Appendix M: Discretionary Project Change Assessment Form (Template)

Change Assessment

Discretionary Project Information		
Name	Number	Investment Category
Municipal Substation Network Cybersecurity Upgrade	SS-05	System Service
Summary		

This project will address two primary objectives, Ontario Energy Board (OEB) Cybersecurity Framework compliance and OPUCN's efforts towards improving service reliability and modernizing the existing grid into a "smarter grid" system.

During the period of 2020-2025, OPUCN will be modernizing its Municipal Substation (MS) digital networks between MSs and control room. Each MS digital network will be segregated from other MS networks as a security control. Various Cybersecurity tools and access systems will be investigated and implemented as security control measures.

OPUCN's MS digital network communication will be migrated to Layer 3 communication to increase cybersecurity, improve data bandwidth, and reduce communication latencies for Operational Technologies (OT) and smart grid device communications. Various Cybersecurity tools will be investigated and implemented accordingly. Some examples include Next Generation Firewalls, Intrusion Detection/Prevention Systems, Security Information and Event Management, and Secure Access Management Systems, Deny-by-default Access Systems.

This program will implement a number of OEB Cybersecurity Framework Security Controls on OT systems such as the following:

- PR.AC-1: Identities and credentials are managed for authorized devices and users
- PR.AC-3: Remote access is managed
- PR.AC-4: Access permissions are managed, incorporating the principles of least privilege and separation of duties
- PR.AC-5: Network integrity is protected, incorporating network segregation where appropriate
- PR.DS-2: Data-in-transit is protected
- PR.PT-1: Audit/log records are determined, documented, implemented, and reviewed in accordance with policy
- PR.PT-4: Communications and control networks are protected
- DE.CM-1: The network is monitored to detect potential cybersecurity events
- DE.CM-3: Personnel activity is monitored to detect potential cybersecurity events
- DE.CM-7: Monitoring for unauthorized personnel, connections, devices, and software is performed

Each MS network will be reconfigured for segmentation (PR.AC-5). Data Concentrators will also be installed to reduce the traffic between IEDs and SCADA. Wide Area Network (WAN) technologies will be implemented on existing fiber communication network. Cybersecurity software and access management tools will be installed to track, manage and handle day-to-day system cybersecurity threats. To reduce costs and improve efficiencies, OPUCN will take advantage of tools that can be used on both IT and OT systems for Cyber-security.

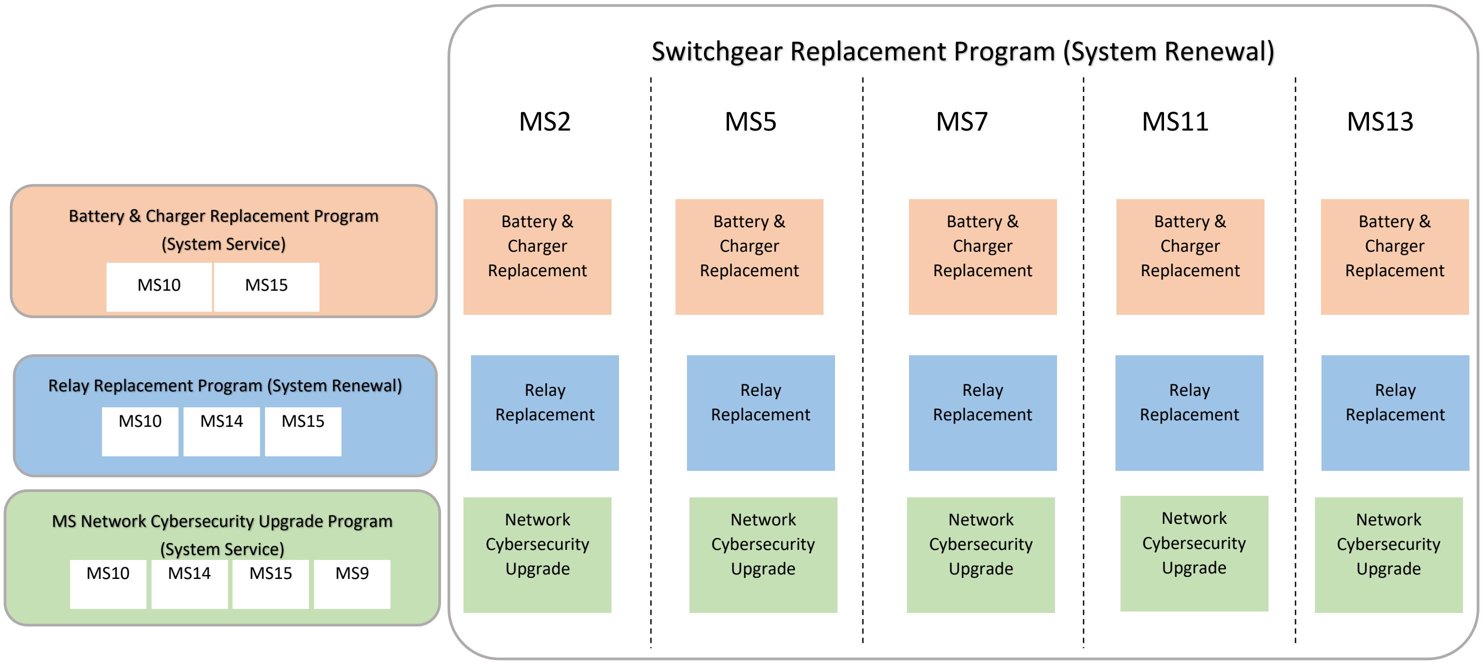

Figure 2 - Coordination of Interdependent Municipal Substation Projects

The Switchgear Replacement Program (System Renewal) will be incorporating new MS digital network. The MS Cybersecurity Network Upgrade will focus on remaining MS, namely MS14, MS10, MS15 and MS9 (see Figure 2 - Coordination of Interdependent Municipal Substation Projects).

Please see **Error! Reference source not found.** which illustrates how the scope of this project is related with other SCADA related projects.

Proposed Change

Type of Change Assessed (select most reasonable)

☐ Scope Change ☒ Budget Change ☐ Cancellation ☐ Advancement ☐ Postponement	☐ Other (describe below)

Reason for Change

Removal of unnecessary funds as there is overlap with Switchgear Replacement Program.

Overlap with switchgear replacement program. Cost reductions.

	2020	2021	2022	2023	2024	2025
Capital Cost	$100,000	-	-	$ 150,000	$ 150,000	$ 150,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	-	-	$ 150,000	$ 150,000	$ 150,000

Risk Assessment on Proposed Change

Score

Probability				
Imminent	3	3	6	9
Likely	2	2	4	6
Unlikely	1	1	2	3
		1	2	3
		Marginal	Fair	Significant
			Consequence	

	Value	Description
Consequence	1	Not likely to have negative consequences.
Probability	1	Not linked to any probability.
Risk (C*P)	1	☒ Green ☐ Yellow ☐ Red (unacceptable)

Implications to Distribution System

The budget change does not have any implications to the distribution system.

Recommendation	Rationale

☒ Accept ☐ Reject	Removal of unnecessary funds as there is overlap with Switchgear Replacement Program. There are no negative implications to the distribution system with budget change.

Appendix N: MS13 Ground Grid Study

KINECTRICS

MS 13 GROUNDING STUDY

K-322019-DOC-0004 R00

Prepared for

Oshawa PUC Networks Inc.
Purchase Order # 60756

Issue Date

2019-March-21

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OCT 11, 2019
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2019-Mar-19	2019-Mar-19	2019-Mar-19

Revision History

Rev	Description:			
A				
	Issue Date: January 21, 2019	**Prepared by:** Mohit Bhatnagar	**Reviewed by:** Emanuel Petrache	**Approved by:** Bert Grespan
Rev B	**Description:** Address Client Comments			
	Issue Date: March 21, 2019	**Prepared by:** Mohit Bhatnagar	**Reviewed by:** Emanuel Petrache	**Approved by:** Bert Grespan
Rev	**Description:**			
	Issue Date:	**Prepared by:**	**Reviewed by:**	**Approved by:**
Document Classification: N/A		**Security Classification:** N/A		

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1 Conclusions

1.1. Based on Kinectrics soil resistivity tests performed near MS 13, a two-layer soil structure with a 14.97 m top soil layer of 48.43 Ωm lying above a bottom layer of 370.27 Ωm resistivity to an infinite depth was concluded for the grounding study.

1.2. Current injection tests indicate that the measured interconnected station ground impedance at MS 13 is 0.0162∠ 32° Ω.

1.3. Using the MALZ module of CDEGS, the modelled interconnected station ground impedance at MS 13 is 0.0245 ∠ 30° Ω, which is reasonably close to the measured impedance.

1.4. The external ground connections at MS 13 include overhead neutrals traversing in multiple directions away from the station on wood pole lines. The neutrals are modeled to provide a parallel impedance of 0.025 ∠ 41.2° Ω.

1.5. A total current split of 0.86 ∠ -7.2° pu was measured on insulated downleads. The modeled current split is 0.98 ∠ -0.49° pu.

1.6. The worst case injected fault current in the station ground grid is 3.6 kA based on fault calculations provided by Oshawa PUC Networks.

1.7. The maximum summer ground potential rise (GPR) due to this fault is approximately 57 V as measured and 86 V as modeled, both of which are comfortably below the limit of 3,000 V commonly specified as the maximum allowable GPR.

1.8. The maximum winter ground potential rise (GPR) due to this fault is approximately 89 V as modeled, which is lower than the limit of 3,000 V commonly specified as the maximum allowable GPR.

1.9. All step and touch voltages measured inside the yard, near the fence, and outside on native soil coordinate with the allowable limits specified in IEEE 80.

1.10. All station equipment is well bonded to the station ground grid.

1.11. The fence panels are not bonded together using a dedicated bond conductor causing the resistance measurements between each riser to be much higher than expected (Recommendation 2.1).

1.12. Station gravel was found to be thin and sparse in certain areas of the station (e.g. near north access gate) (Recommendation 2.2).

2 Recommendations

2.1. A gradient control conductor (2/0 AWG or 7#6 copperweld) should be installed at a distance of 1 m outside the fence and bonded to the fence at every 12 m to provide low resistance connection between the fence panels.

2.2. For areas where the gravel layer is thin, it should be upgraded to be 80 mm thick with a stone that is specified to have wet resistivity of 3,000 Ωm to follow typical practice at electrical substations. This can be achieved by using ¾" clear stone such as washed granite.

3 Introduction

MS 13 is a 44 kV / 13.8 kV station located at 980 Wilson Rd. S. in Oshawa. It has a footprint of approximately 30 m x 30 m and consists of two transformers, associated bus-work, breakers, switching equipment, one switchgear building and a pad-mounted station service transformer. The interconnected grounding system includes the local ground grid of the substation (mainly 4/0 AWG for the grid), overhead multi-grounded neutral conductors traversing north, east, west and south of the station. There are six 13.8 kV distribution lines being supplied by the station. Since this is a heavily developed urban area, there are likely bonds to the metallic water pipe network, building rebars and all other grounded metallic infrastructure in the area.

Figure 3-1: View of MS 13 from the north

Oshawa PUC Networks Inc. retained Kinectrics to evaluate the performance of the grounding system of MS 13. In response to that request, Kinectrics proposed the following scope:

- Perform soil resistivity measurements to understand the soil properties near the station
- Perform a current injection test to measure the interconnected ground grid impedance, ground potential rise (GPR) and step and touch potentials
- Perform grid integrity tests to ensure adequate bonding of grounding conductors.
- Model the currently installed ground grid conductors in CDEGS
- Model the current injection test arrangement using the GPS coordinates of test probes
- Evaluate the performance of the grounding system during winter conditions

The grounding tests at the station were performed on November 26th, 2018 and the soil resistivity measurements were performed on December 6th, 2018.

This report explains the testing methodology, modelling assumptions, and presents the test results.

4 Soil Resistivity Tests

Kinectrics performed a soil resistivity survey near MS 13 using the Wenner method with four probes equally spaced along a survey line. During the soil survey, the spacing was increased over distances of 1, 2, 3, 5, 7, 10, 15, 20, 30 and 50 m. The survey traverse is shown in Figure 4-1 by a red line. The raw measurement test data for the surveys along with the environmental conditions during the tests are presented in Table 4-1.

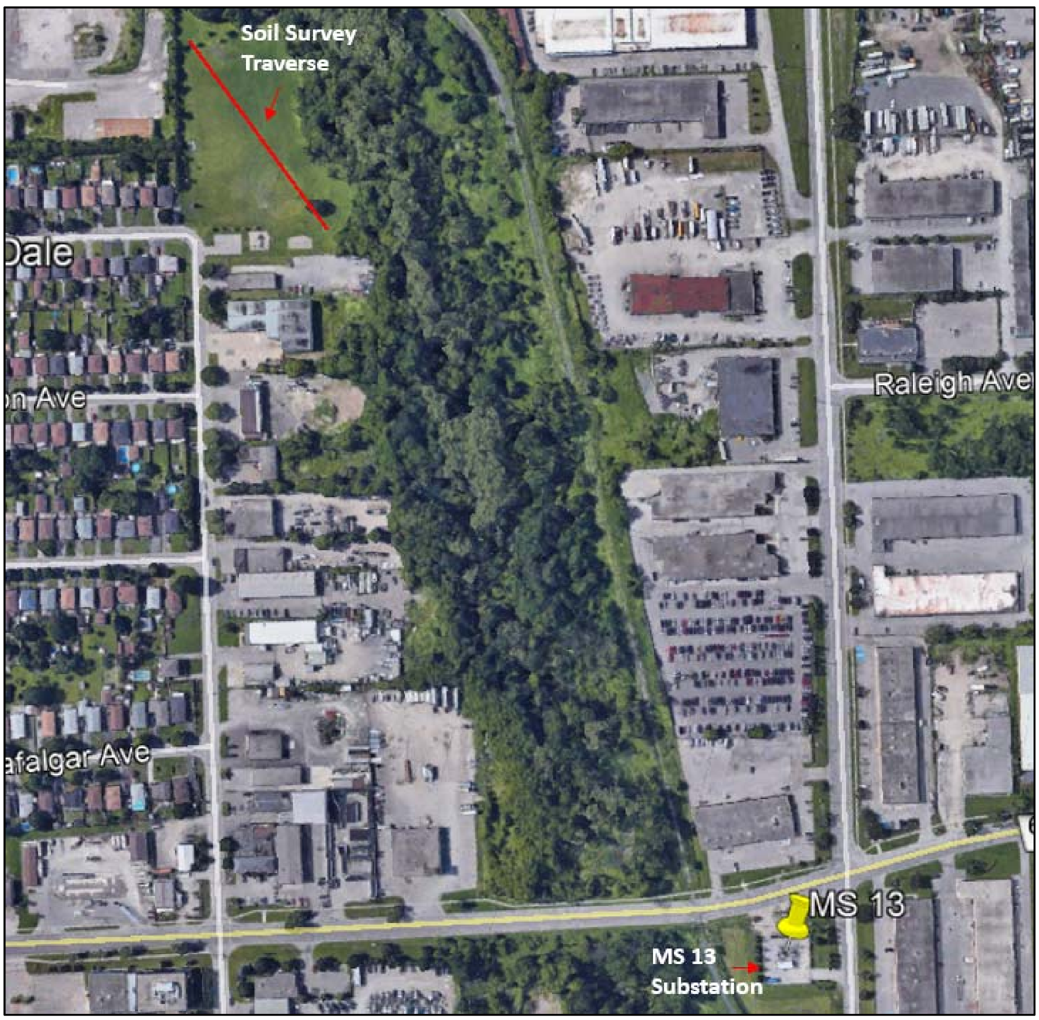


Figure 4-1: Soil resistivity survey traverse

Table 4-1: Raw Resistivity Measurements for MS 13 – Traverse 1

Project No:	K-322019 – OPUC MS 13	
Location:	North West of MS 13 – Conant Park	
Test Date:	December 06, 2018	
Test time:	4:45 9m	
Weather:	-6ºC, Overcast	
Test equipment:	Syscal R1+	
Test No:	#1	
Surface conditions:	moist soil, grass	
s	**Rho**	**Probe Depth**
(m)	(Ωm)	(m)
1.00	56.60	0.3
2.00	56.20	0.3
3.00	53.89	0.3
5.00	38.08	0.3
7.00	50.17	0.3
10.00	57.69	0.3
15.00	69.56	0.3
20.00	79.62	0.3
30.00	100.41	0.3
50.00	147.33	0.3

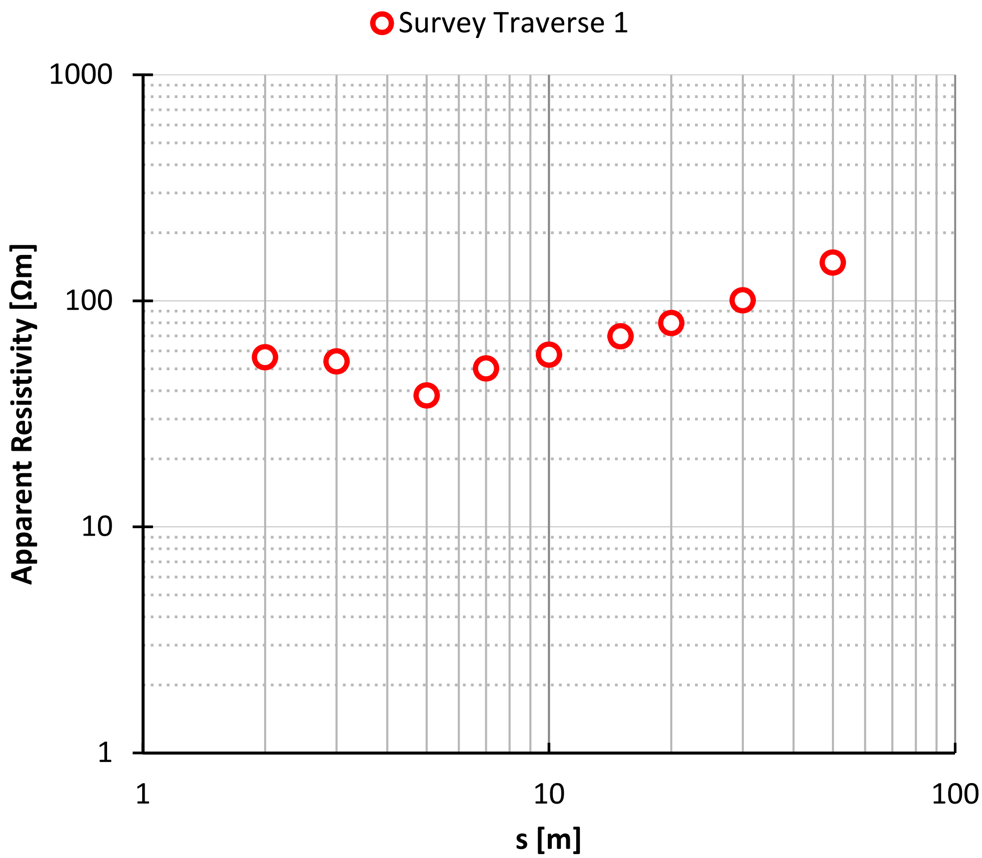


Figure 4-2: Plotted data points for the soil survey traverse near MS 13

Figure 4-3: Soil resistivity survey field – Conant Park

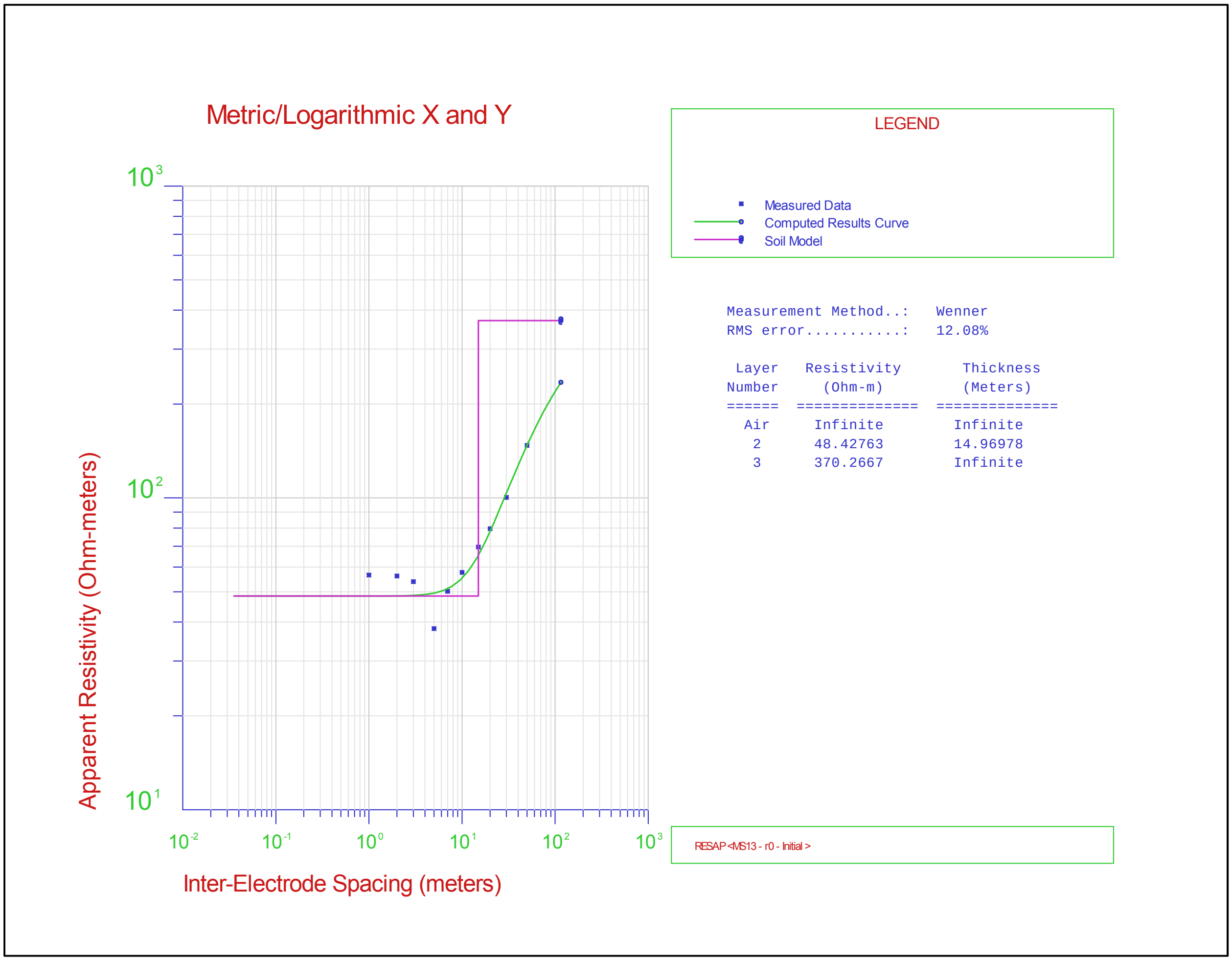


Figure 4-4: Soil model generated in SES RESAP

After interpreting the survey data, the soil model shown in Figure 4-4 was produced.

The RMS error of 12.1% is relatively low which indicates that the model is a good representation of the soil around the station. A two-layer soil model best fits the obtained data and has been presented in Table 4-2.

Table 4-2: Concluded two-layer soil model at MS 13

	Resistivity (Ω-m)	Thickness (m)
Top Layer	48.43	14.97
Bottom Layer	370.27	Infinite

5 Ground Grid Layout – CDEGS Model

The conductor layout of the underground ground conductors was modeled based on the station grounding drawing. The station ground grid conductors are primarily 4/0 Cu conductors and ¾" 10' ground rods. The fence is designed to be isolated from the station grid. It was observed on site to be connected to ground rods located around the perimeter. Integrity measurements revealed that there is likely no fence gradient control conductor installed.

The grounding connection provided by fence posts and ground rods bonded to the fence has been simulated by a 2/0 conductor connected to ground rods as shown in Figure 5-1 below.

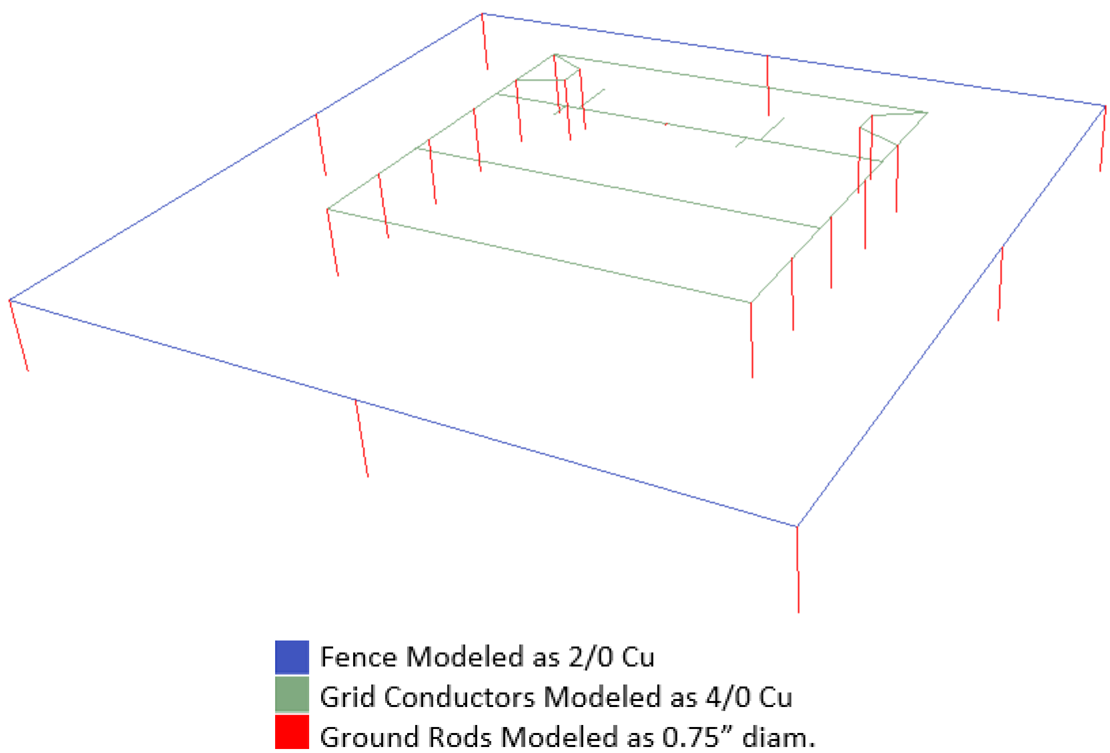


Figure 5-1: Ground conductor arrangement at MS 13 – Modeled in CDEGS

Based on the CDEGS model, the ground grid encased in the soil model concluded in Table 4-2 was found to have a standalone resistance of 1.89 ∠0.15º Ω.

6 External Connections Modeling

The 13.8 kV distribution lines exit with their respective neutral conductors in multiple directions away from the station. The driving point impedance of these multi-grounded neutral connections was modeled as a lumped impedance in the MALZ model of the grid assuming 500 MCM conductors. The parallel impedance provided by this lumped connection was modeled to be 0.025 $\angle 41.2°$ Ω.

Figure 6-1: External Connections at MS 13 – Overhead Neutral Routes

7 Ground Tests at MS 13

7.1 Current Injection Tests

Figure 7-1 shows the current injection test set up for measuring the interconnected grounding impedance, where the testing instruments were set up near the transformer near the center of the yard. Three 1 m long ground rods spaced 3 m apart approximately 215 m south of the testing trailer provided the remote current electrode. With a measured resistance of 20 Ω, this electrode provided a test current of approximately 2.7 A when the test signal amplifier output was at approximately 50 V.

We ran a potential profile west of the station to points 300 m away from the testing trailer as shown in Figure 7-1. In order to properly compensate for the proximity between the probes, the current injection probe and all the potential probes (P probes shown in Figure 7-1) were modelled in the MALZ module of CDEGS as shown in Figure 7-2.

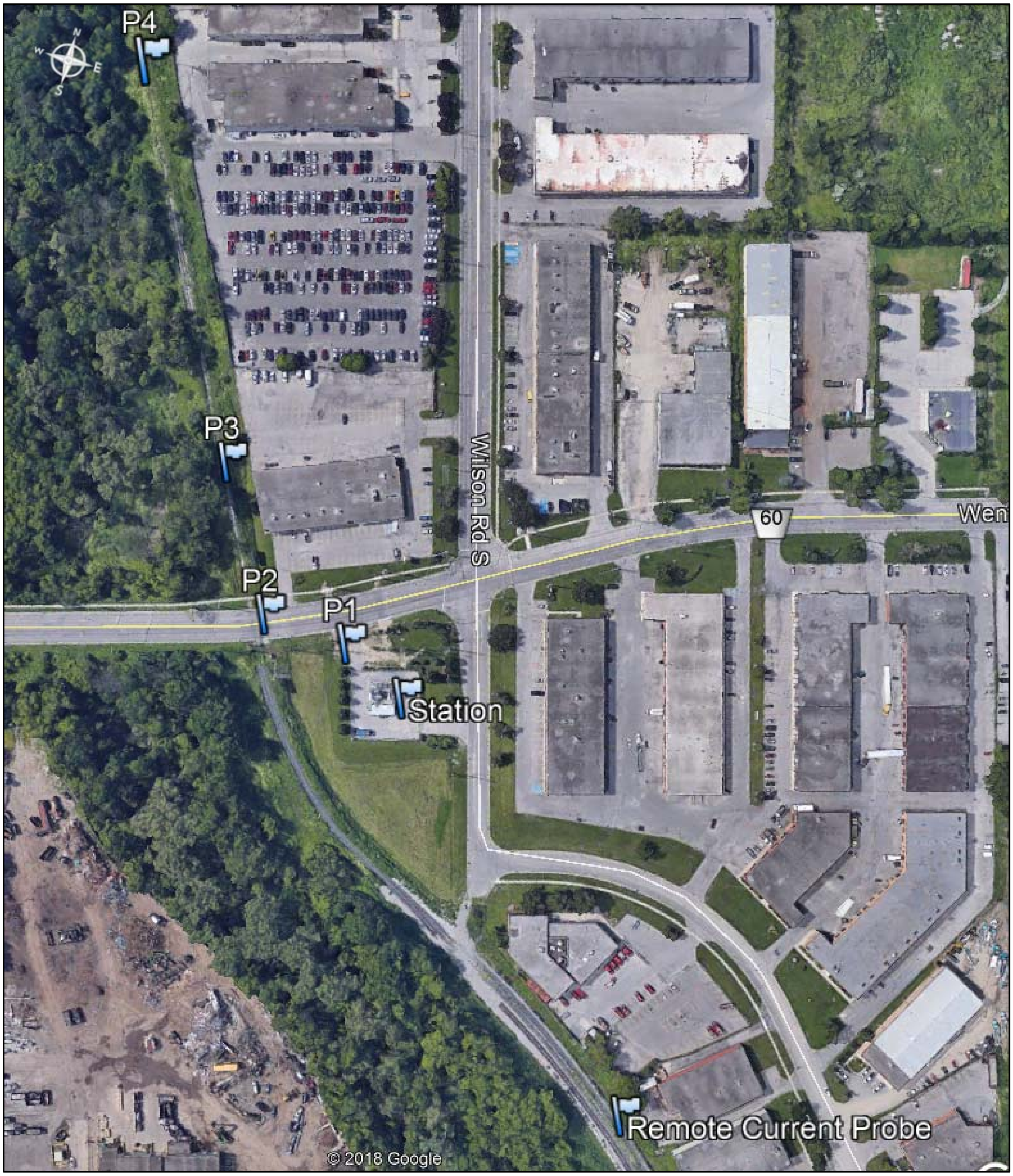


Figure 7-1: Current injection test arrangement at MS 13

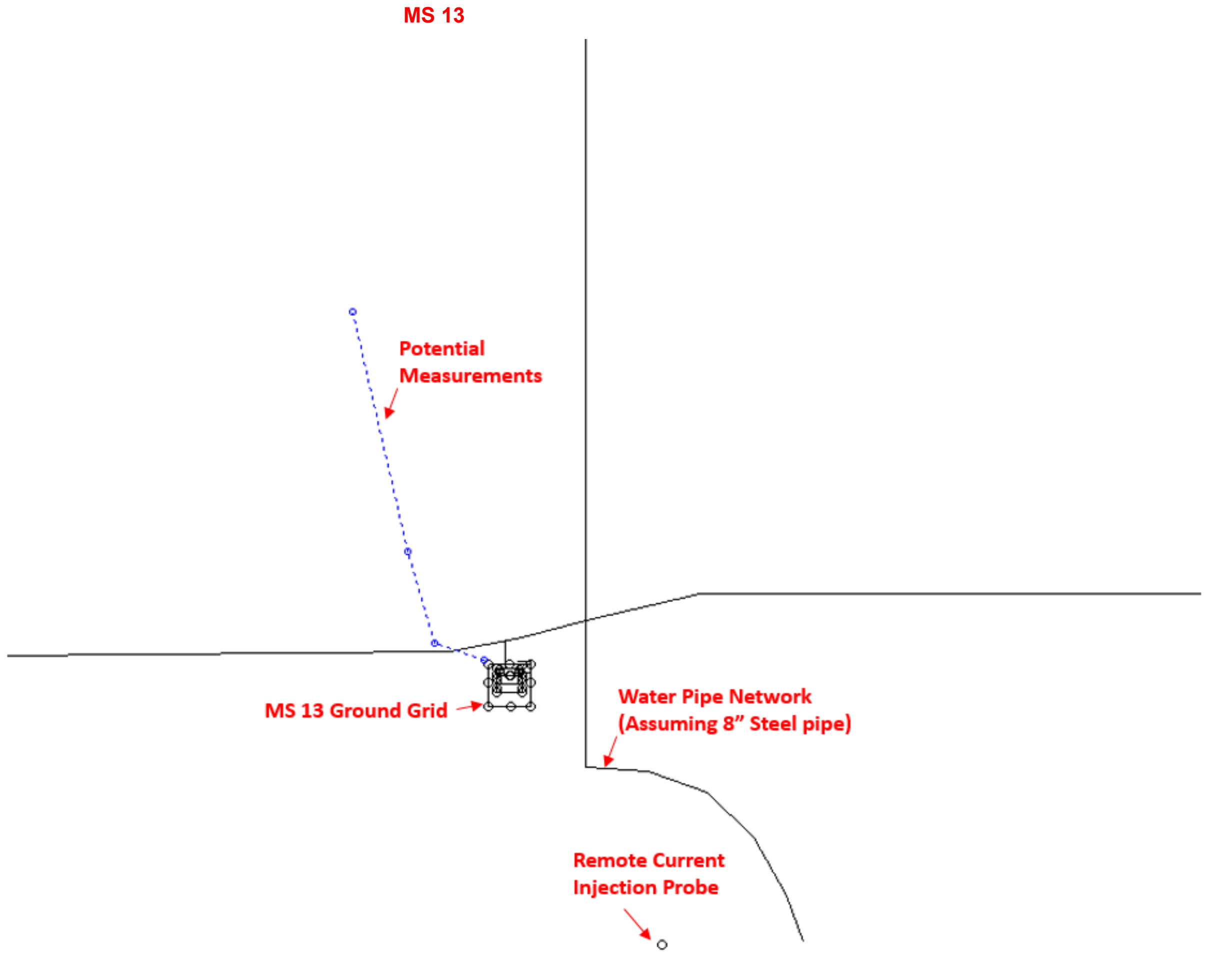


Figure 7-2: Modelled Current injection test arrangements in MALZ

Table 7-2 reports the raw measured impedances obtained from the current injection tests.

Table 7-1: Current injection impedance measurements

#	Distance From Grid Centre to Potential probes	Raw Fall of Potential Readings		
		Abs	Ph	Complex
1	22 m	0.018	38.44	0.014 + j0.011
2	60 m	0.020	47.35	0.014 + j0.015
3	119 m	0.021	58.52	0.011 + j0.018
4	288 m	0.023	58.77	0.012 + j0.02

Figure 7-3 compares the simulated test results with the actual field measurements. The model is slightly conservative when compared to the actual grounding system.

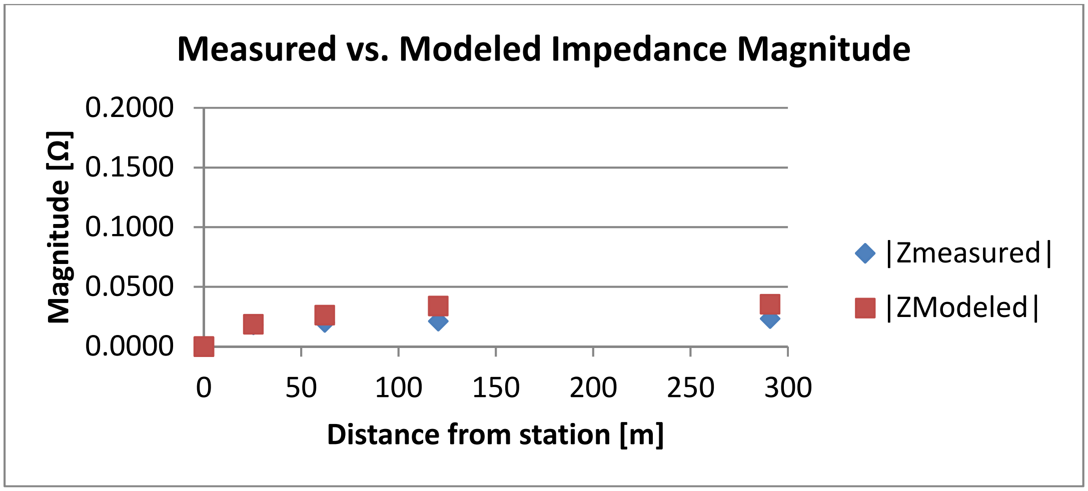


Figure 7-3: Current injection test comparison – Actual vs Simulated in CDEGS

During the current injection tests, the voltage between the station ground and several potential probes (in native soil) outside the station was measured and recorded.

The soil potential at each potential reading is influenced by the proximity of the probe to the grounding system under test and the remote current injection electrode (minimal).

Knowing the soil model of the area (as shown in Figure 4-4), the mutual coupling (conductive coupling through the soil) at each potential probe can be calculated and adjusted.

Table 7-2 reports the adjusted results (after accounting for the mutual resistance due to the proximity between the current injection probe, potential measurement probe and station grid) using the MALZ model shown in Figure 7-2.

Table 7-2: Current injection impedance readings

#	Distance from Grid Centre to Potential probes	Adjusted Fall of Potential Readings		
		Abs	Ph	Complex
1	22 m	0.0244	33.09	0.02 + j0.013
2	60 m	0.0184	37.96	0.014 + j0.011
3	119 m	0.0118	65.41	0.005 + j0.011
4	288 m	0.0128	68.32	0.005 + j0.012
Average of All Adjusted Measurements		0.0162	46.68	0.011 + j0.012

As shown in Table 7-2, the average of adjusted measurement results is within 0.01 Ω from the modelled impedance. The model is slightly conservative when compared to the measurements.

Table 7-3: Measured Vs Modelled Ground Impedance at MS 13

Interconnected Grid	Impedance at 60 Hz
Measured	0.0162 ∠ 32° Ω
Modelled	0.0245 ∠ 30° Ω

7.2 Current Split Measurement

The current split into the neutrals was measured in six insulated downleads exiting underground after connecting to a common grounding bus. These connections become overhead neutrals via riser poles after exiting the station. The measured current split is shown in Table 7-4. The total current split into neutrals was measured to be 0.86 ∠-7.2°.

Table 7-4: Current injection impedance readings

Connection #	Magnitude (pu)	Angle (º)
1	0.1223	-9.25
2	0.1280	-3.00
3	0.1175	-5.00
4	0.2238	-11.30
5	0.1165	-3.18
6	0.1492	-7.87
Total Current Split into neutrals	0.8559	-7.20

Table 7-5 compares the measured current splits to the modelled value.

Table 7-5: Measured Vs Modelled current split measurements at MS 13

Current splits into	Magnitude (pu)	Angle (º)
As measured	0.86	-7.20
As modelled	0.98	-0.49

There is a 14% difference between the modeled and measured current splits, with the modeled value being somewhat conservative. The difference can be attributed to lower effective footing resistances, span lengths etc. than those assumed for the model.

7.3 Fault Current at MS 13

The fault levels at MS-13 are shown in Appendix B. The maximum ground fault current for a fault at the primary (high voltage) side is 3,500 A, and that for the secondary (low voltage) side is 7,010 A.

The source for the LV fault at the stations is the transformer and hence the fault current will circulate through the LV neutral without taking the path through the earth thereby causing no GPR (Figure 7-4).

Therefore, for purposes of this study, the maximum HV fault of 3,500 A fault, and a clearing time of 1.2 s will be assumed to simulate the worst case.

The total fault current of 3,500 A will be reduced due to a shielding factor if there is a parallel neutral conductor on the line. However, since this is a 3-wire 44 kV line, no shielding factor will be assumed to simulate the worst case. Therefore, it is assumed that the full fault current of 3,500 A will energize the grounding system at MS-13.

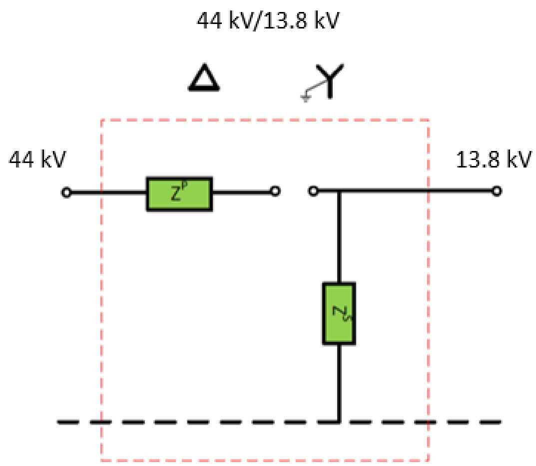


Figure 7-4: Zero sequence model of the transformer at MS-13

7.4 Step and Touch Measurements

Kinectrics measured step and touch voltages inside the yard, outside near the fence and on soil outside the station. The measured step and touch voltages are caused by the low amplitude, off-frequency test fault current that is injected to the grid. These measurements will have to be scaled to the ultimate fault levels at the station and must be checked against the allowable limits.

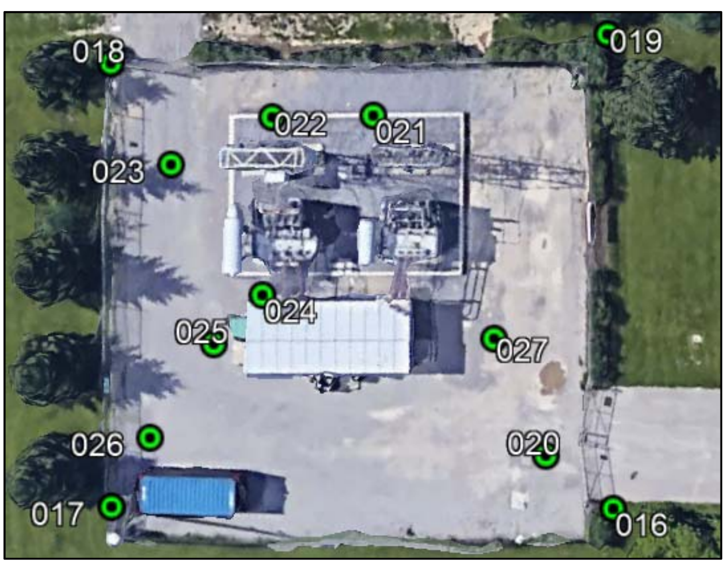


Figure 7-5: Step and Touch Voltage Measurement Locations

IEEE Std. 80 [1] has detailed specifications on the safe allowable step and touch voltages considering the soil resistivity, fault clearing time, and crush stone resistivity. Based on the soil model presented in Table 4-2, the allowable step and touch voltages can be calculated while standing on crushed stone inside the yard and on native soil outside the substation. Table 7-6 presents the safety limits for step and touch voltages when considering a 1.2 s fault and a 50 kg person as specified in IEEE Std.80 [1].

Table 7-6: Tolerable limits for step and touch voltages (Summer Soil)

	Inside and outside the station on crushed stone	Outside the station on Native Soil
Stone/Soil Specification	80 mm of 3,000 Ωm	48.43 Ωm
Touch Voltage Safe Limit	409.2 V	111.5 V
Step Voltage Safe Limit	1,326.0 V	135.0 V

Appendix C shows the scaled measured step and touch voltages with GPS points that correspond to the labels shown in Figure 7-5.

GPS	Description	Touch (Native Soil) (V)	Step Outside (Native Soil) (V)	Touch Structure Inside (Crushed Stone) (V)	Step inside (Crushed Stone) (V)
16	Touch - Fence Corner	47.20			
17	Touch - Fence Corner	15.30			
17	Step - Fence Corner		6.30		
18	Touch - Fence Corner	22.90			
18	Step - Fence Corner		3.60		
19	Touch - Fence Corner	11.90			
19	Step - Fence Corner		0.40		
20	Touch - Gate Swing			35.80	
21	Touch - Structure 13T2L			20.00	
22	Touch - Structure 13T1L			25.00	
23	Step - Station Yard				0.60
23	Step - Station Yard				1.30
23	Step - Station Yard				2.70
23	Step - Station Yard				2.50
24	Touch - Switchgear Building			42.70	
25	Touch - SST			43.00	
26	Touch - Fence from Inside			21.60	
27	Step - Station Yard				5.10
27	Step - Station Yard				12.70
27	Step - Station Yard				20.00
27	Step - Station Yard				21.10

The measured step and touch voltages are all within the safety limits as per Table 7-6.

7.4.1 Ground Potential Rise (GPR)

The measured GPR at the station is 57 V, while the modeled GPR is 86 V which is well below the limit of 3,000 V that is typically specified as the maximum allowable GPR for distribution stations. The difference between the measured GPR and the modeled GPR is due to the conservatively model as per Section 7.1.

8 Winter Conditions (Simulated)

8.1 Winter Soil Model

Winter conditions can be simulated by assuming the top layer of soil freezes up to a depth reported by the Ontario Provincial Standard Drawing OPSD 3090.101 for Frost Penetration Depths for the area. This was determined to be 1.2 m for MS 13.

Upon freezing, the resistivity of that layer is assumed to be multiplied by a factor of 10 to simulate higher resistivity. The resulting GPR in winter conditions is 89 V which is lower than the limit of 3,000 V normally specified for stations.

Table 8-1 presents the three-layer soil model that was used to model winter conditions at MS 13.

Table 8-1: Concluded three-layer winter soil model at MS 13

	Resistivity (Ω-m)	Thickness (m)
Top Layer	484.3	1.2
Central Layer	48.4	13.77
Bottom Layer	370.3	Infinite

Based on the winter soil model presented in Table 8-1, the allowable safe step and voltage can be calculated for a 1.2 sec fault and a 50 kg person according to the IEEE Std.80 [1] using the following formulas:

$$E_{touch50} = (1000 + 1.5C_s \times \rho_s)\frac{0.116}{\sqrt{t_s}}$$

$$E_{step50} = (1000 + 6C_s \times \rho_s)\frac{0.116}{\sqrt{t_s}}$$

Where:

E_{step} is the step voltage in V

E_{touch} Is the touch voltage in V

C_s is the surface layer derating factor which is a function of soil resistivity, surface layer and surface layer thickness

ρ_s is the surface layer resistivity (ohm.m)

t_s is the maximum fault clearing time (s)

Performing the calculation in CDEGS gives us the resulting permissible voltages below.

Table 8-2: Tolerable limits for step and touch voltages in Winter

	Inside the yard	Native soil
Stone/Soil Specification	80 mm of 3000 Ωm*	Top soil layer of 1010 Ωm
Touch Voltage Safe Limit	443.7	182
Step Voltage Safe Limit	1464	417.3

8.2 Simulation Results (Winter)

Winter touch and step voltages were simulated in CDEGS. The results are displayed in

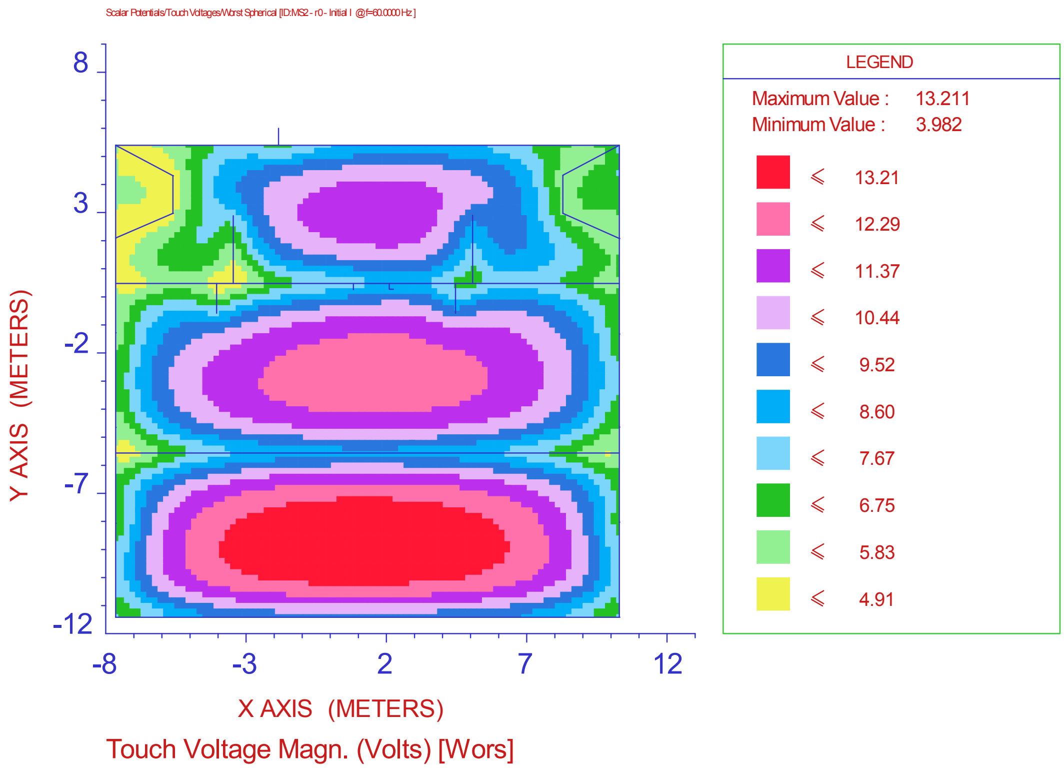


Figure 8-1, Figure 8-2, and Figure 8-3.

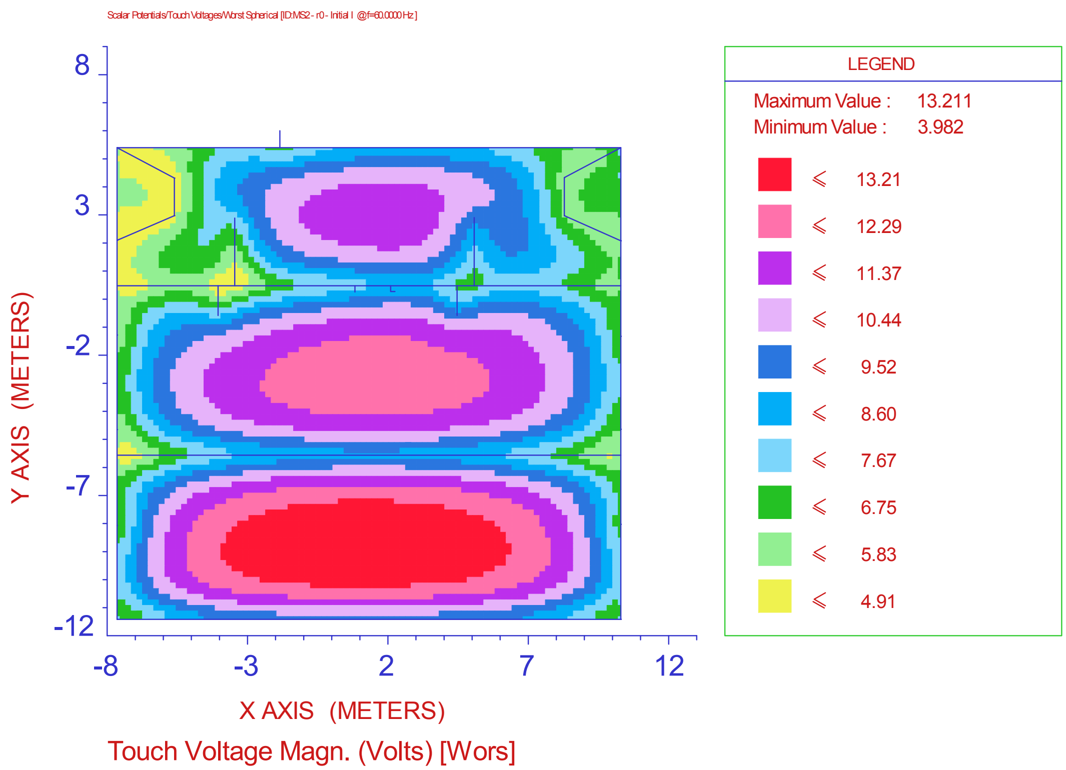


Figure 8-1: Winter Station Touch Voltage Simulation in the yard above crushed stone

The maximum touch voltage inside the station is 13.2 V which is quite low and comfortably within the allowable level of 443.7 V above crushed stone. Therefore, there are no touch voltage concerns in the station.

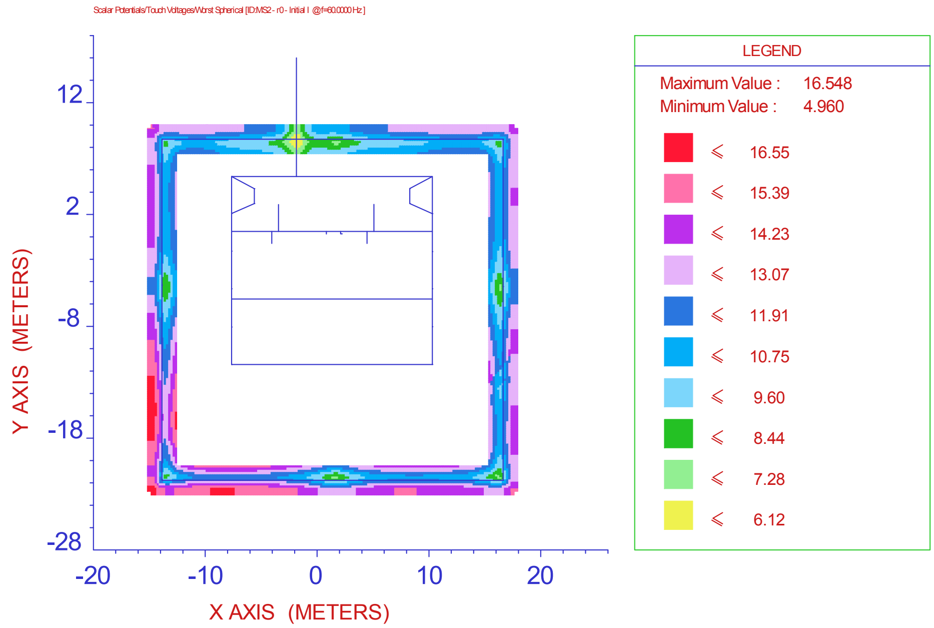


Figure 8-2: Winter Fence Touch Voltage Simulation above crushed stone outside station

The maximum touch voltage on the fence is 16.55 V which is lower than the allowable level of 443.7 V above crushed stone as well as 182 V above native soil. Therefore, there are no touch voltage concerns up to 1 m from the station fence.

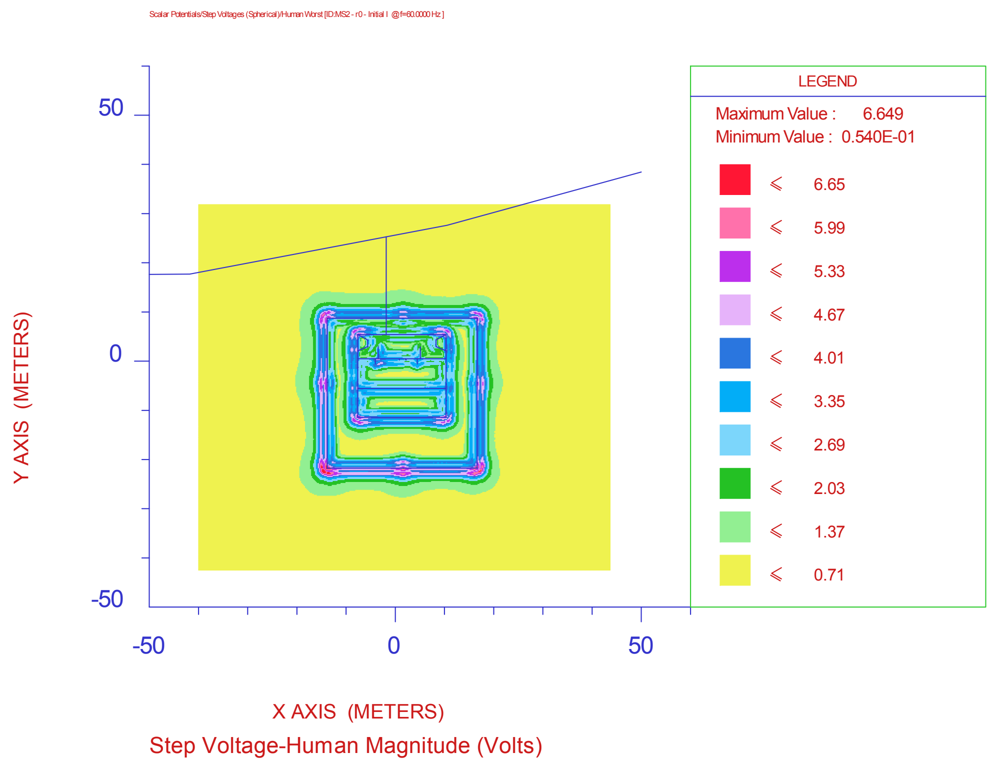


Figure 8-3: Winter Step Voltage Simulation

The maximum step voltage in and outside the station is 6.6 V which is lower than the allowable level of 1464 V above crushed stone, and 417 V above native soil, therefore there are no step voltage concerns in and around the station.

9 Ground Grid Integrity

Kinectrics measures grid integrity using a portable device which injects approximately 10 A dc between accessible grid pigtails/grounding connections. The voltage drop is read on a digital meter and converted to resistance. This is compared to the expected resistance based upon the distance between equipment measured, and the number of ground conductors and their geometry. This method can detect poor connections and broken conductors due to trenching or deterioration.

Figure 9-1 shows the locations inside the station and along the fence at MS 13 where the integrity tests were performed.

Figure 9-1: Integrity Test Locations at MS 13

9.1 Findings from the Integrity Tests

The integrity of the ground grid is generally good within the yard. However, the fence appears to lack a parallel grounding control conductor (e.g. AWG 2/0 Cu or 7#6 copperweld conductor) installed 1 m away from the station at a depth of 200 mm and bonded at regular intervals with the station fence. Although there are no step/touch voltage hazards at this station, this is generally a good practice because it adds layer of safety for the someone who may touch the fence during unexpected fault conditions.

Details on all measurements are shown in Table 9-1. Below are the main conclusions from the integrity tests:

i. Resistance measurements were low between the equipment in the yard which indicates acceptable bonding connections to the ground grid within the station. Refer to Table 9-1 for measure resistances.

ii. The station fence was verified to be isolated from the station ground grid.

iii. The resistance from riser to riser across the north access gate was measured to be much higher than expected. (Figure 9-2). A bonding conductor should be installed between the two posts of the gate.

iv. The resistance between each fence riser was measured to be high, likely because there is no conductor installed along the perimeter of the fence for gradient control. Currently the grounding may be dependent solely on the integrity of materials that bond the fence components together. Many connectors, fence posts looked aged and rusted and therefore it is better to have a dedicated conductor installed 1 m outside the fence that bonds to it at regular intervals around the perimeter.

Figure 9-2: North Access Gate

Table 9-1: Integrity measurements at MS 13

From	To	Description	Measured Resistance (milliohms)	Comments
28	29	13T2L Structure to Bkr 13T2L	1.44	OK, but slightly higher than expected
28	30	13T2L Structure to Transformer T2	0.95	OK
28	30	13T2L Structure to Transformer T2 - 2nd bond	1.58	OK, but slightly higher than expected
28	31	13T2L Structure to exposed grounding pigtail	0.02	OK
28	32	13T2L Structure to 13T1L Structure	1.50	OK
28	33	13T2L Structure to Breaker 13T1L	2.59	OK
28	34	13T2L Structure to Transformer T1	1.14	OK
28	35	13T2L Structure to metalclad switchgear	1.59	OK
28	36	13T2L Structure to Fence - Verify OPEN	#VALUE!	Isolated Fence Verified
37	38	NE Fence corner to Fence riser	14.40	Resistance is higher than expected
38	39	Fence riser to Fence before gate	62.50	Resistance is higher than expected
39	40	Across Open Gate	160.00	Resistance is higher than expected
40	41	NW Fence Corner to Fence Riser	104.00	Resistance is higher than expected
41	42	Fence Riser to SW Fence Corner	85.00	Resistance is higher than expected
42	43	SW Fence Corner to Fence Riser	70.50	Resistance is higher than expected
43	44	Fence riser to SE Fence corner beside gate	73.00	Resistance is higher than expected
44	45	Across gate	6.03	Resistance is higher than expected
45	46	Gate to Fence Riser	8.45	Resistance is higher than expected
46	47	Fence Riser to NE Fence corner	14.76	Resistance is higher than expected

10 References

[1] IEEE Power and Energy Society, *IEEE Guide for Safety in AC Substation Grounding*, no. February. 2013.

Appendix A MS 13 Fault Data

SHORT-CIRCUIT VALUES

MS		Three-phase fault		Phase-to-ground fault	
		kA	X1/R1	kA	X0/R0
5	T1	7.71	8.28	4.08	9.05
	T2	5.48	5.95	3.76	10.04
7	T1	8.38	8.37	4.31	9.64
	T2	8.37	8.34	4.31	9.63
10	T1	9.03	4.74	4.84	5.47
	T2	7.19	5.63	3.76	7.42
13	T1	5.65	6.10	3.03	6.66
	T2	6.54	6.19	3.50	6.21
14	T1	9.01	5.01	4.83	5.70
	T2	6.98	7.17	4.33	11.60

Table 1: Municipal stations 44 kV POI maximum short-circuit levels

MS		Maximum fault (kA)		Minimum fault (kA)	
		Three-phase	Phase-to-Ground	Three-phase	Phase-to-Ground
5	T1	8.91	5.54	7.38	5.10
	T2	8.24	5.43	6.92	5.01
7	T1	9.86	5.85	7.93	5.33
	T2	9.91	5.87	7.97	5.35
10	T1	12.03	6.48	10.48	6.15
	T2	7.45	4.99	6.29	4.61
13	T1	7.88	5.26	6.66	4.86
	T2	8.37	5.40	7.01	4.99
14	T1	10.07	5.89	8.96	5.62
	T2	9.01	5.62	7.45	5.17

Table 3: Municipal stations 13.8 kV short-circuit levels

Appendix B Reference Drawings

Dwg. No. D675-9 R1

NOTE
1 - NEUTRAL CABLES FOR SECOND TRANSFORMER TO BE LEFT COILED IN CABLE TROUGH BUT CONNECTED AT THE TEST LINK
2 - CONNECTION TO GROUND ROD WITH THERMOMOLD
3 - CONNECT ALL LOOPS WITH CRIMPITS

LEGEND 9-8-232

① INSTALL 1/C 250 MCM 15KV NEUTRAL FROM NEUTRAL COUPLING TRANSFORMER TO TEST LINK ON TOWER.

② DIRECT BURY 2-#2 CONDUCTORS FROM NEUTRAL COUPLING TRANSFORMER TO WATER HEATER CONTROL CELL IN THE SWITCHGEAR.

③ INSTALL 1" I.P.S. COPPER FROM NEUTRAL COUPLING TRANSFORMER TO XO BUSHING ON NEW TRANSFORMER.

④ INSTALL INTERNAL GROUND BUS TO EXISTING STATION GROUND.

⑤ RETAIN 4/0 CONDUCTOR FROM TEST LINK TO NEUTRAL STUD IN SWITCHGEAR.

⑥ ABANDON 2/0 NEUTRAL FROM TEST LINK TO 15KV NEUTRAL STUD.

No.	DATE	BY	APP.	REVISION RECORD
1	NOV/78	JS		REVISED ADD. TRANS.

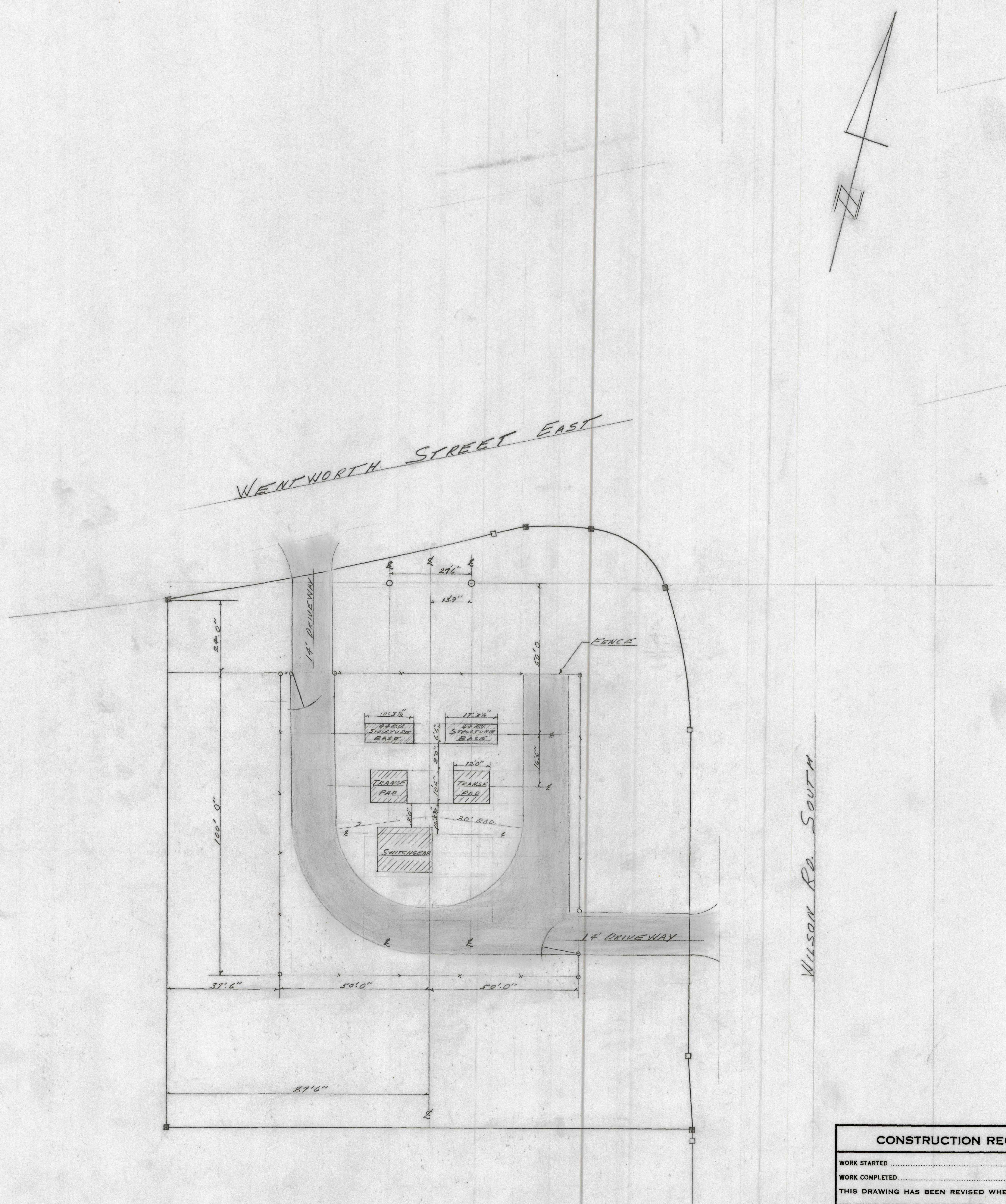
THE PUBLIC UTILITIES COMMISSION OF THE CITY OF OSHAWA

STATION-GROUND
MS #13
WENTWORTH-STREET

CONSTRUCTION RECORD	UNDERGROUND CHECKED	DATE	REMARKS
WORK STARTED	BY		
WORK COMPLETED	TELEPHONE		
THIS DRAWING HAS BEEN REVISED WHERE NECESSARY	GAS		
TO SHOW WORK AS CONSTRUCTED.	WATER		
DATE .... FOREMAN	ELECTRIC		

DRAWN LJB	CKD.	APP.
DATE DEC 12/60	SCALE 1/4 = 1'0"	
W.O. NO. E67-325	DWG. NO. D 675-9 R1	

Dwg. No. D675-12



FOR FENCE DETAIL SEE DWG NO D-665-56

CONSTRUCTION RECORD
WORK STARTED ....
WORK COMPLETED ....
THIS DRAWING HAS BEEN REVISED WHERE NECESSARY TO SHOW WORK AS CONSTRUCTED.
DATE .... FOREMAN ....

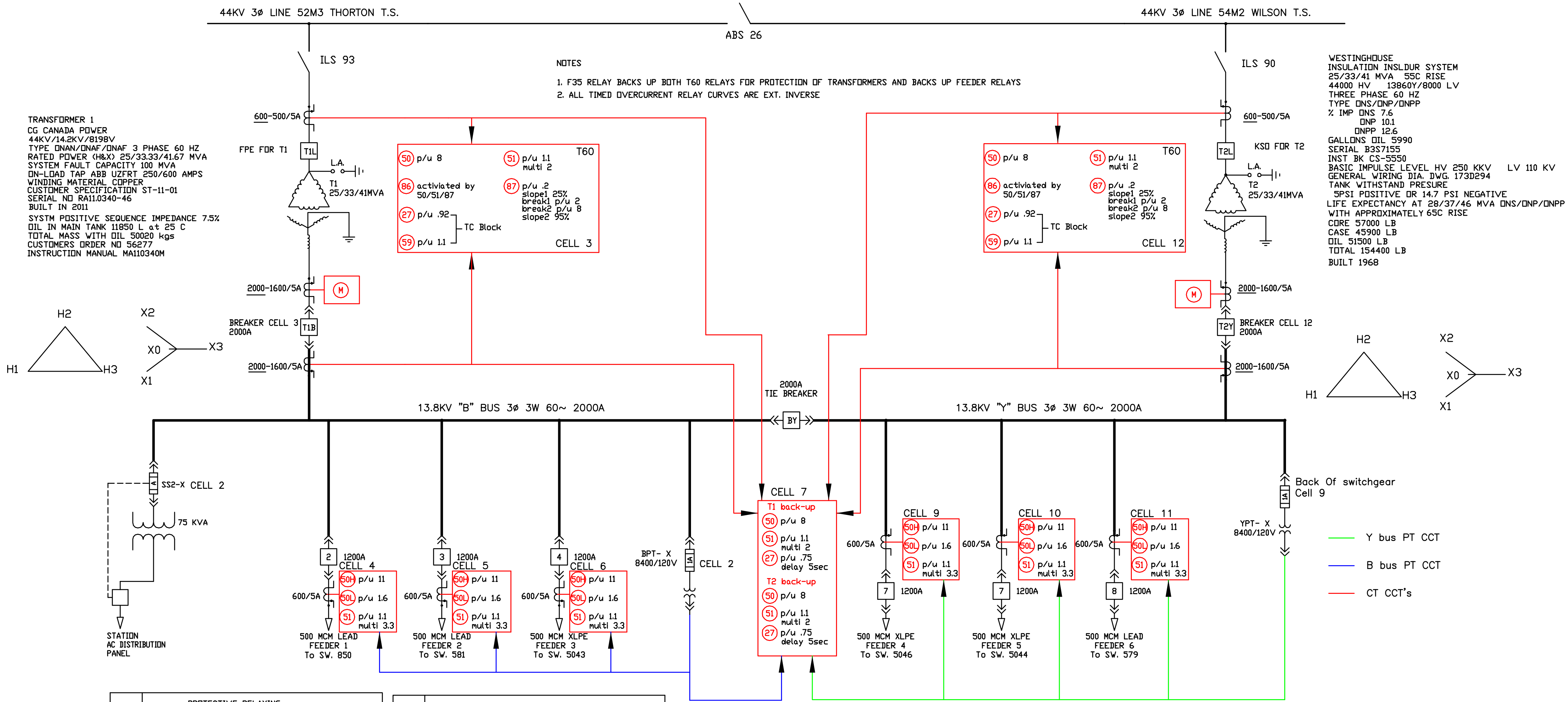
UNDERGROUND CHECKED		
BY	DATE	REMARKS
TELEPHONE		
GAS		
WATER		
ELECTRIC		

No.	DATE	BY	APP.	REVISION RECORD

THE PUBLIC UTILITIES COMMISSION
OF THE CITY OF OSHAWA

PLOT PLAN MS #13
CORNER OF
WENTWORTH ST & WILSON RD.

DRAWN LB	CKD.	APP.	
DATE FEB. 23/67		SCALE 1" = 20'	
W.O. NO.		DWG. NO. D 675-12	



	PROTECTIVE RELAYING
50H/L	INSTANTANEOUS OVERCURRENT RELAY
51	AC TIMED OVERCURRENT RELAY
87	DIFFERENTIAL
86	LOCKOUT RELAY
27	UNDERVOLTAGE

	PROTECTIVE RELAY TYPES GE MULYILIN
F35	TIE BREAKER CELL 5
T60	TRANSFORMER CELL 1 & 9
F60	FEEDER CELLS 2,3,4,6,7,8

No.	DATE	BY	APP'D.	REMARKS
1	OCT 1 2006	SB		AS CONNECTED IN CELL

REVISIONS

CUSTOMER **OSHAWA PUC**

TITLE

MS13 SINGLE LINE DIAGRAM

CAD drawing file Directory and name	DATE	STATION	DWG. BY	SHEET No.	REV.
J:\Distribution\Distribution Dept\Substations\MS11\STATION PROTECTION LAYOUT	APR 2005	MS13	STEWART BROWN	1 OF 1	

Appendix O: Asset Condition Maps (Hot Spots)

Appendix O (i): Overhead Asset Condition Map

Legend

OH Rebuilds
- 2016
- 2017
- 2018
- 2019

OPUC_Poles
- 0 to 20
- 20 to 40
- 40 to 60

OH Small Primary Conductors
- #4
- #6
- #8

OH Conductors
- A
- B
- C
- D
- E

OUTAGES 2011-2016
- Defective Equipment

ENFIELD AND MS9 FEEDER PROJECTS

Oshawa Power & Utilities Corporation

OH ASSET CONDITIONS
NOV 28, 2017

Appendix O(ii): Underground Asset Condition Map

Legend

UG Rebuilds

- 2015
- 2016
- 2017
- 2018
- 2019

UG_Conductors

- A
- B
- C
- D
- E

OUTAGES 2011-2016

- Defective Equipment

SPLICE

- SPLICE

Oshawa Power & Utilities Corporation

UG ASSET CONDITIONS
NOV 28, 2017

Appendix P: Maintenance Plan

Oshawa PUC Networks Inc.

Distribution System

Maintenance Manual

Prepared by: Mike Weatherbee Date: May, 2020
Manager, Dist. Construction

Reviewed by: Matthew Strecker Date: May, 2020
V.P. Eng. & Operations

Table of Contents **Page**

List of Figures

Executive Summary

This maintenance manual for Oshawa PUC Networks Inc. (OPUCN) is used to establish the maintenance program that will improve efficiency and prevent unnecessary or unexpected equipment outages. It identifies equipment required for maintenance, the categories, the methods and the justifications. A maintenance plan will be established from this manual so that the expenditure on the assets is maximized. This is very important as the revenue is limited and OPUCN is still expected to meet all the Ontario Energy Board (OEB) regulatory requirements in the Distribution System Code (DSC). Without such a program, it will be difficult to keep equipment in its top operational condition and will result in unexpected power outages, equipment damage, and high cost of repair or replacement in an emergency condition. Also, the public and employee safety of OPUCN will be improved as this manual will be an effective document to communicate work procedures, specifications and standards.

As specified in the Distribution System Code (DSC), all Local Distributor Companies (LDCs) must patrol/inspect the Outdoor Open Stations once a month, the Overhead and the Underground System once every three years. A summary report must be submitted annually to OEB. With the combination of time (frequency) and condition such as infrared scanning, OPUCN maintenance program will be in compliance with the OEB regulatory requirements.

Introduction and Background

Oshawa PUC Networks Inc. (OPUCN) is licensed by the Ontario Energy Board (OEB) as a Local Distributor Company (LDC) to supply electricity to 59,000 customers in the City of Oshawa. OPUCN purchases power from Hydro One at Wilson, Thornton, and Enfield Transformation Stations (TS) where the voltage is transformed from 230kV to 44kV. Through the overhead lines, OPUCN distributes electricity at 44kV to its large customers and its nine 13.8kV Municipal Stations. At the Municipal station, the voltage is converted from 44kV to 13.8kV. By way of the 13.8kV underground and overhead systems, the electricity is further distributed to locations close to customers where the voltage is reduced to a lower level to supply customers, such as hospitals, commercial premises, apartment buildings and residential homes.

The Engineering & Operation Business Unit of OPUCN is responsible to establish an annual capital and operating/maintenance plans for the electric distribution system to ensure that all requirements are met and the expenditure of funding is optimal. The capital plan is well organized and set up based on a detailed project list. Justifications and costs for projects are well documented. However, in the maintenance plan and the process to determine the needs must be defined. This is to ensure that maintenance resource will be spent in areas of high priority that is needed to comply with the regulatory requirements in the Distribution System Code (DSC) of the Ontario Energy Board (OEB).

Maintenance Policy, Objective & Strategy

Policy:

The Mission statement of OPUCN is “We earn the trust of our customers every day by delivering safe, sustainable, reliable energy our customer’s value at a competitive rate”

To support the mission, the Maintenance Policy of the Engineering & Operations business unit is “To operate and maintain the OPUCN distribution system in the most efficient way so the expenditure on assets is maximized and the requirements of the Ontario Energy Board are met”.

Objective:

The objective of a maintenance program is to prevent unnecessary or unexpected equipment outages. Without a program, it is impossible to keep equipment that supplies customers in a reliable condition. A failure in the operation of the equipment will result in unexpected power outages, equipment damage, and high cost of repair or replacement in an emergency condition. An effective maintenance program will provide the following:

1. Equipment is in top operational condition
2. Improve system reliability
3. Maximize the utilization of asset life cycle
4. Improve public and employee safety

Maintenance Definitions & Categories

Definitions:

1. Emergency Maintenance----Maintenance is performed in response to failure of equipment resulting in power outage, safety hazard and/or environmental problems. It is urgent and required immediate action. Equipment is repaired or replaced to restore service immediately and in some cases, permanent repair or replacement is done in subsequent days. This is an unplanned maintenance.

2. Preventive Maintenance----Maintenance is scheduled or performed in response to problems identified in inspection, testing and/or trouble reports. Equipment is repaired or replaced prior to a failure. Testing may be performed to predict the equipment condition. This is a planned maintenance.

Categories:

1. Main Category----Reactive
    - Sub-category----Station
    - Sub-category----Overhead System
    - Sub-category----Underground System

2. Main Category----Routine System Operations and Maintenance
    - Sub-category----Station
    - Sub-category----Overhead System
    - Sub-category----Underground System

Reactive Maintenance

Category: **Station**

Program: **Trouble Response & Restoration**

Description/ Justification:

This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment failure inside OPUCN's Municipal Stations and the underground riser cables between the stations and the line side of the first terminations at the riser poles outside the stations. Equipment is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment is done in a subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment required to restore power without any delay.

Procedure:

There are nine Municipal Stations (MS): MS-2, MS-5, MS-7, MS-9, MS-10, MS-11, MS-13, MS-14 and MS-15. Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system..

Reactive Maintenance

Category: **Overhead System**

Program: **Trouble Response & Restoration**

Description/ Justification:

This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment or pole failure in the overhead system. The equipment or pole is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment is done in subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment to restore power without any delay.

Procedure:

Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system.

Reactive Maintenance

Category: **Underground System**

Program: **Trouble Response & Restoration**

Description/ Justification:

This program is the trouble response call to a power outage, safety hazard and/or environmental problem due to equipment or structure failure in the underground system. The equipment or structure is repaired or replaced to restore service immediately. It is urgent and requires immediate action. In some cases, permanent repair or replacement of equipment or structure is done in subsequent follow-up.

To maintain revenue flow, minimize customer complaints and meet the Ontario Energy Board (OEB) system reliability requirements, it is important to have the resources and equipment to restore power without any delay.

Procedure:

Trouble Calls will be directed through the Distribution Operator or Supervisor during regular hours and after hours, through a call center, Outage Management System, or SCADA system..

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Batteries and Chargers**

Description/ Justification:

All the protective relays and their control circuits are powered by D.C. supply from batteries charged by station battery charger. Station batteries are used for the storage of electric energy that is readily available for the control of electrical equipment such as circuit breaker. Also, the batteries provide power for indication lights, alarms and SCADA control system. Failure to maintain the batteries and the battery charger will cause the protective system and the operation of circuit breakers inactive. This will result in damage to electrical equipment and possibly loss of the entire station.

Maintenance cycle is once every three months. Load test on batteries is once a year.

Procedure:

Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion, leakage, heating and venting at terminals, connectors and racks. Check and test voltage of each cell and the total battery voltage. Fill up water if required. Once a year, perform load test on the batteries.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Full Station Maintenance**

Description/ Justification:

OPUCN owns and operates nine (9) Municipal Substations (MS) where the voltage is converted from 44kV to 13.8kV. By way of the 13.8kV underground and overhead systems, the electricity is further distributed to locations close to customers where the voltage is reduced to a lower level to supply customers, such as hospitals, commercial premises, apartment buildings and residential homes.

To ensure ultimate reliability, asset management and continuity of service, all mechanical and electrical components within the MS must be tested, inspected and maintained once every three (3) years.

Also, an oil sample shall be obtained yearly and subjected to inspection and testing by a 3rd party.

Procedure:

OPUCN has adopted and will utilize NETA MTS-2015 Standard for Maintenance Testing Specifications for Electrical Power Equipment & Systems. This maintenance testing standard is recognized internationally and was developed for use by those responsible for the continued operation of existing electrical systems and equipment to guide them in specifying and performing the necessary tests to ensure that these systems and apparatus perform satisfactorily, minimizing downtime, and maximizing life expectancy.

In addition, all Power Transformers located within OPUCN Municipal Substations will have an oil sample drawn yearly. This sample will be subjected to NETA MTS-2015 recommended transformer insulating liquid testing.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Infra-red Scanning**

Description/ Justification: One of the most common sources of trouble in the station equipment is deteriorating terminators and connectors resulting in overheating and eventual failure. Infra-red scanning of these components identifies these potential anomalies and allows for corrective measures to be taken before they fail causing power outage. Since the reliability of station equipment is very important, all the termination and joint components will be scanned once a year.

Procedure: The infrared scanning will be done once a year in conjunction with the full Distribution System infrared scanning program. Problems identified during the scanning will be recorded for follow-up repairs or replacements.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Municipal Station and Building(s) Inspection**

Description/ Justification:

Nine Municipal Stations (MS) are used to transform voltage from 44kV to 13.8kV. Through underground or overhead, the 13.8kV feeders will exit the stations and distribute electricity to the City of Oshawa. Proper operation of these stations is essential to the reliability of supply. Problems associated with equipment failure at stations have a high impact on overall system reliability.

Six of these stations are outdoor type surrounded by locked security fences. The terminations of power transformers are exposed, energized and readily accessible although the switchgears are metal enclosed. These stations are defined as "Outdoor Open Stations" in the Distribution System Code (DSC) of the Ontario Energy Board (OEB) and require monthly inspection. The other three stations are classified as "Indoor Enclosed Stations" since the equipment is installed inside buildings.

In order to simplify procedures and provide high reliable supply, all nine stations will be inspected monthly.

Procedure:

There are nine Municipal Stations (MS): MS-2, MS-5, MS-7, MS-10, MS-9, MS-11, MS-13, MS-14 and MS-15. Each station consists of 44kV circuit breakers, 44kV to 13.8kV station power transformers and cooling fans, cable terminators, 13.8kV circuit breakers in the switchgears, station service transformer, batteries, battery chargers, lighting, heating, ventilation, drains, door, lock, fence, building envelope and roof, safety equipment, fire extinguisher, eye-wash station and all associated devices used to provide protection, control, metering and monitoring of the station. Perform visual inspection on these items monthly.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Station**

Program: **Customer Owned Station Inspection**

Description/ Justification: Various large customers throughout the city have privately owned substations intended to transformer 44kV power distribution to a voltage more suitable to their operation. As these substations are connected to Oshawa Power's distribution network, they have the potential to adversely affect the reliability of the system should they malfunction. Oshawa power has no jurisdiction or responsibility to maintain these privately owned substations and thus has no control over their condition.

Procedure: A visual inspection will be performed on the customer owned substation on a three year cycle to identify any obvious signs of disrepair that could cause a failure, resulting in a disruption to Oshawa Power's distribution network. Any deficiencies found will be reported to the customer with a required timeline for remediation. A follow-up inspection will be performed to ensure compliance.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Infra-red Scanning**

Description/ Justification:

One of the most common sources of trouble on the overhead system is deteriorating connectors resulting in overheating and eventual failure. Infra-red scanning of overhead line components identifies these potential anomalies and allows for corrective measures to be taken before they fail causing power outage.

Procedure:

The infrared scanning will be done on geographic area basis in co-ordination with tree trimming and system patrols. In addition to the overhead line components, any electrical equipment such as overhead transformers, switches which exist in proximity will be scanned. All main feeder circuits will be scanned once a year and all single phase circuits will be done once every three years.

Problems identified during the scanning will be recorded and documented for follow-up repairs or replacements.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **System Patrol**

Description/ Justification: The Overhead Distribution System, over time, if not inspected can erode and deficiencies can become present. These deficiencies could include items such as missing/broken guys, broken insulators, unapproved third party attachments, missing or incorrect nomenclature, etc. These deficiencies can introduce reliability risks to the system or safety risks to the public.

Procedure: System patrols will be done on a three year cycle based on geographic areas in coordination with infrared scanning and tree trimming. The system patrol will look for all potential deficiencies in the overhead network.

Problems identified during the scanning will be recorded and documented for follow-up repairs or replacements.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Insulator Washing**

Description/ Justification:

The accumulation of dirt during summer and salt during winter, combined with moisture will reduce insulation levels of the insulators and lead to tracking. As a result, flashovers and pole fires will occur. Insulator washing can eliminate this problem. The need for insulator washing depends on location, type of insulator and voltage. Polymeric insulators due to the material properties do not require washing. All porcelain insulators are washed yearly before the winter in November.

During the washing, system deficiencies should be reported. Repairs can be done under various Preventive Maintenance program to minimize system disruptions.

Procedure:

The insulators will be contaminated by road salt, jet fuel, diesel and exhaust. When damp, these insulators are likely to flashover. Avoid partially wetting an insulator before the solid stream is applied. The water must be brought to the full nozzle pressure required before it is directed toward the insulator. In general, direct the solid stream to the lowest insulator first then move progressively upward on the string of the insulators.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Load Break Switches**

Description/ Justification:

This program includes maintenance on all three phase load break switches (LBS) also called air break switches (ABS). These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. Maintenance is performed on a three year cycle.

Procedure:

Switch selection is coordinated through System Operator due to system loading considerations and the capability to take a switch out of service. Switch and the manual operating device will be cleaned, lubricated, aligned and adjusted. Any defective components will be replaced as required.

Other deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **In-Line Switches**

Description/ Justification: This program includes maintenance on all 13.8kV and 44kV in-line switches. These switches are used on the distribution system to reconfigure overhead circuits as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. Maintenance is performed on a three year cycle.

Procedure: Switch selection is coordinated through System Operator due to system loading considerations and the capability to take a switch out of service. Switch and the manual operating device will be cleaned, lubricated, aligned and adjusted. Any defective components will be replaced as required.

Other deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Distribution Automation Battery, Communication and Protection Control Maintenance, Inspection and Replacement**

Description/ Justification:

This program includes maintenance, inspection and/or replacement of batteries, communication devices and all protection control equipment on all SCADA operated three phase load break switches. These switches are used on the distribution system to reconfigure overhead circuits on load as required to ensure sufficient supply to the customers during routine and emergency switching. Proper operation of these switches will shorten the outage restoration time resulting in the improvement of system reliability. All the overhead SCADA operated switches are powered by a D.C. supply from batteries charged by a control box charger. Failure to inspect, maintain and/or replace the batteries or the battery charger will cause the protective system and the operation of remote switches inactive. This will result in damage to electrical equipment and possibly loss of the entire feeder.

Full maintenance, inspection and replacement is performed on a three year cycle in conjunction with the Overhead Load Break Switch Maintenance Program. Simple battery inspection is performed once every three (3) months. Protection control equipment and communication device maintenance and inspection is performed yearly. Battery replacement is performed every three (3) years.

Procedure:

Protection Control/Communication Device: Update relay firmware as directed by Protection & Control Engineer. Check protection control and communication devices settings to ensure proper communication, calibration and mechanism for opening and closing functions. Verify voltage and current transducer calibration, alarm circuit and SCADA points. This shall be completed yearly.

Battery & Charger: Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion and leakage. Every three (3) years replace battery and if required, the charger.

Enclosure: Inspect enclosure gasket. Inspect enclosure for presence of corrosion, holes and moisture.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Wood & Concrete Pole Inspection & Treatment**

Description/ Justification:

This program includes wood and concrete pole inspection and treatment. Poles requiring immediate replacement as identified in the inspection are covered under the Capital Program. Distribution lines and equipment are mounted on poles throughout the City. It is important that the strength of pole is sufficient to support the overhead lines and equipment.

As wood is a natural material, the degradation of wood pole can occur inside and/or outside the pole. For concrete poles, the deterioration is the result of rusting on the re-enforcing steel bars caused by moisture and salt. Inspection and treatment of the deterioration of pole can reduce the risk of defective pole and the resulting in power outage and safety hazard.

Procedure:

Poles are inspected and treated on an ongoing basis. Assessment techniques start with a simple visual inspection of poles accompanied by basic physical tests, such as prodding tests for external conditions and hammer tests to detect evidence of internal decay. If there is any indication of decay from these tests, a full assessment such as Resistograph and/or Ultra Sound test shall be applied. The inspection is done at the bottom of the pole only. The finding of rot at the top of pole will be reported by the Line Crew working on the pole.

The inspection record shall include basic identification information, pole type, class, species, height, date of installation and original treatment (if available), condition and damage to the pole.

If treatment is required, either the wrap method of external treatment or the Copper Boron Rod method for internal treatment shall be applied.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Overhead System**

Program: **Tree Trimming**

Description/ Justification:

While trees are aesthetically pleasing, they do present a reliability and safety hazard when they are close to the power lines. To minimize tree contact interruptions, a tree trimming program is required to maintain adequate clearance so the system reliability will not fall below the Ontario Energy Board (OEB) requirements. The tree trimming is completed on a three year cycle. Secondary overhead line routes and spot work to deal with the fast growing species will be performed as required.

Procedure:

All tree trimming will be carried out according to approved arboricultural standards. All clearances must be relative to the estimated position of maximum sag and swing of the nearest conductor. All limbs or main stems of trees that could sag or fall into the lines when weighted with snow or ice shall be removed. All deadwood which, under normal wind conditions, could strike or fall into energized lines or electrical apparatus and cause damage and interruption, shall be removed. For the maintenance of tree symmetry, limbs may be removed.

Any deficiencies of equipment shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Manholes**

Description/ Justification: Manholes are enclosures found within the road allowance, located below grade, have a round lid and primarily contain cables. However, manholes may contain small electrical equipment and are considered a confined space. Periodic inspection is required to ensure the integrity of the structure, cable and electrical equipment. Inspection and maintenance will be performed once every 3 years or yearly if the manhole houses critical infrastructure.

Procedure: Visual inspection will be performed on the surface to ensure no obvious problems such as damaged lids. Follow rules and regulation, such as checking explosive gas, for entering confined space environment. The lids will be removed and confined space entry equipment will be set up. Perform detailed inspection on structures, cable racks, cables, splices, other equipment and environmental conditions.

Any minor deficiencies will be repaired during inspection. Major problems, such as structures, washing, cables and splices shall be documented and reported for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Pad-mount & Submersible Transformers (Single and Three Phase) and Switchgear**

Description/ Justification: Single and three phase pad-mounted transformers or switchgear are metal clad enclosures located above grade on concrete pads with lockable facilities. Submersible transformers are installed in below grade vaults. As required by the Distribution System Code (DSC) of the Ontario Energy Board (OEB), all major equipment for underground distribution system must be patrolled or visually inspected at least once every three years to identify obvious structural problems and hazards such as damaged equipment, enclosures and vandalism. The inspection will also identify any potential problems which will cause system outage and possible environmental disaster.

Procedure: For all pad-mount and submersible transformers as well as switchgear, external visual inspections will be performed to ensure no obvious problems such as missing locks, holes due to enclosures rusting or unleveled concrete pad foundation are present. Internal visual inspections with be performed on elbows and inserts, primary and secondary cables, secondary paddles, fiber board(s), nomenclature and terminations.

Any deficiencies shall be reported and documented for follow-up repairs.

Routine Systems Operations and Maintenance

Category: **Underground System**

Program: **Vaults—Downtown, Critical & Non-critical**

Description/ Justification:

There are three types of vaults---Downtown, Critical and Non-Critical. Downtown Vaults are below grade in the downtown core supplying power to commercial customers. Critical Vaults are defined as vaults either below grade, above grade or with poor access. These vaults are used to supply power to major customers, such as Health Centers and Shopping Malls. Non-critical vaults are typically above grade rooms in industrial/commercial type buildings with locked doors.

All vaults contain transformers and/or other switching devices, such as SF6 and vacuum switches, ventilation equipment and/or sump pumps. Periodic inspection and maintenance are required to ensure the integrity of the structure and equipment. Below grade vaults are considered a confined space.

Since Downtown Vaults are frequently subjected to leaking of contaminated water from the ceiling and walls of vaults, inspection and maintenance shall be performed twice a year, in spring and fall. For Critical Vaults, reliable power supply to customers is important. These vaults shall be inspected and maintained once a year. For Non-critical Vaults, the inspection and maintenance cycle shall be once every three years which will comply with the three years inspection requirements in the Distribution System Code (DSC) of the Ontario Energy Board (OEB).

All the underground remote switches are powered by D.C. supply from batteries charged by a control box charger. Batteries are used for the storage of electric energy that is readily available for the control of electrical equipment during outages. Also, the batteries provide power for communication, indication lights, alarms, SCADA control system and automation. Failure to maintain the batteries and the battery charger will cause the protective system and the operation of remote switches inactive. This will result in damage to electrical equipment and possibly loss of the entire feeder.

Procedure: Visual inspection will be performed to ensure no obvious problems such as damaged ventilation. Set up confined space entry equipment and follow rules and regulation, such as checking explosive gas, for entering a confined space environment. Perform detailed inspection on structures, equipment and environmental conditions. Inspect gauges on transformers, SF6 and vacuum switches. Clean ventilations and remove debris. Test and lubricate sump pumps. Perform infra-red scanning on elbows, cables and terminations.

Protection Control/Communication Device: Update relay firmware as directed by Protection & Control Engineer. Check protection control and communication devices settings to ensure proper communication, calibration and mechanism for opening and closing functions. Verify voltage and current transducer calibration, alarm circuit and SCADA points. This shall be completed yearly.

Battery & Charger: Every three (3) months, check the charger output for current and voltage. Visually inspect batteries for evidence of corrosion and leakage. Test remote control of switch (if applicable) with no A.C supply and perform a load test during routine inspection cycle. Replace battery and if require, the charger, every three (3) years.

Enclosure: Inspect enclosure gasket. Inspect enclosure for presence of corrosion, holes and moisture.

Major problems, such as structures, cables and defective equipment shall be documented and reported for follow-up repairs.

Other deficiencies shall be reported and documented for follow-up repairs.

Process Maps

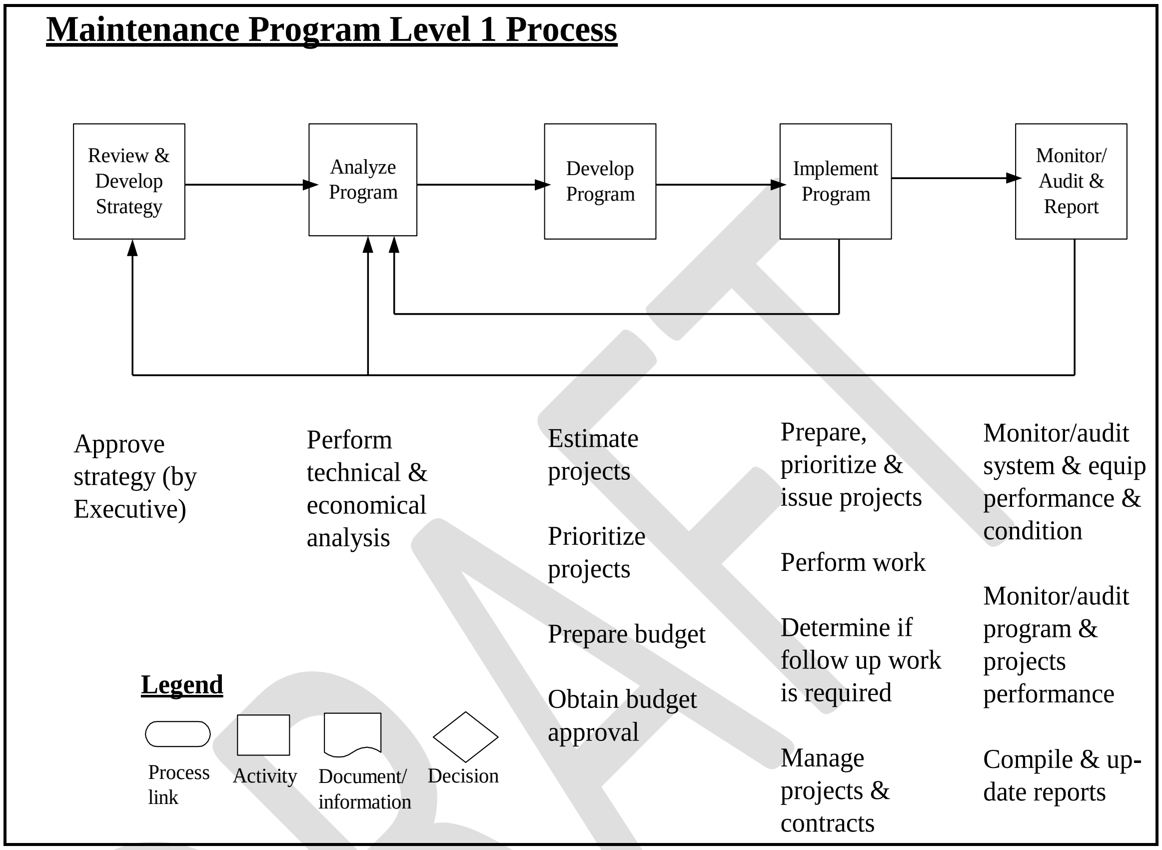


Figure 1: Maintenance Program Level 1 Process

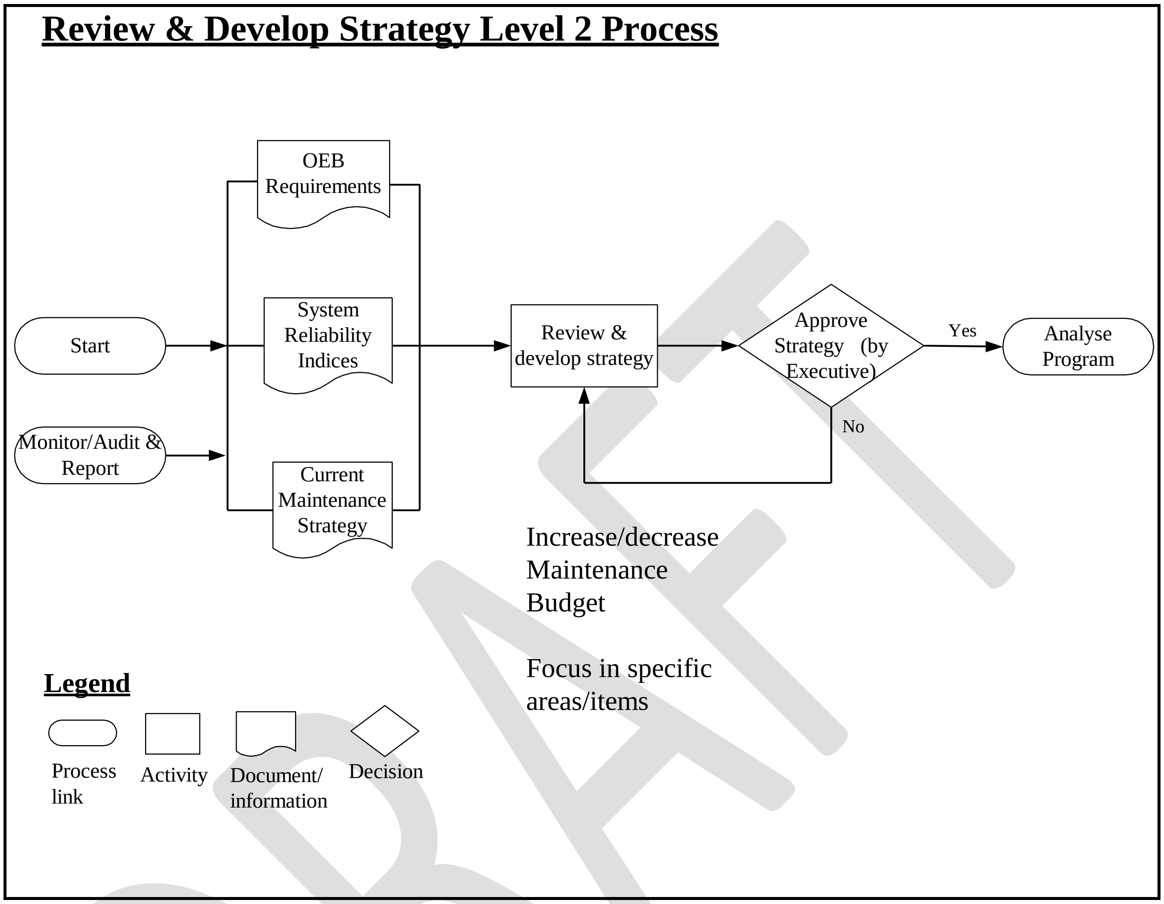


Figure 2: Review & Develop Strategy Level 2 Process

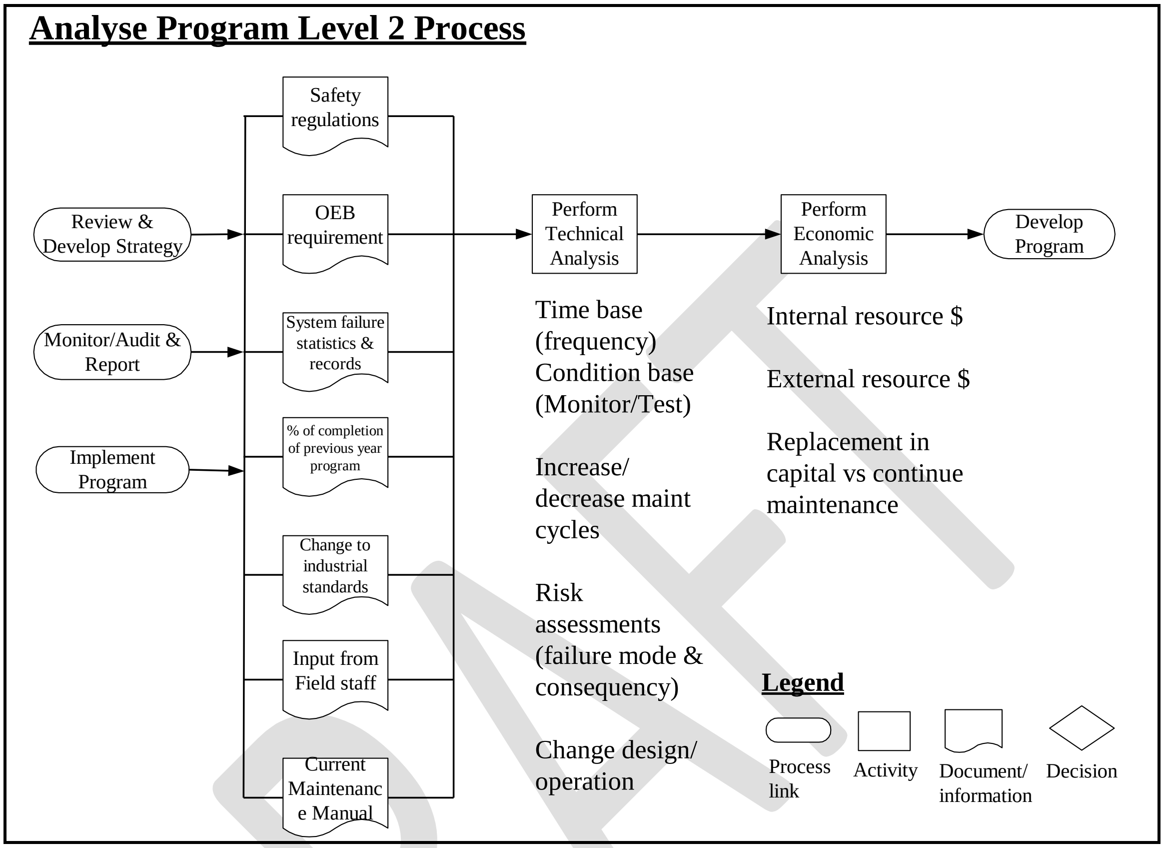


Figure 3: Analyse Program Level 2 Process

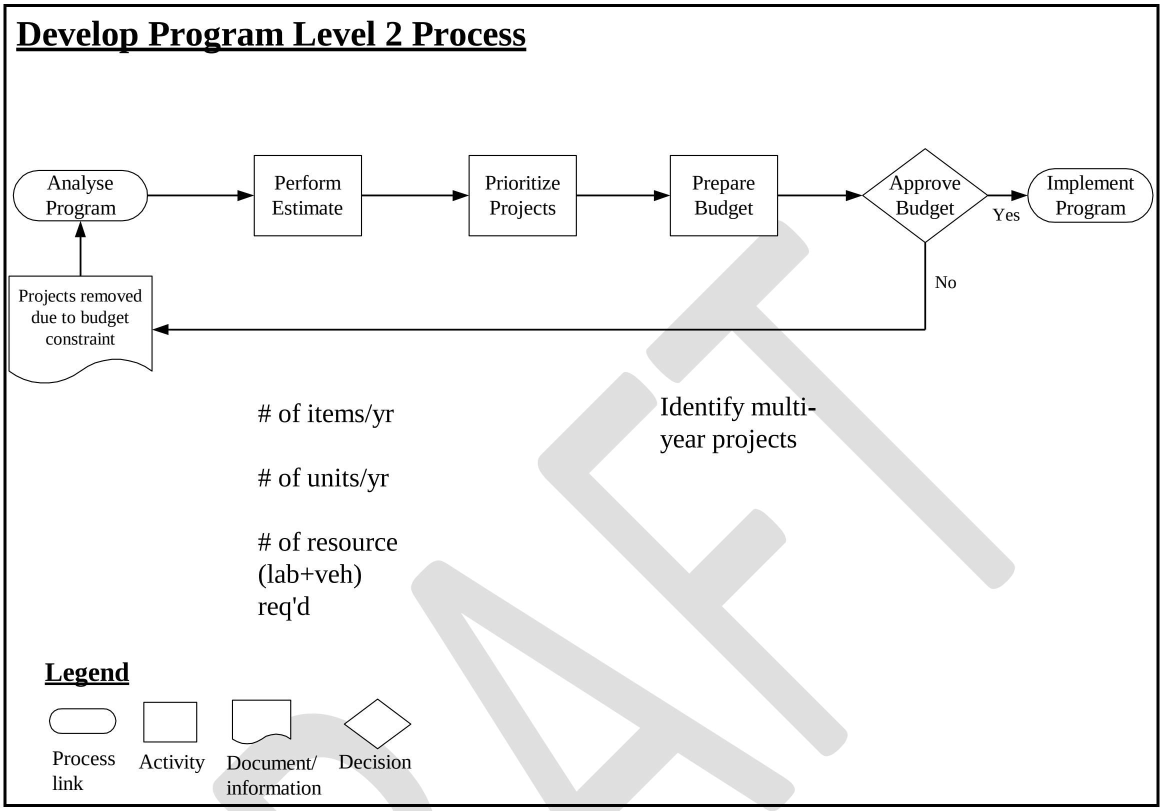


Figure 4: Develop Program Level 2 Process

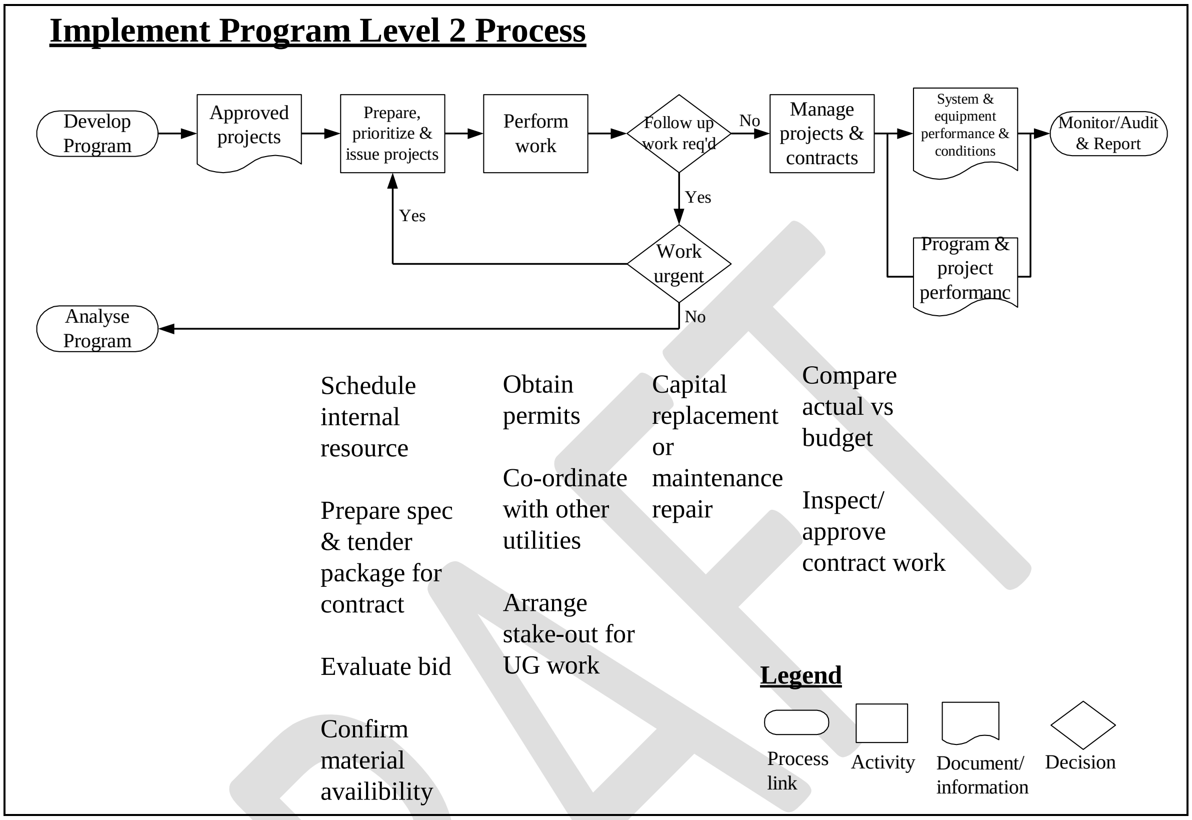


Figure 5: Implement Program Level 2 Process

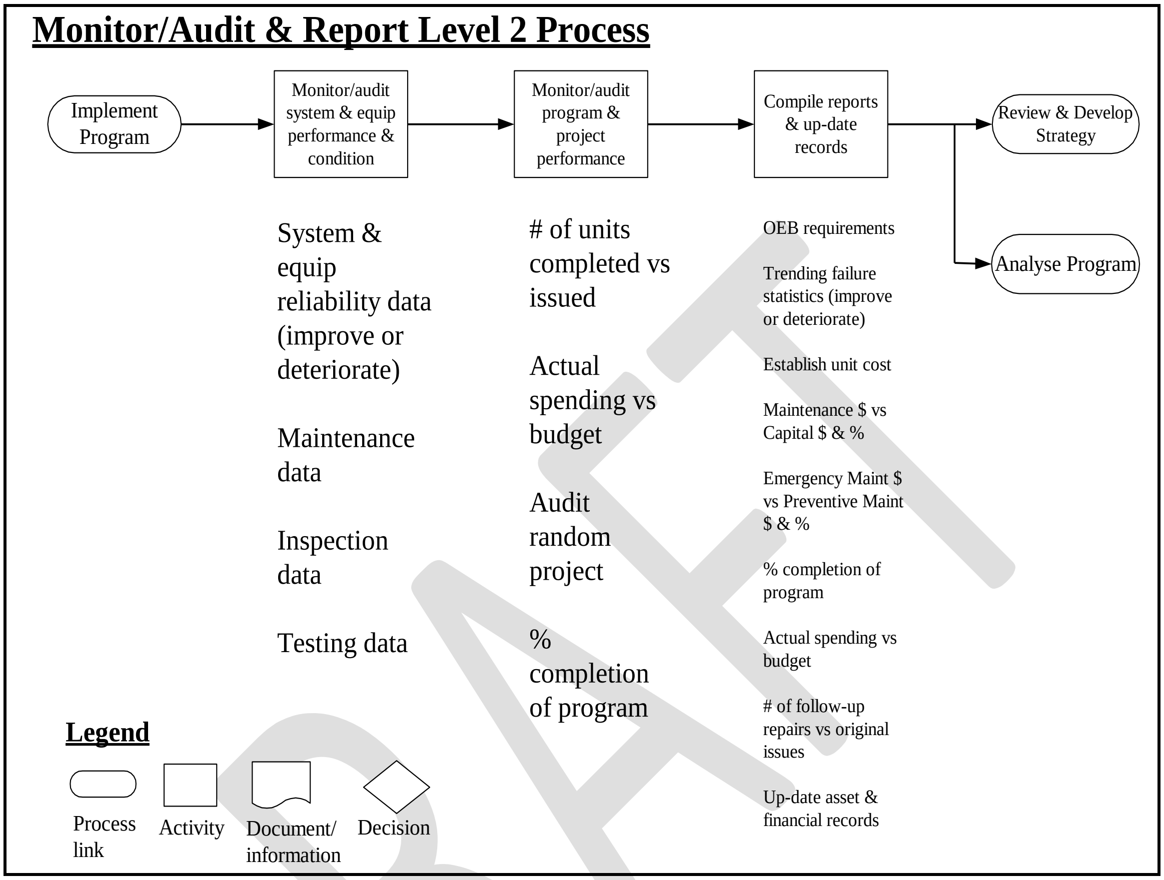


Figure 6: Monitor/Audit & Report Level 2 Process

Appendix Q: Sections of Hydro One List of Station Capacity

Hydro One List of Station Capacity

This document lists the estimated thermal and short circuit capacities for generation connections to distribution system supplied by Hydro One stations in the province of Ontario. Capacity on those stations constrained by limits on the transmission system is shown as Transmission Constraints (TC). For more information, please refer to the glossary of terms at the end.

The Thermal Capacity represents the estimated total name plate amount of generation that can be connected to the distribution system supplied by the subject bus or station. The Short Circuit capacity represents the estimated total acceptable short circuit contribution by generation connected to the distribution system supplied by the subject bus or station. Estimated short circuit capacity is not applicable to all Hydro One stations and buses depending on their type and configuration. Estimated short circuit capacity for those stations is shown as “N/A”.

The listed capacity values in this document are estimates only and are based on the maximum permissible thermal and short circuit levels at Hydro One stations. This list does not reflect the capacity on Hydro One transmission network or indicate the condition of any Hydro One equipment. These estimated thermal and short circuit capacities are calculated without considering any existing or allocated generation capacity listed in Hydro One’s List of Applications.

Please refer to the online station capacity calculator to determine preliminary connection availability. Note that capacity allocation will be determined when the generator applies for a Connection Impact Assessment (CIA) excluding microFIT applicants.

This document will be updated regularly. For any questions, please contact the Business Customer Centre at dxgenerationconnections@hydroone.com or 1-877-447-4412 (Option #2). An accompanying document titled “List of Applications” provides information regarding applications to connect at Hydro One-owned transformer stations. This document can be found on Hydro One’s website www.HydroOne.com under the Distribution-Connected Generators section. The potential capacity of a feeder is described in that section as well.

The list was updated on December 19, 2019

Notes:

Coniston TS was removed as it is being decommissioned

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
ELGIN TS DESN1	JQ	M22,M23,M24,M25,M26,M27,M28,M30,M31,M32,M33,M34	13.8	10.87	32.0	10.9		
ELGIN TS DESN1	Total	M22,M23,M24,M25,M26,M27,M28,M30,M31,M32,M33,M34,M41,M42,M43,M44,M45,M46,M47,M48	13.8	17.71	N/A	Sum of Buses		
ELGIN TS DESN2	EZ	M51, M52, M53, M61, M62, M63	13.8	14.10	1.3	30.1		
ELGINBURG DS	Total	F1,F2,F3	8.32	1.17	N/A	3.6	KINGSTON GARDINER TS DESN1	M3
ELK LAKE DS	Total	F1	4.16	0.17	N/A	1.1	KIRKLAND LAKE TS	G3K
ELLESMERE TS	J	M21,M23,M25,M27,M29,M31	27.6	19.54	50.5	44.5		
ELLESMERE TS	Q	M22,M24,M26,M28,M30,M32	27.6	16.38	48.3	41.4		
ELLESMERE TS	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	35.92	N/A	Sum of Buses		
ELLIOT LAKE DS	Total	F1,F2	12.5	0.89	N/A	3.3	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T1	F1,F3	12.47	0.34	N/A	2.7	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	T2	F4,F5	12.47	0.69	N/A	3.6	ELLIOT LAKE TS	M3
ELLIOT LAKE MISS DS	Total	F1,F3,F4,F5	12.47	1.03	N/A	3.4	ELLIOT LAKE TS	M3
ELLIOT LAKE TS	B1B3	M1, M3	44	5.04	399.2	25.0		
ELMHURST DS	T1	F1,F2,F3	8.32	0.48	N/A	2.9	BROWN HILL TS	M2
ELMHURST DS	T2	F4,F5	27.6	1.60	N/A	5.0	BROWN HILL TS	M2
ELMIRA TS	BY	M1, M2, M3	27.6	10.99	76.7	31.0		
ELMVALE DS	Total	F1,F2	8.32	0.81	N/A	2.2	MIDHURST TS - DESN1	M10
ELORA UNION DS	Total	F1,F2,F4	8.32	0.64	N/A	3.0	FERGUS TS	M7
ELSINORE DS	Total	F1,F2,F3	8.32	1.11	N/A	3.5	OWEN SOUND TS	M25
EMBRUN DS	Total	F2,F3,F4,	8.32	0.91	N/A	TC	CHESTERVILLE TS	M1
EMO DS	Total	F1,F2	12.47	0.66	N/A	2.1	BARWICK TS	M1
EMSDALE DS	Total	F1,F2,F3	12.47	1.75	N/A	4.6	MUSKOKA TS	M10
ENFIELD TS DESN1	BY	M3,M4,M5,M6,M7,M8	44	31.90	254.6	91.9		
ENGLEHART NORTH DS	Total	F1,F2,F3	12.47	0.68	N/A	3.6	KIRKLAND LAKE TS	M62
ENNISMORE DS	Total	F1,F2,F3	8.32	0.88	N/A	3.3	DOBBIN TS	M2
ERAMOSA DS	Total	F4,F5,F6	8.32	0.80	N/A	3.2	FERGUS TS	M8
ERIEAU DS	Total	F1,F2,F3	8.32	0.78	N/A	3.2	KENT TS DESN1	M18
ERIN DS	Total	F1,F2,F3	12.47	1.81	N/A	5.0	ORANGEVILLE TS DESN2	M1
ERINDALE TS DESN1	E	M32,M34,M36,M38,M40,M42	27.6	25.83	107.7	25.8		
ERINDALE TS DESN1	Q	M31,M33,M35,M37,M39,M41	27.6	21.01	107.2	21.0		
ERINDALE TS DESN1	Total	M32,M34,M36,M38,M40,M42,M31,M33,M35,M37,M39,M41	27.6	46.83	N/A	Sum of Buses		
ERINDALE TS DESN2	YZ	M23, M24, M25, M26, M27, M28, M29, M30	44	33.57	193.6	93.6		
ERINDALE TS DESN3	BJ	M1, M2, M3, M4, M5, M6, M7, M8	44	42.93	114.6	102.9		
ESPANOLA DS	Total	F1,F2	12.47	0.71	N/A	3.6	ESPANOLA TS	M1
ESPANOLA TS	BY	M1, M2	44	3.67	162.3	10.9		
ESPLANADE TS	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	18.30	57.6	18.3		
ESPLANADE TS	J1J2	M1,M2,M3,M4	13.8	24.35	60.0	24.4		
ESPLANADE TS	Q1Q2	M11,M12,M13,M14	13.8	18.54	57.8	18.5		
ESPLANADE TS	Total	M1,M2,M3,M4,M11,M12,M13,M14	13.8	61.08	N/A	Sum of Buses		
ESSEX DS	Total	F1,F2	8	0.54	N/A	2.9	LAUZON TS DESN2	M24
ESSEX TS	JQ	M5, M6, M7, M8, M10, M11	27.6	14.33	105.0	54.3		
ETON DS	Total	F1,F2,F3	12.5	0.92	9.2	9.3		
EVERETT DS	Total	F1,F2,F3	8.32	1.82	N/A	5.0	EVERETT TS	M5
EVERETT TS	BY	M5, M6, M7, M8	44	23.82	473.1	63.8		
EVERSLEY DS	T1	F1,F2,F3	13.8	1.42	N/A	9.4	KLEINBURG TS 44 KV	M23
EVERSLEY DS	T2	F5,F6	13.8	1.25	N/A	9.2	KLEINBURG TS 44 KV	M23
EVERSLEY DS	Total	F1,F2,F3,F5,F6	13.8	2.67	N/A	10.7	KLEINBURG TS 44 KV	M23
EVERTON DS	Total	F1,F2	8.32	0.75	N/A	3.1	FERGUS TS	M2
EXETER DS #2	Total	F1,F2	8.32	0.64	N/A	1.6	CENTRALIA TS	M1
EXETER ROSEMOUNT DS	Total	F1,F2,F3	4.16	0.64	N/A	3.0	CENTRALIA TS	M1
EXETER SANDERS DS	Total	F1,F2,F3	4.16	0.46	N/A	2.9	CENTRALIA TS	M1
EXETER WELLINGTON DS	Total	F1,F2	4.16	0.38	N/A	1.8	CENTRALIA TS	M1
FAIRBANK TS DESN1	YZ	M11,M12,M7,M3,M5,M8	27.6	22.95	3.8	62.9		
FAIRBANK TS DESN2	BQ	M1,M10,M2,M23,M24,M4,M6,M9	27.6	21.49	60.0	61.5		
FAIRCHILD TS DESN1	B	M1,M3,M5,M7,M9,M11	27.6	18.01	71.8	18.0		
FAIRCHILD TS DESN1	Y	M2,M4,M6,M8,M10,M12	27.6	18.79	66.1	18.8		
FAIRCHILD TS DESN1	Total	M1,M3,M5,M7,M9,M11,M2,M4,M6,M8,M10,M12	27.6	36.13	N/A	Sum of Buses		
FAIRCHILD TS DESN2	J	M21,M23,M25,M27,M29,M31	27.6	11.21	112.5	27.2		
FAIRCHILD TS DESN2	Q	M22,M24,M26,M28,M30,M32	27.6	20.47	113.9	36.5		
FAIRCHILD TS DESN2	Total	M21,M23,M25,M27,M29,M31,M22,M24,M26,M28,M30,M32	27.6	32.60	N/A	Sum of Buses		
FAIRFIELD DS	Total	F1,F2,F3	8.32	1.23	N/A	3.6	KINGSTON GARDINER TS DESN1	M14

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
SUNDRIDGE NORTH DS	Total	F2,F3	12.47	1.18	N/A	4.1	MUSKOKA TS	M2
SUNNIDALE CORNERS DS	Total	F1,F2,F3	8.32	1.00	N/A	3.4	STAYNER TS	M5
SUTTON BASE LN DS #1	T1	F2,F3	8.32	0.16	N/A	2.6	BROWN HILL TS	M12
SUTTON BASE LN DS #1	T2	F1	8.32	0.51	N/A	2.9	BROWN HILL TS	M12
SUTTON BASE LN DS #1	Total	Field Check	8.32	0.66	N/A	3.1	BROWN HILL TS	M12
SUTTON DS #2	Total	F1,F2,F3	8.32	0.86	N/A	3.3	BROWN HILL TS	M12
SWANSON DS	Total	F1,F2,F3	12.47	0.23	N/A	3.1	KIRKLAND LAKE TS	G3K
TALBOT TS DESN1	BY	M11,M12,M13,M14,M21,M22,M23,M25	27.6	21.32	0.0	61.3		
TALBOT TS DESN2	J1J2	M41, M42, M43, M46, M47, M48	27.6	17.69	131.3	33.7		
TALBOT TS DESN2	Q1Q2	M51, M52, M53, M54, M55, M56	27.6	17.51	129.2	33.5		
TALBOT TS DESN2	Total	M41, M42, M43, M46, M47, M48,M51, M52, M53, M54, M55, M56	27.6	36.29	N/A	Sum of Buses		
TAMWORTH DS	Total	F1,F2,F3	12.47	0.82	N/A	3.7	NAPANEE TS	M2
TARA DS #2	Total	F1,F2,F3	8.32	0.92	N/A	2.4	OWEN SOUND TS	M25
TAUNTON DS	Total	F1,F2	29.3	3.03	N/A	5.0	WILSON TS DESN2	M11
TAYLOR DS	Total	F1,F2,F3	12.47	1.70	N/A	4.6	MUSKOKA TS	M3
TAYLOR KIDD DS	T1	F1,F2,F3	8.32	0.98	N/A	3.4	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	T2	F4,F5,F6	8.32	1.32	N/A	3.7	KINGSTON GARDINER TS DESN1	M13
TAYLOR KIDD DS	Total	F1,F2,F3,F4,F5,F6	8.32	2.29	N/A	4.7	KINGSTON GARDINER TS DESN1	M13
TEMAGAMI DS	Total	F1, F2	12.5	0.44	32.4	3.3		
TERAULEY TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	18.37	59.3	18.4		
TERAULEY TS DESN1	A9A10	For any information or inquiries please contact Toronto Hydro	13.8	14.25	57.3	14.2		
TERAULEY TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	32.71	N/A	Sum of Buses		
TERAULEY TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.70	97.6	13.7		
TERAULEY TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	19.09	97.6	19.1		
TERAULEY TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	34.45	N/A	Sum of Buses		
TESSIER DS	Total	F1,F2	12.47	0.29	N/A	1.7	LONGUEUIL TS	M24
THAMESVILLE NORTH DS	Total	F1,F2,F3	8.32	0.74	N/A	3.1	KENT TS DESN2	M24
THEDFORD DS	Total	F1,F2,F3	8	0.89	N/A	1.9	FOREST JURA DS	F1
THESSALON PEACHY DS	Total	F1,F2,F3	2.4	0.22	N/A	1.7	WHARNCLIFFE DS	F2
THORAH DS	Total	F1,F2,F3	8.32	1.05	N/A	3.4	BEAVERTON TS	M24
THORNDALE DS	Total	F1,F2,F3	8	0.75	N/A	3.2	HIGHBURY TS	M11
THORNTON DS	Total	F1,F2,F3	8.32	0.86	N/A	3.3	ALLISTON TS	M4
THORNTON TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	30.97	346.0	98.2		
THOROLD ALLANPORT DS	Total	F1,F2	4.16	0.37	N/A	3.0	ALLANBURG TS	M8
THOROLD CLEVELAND DS	Total	F1,F2	4.16	0.33	N/A	2.7	THOROLD TS	M1
THOROLD DEFOE DS	Total	F1,F2	13.8	0.45	N/A	5.0	ALLANBURG TS	M8
THOROLD FRONT DS	Total	F1,F2	4.16	0.56	N/A	3.2	THOROLD TS	M1
THOROLD ORMOND DS	Total	F1,F2	4.16	0.53	N/A	2.9	THOROLD TS	M1
THOROLD PT ROBINS DS	Total	F2	4.16	0.20	N/A	1.2	ALLANBURG TS	M6
THOROLD SOUTH DS	Total	F1,F2	8.32	0.74	N/A	1.7	ALLANBURG TS	M8
THOROLD TS	BY	M5,M6,M7,M9	13.8	5.93	50.9	5.9		
THOROLD TS	EQ	M1,M2,M3	13.8	6.07	7.6	6.1		
THOROLD TS	Total	M1,M2,M3	13.8	12.01	N/A	Sum of Buses		
THOROLD TURNER DS	Total	F1,F2,F3,F4	8.32	0.57	N/A	2.3	ALLANBURG TS	M6
THRASHERS CORNERS DS	Total	F1,F2	27.6	2.17	N/A	5.0	BELLEVILLE TS	M2
THUNDER BEACH DS	Total	F1,F2,F3	8.32	1.12	N/A	3.5	WAUBAUSHENE TS	M7
TILBURY PELTIER DS	Total	F1,F2	8	0.52	N/A	2.9	TILBURY WEST DS	F2
TILBURY TS	B	M1	27.6	0.37	683.8	4.2		
TILBURY WEST DS	T1	F1	27.6	2.06	238.4	14.1		
TILBURY WEST DS	T2	F2	27.6	3.16	237.6	15.2		
TILBURY WEST DS	Total	F1,F2	27.6	5.22	N/A	17.2		
TILLSONBURG DS	Total	F1,F2,F3	8	0.58	N/A	2.5	TILLSONBURG TS	M2
TILLSONBURG TS	BY	M1,M2,M3,M4,M5,M6,M7,M8,M10	27.6	26.39	407.9	66.4		
TIMMINS TS	QZ	M5,M6,M7,M8,M9,M10,M11	27.6	19.65	176.6	66.5		
TINCAP DS	Total	F1,F2,F3	8.32	1.19	N/A	3.6	BROCKVILLE TS	M6
TIVERTON DS	Total	F1,F2,F3	8.32	1.49	N/A	3.9	DOUGLAS POINT TS	M6
TOMKEN TS DESN1	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	41.24	85.5	101.2		
TOMKEN TS DESN2	EZ	M23,M24,M25,M26,M27,M28,M29,M30	44	42.58	254.0	102.6		
TORY HILL DS	Total	F1,F2,F3	12.47	1.03	N/A	3.9	MINDEN TS	M1
TOTTENHAM NORTH DS	Total	F1,F2	8.32	1.05	N/A	3.5	EVERETT TS	M5
TRAFALGAR TS	BY	M4,M5,M6,M7,M8	27.6	23.10	0.0	63.1		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
WARKWORTH DS	Total	F1,F2	8.32	0.96	N/A	2.4	SIDNEY TS	R8S
WARREN DS	T1	F1, F2	12.5	0.55	134.0	4.6		
WARREN DS	T2	F3, F4	12.5	1.12	134.4	5.2		
WARREN DS	Total	F1,F2,F3,F4	12.5	1.64	N/A	5.7		
WARTBURG DS	Total	F1,F2,F3	8.32	0.96	N/A	2.7	STRATFORD TS	M6
WARWICK DS	Total	F1,F2,F3	8.32	1.11	N/A	3.5	WANSTEAD TS	M1
WASHAGO DS	Total	F1,F2,F3	8.32	1.32	N/A	3.7	ORILLIA TS	M2
WASHBURN ISLAND DS	Total	F1,F2,F3	8.32	1.14	N/A	3.5	LINDSAY TS	M8
WATERFORD JAMES DS	Total	F1,F2,F3	8.32	0.90	N/A	3.3	NORFOLK TS	M6
WAUBAMIK DS	Total	F1	12.47	1.30	N/A	4.2	PARRY SOUND TS	M1
WAUBAUSHENE NORTH DS	Total	F1,F2,F3	8.32	1.08	N/A	3.5	WAUBAUSHENE TS	M1
WAUBAUSHENE TS	JQ	M1,M2,M3,M4,M5,M6,M7	44	35.87	532.0	75.9		
WAUPOOS DS	Total	F1,F2,F3	8.32	1.40	N/A	3.8	PICTON TS	M5
WELCOME DS	Total	F1,F2,F3	8.32	0.79	N/A	3.2	PORT HOPE TS DESN1	M18
WELLAND EFFINGHAM DS	Total	F1,F2,F3	8.32	0.96	N/A	3.4	CROWLAND TS	M13
WELLINGTON DS	Total	F1,F2,F3	8.32	0.77	N/A	3.2	PICTON TS	M5
WELLINGTON WHARF DS	Total	F1,F2	8.32	0.60	N/A	3.0	PICTON TS	M6
WENDOVER DS	T1	F1	27.6	1.89	237.7	13.9		
WENDOVER DS	T2	F3	27.6	1.57	437.6	15.0		
WENDOVER DS	Total	F1,F3	27.6	3.46	N/A	15.5		
WESLEY DS	T1	F1,F2	27.6	0.45	N/A	5.0	ARMITAGE TS DESN1	M12
WESLEY DS	T2	F3,F4	8.32	0.37	N/A	2.8	ARMITAGE TS DESN1	M12
WEST BAY DS # 2	Total	F1,F2,F3	12.47	0.00	N/A	4.8	MANITOULIN TS	M25
WEST FLAMBORO DS	Total	F1,F2	8.32	0.57	N/A	2.3	DUNDAS TS	M8
WEST LAKE DS	Total	F1,F2,F3	8.32	0.86	N/A	3.3	PICTON TS	M5
WEST LORNE DS	Total	F1,F2,F3	8.32	0.75	N/A	3.1	DUART TS DESN1	M6
WESTBROOK DS	Total	F1,F2,F3	8.32	0.92	N/A	3.3	KINGSTON GARDINER TS DESN1	M14
WESTON LAKE DS	Total	F1, F2	24.9	0.75	443.7	6.7		
WESTWOOD DS	Total	F1,F2,F3	8.32	1.34	N/A	3.7	OTONABEE TS DESN2	M28
WHARNCLIFFE DS	Total	F1, F2	24.9	1.28	37.2	3.7		
WHEATLEY DS #2	Total	F1,F2,F3	8.8	1.69	N/A	4.1	LEAMINGTON TS DESN1	M22
WHITBY TS DESN1	BY	M43, M44, M45, M46, M47, M48	27.6	0.41	5.7	25.4		
WHITBY TS DESN1	EZ	M5, M6, M7, M8	44	10.92	527.9	35.9		
WHITBY TS DESN2	JQ	M21,M22,M23,M24,M25,M26,M27,M28	44	50.02	274.6	110.0		
WHITE RIVER DS	Total	F1, F2, F3	24.9	10.00	106.4	13.6		
WHITEDOG DS	Total	F1	12.47	0.49	N/A	1.5	WHITEDOG FALLS GS	FP3
WHITEFISH DS	Total	F1, F2, F3	12.5	1.60	18.4	4.8		
WHITNEY DS	Total	F1,F2	12.48	0.54	N/A	TC	WALLACE TS	M6
WIARTON CLAUDE DS	Total	F1,F2,F3,F4,F5,F6	4.16	0.69	N/A	3.1	OWEN SOUND TS	M23
WILHAVEN DS	T1	F1, F2, F3	27.6	4.07	374.5	20.4		
WILHAVEN DS	T2	F4, F5	27.6	4.53	373.7	20.8		
WILHAVEN DS	Total	F1,F2,F3,F4,F5	27.6	8.60	N/A	20.0		
WILLIAMSTOWN DS	Total	F1,F2,F3	8.32	0.95	N/A	3.4	ST LAWRENCE TS	M25
WILLOW BEACH DS	Total	F1,F2,F3	8.32	0.69	N/A	3.1	BROWN HILL TS	M11
WILSON TS DESN1	BY	M1,M2,M3,M4,M5,M6,M7,M8	44	52.13	278.0	112.1		
WILSON TS DESN2	JQ	M11,M12,M13,M14,M15,M16,M17,M18	44	46.30	260.8	106.3		
WILSONVILLE DS	Total	F1,F2,F3	8.32	1.09	N/A	2.8	NORFOLK TS	M6
WILTSHIRE TS DESN1	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	21.51	95.7	41.7		
WILTSHIRE TS DESN2	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	13.84	84.5	37.8		
WILTSHIRE TS DESN2	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	13.84	86.3	37.8		
WILTSHIRE TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	27.69	N/A	Sum of Buses		
WINCHESTER DUFFRN DS	Total	F1,F2,F3	8.32	0.41	N/A	TC	CHESTERVILLE TS	M2
WINCHESTER ST LAW DS	Total	F1,F2,F3	8.32	0.56	N/A	TC	MORRISBURG TS	M26
WINGHAM DS	Total	F1,F2	8.32	0.93	N/A	2.4	WINGHAM TS	M5
WINGHAM TS	BY	M3,M4,M5,M6	44	17.01	235.6	57.0		
WINONA TS	JQ	M11,M12,M13,M14,M15,M16	27.6	13.26	166.5	53.3		
WOLSEY LAKE DS	Total	F1,F2	12.5	0.50	N/A	3.3	MANITOULIN TS	M25
WOLVERTON DS	T1	F1	27.6	3.34	587.7	15.3		
WOLVERTON DS	T2	F2	27.6	3.18	587.4	15.2		
WOLVERTON DS	Total	F1,F2	27.6	6.53	N/A	18.5		
WONDERLAND TS	BY	M1,M2,M3,M4,M5,M6,M7,M8	27.6	28.28	21.4	68.3		

Glossary

Bus Name – The name of the distribution bus connected to the associated Hydro One transformer station.

Feeder Name – The Hydro One designation for the feeder connected to the associated distribution bus.

Minimum Load – The lowest load that we can reasonably expect to experience on the bus.

Short Circuit Capacity – The maximum amount of short circuit contribution that a generator can add to a station bus before short circuit limits are exceeded.

Station Name – The name of the Hydro One-owned transformer station.

Sum of Buses – This is a term used at a Dual Element Spot Network (DESN) station to define the amount of overall capacity available at the station. It is determined by adding the capacity available on each individual bus.

Thermal Capacity – The estimated amount of generation that can be connected to a bus before exceeding the reverse flow limits of the transformer.

Upstream TS – The name of the Hydro One-owned, transmission-connected transformer station that supplies the identified distribution

Upstream TS Feeder – The Hydro One designation for the feeder that connects the identified distribution station to the Upstream TS.

Voltage – The nominal voltage level of the distribution feeder.

TC – Capacity Allocation Required projects are restricted at these stations due to Transmission Constraints (TC).
All other projects will be assessed individually.

Appendix R: Fleet Management Policy

Fleet Management Policy

Policy Statement

All vehicle procurement decisions regarding existing fleet shall follow the criteria and assessment guidelines outlined in this document.

Scope

This policy applies to all vehicles owned and operated by Oshawa Power.

Roles

Fleet management shall be overseen by the Fleet Management Committee ("Committee") to be comprised of the following:

Title	Committee Role
Vice President, Engineering & Operations	Executive Sponsor
Manager, Distribution Construction	Operations Manager
Supervisor, Distribution Construction	Operations Representative
Fleet and Facilities Advisor	Chair
Manger, Procurement	Procurement Representative
Systems Engineer	Engineering Representative
Distribution Engineer	Engineering Representative
Powerline Technician	Operations Representative
Powerline Technician on JHSC	Operations JHSC Representative

In particular …

The Committee Chair is responsible for:

1. Conducting an annual review and/or update of this policy;
2. Communicating any policy changes to staff;
3. Coordinating fleet condition assessments;
4. Establishing and chairing quarterly Committee meetings;
5. Ensuring all vehicles are maintained in a state of good repair, and all safety issues are dealt with appropriately and forthwith; and
6. Escalating major, emerging or systemic fleet problems or concerns to the Committee for discussion and determination of appropriate solutions.

All Committee members are responsible for:

1. Contributing to the effective and fiscally responsible management of fleet assets in accordance with this policy by:
    a. Ensuring all functional, operational, health and safety and regulatory requirements are met and addressed in a timely manner; and
    b. Reviewing fleet asset information used to make procurement decisions

Fleet Management Policy

Committee Mandate

The Committee will meet quarterly to review fleet asset information, discuss fleet management issues and help determine any vehicle procurement decisions.

Information to be reviewed will include:

- Key performance indicators and trends for all vehicles such as fleet utilization, engine hours, kilometers, and maintenance expenses;
- Fleet condition assessments; and
- Operational, functional, regulatory and/or health and safety concerns

Fleet condition assessments will be conducted yearly on each vehicle, or at intervals determined most appropriate by the Committee depending on vehicle type and usage. Assessments will be completed by a third party and Oshawa Power jointly, and will deliver the following information:

- Vehicle Condition;
- Appraisal Value; and
- Photo records of interior and exterior.

The Committee is also responsible for preparing annual capital investment work plans for fleet that seek to align planned expenditures with the approved Distribution System Plan ("DSP"). Any deviation from the approved DSP will require a formal change request and justification supported by updated asset information and condition assessments.

Vehicle Procurement Criteria

The Committee shall use the criteria listed below to determine if an existing vehicle is eligible for consideration of replacement. All vehicles in service are listed in Appendix A. When replacement criteria has been met and Committee members have reached consensus on replacement, a Vehicle Replacement Form shall be prepared for review and approval by the Committee Executive Sponsor. The Vehicle Replacement form is found in Appendix B.

Commercial vehicle classification is determined by the *Highway Traffic Act* R.S.O 1990, regulation O. Reg. 419/15.

1. Diesel Engine Heavy Fleet

Heavy Vehicles include Digger Derrick, Single Bucket, and Double Bucket trucks.

Criteria:

- Recorded mileage of 250,000 km;
- Recorded engine hours of 10,000 hours;
- 10 years of service;
- Changing departmental needs;
- Maintenance and repair costs over a year exceed the book value;
- Condition assessment finds the vehicle to be unfit for service;
- Changing emissions, weight, and safety regulations;
- Usefulness to the company.

Replacement of Heavy Vehicles are limited to one per fiscal year to minimize capital expenditures unless an emergency occurs in the fleet. If two vehicles are eligible for replacement in the same year, the vehicle with higher Kilometers/Hours/Age will take precedent and the other will follow in the subsequent year.

If a vehicle with 10 years of service has considerably less than 250,000 km and/or 10,000 hours, consideration will be made to postpone the unit's replacement if the estimated remaining service life is estimated to be 5 years or more.

2. Light Duty Fleet

These vehicles include all light fleet such as pickup trucks, vans, service vehicles, and sedans either gasoline or diesel-powered.

Criteria:

- Recorded Mileage of 150,000 km;
- 6 years of service;
- Changing Departmental needs;
- Maintenance and repair costs over a year exceed the book value;
- Condition assessment finds the vehicle to be unfit for service;
- Changing emissions or safety regulations;
- Usefulness to the company.

If a vehicle with 6 years of service has considerably less than 150,000 km, consideration will be made to postpone the unit's replacement if the estimated remaining service life is estimated to be 3 years or more.

Document Review

This document will be reviewed annually and updated as required.

APPENDIX "A" Fleet Inventory

Truck Numb	Body	Make	Model	Truck Year
3	Sierra LT Dump Truck	GMC	GMC Sierra Dump Truck	2016
5	Double Bucket	Freightliner	Freightliner Double Bucket	2012
7	Double Bucket	Freightliner	Freightliner Double Bucket	2015
10	Radial Boom Derrick	Freightliner	Freightliner Digger Derrick	2012
12	Digger Derrick Protek Body (Freightlin	Freightliner	Freightliner Digger Derrick	2012
14	Single Bucket	Freightliner		2011
15	Single Bucket	Freightliner	Freightliner Single Bucket	2018
16	52' Single Bucket Truck	Freightliner	Freightliner Single Bucket	2016
18	50' Single Bucket Material Handler	Freightliner	Freightliner Single Bucket	2012
19	46' Single Bucket Material Handler	Freightliner	Freightliner Single Bucket	2012
20	Chevrolet Cruze - 4 DR LS Sedan	Chevrolet	Chevy Cruze	2013
22	E-450 Special Services	Ford		2016
24	1/2 Ton Pickup	Chevrolet	Chevy Silverado 1500	2013
25	1/2 ton pickup	Chevrolet	Chevy Silverado 1500	2013
26	3/4 Ton Chev Pickup 4x4	Chevrolet	Chevy Silverado 2500	2013
27	1/2 ton pickup	Chevrolet	Chevy Silverado 1500	2014
29	City Express Van LS Fwd	Chevrolet	Chevy City Express Van	2015
32	1/2 Ton 4x4 Ex Cab	Chevrolet	Chevy Silverado 1500	2006
33	1/2 Ton Pick Up	Chevrolet	Chevy Silverado 1500	2015
35	Silverado 4WD Double Cab	Chevrolet	Chevy Silverado 1500	2017
44	Cub Van	Freightliner	Freightliner Cub Van	2012
48	Volt Electric Car (Regent Park)	Chevrolet	Chevy Volt	2012
68	3/4 Ton Cargo Van	GMC		2014
69	1/2 Ton Pick Up	Chevrolet	Chevy Silverado 1500	2015
80	Dump Body	Chevrolet	Chevrolet Silverado 3500	2019
81	Underground Service	Ford		2019
82	1/2 ton pickup	Chevrolet	2019 CHEV 1/2 Ton Extra Ca	2019
83	1/2 ton pickup	Chevrolet	2019 CHEV 1/2 Ton Extra Ca	2019
84	1/2 ton pickup	Chevrolet	2019 CHEV 1/2 Ton Extra Ca	2019
85	1/2 ton pickup	Chevrolet	2019 CHEV 1/2 Ton Crew Ca	2019
87	Transit Van	Ford	2019 Ford Transit Van	2019

APPENDIX "B" – Vehicle Replacement Form

Fleet Replacement Request Form

Date: ____________ **Request Submitted by:** ____________

Truck Information:

Vehicle Number:		**Department:**	
Body:		**Year:**	
Truck Type:			

Factor	Current LTD	Renewal Threshold
Age		6
Kilometers		150,000
M&R Costs		

Additional Replacement Comments:

Renewal Information:

DSP Planned Replacement Year		**Current Year**		**Lead Time**	
Budgeted Replacement Cost		**Quoted Price**		*Lead time in Months	
Replacement Type:	Increased Functionality	Decreased Functionality		Like for Like	
Explain Replacement Requirements that differ from current vehicle:					

List of included documentation:

Confirmation

Distribution

Signature: ____________ Date: ____________

Name(Printed):

Approval

Signature: ____________ Date: ____________

Matthew Strecker, VP, Engineering and Operations

Finance

Signature: ____________ Date: ____________

Name (Printed): ____________

Fleet Management Policy

Fleet Replacement Request Form - Heavy Fleet

Date: ____________ **Request Submitted by:** ____________

Truck Information:

Vehicle Number:		**Department:**	
Body:		**Year:**	
Truck Type:			

Factor	Current LTD	Renewal Threshold
Age:		10
Engine Hours		10,000
Kilometers		250,000
Cumulative Repair Costs		

Additional Replacement Comments:

Renewal Information:

DSP Planned Replacement Year		**Current Year**		**Lead Time**	
Budgeted Replacement Cost		**Quoted Price**		*Lead time in Months	
Replacement Type:	*increased/ decreased/ like for like functionality*				

Explain Replacement Requirements that differ from current vehicle:

List of included documentation:

Confirmation

Distribution

Signature: ____________ Date: ____________

Name (Printed): ____________

Engineering (Specs)

Signature: ____________ Date: ____________

Name (Printed): ____________

Approval

Signature: ____________ Date: ____________

Name: **Matthew Strecker, VP, Engineering and Operations**

Finance

Signature: ____________ Date: ____________

Name (Printed): ____________

Appendix S: Historical 2020 Miscellaneous Project Narratives

A. General Information (5.4.3.2.A)						
Project/Activity	Pole Yard Metal Building Storage and Security					
Project Number	GP-07					
Investment Category	General Plant					
	2020	2021	2022	2023	2024	2025
Capital Cost	$175,000	-	-	-	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A	N/A
Net Cost	$175,000	-	-	-	-	-
O&M Cost	2020	2021	2022	2023	2024	2025
	-	-	-	-	-	-
Customer Attachments and Load						
Not Applicable						
Start Date	2020	In-Service Date	2020			
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4		
	-	-	-	-		
Project Summary						
OPUCN plans to construct a metal building and install security cameras at the existing remote pole yard location to address ongoing security issues. This metal building would enclose critical equipment that is stored in this yard.						
Risk Identification & Mitigation						
OPUCN will request quotes and perform the proper procurement policy (RFQ/RFP) to mitigate any risk associated with the procurement process. This project should not experience any scheduling risks. In order to mitigate the risk that this structure will not fulfill all design and construction requirements, OPUCN will ensure that each department is approached to indicate any further requirements and that licensed contractors are hired to complete the installation. In the future if the pole yard location is retired, the structure, not including the concrete pad, can still be utilized in a different location mitigating any risk associated with obsolescence.						
Comparative Information on Expenditures for Equivalent Projects/Activities						
Year	2015	2016	2017	2018	2019	
Historical Charges	-	-	-	-	-	
This project is an additional investment to address the security issues we have been experiencing at this location. There are no comparative information relative to OPUCN work.						
REG Investment Details including Capital and OM&A costs						
Not Applicable						
Leave to Construct approval under Section 92 of the OEB Act						
Not Applicable						
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material						
The following is a typical image of a metal building infrastructure that will be utilized to house distribution equipment in the pole yard.						

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver of this initiative is in the General Plant investment category aimed at addressing the theft and/or damage concerns that are being experienced at the pole yard location.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
This investment is aimed at meeting business efficiencies and effectiveness. Critical pieces of equipment will be kept in a safe location to protect asset from environmental damage or prevent asset from being stolen which will result in having a more reliable storage location.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source and nature of information used to justify this investment are historical theft instances, vandalism instances, etc. which are currently hard to prevent.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Having available required equipment ensures that necessary maintenance work can be completed to support the reliability of the system.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This project has been identified as high priority based on the level of AM objectives met and will improve business efficiencies and effectiveness providing increased security for critical distribution equipment. We rely on the equipment stored at the pole yard for both planned construction and corrective maintenance work.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Reliable equipment storage is required to support OPUCN's crews in their day-to-day activities and missing or damaging some of this equipment will results in delays of completing planned work and longer time in performing corrective maintenance.

Analysis of Project & Alternatives – Net Benefits Accruing to Customers

Ability to meet scheduled planned work to meet new customers' requests and complete corrective work as quickly as possible.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

Not Applicable

Project Alternatives (Design, Scheduling, Funding/Ownership)

The following project alternatives for this investment have been considered:

1. "Do Nothing" – Security personnel are currently checking the pole yard at intervals during the night. This still does not stop theft from occurring. Increasing the length of time the security personnel are onsite during the overnight hours would increase operational charges for this site significantly. Doing nothing will also not provide additional protection from environmental damage.
2. Relocation of Assets – This alternative would require leasing land or space which requires more capital expenditures to complete. There is also no guarantee that the new location will be more secure.

Safety

Securing the equipment in the pole yard will act as a deterrent to theft, vandalism and contamination of the assets. It may also protect potential perpetrators from injuring themselves which would cover OPUCN in the case that legal action is pursued.

Cyber-Security, Privacy (where applicable)

Camera infrastructure will be installed and secured through our OPUCN fibre infrastructure.

Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

Not Applicable

Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)

The metal portion of the building (foundation not included) can be repurposed if required.

Environmental Benefits (where applicable)

The enclosed building will ensure that contaminants remain contained and will not harm the local environment.

Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)

Not Applicable

Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)

Not Applicable

Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity

Camera infrastructure will be installed and secured through our OPUCN fibre infrastructure.

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
The construction of a metal building and installation of security cameras at the remote pole yard location will address ongoing security issues. This metal building will also enclose critical equipment that is stored in this yard thus protecting it from the environmental damage.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
Equipment damages, theft, and soil contamination are incurring unforeseen costs and impacts to reliability. Additionally, OPUCN is employing a security company to monitor and patrol the premises 10-12 hours per day. Constructing a metal enclosure would eliminate both of these costs.

A. General Information (5.4.3.2.A)						
Project/Activity	Back- Up Generator Replacement					
Project Number	GP-08					
Investment Category	General Plant					
	2020	2021	2022	2023	2024	2025
Capital Cost	$205,000	-	-	-	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A	N/A
Net Cost	$205,000	-	-	-	-	-
O&M Cost	2020	2021	2022	2023	2024	2025
	-	-	-	-	-	-
Customer Attachments and Load						
Not Applicable						
Start Date	2020	In-Service Date	2020			
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4		
	-	-	-	-		
Project Summary						
OPUCN plans to replace the existing back-up generator which is aged. This backup generator supports the control room, IT infrastructure, metering & operations work stations, emergency lighting, storehouse elevator, and the garage doors. The existing generator is currently being supported by a rental unit to ensure we have back-up redundancy. The replacement generator will be mobile and able to relocate to new buildings or locations to support a variety of needs.						
Risk Identification & Mitigation						
OPUCN will request quotes, and perform the proper procurement policy (RFQ/RFP) to mitigate any risk associated with the procurement process. This project should not experience any scheduling risks. The replacement generator that will be selected will meet all future foreseeable loads that will need to be supported during a major outage event.						
Comparative Information on Expenditures for Equivalent Projects/Activities						
Year	2015	2016	2017	2018	2019	
Historical Charges	-	-	-	-	-	
This project is an additional investment that addresses the back-up generation concerns. There are currently no relevant comparative information for this investment.						
REG Investment Details including Capital and OM&A costs						
Not Applicable						
Leave to Construct approval under Section 92 of the OEB Act						
Not Applicable						
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material						
The following image is a typical diesel generator that is being considered.						

XQ230 GENERATOR

The XQ230 provides 230 kW of standby power. The trailer mounted generator is EPA Tier 4 certified and CSA-282 compliant, with fully weatherproof and sound attenuated enclosure. Other features include automatic voltage regulation, switchable voltage output and automatic start.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The main driver of this project is General Plant Investment Category to ensure that a resilient back-up power system is available to support our critical systems in an emergency situation.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Back-up generator will support critical systems during a major outage so our team is able to communicate with customers, employees, and our electric system to efficiently dispatch crews.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source and nature of information use to support this investment is the existing generator’s age, hours, and deteriorating reliability as well as the requirement to support additional loads that exceed that of the existing generator.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

Ensuring that our Control Room and associated systems are operational in an emergency is imperative to our effectiveness in restoring power and minimizing risks during planned outages to portions of the system.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

This is medium priority due to the level of AM objectives met identified in Section 5.3.1, however, this is an essential equipment to improved business efficiencies and effectiveness which will provide a reliable back-up generation system. Without a reliable back-up power solution, our team would not be able to react to an emergency situation effectively and expediently.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

A reliable back up generator will support critical systems during a major outage so our team is able to restore system in expedient manner and will allow us to maintain required level of operability

Analysis of Project & Alternatives – Net Benefits Accruing to Customers

The following are the benefits accruing to customers:

1. Faster restoration during major forced outages.
2. Lower risk during planned outages
3. Ensured level of system operability
4. Alternative power solutions for key accounts during isolated outages.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

The duration of a widespread outage will be mitigated if our critical systems remain online throughout the emergency situation.

Project Alternatives (Design, Scheduling, Funding/Ownership)

The “do nothing” approach was considered as a project alternative, however, doing nothing would increase risk of prolonged outages and system response to planned outages.

Safety

Without backup generation employees and customers (the community) are exposed to inherent safety risks associated with ability to reliably support the business, particularly during emergencies.

Cyber-Security, Privacy (where applicable)

Not Applicable

Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

Not Applicable

Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)

The new generator unit will include the ability to be able to relocate.

Environmental Benefits (where applicable)

Not Applicable

Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C.   Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
This backup generator supports the control room, IT infrastructure, metering & operations work stations, emergency lighting, storehouse elevator, and the garage doors. The existing generator is currently being supported by a rental unit to ensure OPUCN has back-up redundancy, however, a reliable permanent back-up generator is the most preferred approach to ensure that OPUCN has a reliable back-up generating infrastructure.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
The current system employs a rental unit as an auxiliary to our existing generator. The purchase of a new generation unit would decrease our operational expenditures associated with the rental unit.

A. General Information (5.4.3.2.A)						
Project/Activity	Back-Up Control Room and Associated IT Infrastructure					
Project Number	GP-09					
Investment Category	General Facilities					
	2020	2021	2022	2023	2024	2025
Capital Cost	$200,000	-	-	-	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A	N/A
Net Cost	$200,000	-	-	-	-	-
O&M Cost	2020	2021	2022	2023	2024	2025
	-	$11,300	$7,300	$7,300	$7,300	$7,300
Customer Attachments and Load						
Not Applicable						
Start Date	2020	In-Service Date	2020			
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4		
	-	-	-	-		

Project Summary

OPUCN plans to install a back-up operations centre and associated IT infrastructure at MS-9 and update the current system control:

- Investments in 2020 include building office Control Room update
- New backup System Control at MS-9 with "Emergency Restoration Backup Center"
- IT Network Infrastructure and Additional IT Appliances

Risk Identification & Mitigation

In order to mitigate risks, these initiative should be undertaken to support and allow us to sustain (and improve) the overall business from an operations standpoint. OPUCN will request quotes, and perform the proper procurement policy (RFQ/RFP) for each requirement prior to commencing, team input, system controller involvement and senior management will have an opportunity to provide input and options. Full commissioning of backup power supplies, system security and facility operation will be completed prior to installing equipment. System implementation for backup System Control and Data Acquisition (SCADA), and Outage Management System (OMS) will be completed prior to being implemented into production. Emergency preparedness exercises will be implemented prior to deeming the back-up emergency centre in-service.

Comparative Information on Expenditures for Equivalent Projects/Activities

There is no comparative data going back to 2015, or more recently.

REG Investment Details including Capital and OM&A costs

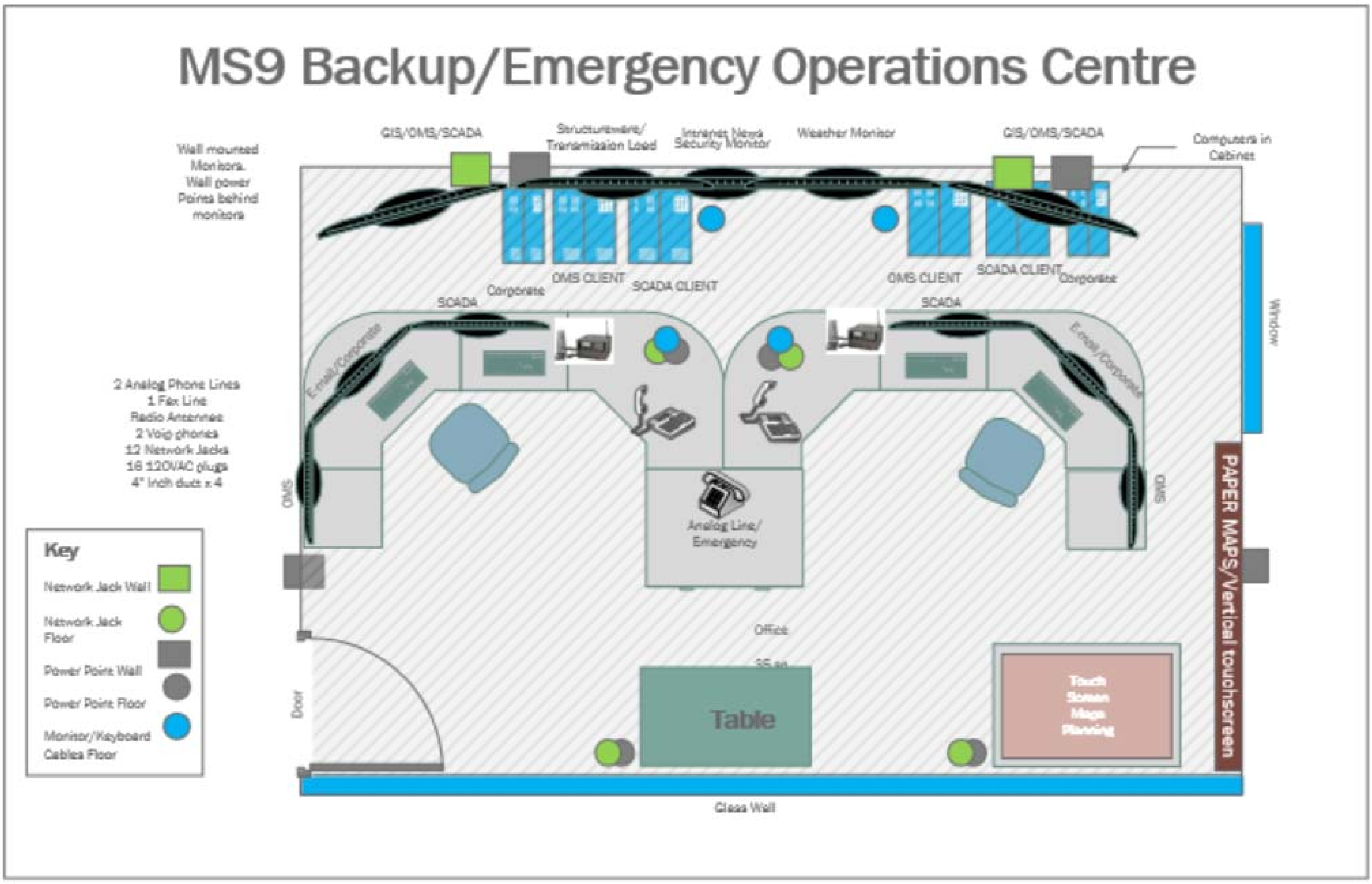
Not Applicable

Leave to Construct approval under Section 92 of the OEB Act

Not Applicable

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following image is the proposed layout of the back-up control room in MS9.



The image below shows a typical view of a control room set-up.

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver of these initiative is in General Plant Investment Category and addresses “essential needs” to support the business. The system control room operation has not been updated in 10 years and the opportunity of efficiencies and digitization would provide redundancy currently not available (due to current paper maps and processes).
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are reliability and customer satisfaction.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Given that we are in an aged facility, a lot of the equipment is aged, deteriorating, and unreliable. The back-up operations centre will provide redundancy in operations for all systems currently being utilized.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Having back-up system and equipment ensures that necessary planned and corrective work can be completed to support the reliability of the system.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This is high priority investment that meets major AM objectives identified in Section 5.3.1 as it provides redundancy to the operational systems.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
The back-up control room ensures that our team will have an available back-up system if the main system becomes unavailable during an outage situation. This will provided efficiencies and will streamline the process when the main system fails.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Having a properly laid-out back-up operational center will assist with faster response, communication and information provided if the main system fails.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
A back-up operations centre ensures that a proper infrastructure is available during emergency situations. Without system back-up, reactive response time could suffer and frequency and duration of outages could increase if there is no access to the main control room or the main systems become unavailable.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternative considered is to “do-nothing”, however, this will not provide any redundancy in the system and can be impactful if the main system is damaged or inaccessible during both normal operation and emergencies.

Safety
A back-up control system will improve the safety of the field crews by ensuring that they always have reliable information on-time.
Cyber-Security, Privacy (where applicable)
The system control would have restricted access, updated security, and isolation to the system control area.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
To meet cyber security requirements changes at system control rooms are required to keep with current regulations.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The back-up control room and IT room will also serve as a back-up to all systems ensuring that the systems in place are compatible with any future operational requirements.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The back-up control room and IT room will also serve as a back-up to all systems ensuring that the systems in place are compatible with any future operational requirements.

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
A back-up operations centre ensures that a proper infrastructure is available during emergency situations. Without system back-up, reactive response time could suffer and frequency and duration of outages could increase if there is no access to the main control room or the main systems become unavailable.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
here are currently no alternatives to updating the current system control room as security is a high concern. A backup system control disaster recovery area is required as a risk mitigation strategy for any loss of current facilities. Business operations would be operating at a significantly reduced efficiency if the current system control room was not available.

A. General Information (5.4.3.2.A)						
Project/Activity	Customer Self-Serve Online Portal (Green Button Dashboard)					
Project Number	GP-10					
Investment Category	General Plant					
	2020	2021	2022	2023	2024	2025
Capital Cost	$140,000	-	-	-	-	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A	N/A
Net Cost	$140,000	-	-	-	-	-
O&M Cost	2020	2021	2022	2023	2024	2025
	-	-	-	-	-	-

Customer Attachments and Load

All Customers

Start Date	2020	In-Service Date	2020

Expenditure Timing for the Planning Horizon	2021Q1	2021Q1	2021Q1	2021Q1
	-	-	-	-

Project Summary

Enhanced self-service tool that will allow customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics. The software has the ability to provide current alerts based on customer settings including bill/usage thresholds, high usage and other configurable options. It allows the customer to sign up for payment and past due reminders as well as a quick pay feature which links to several financial institutions. It has the ability to show net metering charts and provide weather chart overlays as well as holiday and rate management tools. The software has an OMS real time secure web service which allow customers to sign up for outage notifications by email, text or IVR.

Quick and easy access to data is at the heart of modernizing Ontario's energy system and it represents a growing area of effort for Ontario LDCs. When done right, data access platforms allow us to optimize the grid and convert passive energy users to educated energy prosumers. When done in an outdated way, data platforms provide unusable data sets that alienate customers and add to LDC staff burden.

In a 2018 Customer Satisfaction survey is was noted that providing several communication channels to meet customer need was key to improving the customer experience. It was also noted that rising customer expectation meant 24/7 availability to various communication avenues such as an online self-serve option for managing their account.

Risk Identification & Mitigation

Data-related projects are all subject to risks associated with customer privacy and cyber security. To mitigate these risks, the project will use two strategies:

- Ongoing monitoring and deployment of industry best practices such as multi-layer authentication processes and Canadian data warehousing; and,
- Compliance and monitoring under the Ontario Energy Board cyber-security protocol.

Compliance will be established using independent legal review and monitoring will take place via OPUCN's Privacy Officer.

As for mitigating scheduling risks, OPUCN will request quotes, and perform the proper procurement policy (RFQ/RFP) for each requirement prior to commencing.

Comparative Information on Expenditures for Equivalent Projects/Activities

There are no comparable projects at this time.

REG Investment Details including Capital and OM&A costs

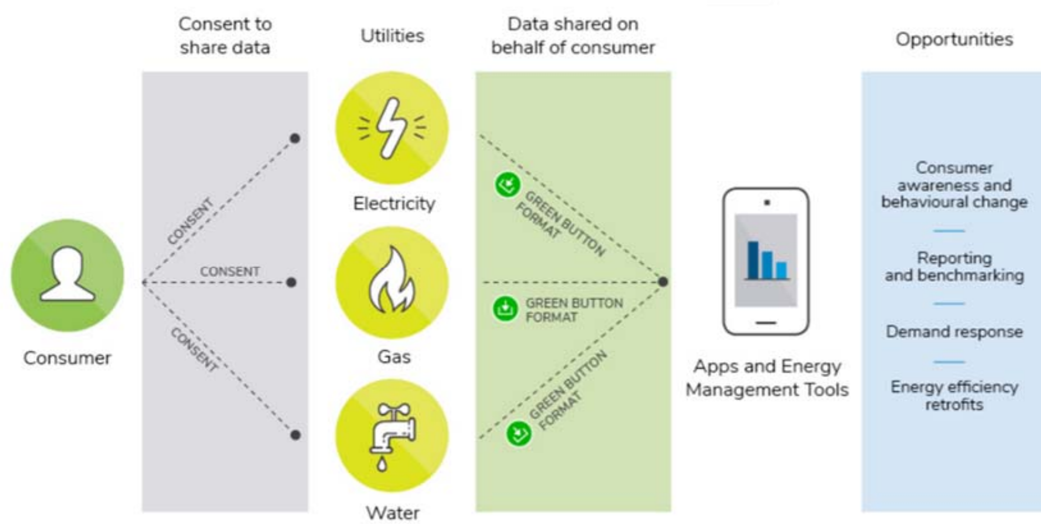
Not Applicable

Leave to Construct approval under Section 92 of the OEB Act

This project does not fall in the category requiring leave to construct.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

The following is a typical overview of Green Button:



B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)

Efficiency, Customer Value & Reliability – Investment Main Driver

The main driver for this project is to increase customer satisfaction by offering a customer care web self-service experience that engages customers while also reducing call/wait times, improve communication by providing targeted messages and information as well as a tool that will help to educate customers on consumption patterns, conservation trends and reduce customer costs.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

The secondary driver is operational cost efficiencies as it will decrease operational costs, improve bill payment and have a positive impact on overall customer satisfaction. Our current tool is old and is no longer supported.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

Aligns with customer interests will improve overall quality of customer service and customer communications.

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

In a 2018 Customer Satisfaction survey is was noted that providing several communication channels to meet customer need was key to improving the customer experience. It was also noted that rising customer expectation meant 24/7 availability to various communication avenues such as an online self-serve option for managing their account.

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
An up-to-date Customer Self-Service Online Portal Software will allow the customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics meeting the needs of the customers. This will also provide an OMS real time secure web service reflecting the current state of the network.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
There is a high level of prioritization for this project as it meets majority of AM objectives identified in Section 5.3.1 and will address customer satisfaction and expectation by providing an online self-serve option for customer to manage their account.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
Expected to allow OPUCN online tool that is more commonly used in the Ontario Market and provides customers with on line customer service improvements.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Investment in a new customer self-service tool will provide a more robust service offering to customers including expanded self-service options and improved communication to customers. This investment will allow a better ability to respond to changes, enhanced customer service ability, better responsiveness and timely updates to customers.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
Not Applicable
Project Alternatives (Design, Scheduling, Funding/Ownership)
Do Nothing – This would result in the existing system which will not provide any benefits to the customers and will not address the comments that was received during the customer satisfaction survey.
Safety
Not Applicable
Cyber-Security, Privacy (where applicable)
OPUCN emphasizes the importance of security. This self-serve portal is secure and requires a customer password and username for authentication.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
An up-to-date Customer Self-Service Online Portal Software will allow the customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics meeting the needs of the customers. This will also provide an OMS real time secure web service reflecting the current state of the network.

Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
One of the modules has a Commercial and Industrial demand portal that is specifically designed for large commercial and industrial customers and key accounts where energy demand management and monitoring are critical to cost controls and savings for the customer.
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
An up-to-date Customer Self-Service Online Portal Software will allow the customers the ability to log into a secure portal to view balances, due dates, bills as well as smart meter activity and predicted bill statistics meeting the needs of the customers. This will also provide an OMS real time secure web service reflecting the current state of the network.

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
Using existing systems will result in a decrease in customer satisfaction in terms of providing customer service.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts
Feedback on the 2018 customer satisfaction survey was used as a justification to proceed with the project which will provide customers the ability to view and understand their electric consumption and billing information.