions	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		19,519
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	4,845,358
Soft costs on construction and renovation of buildings	127		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		

Ontario Energy Board

Income Tax/PILs Workform for 2

Adjusted Taxable Income - Bridge Year

Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			2,985,967
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			13,589
Total Additions			**16,098,230**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	11,153,815
Terminal loss from Schedule 8	404	B8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	4,780,183
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			

Ontario Energy Board

Income Tax/PILs Workform for 2

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Net movement in regulatory			0
Depreciation of cap contributions			1,025,957
Capital contributions received 13(7.4)			2,985,967
Total Deductions		calculated	**19,945,922**
Net Income for Tax Purposes		calculated	**-168,689**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	B4	0
Net capital losses of previous tax years from Schedule 4	332	B4	0
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		calculated	**-168,689**


2021 Filers


2021 Filers

2021 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2021 File

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	2,029,931	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	168,689	
Other Adjustments		0	
Balance available for use post Bridge Year	calculated	2,198,620	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4


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Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 44,854,026							$ 44,854,026	$ -	$ -	0.50	$ -	$ -	4%			$ 1,794,161		$ 43,059,865	T8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ 9,022,018	$ 1,680,090	$ 1,680,090					$ 10,702,108	$ -	$ 1,680,090	0.50	$ 840,045	$ -	6%			$ 692,529		$ 10,009,579	T8
2	Distribution System (acq'd pre 1988)	H8	$ 2,506,498							$ 2,506,498	$ -	$ -		$ -	$ -	6%			$ 150,390		$ 2,356,108	T8
3	Buildings (acq'd pre 1988)	H8	$ 937,445							$ 937,445	$ -	$ -		$ -	$ -	5%			$ 46,872		$ 890,573	T8
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -	T8
8	General Office Equipment, Furniture, Fixtures	H8	$ 1,262,204	$ 274,749	$ 274,749					$ 1,536,953	$ -	$ 274,749	0.50	$ 137,375	$ -	20%			$ 334,865		$ 1,202,087	T8
10	Motor Vehicles, Fleet	H8	$ 1,827,789	$ 113,650	$ 113,650					$ 1,941,439	$ -	$ 113,650	0.50	$ 56,825	$ -	30%			$ 599,479		$ 1,341,960	T8
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
12	Computer Application Software (Non-Systems)	H8	$ -	$ 197,497	$ 197,497					$ 197,497	$ -	$ 197,497	0.00	$ -	$ -	100%			$ 197,497		$ -	T8
13_1	Lease # 1	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_2	Lease # 2	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_3	Lease # 3	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_4	Lease # 4	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ 631,790							$ 631,790	$ -	$ -		$ -	$ -	7%			$ 44,225		$ 587,565	T8
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -	T8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ 171,240							$ 171,240	$ -	$ -	0.50	$ -	$ -	8%			$ 13,699		$ 157,540	T8
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -	T8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -	T8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -	T8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ 78							$ 78	$ -	$ -		$ -	$ -	45%			$ 35		$ 43	T8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
47	Distribution System (acq'd post Feb 22/05)	H8	$ 72,045,301	$ 10,567,856	$ 10,567,856					$ 82,613,157	$ -	$ 10,567,856	0.50	$ 5,283,928	$ -	8%			$ 7,031,767		$ 75,581,390	T8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ 198,675	$ 168,513	$ 168,513					$ 367,188	$ -	$ 168,513	0.50	$ 84,256	$ -	55%			$ 248,294		$ 118,893	T8
95	CWIP	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
	TOTALS		$ 133,457,063	$ 13,002,355	$ 13,002,355	$ -	$ -	$ -	$ -	$ 146,459,418	$ -	$ 13,002,355		$ 6,402,429	$ -		$ -	$ -	$ 11,153,815	B1	$ 135,305,603	

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	
Capital gains reserves ss.40(1)	H13	0		0				0	T13
Tax Reserves Not Deducted for Accounting Purposes									
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13
Debt & share issue expenses ss. 20(1)(e)	H13	0		0				0	T13
Other tax reserves	H13	0		0				0	T13
		0		0				0	
		0		0				0	
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1
Financial statement reserves (not deductible for tax purposes)									
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13
General Reserve for Bad Debts	H13	0		0				0	T13
Accrued Employee Future Benefits:	H13	4,780,183		4,780,183		65,175		4,845,358	T13
- Medical and Life Insurance	H13	0		0				0	T13
- Short & Long-term Disability	H13	0		0				0	T13
- Accumulated Sick Leave	H13	0		0				0	T13
- Termination Cost	H13	0		0				0	T13
- Other Post-Employment Benefits	H13	0		0				0	T13
Provision for Environmental Costs	H13	0		0				0	T13
Restructuring Costs	H13	0		0				0	T13
Accrued Contingent Litigation Costs	H13	0		0				0	T13
Accrued Self-Insurance Costs	H13	0		0				0	T13
Other Contingent Liabilities	H13	0		0				0	T13
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13
Other	H13	0		0				0	T13
		0		0				0	
		0		0				0	
Total		**4,780,183**	**0**	**4,780,183**	B1	**65,175**	**0**	**4,845,358**	B1

Change During the Year	Disallowed Expenses
0	
0	
0	
0	
0	
0	
0	
0	
0	**0**
0	
0	
65,175	
0	
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0	
0	
65,175	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income					T1	$ 1,149,065	**A**

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate	
Ontario (Max 11.5%)	11.5%	11.5%	$ 132,142	11.5%	**B**
Federal (Max 15%)	15.0%	15.0%	$ 172,360	15.0%	**C**

Combined effective tax rate (Max 26.5%)			26.50%	**D = B + C**	
Total Income Taxes			**$ 304,502**	**E = A * D**	
Investment Tax Credits			$ 17,315	**F**	
Miscellaneous Tax Credits				**G**	
Total Tax Credits			**$ 17,315**	**H = F + G**	
Corporate PILs/Income Tax Provision for Test Year			**$ 287,187**	**I = E - H**	S. Su
Corporate PILs/Income Tax Provision Gross Up [1]	73.50%	**J = 1-D**	**$ 103,544**	**K = I/J-I**	
Income Tax (grossed-up)			**$ 390,731**	**L = K + I**	S. Su

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	5,608,236

	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		8,463,011
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107	T8	0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		22,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	4,929,236
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		

Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
Inducement under 12(1)(x)ITA	295		17,315
	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			3,600,001
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**17,031,562**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	11,554,371
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	4,845,358
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			

Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
Depreciation of cap contributions	395		1,203,737
Capital contributions received 13(7.4)	395		3,600,001
	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**21,203,467**
NET INCOME FOR TAX PURPOSES		calculated	**1,436,331**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	287,266
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,149,065**

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Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Working Paper Reference**	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	2,198,620		2,198,620
Amount to be used in Test Year and Price Cap Years	T1	1,436,331		1,436,331
Number of years loss until next cost of service (i.e. years the loss is to be spread over)		5		
Amount to be used in Test Year	calculated	287,266		287,266
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	762,288		762,288

Net Capital Loss Carry Forward Deduction		**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 43,059,865			
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ 10,009,579	235,500	235,500	
2	Distribution System (acq'd pre 1988)	B8	$ 2,356,108			
3	Buildings (acq'd pre 1988)	B8	$ 890,573			
6	Certain Buildings; Fences	B8	$ -			
8	General Office Equipment, Furniture, Fixtures	B8	$ 1,202,087	287,400	287,400	
10	Motor Vehicles, Fleet	B8	$ 1,341,960	546,000	546,000	
10.1	Certain Automobiles	B8	$ -			
12	Computer Application Software (Non-Systems)	B8	$ -	274,300	274,300	
13_1	Lease # 1	B8	$ -			
13_2	Lease # 2	B8	$ -			
13_3	Lease # 3	B8	$ -			
13_4	Lease # 4	B8	$ -			
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -			
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ 587,565			
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -			
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ 157,540			
42	Fibre Optic Cable	B8	$ -			
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -			
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -			
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 43			
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			
47	Distribution System (acq'd post Feb 22/05)	B8	$ 75,581,390	11,124,070	11,124,070	
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 118,893	332,780	332,780	
95	CWIP	B8	$ -			
		B8	$ -			
		B8	$ -			
		B8	$ -			
		B8	$ -			
		B8	$ -			

		B8	$ -				
		B8	$ -				
		B8	$ -				
	TOTALS		**$ 135,305,603**	**$ 12,800,050**	**$ 12,800,050**	**$ -**	

(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA
			$ 43,059,865	$ -	$ -	0.50	$ -	$ -	4%	
			$ 10,245,079	$ -	$ 235,500	0.50	$ 117,750	$ -	6%	
			$ 2,356,108	$ -	$ -		$ -	$ -	6%	
			$ 890,573	$ -	$ -		$ -	$ -	5%	
			$ -	$ -	$ -	0.50	$ -	$ -	10%	
			$ 1,489,487	$ -	$ 287,400	0.50	$ 143,700	$ -	20%	
			$ 1,887,960	$ -	$ 546,000	0.50	$ 273,000	$ -	30%	
			$ -	$ -	$ -	0.50	$ -	$ -	30%	
			$ 274,300	$ -	$ 274,300	0.00	$ -	$ -	100%	
			$ -	$ -	$ -	0.00	$ -	$ -	NA	
			$ -	$ -	$ -	0.00	$ -	$ -	NA	
			$ -	$ -	$ -	0.00	$ -	$ -	NA	
			$ -	$ -	$ -	0.00	$ -	$ -	NA	
			$ -	$ -	$ -	0.00	$ -	$ -	NA	
			$ 587,565	$ -	$ -		$ -	$ -	7%	
			$ -	$ -	$ -	0.50	$ -	$ -	5%	
			$ 157,540	$ -	$ -	0.50	$ -	$ -	8%	
			$ -	$ -	$ -	0.50	$ -	$ -	12%	
			$ -	$ -	$ -	2.33	$ -	$ -	30%	
			$ -	$ -	$ -	1.00	$ -	$ -	50%	
			$ 43	$ -	$ -		$ -	$ -	45%	
			$ -	$ -	$ -	0.50	$ -	$ -	30%	
			$ 86,705,460	$ -	$ 11,124,070	0.50	$ 5,562,035	$ -	8%	
			$ 451,673	$ -	$ 332,780	0.50	$ 166,390	$ -	55%	
			$ -	$ -	$ -	0.00	$ -	$ -	0%	
			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		

			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		
			$ -	$ -	$ -		$ -	$ -		
$ -	**$ -**	**$ -**	**$ 148,105,653**	**$ -**	**$ 12,800,050**		**$ 6,262,875**	**$ -**		**$ -**

(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
	$ 1,722,395		$ 41,337,471
	$ 621,770		$ 9,623,309
	$ 141,366		$ 2,214,741
	$ 44,529		$ 846,044
	$ -		$ -
	$ 326,637		$ 1,162,850
	$ 648,288		$ 1,239,672
	$ -		$ -
	$ 274,300		$ -
			$ -
			$ -
			$ -
			$ -
			$ -
	$ 41,130		$ 546,435
	$ -		$ -
	$ 12,603		$ 144,937
	$ -		$ -
	$ -		$ -
	$ -		$ -
	$ 19		$ 24
	$ -		$ -
	$ 7,381,400		$ 79,324,060
	$ 339,935		$ 111,739
	$ -		$ -
			$ -
			$ -
			$ -
			$ -
			$ -

			$ -
			$ -
			$ -
$ -	**$ 11,554,371**	T1	**$ 136,551,282**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Test Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	
Capital Gains Reserves ss.40(1)	B13	0		0				0	
Tax Reserves Not Deducted for accounting purposes									
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0				0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0	
Other tax reserves	B13	0		0				0	
		0		0				0	
		0		0				0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1
Financial Statement Reserves (not deductible for Tax Purposes)									
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0	
General reserve for bad debts	B13	0		0				0	
Accrued Employee Future Benefits:	B13	4,845,358		4,845,358		83,878		4,929,236	
- Medical and Life Insurance	B13	0		0				0	
-Short & Long-term Disability	B13	0		0				0	
-Accmulated Sick Leave	B13	0		0				0	
- Termination Cost	B13	0		0				0	
- Other Post-Employment Benefits	B13	0		0				0	
Provision for Environmental Costs	B13	0		0				0	
Restructuring Costs	B13	0		0				0	
Accrued Contingent Litigation Costs	B13	0		0				0	
Accrued Self-Insurance Costs	B13	0		0				0	
Other Contingent Liabilities	B13	0		0				0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0	
Other	B13	0		0				0	
		0		0				0	
		0		0				0	
Total		**4,845,358**	**0**	**4,845,358**	T1	**83,878**	**0**	**4,929,236**	T1

Change During the Year	Disallowed Expenses
0	
0	
0	
0	
0	
0	
0	
0	
0	**0**
0	
0	
83,878	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
0	
83,878	**0**

Attachment 7

PILS Settlement Proposal

Proposed PILS Settlement

	2018 using 2018 actual % claimed under the AII	2019 Balance	2020 Balance	Total
CCA under the legacy rules using the actual capital additions (a)	10,397,485	10,410,893	10,378,418	31,186,796
CCA under the accelerated rules using the actual capital additions (b)	10,445,587	11,448,593	11,153,815	33,047,996
Difference in CCA (c= a-b)	(48,103)	(1,037,700)	(775,397)	(1,861,200)
Tax rate (%) in effect of 2015 CoS (d)	26.5%	26.5%	26.5%	26.5%
$ Impact on the revenue requirement (e=cXd)	(12,747)	(274,991)	(205,480)	(493,218)
Grossed-up Revenue Requirement Impact $ (f=e/1-d)	(17,343)	(374,137)	(279,565)	(671,045)
Proration %	10.68%	100%	100%	
Balance Calculated in Account 1592(g)	(17,343)	(374,137)	(279,565)	(671,045)
NPEI Balance included in Account 1592 to be disposed in 2021 Test Year (h)	(19,874)	(109,157)	(109,157)	(238,188)
Residual balance in Account 1592 to be disposed of over the number of years until next COS (h=f-g)	2,531	(264,980)	(170,408)	(432,857)
# of Years until next Cost of Service				5
Reduction to 2021 Test Year PILS Grossed Up				**(86,571.31)**

Note the $86,571 is equivalent to a rate rider over the Cost of Service Period of 5 Years

The $238,188 will be the balance in Account 1592 before carrying charges to be disposed of on the DVA model for 2021

The 2021 DVA model includes $244,577 in Account 1592 after carrying charges

The Reduction to the 2021 Test Year PILS is equivalent to the following:

Reduction to 2021 Test Year PILS Grossed Up	(86,571)
Reduction to 2021 Test Year PILS Before Gross Up	63,630
Tax Rate	0.265
Loss Carry forwardAmount to be used in 2021 Test Year on T4 Sch 4 Loss Cfwd Test	240,113
# of Years until next Cost of Service	5
Loss Carryforward to be used entered on B4 Sch 4 Loss Cfwd Bridge-OEB PILS model	**1,200,564**

2018 - Accelerated CCA based on 2018 Actual Additions

Class		2 Balance 12/31/2017	3 Cost of Additions during the year	4 Cost of additions accelerated Cost	8 Proceeds of Disposition	9 UCC 2 + 3 - 5	11 UCC adjustment for accelerated CCA	12 UCC adjustment for accelerated by factor	13 UCC adjustment for non accelerated CCA	14 CCA %	17 CCA for the year	18 UCC Balance 12/31/2018
1	Buildings	48,669,733				48,669,733	-			4%	1,946,789	46,722,944
1b	Buildings	3,193,329				3,193,329	-			6%	191,600	3,001,729
1b	Buildings > 18-03-17	3,880,144	1,024,864	302,452		4,905,008	302,452	151,226	361,206	6%	281,702	4,623,306
2	Electrical generating equipment	2,836,688				2,836,688	-	-		6%	170,201	2,666,487
3	Building < 1990	1,038,720				1,038,720	-	-		5%	51,936	986,784
8	Office Equipment, Tools, Other	1,283,260	318,683	23,039		1,601,943	23,039	11,520	147,822	20%	293,128	1,308,815
10	Vehicles and Equipment	2,434,193	518,258	0	5133	2,947,318	-	-	256,563	30%	807,227	2,140,091
12	Computer Software	355,448	288,891	146,406		644,339	146,406	-	71,243	100%	573,097	71,243
14.1	Goodwill	730,478				730,478	-	-		7%	51,133	679,345
17	Roads, parking lots	202,315				202,315	-	-		8%	16,185	186,130
45	Computers	259				259	-	-		45%	117	142
47	Transmission and Dist Equipment	68,927,140	9,993,141	847,768		76,448,796	847,768	423,884	4,572,687	8%	5,783,999	70,664,797
50	Computers > 3/18/07	344,053	304,037	10,254		648,070	10,254	5,127	146,882	55%	278,474	369,596
		133,895,760	12,447,874	1,329,919	5,133	143,866,996	1,329,919	591,757	5,556,401		10,445,587	133,421,409

2019 - Accelerated CCA based on 2019 Actual Additions

Class		2 Balance 12/31/2018	3 Cost of Additions during the year	4 Cost of additions accelerated Cost	8 Proceeds of Disposition	9 UCC 2 + 3 - 5	11 UCC adjustment for accelerated CCA	12 UCC adjustment for accelerated by factor	13 UCC adjustment for non accelerated CCA	14 CCA %	17 CCA for the year	18 UCC Balance 12/31/2019
1	Buildings	46,722,944				46,722,944	-			4%	1,868,918	44,854,026
1b	Buildings	3,001,729				3,001,729	-			6%	180,104	2,821,626
1b	Buildings > 18-03-17	4,623,306	2,037,896	2,037,896		6,661,202	2,037,896	1,018,948	-	6%	460,809	6,200,393
2	Electrical generating equipment	2,666,487				2,666,487	-	-		6%	159,989	2,506,498
3	Building < 1990	986,784				986,784	-	-		5%	49,339	937,445
8	Office Equipment, Tools, Other	1,308,815	307,359	307,359		1,616,174	307,359	153,680	-	20%	353,971	1,262,203
10	Vehicles and Equipment	2,140,091	599,766	599,766	265	2,739,592	599,501	299,751	-	30%	911,803	1,827,789
12	Computer Software	71,243	361,773	361,773		433,016	361,773	-	-	100%	433,016	-
14.1	Goodwill	679,345				679,345	-	-		7%	47,554	631,790
17	Roads, parking lots	186,130				186,130	-	-		8%	14,890	171,239
45	Computers	142				142	-	-		45%	64	78
47	Transmission and Dist Equipment	70,664,797	7,992,827	7,992,827		78,657,624	7,992,827	3,996,414	-	8%	6,612,323	72,045,301
50	Computers > 3/18/07	369,596	184,892	184,892		554,488	184,892	92,446	-	55%	355,814	198,675
		133,421,409	11,484,513	11,484,513	265	144,905,657	11,484,248	5,561,238	-		11,448,593	133,457,063

2020 - Accelerated CCA based on 2020 Bridge Year Additions

Class		2 Balance 12/31/2019	3 Cost of Additions during the year	4 Cost of additions accelerated Cost	8 Proceeds of Disposition	9 UCC 2 + 3 - 5	11 UCC adjustment for accelerated CCA	12 UCC adjustment for accelerated by factor	13 UCC adjustment for non accelerated CCA	14 CCA %	17 CCA for the year	18 UCC Balance 12/31/2020
1	Buildings	44,854,026				44,854,026	-			4%	1,794,161	43,059,865
1b	Buildings	2,821,626				2,821,626	-			6%	169,298	2,652,328
1b	Buildings > 18-03-17	6,200,393	1,680,090	1,680,090		7,880,483	1,680,090	840,045	-	6%	523,232	7,357,252
2	Electrical generating equipment	2,506,498				2,506,498	-	-		6%	150,390	2,356,108
3	Building < 1990	937,445				937,445	-	-		5%	46,872	890,573
8	Office Equipment, Tools, Other	1,262,203	274,749	274,749		1,536,952	274,749	137,375	-	20%	334,865	1,202,087
10	Vehicles and Equipment	1,827,789	113,650	113,650		1,941,439	113,650	56,825	-	30%	599,479	1,341,960
12	Computer Software	-	197,497	197,497		197,497	197,497	-	-	100%	197,497	-
14.1	Goodwill	631,790				631,790	-	-		7%	44,225	587,565
17	Roads, parking lots	171,239				171,239	-	-		8%	13,699	157,540
45	Computers	78				78	-	-		45%	35	43
47	Transmission and Dist Equipment	72,045,301	10,567,856	10,567,856		82,613,156	10,567,856	5,283,928	-	8%	7,031,767	75,581,390
50	Computers > 3/18/07	198,675	168,513	168,513		367,187	168,513	84,256	-	55%	248,294	118,893
		133,457,063	13,002,355	13,002,355	-	146,459,418	13,002,355	6,402,429	-		11,153,815	135,305,603

2018 - CCA Schedule 8
using legacy rules

Class		2 Balance 12/31/2017	3 Cost of Additions during the year	4 Adjustments Transfers	5 Proceeds of Disposition	6 50% Rule (1/2 of the amount	7 UCC 2 + 3 +4 - 5	8 CCA %	11 CCA for the year	12 UCC Balance 12/31/2018
1	Buildings	48,669,733	-		0	-	48,669,733	4%	1,946,789	46,722,944
1b	Buildings	3,193,329	-		0	-	3,193,329	6%	191,600	3,001,729
1b	Buildings > 18-03-17	3,880,144	1,327,316		0	663,658	4,543,802	6%	272,628	4,934,832
2	Electrical generating equipment	2,836,688	-		0	-	2,836,688	6%	170,201	2,666,487
3	Building < 1990	1,038,720	-		0	-	1,038,720	5%	51,936	986,784
8	Office Equipment, Tools, Other	1,283,260	341,722		0	170,861	1,454,121	20%	290,824	1,334,158
10	Vehicles and Equipment	2,434,193	518,258		5133	256,563	2,690,756	30%	807,227	2,140,091
12	Computer Software	355,448	435,297		0	217,649	573,097	100%	573,097	217,649
14.1	Goodwill	730,478	-		0	-	730,478	7%	51,133	679,345
17	Roads, parking lots	202,315	-		0	-	202,315	8%	16,185	186,130
45	Computers	259	-		0	-	259	45%	117	142
47	Transmission and Dist Equipment	68,927,140	10,840,909		0	5,420,455	71,876,110	8%	5,750,089	71,546,475
50	Computers > 3/18/07	344,053	314,291		0	157,146	501,199	55%	275,659	382,685
		133,895,760	13,777,793	-	5,133	6,886,330	138,310,605		10,397,485	134,799,450

2019 - CCA Schedule 8
using legacy rules

Class		2 Balance 12/31/2018	3 Cost of Additions during the year	4 Adjustments Transfers	5 Proceeds of Disposition	6 50% Rule (1/2 of the amount	7 UCC 2 + 3 +4 - 5	8 CCA %	11 CCA for the year	12 UCC Balance 12/31/2019
1	Buildings	46,722,944	-		0	-	46,722,944	4%	1,868,918	44,854,026
1b	Buildings	3,001,729	-		0	-	3,001,729	6%	180,104	2,821,626
1b	Buildings > 18-03-17	4,934,832	2,037,896		0	1,018,948	5,953,780	6%	357,227	6,615,501
2	Electrical generating equipment	2,666,487	-		0	-	2,666,487	6%	159,989	2,506,498
3	Building < 1990	986,784	-		0	-	986,784	5%	49,339	937,445
8	Office Equipment, Tools, Other	1,334,158	307,359		0	153,680	1,487,837	20%	297,567	1,343,949
10	Vehicles and Equipment	2,140,091	599,766		265	299,751	2,439,842	30%	731,953	2,007,640
12	Computer Software	217,649	361,773		0	180,887	398,535	100%	398,535	180,887
14.1	Goodwill	679,345	-		0	-	679,345	7%	47,554	631,790
17	Roads, parking lots	186,130	-		0	-	186,130	8%	14,890	171,239
45	Computers	142	-		0	-	142	45%	64	78
47	Transmission and Dist Equipment	71,546,475	7,992,827		0	3,996,414	75,542,889	8%	6,043,431	73,495,871
50	Computers > 3/18/07	382,685	184,892		0	92,446	475,131	55%	261,322	306,255
		134,799,450	11,484,513	-	265	5,742,124	140,541,574		10,410,893	135,872,805

2020 Bridge Year additions - CCA Schedule 8
using legacy rules

Class		2 Balance 12/31/2019	3 Cost of Additions during the year	4 Adjustments Transfers	5 Proceeds of Disposition	6 50% Rule (1/2 of the amount	7 UCC 2 + 3 +4 - 5	8 CCA %	11 CCA for the year	12 UCC Balance 12/31/2020
1	Buildings	44,854,026	-		0	-	44,854,026	4%	1,794,161	43,059,865
1b	Buildings	2,821,626	-		0	-	2,821,626	6%	169,298	2,652,328
1b	Buildings > 18-03-17	6,615,501	1,680,090		0	840,045	7,455,546	6%	447,333	7,848,258
2	Electrical generating equipment	2,506,498	-		0	-	2,506,498	6%	150,390	2,356,108
3	Building < 1990	937,445	-		0	-	937,445	5%	46,872	890,573
8	Office Equipment, Tools, Other	1,343,949	274,749		0	137,375	1,481,324	20%	296,265	1,322,434
10	Vehicles and Equipment	2,007,640	113,650		0	56,825	2,064,465	30%	619,339	1,501,950
12	Computer Software	180,887	197,497		0	98,749	279,635	100%	279,635	98,749
14.1	Goodwill	631,790	-		0	-	631,790	7%	44,225	587,565
17	Roads, parking lots	171,239	-		0	-	171,239	8%	13,699	157,540
45	Computers	78	-		0	-	78	45%	35	43
47	Transmission and Dist Equipment	73,495,871	10,567,856		0	5,283,928	78,779,799	8%	6,302,384	77,761,343
50	Computers > 3/18/07	306,255	168,513		0	84,256	390,511	55%	214,781	259,987
		135,872,805	13,002,355	-	-	6,501,178	142,373,982		10,378,418	138,496,742

	CCA calculated usin legacy rules on Actual additions	Accelerated AII CCA using Actual Additions	CCA Difference	Tax Rate	PILS not Grossed UP on CCA Difference	PILS Grossed UP on CCA Difference	Grossed up PILS included in NPEI's Revenue Requirement	Difference in Pils grossed Up Available to reduce 2021 PILS	Difference in Pils NOT grossed Up Available to reduce 2021 PILS	Loss Carryforward to be used entered on B4 Sch 4 Loss Cfwd Bridge-OEB PILS model	# of Years Loss until next Cost of Service	Loss Carry forwardAmount to be used in 2021 Test Year on T4 Sch 4 Loss Cfwd Test	Tax Rate	Reduction to 2021 Test Year PILS not Grossed UP	Reduction to 2021 Test Year PILS Grossed UP
CCA 2018 using Actual additions	10,397,485	10,445,587	48,103	0.265	12,747	17,343	19,874	(2,531)	(1,860)	(7,021)	5	(1,404)	0.265	(372)	(506)
CCA 2019	10,410,893	11,448,593	1,037,700	0.265	274,991	374,137	109,157	264,980	194,760	734,944	5	146,989	0.265	38,952	52,996
2020 Bridge Year Additions	10,378,418	11,153,815	775,397	0.265	205,480	279,565	109,157	170,408	125,250	472,641	5	94,528	0.265	25,050	34,082
Non-capital loss using AII per tax return	31,186,796	33,047,996	1,861,200		493,218	671,045	238,188	432,857	318,150	1,200,564		240,113		63,630	86,571

2021 Test Year PILS using Accelerated AII for CCA	494,303
Reduction to 2021 Test Year PILS for 2018 to 2020 Accelerated AII CCA	(86,571)
2021 Test Year PILS	407,732

Per OEB Staff

	2018 using 2018 actual % claimed under the AII	2019 Balance	2020 Balance	Total
CCA under the legacy rules using the 2015 approved capital additions (a)	9,700,584	9,700,584	9,700,584	29,101,752
CCA under the accelerated rules using the 2015 approved capital additions (b)	11,027,393	11,027,393	11,027,393	33,082,179
Difference in CCA (c= a-b)	(1,326,809)	(1,326,809)	(1,326,809)	(3,980,427)
	26.5%	26.5%	26.5%	26.5%
$ Impact on the revenue requirement (e=cXd)	(351,604)	(351,604)	(351,604)	(1,054,813)
Grossed-up Revenue Requirement Impact $ (f=e/1-d)	(478,373)	(478,373)	(478,373)	(1,435,120)
Proration %	10.68%	100%	100%	
PILS grossed up Balance Calculated (g)	(51,090)	(478,373)	(478,373)	(1,007,837)
NPEI Proposed Balance (h)	(19,874)	(109,157)	(109,157)	(238,188)
Difference (h=f-g)	(31,216)	(369,216)	(369,216)	(769,649)

Per NPEI

	2018 using 2018 actual % claimed under the AII	2019 Balance	2020 Balance	Total
CCA under the legacy rules using the 2015 approved capital additions (a)	9,700,584	9,700,584	9,700,584	29,101,752
CCA under the accelerated rules using the 2015 approved capital additions (b)	9,755,707	11,027,393	11,027,393	31,810,493
Difference in CCA (c= a-b)	(55,123)	(1,326,809)	(1,326,809)	(2,708,741)
	26.5%	26.5%	26.5%	26.5%
$ Impact on the revenue requirement (e=cXd)	(14,608)	(351,604)	(351,604)	(717,816)
Grossed-up Revenue Requirement Impact $ (f=e/1-d)	(19,874)	(478,373)	(478,373)	(976,621)
Proration %		100%	100%	
PILS grossed up Balance Calculated (g)	(19,874)	(478,373)	(478,373)	(976,621)
NPEI Proposed Balance (h)	(19,874)	(109,157)	(109,157)	(238,188)
Difference (h=f-g)	0	(369,216)	(369,216)	(738,432)