Hydro Ottawa
ENGO®+GEMS® Project Report

Report on Evaluation, Measurement & Verification Analysis and Economic Use Case for Kanata MTS

Version 2.3

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Sentient Energy
Authors: Umang Deora, Damien M Tholomier
Reviewers: Wassim Akhdar, Hong Chun, Kevin Ainsworth

RECORD OF REVISION

Issue	Date	Authors	Comments
Rev1.0	October 10, 2020	Umang Deora	Version creation with EM&V performed with field-based estimates
Rev2.1	November 9, 2020	Umang Deora, Damien Tholomier	EM&V computed using June 2018 – May 2019 to June 2019 – May 2020 data and associated Economic Use Cases (Capacity Reduction, Energy Savings, Technical Loss Reduction)
Rev2.2	December 1, 2020	Umang Deora, Damien Tholomier	Integration of comments from Hydro Ottawa into final report
Rev2.3	September 22, 2021	Damien Tholomier	Addition of an abbreviation / definition section Integration of the Winter testing period Integration of the final economic analysis Update of all numbers using measured CVR factor for Power and Energy Update of the section 6.3 Sentient Energy's formatting of the document

APPROVAL

Name	Function
Damien M. Tholomier	EVP Product Management & Project Delivery

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1. Abbreviations and definitions

All capitalized terms not defined herein will have the meanings set forth in the document.

a) **AMI: Advanced metering infrastructure** is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

b) **CSA**: the **Canadian Standards Association** is a standards organization which develops standards in 57 areas.

c) **CVR: Conservation voltage reduction** enables electric distribution utilities to achieve a significant reduction in energy and peak demand at little or no cost, and without impacting customers through load shedding or equipment investments. Advantages of CVR include peak shaving, energy conservation, potential lowering of greenhouse gases and mitigation of distributed generation (DG) voltage impacts.

d) **LCOC: Levelized Cost of Capacity** refers to the annual fixed revenue requirements in nominal dollars for each resource that are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month/year.

e) **LCOE: Levelized cost of electricity** refers to the estimates of the revenue required to build and operate a generator over a specified cost recovery period. The LCOE is also referred to as the levelized cost of electricity or the levelized energy cost, is a measurement used to assess and compare alternative methods of energy production. The LCOE of an energy-generating asset can be thought of as the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime.

f) **LTC or OLTC: on-load tap changers** regulate the turns ratio and thus the voltage ratio of an electrical transformer. Unlike its no-load counterpart, on-load tap changers do this without interrupting the load current.

g) **VVC: Volt-VAr Control is the capability** to control the voltage level and reactive power (VArs) level at different points of the distribution grid by using a combination of LTCs, LVRs and Capacitor Bank controllers. Without a proper coordination, control actions may affect voltages, VArs flow, power factor and finally raise energy loss, load demand, etc.

h) **VVO: Volt-VAr Optimization** is the capability to optimize the vars & voltage in the system in order to achieve a certain objective by controlling capacitor banks and voltage regulators. VVO usually is accomplished by a ADMS system and requires communication to field devices (for measurement reading and issuing controls).

2. Executive Summary

The purpose of this document is to present and assess results from the Kanata Municipal Transmission Substation (MTS) deployment of Sentient Energy's GEMS®+ENGO® solution. High level benefits measured by the project include Voltage Support/Visibility and Peak Demand / Capacity Reduction as primary objectives, and Energy Savings and Technical Loss Reduction as secondary benefits.

Hydro Ottawa's Kanata MTS has five (**5**) distribution circuits and forty-three (**43)** pole-mount ENGO units deployed at the low voltage outliers to ensure the tight regulation of voltage at a local and feeder wide level and prevent a dip below the minimum **CSA-CAN3-C235-83** standard (Normal and Extreme Voltage Operating Limits) during periods of normal or peak loading conditions.

The Sentient Energy's GEMS+ENGO solution allows Hydro Ottawa to reap multiple benefits of peak demand / capacity reduction, voltage stability, grid visibility and dynamic VAr management, all with deterministic control within the hands of the distribution operators.

Voltage Optimization (VO) is defined as a combination of VVO and CVR. VVO regulates distribution voltages by coordinating medium voltage (MV) assets such as LTC and switched capacitor banks (SCB) to reduce distribution losses and improve power factors. As provinces continue to advance ratepayer-funded EE initiatives and establish increasingly aggressive energy conservation goals, it is vitally important to consider VVO/CVR programs as a cost-effective tool. Conventional VVO/CVR, traditionally managed from centralized software platforms, initiates a systematic reduction of consumer voltages to reduce energy consumption or demand with performance in the range of 0.8% to 2% efficiency.

Using its patented advanced technology, Sentient Energy has developed a Grid Edge VVO/CVR technology, which delivers greatly improved VVO/CVR performance, in the range of 4 to 6% energy savings and peak demand reduction (e.g., CVR factor equal to 1), as demonstrated by the voltage control range of ~5% created by Sentient Energy's technology on multiple pilot projects in the USA and Canada.

CVR is traditionally used as a "Supply-Side" energy conservation and peak demand reduction from the grid side, as opposed to "demand-side management (DSM)". CVR can be used to achieve regulatory or legislative EE objectives without requiring the engagement of consumers (no change of consumer behavioral), the financial contribution of EE participants or the distribution utility costs to administer the EE program. From a utility perspective, it reduces the amount of power utilities need to generate or purchase from a generation and transmission utility (G&T) and it lowers operating costs, among many other benefits such as building of new generation power plant and transmission & distribution assets e.g., reconducting feeders, adding voltage regulators and capacitors, and balancing feeders) and reducing technical losses.

CVR is beneficial to all consumers, even low-income participants who might not be able to invest in EE programs and is well adapted to all residential and commercial customers, and partially adapted to larger C&I customers. The supply-side benefits of VVO/CVR are additive and cumulative to any existing or new DSM benefits.

Prior to implementing CVR, the lowest recorded voltage (at the AMI location) without the ENGO devices deployed was below the CSA limits (i.e., service entrance between 110V and 125V during normal conditions) and did not permit any reduction in voltage at the substation without CSA violations. Comparing the voltages on a similar loading day with one transformer upgrade (X07487) and the ENGO devices turned ON showed a healthy improvement of **12.3%** (**14.8V)** resolving all CSA violations and creating an additional voltage margin for planned voltage reductions.

The Kanata MTS being a heavily commercial and industrial substation (C&I customers represent 83% of the billed kWh in August 2019), the CVR factor for power was measured to be **0.52** during summertime and **0.76** during wintertime. **Section 6.3** of this report elaborates on how the customer class was determined as well as the CVR factor for Power and Energy. CVR tests were conducted through the peak load month of July/September 2020 and November/February 2020 with a **2.5%** and **5%** reduction in voltage at the LTC. Stepping down the voltage during the summer peak load hours provided a load reduction of **1.31 MW** or **~2.60%** of the substation load **(50.53 MW**) by reducing the voltage by **5%** at the LTC. Stepping down the voltage during the winter peak load hours provide a load reduction of **1.52 MW** or **~3.95%** of the substation load **(36.80 MW**) by reducing the voltage by **5%** at the LTC

Simulations were run on the CYME model along with an AMI data-based analysis to determine the voltage outliers and select suitable locations for ENGO deployment. A combination of the two methodologies helped reconcile the differences between the model and the field and decide on an optimal set of transformers for implementation.

The ENGO devices were primarily responsible for facilitating a risk-free reduction in voltage as well as identifying the worst voltage outliers (visibility in field) that did require service transformer upgrade/tap change to maximize the conservation voltage reduction at the Kanata MTS.

This report presents the EM&V test results as well as the economics of the project. VVO/CVR is a significant opportunity to increase ambitious Energy Savings and Demand Reduction objectives at a competitive cost. A summary of the results captured during testing and the field based annual estimates are provided below.

3. Varentec Solution Overview

One of the promising methods to enhance system's efficiency by increasing Demand/Capacity Reduction and Energy Savings is through the deployment of utility owned assets called Dynamic VAr Controllers (DVCs). Each device is connected to the secondary side of a pole- or pad-mounted service transformer and tightly regulates the voltage at local and feeder wide level. For the Kanata MTS project, only pole units have been deployed. Sentient Energy is a pioneer in the development and deployment of these DVCs.

Sentient Energy's solution comprises hardware components called Edge of Network Grid Optimization (ENGO®) and a cloud-based software component called Grid-Edge Management Solution (GEMS®). ENGOs are fast-acting power-electronics devices that are installed on the secondary side of a distribution transformer, to autonomously sense and regulate voltage with a ± 0.5% within control range by injecting sub-cycle VArs between **0 to 10 kVArs**.

DVCs are well designed to mitigate in real-time Distributed Generation (DG) voltage impacts such as residential PVs. This results in the flattening of the primary and secondary feeder voltage. GEMS acts as a supervisory control and provides a data analytics and visualization engine. A recommended solution by Sentient Energy provides visibility to low voltage locations/nodes; enables real-time VVO system at the grid edge to achieve a fast and dynamic response to load; and enables CVR for either Energy Savings and/or Demand Reduction.

CVR enables electric distribution utilities to achieve a significant reduction in energy and peak demand, and without impacting customers through load shedding or major equipment investments. With the deployment of ENGO units at the low voltage outliers, this will ensure that the voltage will not temporarily dip below the minimum CSA standard level during heavy load conditions when the maximum drops occur and during out-of-normal conditions when voltage sags — caused by short circuits that occur on the grid.

GEMS+ENGO facilitates CVR by using power electronics devices installed on feeders, close to consumers, to flatten and equalize voltages. Utilities can then reduce the voltage on the feeder lines that run from substations to homes and businesses. This capability enables distribution utilities to operate their distribution grids at the low end of the acceptable supply voltage level without exposing consumers to undervoltage conditions.

CVR could be used as a **Non-Wires Alternatives** solution to offset distribution investment by deferring or replacing the need for specific equipment upgrades such as T&D lines or power transformers by reducing load / demand at a substation or circuit level (CAPEX Deferral).

The Sentient Energy solution benefits society and the environment because less energy is used to meet the same load, which helps reduce CO_2 and other harmful emissions. Consumers also benefit because they receive lower energy bills without any change in the quality of their services.

4. Field Testing Results

4.1. Executive Summary

In the project, **43** ENGO devices were installed in the Kanata MTS with a peak loading of:

- **66,129 kW** in **July 2018**
- **52,807 kW** in **July 2019**
- **50,530 kW** in **July 2020**

and an average loading of:

- **35,710 kW** measured over the period of **June 2018 – May 2019**
- **31,690 kW** measured over the period of **June 2019 – May 2020**

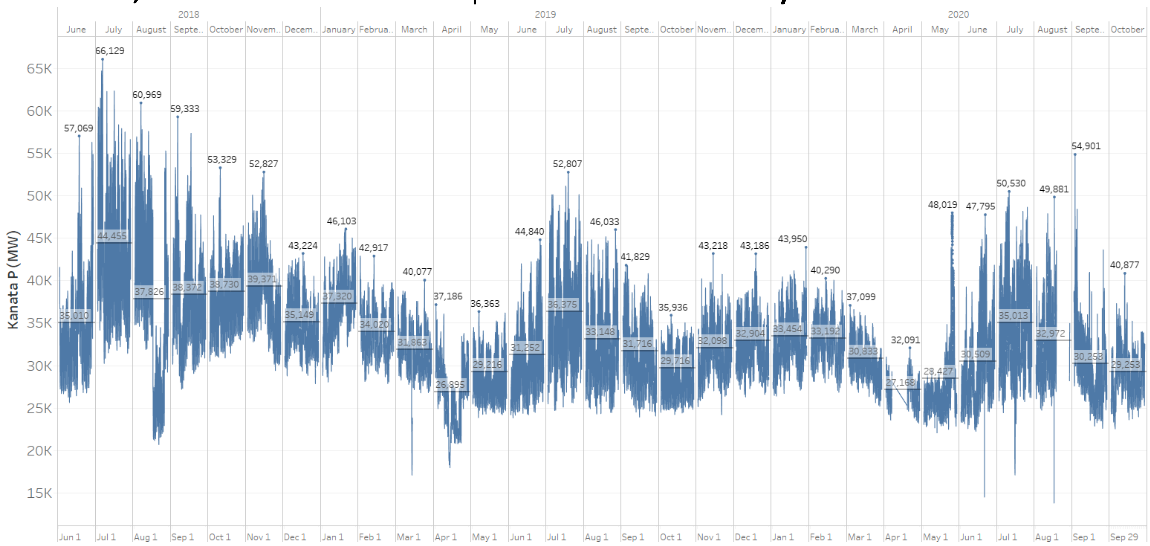


Figure 1: Substation Load from June 2018 through Sep 2020

<u>Note 1:</u> The first test period (peak demand reduction) was conducted over the period of **June 2020** through **September 2020** and the second test period (energy savings) over the period of **November 2020** through **February 2021**.

The results using field-based estimates computed over the period of **June 2018 to May 2019** data are shown in the Table 1.

Table 1: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2018 to May 2019

Month		Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Total / Maximum / Average
Measured Substation Loading	Sub Peak kW	57,069	66,129	60,969	59,333	53,329	52,827	43,224	46,103	42,917	40,077	37,186	36,363	66,129 kW (Max.)
	Sub Avg kW	35,010	44,455	37,826	38,372	38,730	39371	35,149	37,320	34,020	32,155	26,895	29,216	35,733 kW (Avg.)
	MWh Energy	25,207	33,075	28,143	27,628	28,815	28,347	26,151	27,766	22,861	23,923	19,364	21,737	313,017 MWh (Total)
Without ENGO + No System Upgrades	Min Voltage	0.930	0.919	0.925	0.927	0.935	0.936	0.948	0.944	0.948	0.952	0.956	0.957	0.940 p.u. (Avg.)
	Voltage Margin	-0.31%	-1.46%	-0.80%	-0.59%	0.17%	0.23%	1.45%	1.09%	1.49%	1.85%	2.22%	2.33%	0.64% (Avg.)
With ENGO + System Upgrades	Min Voltage	0.986	0.974	0.981	0.983	0.991	0.992	1.005	1.001	1.006	1.009	1.013	1.015	0.996 p.u. (Avg.)
	Voltage Margin	5.30%	4.06%	4.77%	4.99%	5.81%	5.87%	7.18%	6.79%	7.23%	7.61%	8.01%	8.12%	6.31% (Avg.)
	Incremental Voltage Margin	5.60%	5.52%	5.57%	5.58%	5.64%	5.64%	5.73%	5.70%	5.73%	5.76%	5.78%	5.79%	5.67% (Avg.)
	MWh Saved	668	671	671	869	1055	1048	1352	1357	1190	1147	977	1112	12,117.6 MWh Saved (Total)
	kW Shaved	1,573	1,396	1,511	1,954	2,045	2,047	2,359	2,379	2,358	2,013	1,966	1,949	Up to 2,379 kW Shaved (Max)
	tonnes CO2e/MWh saved	107	107	107	139	169	168	216	217	190	184	156	178	1,939 Tonnes CO2 Avoided (Total)
	tonnes CO2e/MW saved	1,565	1,389	1,503	1,944	2,035	2,037	2,347	2,367	2,346	2,003	1,956	1,939	2,367 Tonnes CO2 Avoided (Max)

The results using field-based estimates computed over the period of **June 2019 to May 2020** data are shown in the Table 2: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2019 to May 2020

Table 2: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2019 to May 2020

Month		Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Total / Maximum / Average
Measured Substation Loading	Sub Peak kW	44,840	52,807	46,033	41,829	35,936	43,218	43,186	43,950	40,290	37,099	32,091	48,019	52,807 kW (Max)
	Sub Avg kW	31,252	36,375	33,148	31,716	29,716	32098	32,904	33,454	33,192	30,833	27,168	28,427	31,690 kW (Avg.)
	MWh Energy	22,501	27,063	24,662	22,836	22,109	23,111	24,481	24,890	23,102	22,940	19,561	21,150	278,404 MWh (Total)
Without ENGO + No System Upgrades	Min Voltage	0.946	0.936	0.944	0.950	0.957	0.948	0.948	0.947	0.952	0.956	0.962	0.942	0.949 p.u. (Avg.)
	Voltage Margin	1.25%	0.24%	1.10%	1.63%	2.38%	1.46%	1.46%	1.36%	1.83%	2.23%	2.87%	0.84%	1.55% (Avg.)
With ENGO + System Upgrades	Min Voltage	1.003	0.992	1.001	1.007	1.015	1.005	1.005	1.004	1.009	1.014	1.020	0.999	1.006 p.u. (Avg.)
	Voltage Margin	6.96%	5.88%	6.80%	7.37%	8.18%	7.18%	7.19%	7.08%	7.58%	8.02%	8.70%	6.53%	7.29% (Avg.)
	Incremental Voltage Margin	5.71%	5.64%	5.70%	5.74%	5.79%	5.73%	5.73%	5.72%	5.76%	5.78%	5.83%	5.69%	5.74% (Avg.)
	MWh Saved	783.0	795.7	838.5	1060.3	1139.4	1045.4	1267.3	1268.8	1260.8	1159.1	1072.1	870.1	12,560.6 MWh Saved (Total)
	kW Shaved	1623	1615	1628	2035	1940	2048	2360	2365	2321	1964	1843	2070	Up to 2,365 kW Shaved (Max)
	tonnes CO2e/MWh saved	125	127	134	170	182	167	203	203	202	185	172	139	2,010 Tonnes CO2 Avoided (Total)

	tonnes CO2e/MW saved	1,615	1607	1620	2024	1930	2038	2348	2353	2309	1954	1833	2059	2,353 Tonnes CO2 Avoided (Max)

Note 2: The above voltage margin has been calculated from 112V or 0.933 p.u. considering a 2V voltage drop on the secondary line (or 110V at the meter)

Note 3: We did not use Aug 2020 data and subsequent months (Sep and Oct 2020) as the Kanata MTS Wholesale meter connection at the Kanata MTS had malfunctioned and stopped sending U/I/P/Q reads for the last 10 days of the month.

Note 4: The estimated energy savings and peak demand reduction are based on the measurement and computation of the CVR factor for Power and Energy

As per the testing conducted and results obtained, the detailed EM&V analysis provides the following key findings for both periods (**June 2018 – May 2019** and **June 2019 – May 2020**).

4.2. CSA Standard – Voltage Guidelines

Hydro Ottawa's Power Quality Standard (ECG0008- Distribution System Voltage and Power Quality https://static.hydroottawa.com/documents/specifications/ECG0008.pdf) is shown in Table 3: Steady State Operating Voltage Ranges Under Normal Conditions (Adapted from CSA CAN-3-C235-83 and Table 4:

Table 3: Steady State Operating Voltage Ranges Under Normal Conditions (Adapted from CSA CAN-3-C235-83)

Nominal Voltage (RMS V)	Allowable Deviation from Nominal (%)	Normal Minimum Voltage (RMS V)	Normal Maximum Voltage (RMS V)	Reference
120V / 240V	+4.17% ; -8.33%	110V / 220V	125V / 250V	At Service Entrance per CSA CAN3-C235-83 Table 3.0
120V / 208Y	+4.17% ; -6.67%	112V / 194Y	125V / 216Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
347V / 600Y	+3.75% ; -8.33%	318V / 550Y	360V / 625Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
2400V / 4160Y	+6.00% ; -6.00%	2256V / 3910Y	2544V / 4410Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
4800V / 8320Y*	+6.00% ; -6.00%	4512V / 7821Y	5088V / 8819Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7200V / 12470Y	+6.00% ; -6.00%	6768V / 11722Y	7632V / 13218Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7600V / 13200Y*	+6.00% ; -6.00%	7144V / 12408Y	8056V / 13992Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
15930V / 27600Y*	+6.00% ; -6.00%	14974V / 25944Y	16886V / 29256Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
44000V*	+6.00% ; -6.00%	41360V	46640V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
46000V	+6.00% ; -6.00%	43240V	48760V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1

Table 4: Steady State Operating Voltage Ranges Under Extreme Conditions (Adapted from CSA CAN-3-C235-83)

Nominal Voltage (RMS V)	Allowable Deviation from Nominal (%)	Extreme Min. Voltage (RMS V)	Extreme Max. Voltage (RMS V)	Reference
120V / 240V	+5.83% ; -11.67%	106V / 212V	127V / 254V	At Service Entrance per CSA CAN3-C235-83 Table 3.0
120V / 208Y	+5.83% ; -8.65%	110V / 190Y	127V / 220Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
347V / 600Y	+5.76% ; -11.82%	306V / 530Y	367V / 635Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
2400V / 4160Y	+6.00% ; -6.00%	2256V / 3910Y	2544V / 4410Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
4800V / 8320Y*	+6.00% ; -6.00%	4512V / 7821Y	5088V / 8819Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7200V / 12470Y	+6.00% ; -6.00%	6768V / 11722Y	7632V / 13218Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7600V / 13200Y*	+6.00% ; -6.00%	7144V / 12408Y	8056V / 13992Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
15930V / 27600Y*	+6.00% ; -6.00%	14974V / 25944Y	16886V / 29256Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
44000V*	+6.00% ; -6.00%	41360V	46640V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
46000V	+6.00% ; -6.00%	43240V	48760V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1

4.3. Voltage Visibility/Support and CSA Compliance

As per Sentient Energy's recommendation based on AMI-data analysis and in coordination with HOL, a few transformer upgrades were performed as well as tap changes that led to a MV voltage improvement. Further, the ENGOs deployed in the system provided an incremental LV voltage improvement in addition to the real-time voltage visibility provided by ENGOs (the ENGO device is a **0.5%** voltage accuracy sensor). Based on ENGO-DAY ON/OFF testing, the combined MV and LV solution demonstrated ability to maximize voltage reduction and achieve significant demand reduction and energy savings.

Results:

- In **2019**, the minimum AMI voltage observed on **July 4th** was **101.8V**. Based on this measurement, it is clear that there is no existing voltage margin for performing a safe peak demand reduction (no customer voltage below CSA threshold of 110V during normal operating conditions or 106V during extreme operating conditions) and therefore system upgrades and ENGO deployment are required

4.4. ENGO ON/OFF Test

Based on ENGO-DAY ON/OFF testing during nominal operation, the GEMS+ENGO solution demonstrated ability to provide improvement in voltage margin.

Results:

- ENGOs provided in May 2020 an incremental improvement in voltage margin by **3.10V** (**2.58%**) prior to MV System Upgrade/Change
- This paired with the system upgrades as showed in Table 5: MV System Upgrades/Changes (transformer upgrades and tap changes) allowed us to comfortably proceed with CVR reduction of **5%** for the peak demand reduction testing

- ENGOs Improve lightly the substation Power Factor PF from **0.9478** to **0.9503**, which reduces line losses by **0.53%**

Table 5: MV System Upgrades/Changes

Xfmer	Phase	ENGO Unit	Min. ENGO V (15min Avg) Before System Upgrades and ENGO OFF May 26th, 2020 / 43.93MW	MV Upgrade	Min. ENGO V (15min Avg) After System Upgrades and ENGO ON October 12th, 2020 / 40.88MW
X07484	B	2112692	107.9V	Xfmer Replaced (August 26th, 2020)	120.3V
X50916	A	2106377	108.7V	Xfmer Replaced (August 26th, 2020)	120.8V
X07508	B	2122829	108.7V	Xfmer Replaced (August 26th, 2020)	123.7V
X07487	B	2100193	104.6V before Xfmer Upgrade 108.9V after Xfmer Upgrade	Xfmer Replaced (May 7th, 2020) and then Taps increased by 5% (July 30th, 2020)	123.4V
X07491	B	2125813	108.8V	Taps increased by 5% (July 30th, 2020)	123.8V

4.5. Voltage Support

Based on ENGO-DAY ON/OFF and CVR-DAY ON/OFF testing, the combined MV and LV solution demonstrated ability to maximize voltage reduction and achieve significant demand reduction and energy savings.

Results:

- In 2020, after performing system upgrade and deployment of ENGO units, the minimum voltage recorded on July 2nd is **116.6V**. If we compare this result to July 4th, 2019 (**101.4V**), we observed a voltage improvement of nearly **14.8V** (**12.34%**). This allows the voltage to be reduced at the LTC without causing any CSA violations
- Estimated average voltage reduction of ~**6.31%** with an average incremental of **~5.67%** over the period of June 2018 to May 2019 (or ~**90%** contribution coming from combined MV System Upgrade and GEMS-ENGO solution). The incremental of the GEMS+ENGO is ~**2.80%** (or ~**44%** contribution coming from GEMS-ENGO solution)
- Estimated average voltage reduction of ~**7.29%** with an average incremental of ~**5.74%** over the period June 2019 to May 2020 (or ~**79%** contribution coming from GEMS+ENGO solution). The incremental of the GEMS+ENGO is ~**2.25%** (or ~**31%** contribution coming from GEMS-ENGO solution)

4.6. System Error Computation

As there is bound to be differences in voltage margin obtained from CYME analysis and that obtained from the field data, it was decided to add the concept of a system error in the contract. The system error essentially aligns the results from CYME with the field results and allows a fair comparison between the two results.

Using the methodology outlined in the contract, the average system error was found to be **2.39%** and the average percentage voltage margin was **3.53%**.

So, the adjusted voltage margin for comparison purposes was found to be **5.92%**, which shows that the ENGOs exceed performance. Essentially, ENGOs deliver a minimum voltage improvement of what was promised during the analysis phase now validated from the field results.

4.7. Capacity/Peak Demand Reduction Testing

Capacity/Peak Demand reduction tests have been conducted in three consecutive months (July, August, September 2020) with 54 LTC events or 108 LTC transitions (step down and step up/return to nominal). Tests were initially conducted at 2.5% CVR followed by 5% CVR after system upgrades (transformer tap and rating changes). Additional Capacity/Peak Demand reduction tests have been conducted from November 2020 through February 2021 with 36 LTC events or 72 LTC transitions.

Results:

- A **5% CVR reduction** was performed, and the minimum voltage recorded on September 24th was **114.3V** which is again above the CSA lower limit.
- A **5% CVR** was proved to be safe and feasible unlocking a potential of **1.31 MW** of reduction during peak load month of July 2020 (**50.53 MW**) with no CSA violations (CVR_{factor} for Power = **0.52** in summertime)
- Based on the analysis of "voltage drop on secondary lines" and AMI data assessment – an additional margin of **2.3V (>1.92%)** is available unlocking a potential CVR reduction up to **6%** (or **1.58 MW**) while keeping CSA compliance at customer location (110V at customer location and 112V at transformer location considering a 2V voltage drop on the secondary run)
- Based on historical **July** Peak Month and estimated voltage margin, a potential of **1.40 MW** (July 2018 Peak @ 66.1MW) **– 1.63 MW** (July 2019 Peak @ 52.8MW) of reduction is feasible as showed in

- Table 6: Voltage Margin during July Peak Month.

Table 6: Voltage Margin during July Peak Month

Year	System Upgrades	Month	Voltage Margin (Without ENGO)	Lowest Voltage (Without ENGO)	Peak Shaving (Without ENGO)	Voltage Margin (With ENGO)	Lowest Voltage (With ENGO)	Peak Shaving
2018-2019	No	**July 2018 (66.13 MW)**	**-1.46%**	**110.25**	**NOT POSSIBLE**	**0.62%**	**112.74**	**0.21 MW**
2018-2019	Yes	**July 2018 (66.13 MW)**	**2.29%**	**114.75**	**0.79 MW**	**4.06%**	**116.87**	**1.40 MW**
2019-2020	No	**July 2019 (52.81 MW)**	**0.24%**	**112.29**	**0.07 MW**	**2.51%**	**115.01**	**0.69 MW**
2019-2020	Yes	**July 2019 (52.81 MW)**	**3.96%**	**116.75**	**1.09 MW**	**5.88%**	**119.06**	**1.61 MW**
2020-2021	No	**July 2020 (50.53 MW)**	**0.53%**	**112.64**	**0.14 MW**	**2.83%**	**115.40**	**0.74 MW**
2020-2021	Yes	**July 2020 (50.53 MW)**	**4.25%**	**117.1**	**1.12 MW**	**6.19%**	**119.43**	**1.63 MW**

- Annual demand reduction using June 2018 to May 2019 data ranges between **~1.40 MW** (July 2018 Peak) to **~2.38 MW** (Jan 2019 Peak) shaved
  - ✓ ~**2.11%** (Summer Peak: **July 2018 / 66.13 MW**) or ~**5.16%** (Winter Peak: **January 2019 / 46.10 MW**) Demand Reduction with an incremental of **~2.87%** or **~4.33% (~5.52%** or **~5.70%** Voltage Incremental x 0.52 (summer) or 0.76 (winter) $CVR_{f\ Power}$) (or >**~100%** or **~84%** contribution coming from GEMS+ENGO solution)
- Similar peak shaving performance has been estimated using June 2019 to May 2020 data
  - ✓ Annual demand reduction between **~1.61 MW** (July 2019 Peak) to **~2.37 MW** (January 2020 Peak) shaved
  - ✓ ~**3.06%** (Summer Peak: **July 2019 / 52.81 MW**) or ~**5.38%** (Winter Peak: **January 2020 / 43.95 MW**) Demand Reduction with an incremental of **~2.93%** or **~4.35% (~5.64%** or **~5.72%** Voltage Incremental x 0.52 (summer) or 0.76 (winter) $CVR_{f\ Power}$) (or **~96%** to **~81%** contribution coming from GEMS+ENGO solution)

4.8. Energy Savings

Energy Savings tests have been conducted from November 2020 through February 2021 with 144 CVR events (LTC operation, daily CVR ON/OFF @ 5%).

Energy Savings = Consumer Consumption Reduction + Technical Loss Reduction (Line + Transformer Losses)

Results:

- Annual avoided energy due to Visibility and MV System Upgrade/ENGOs of **~12,117.6 MWh** saved or **3.87%** Energy Savings with an incremental of **~3.49%** estimated over the period of **June 2018 to May 2019** (or **~90%** contribution coming from MV System Upgrades/ENGOs solution)
- Annual avoided energy due to Visibility and MV System Upgrade/ENGOs of **~12,560.5 MWh** saved or **~4.51%** Energy Savings with an incremental of **~3.55%** estimated over the period of **June 2019 to May 2020** (or **~79%** contribution coming from MV System Upgrades/ENGOs solution)

Note 5: For the calculation of Energy Savings, we assume a CVR factor for Energy ($CVR_{f\ Energy}$) equal to 0.62.

4.9. CVR Factor Test

Based on CVR-DAY ON/OFF testing, CVR factor for Power was measured and computed during the first test period (peak demand reduction) **June 2020** through **September 2020.** During the second test period (energy savings) over the period of **November 2020** through **February 2021,** CVR factor for Power and Energy were measured and computed.

Results:

- CVR Factor for Power and Energy:

Peak Demand Reduction Test (Summer 2020)	July – Sept 2020
LTC Reduction in Voltage	2.5% - 5%
Number of CVR Events	54
Error Band (95% confidence)	0.06
CVR Factor for Power	**0.52 ± 0.03**
CVR Factor for Energy	**No Test**

Energy Savings Test (Winter 2020)	Nov 2020 – Feb 2021
LTC Reduction in Voltage	4,1%
Number of CVR Events	36
Error Band (95% confidence)	0.026
CVR Factor for Power	**0.76 ± 0.013**
LTC Reduction in Voltage	4,56%
Number of CVR Events	144
Error Band (95% confidence)	0.46
CVR Factor for Energy	**0.72 ± 0.23**

- Considering the period of **June 2018 to May 2019**, MV System Upgrade and ENGO deployment allow the system to perform an annual average voltage reduction of **~6.24%** (Energy Savings) and **~4.06%** during **July 2018** peak month
- Considering the period of **June 2019 to May 2020**, MV System Upgrade and ENGO deployment allow the system to perform an annual average voltage reduction of **~7.28%** (Energy Savings) and **~5.88%** during **July 2019** peak month

Based on the billing data of August 2019 (see **Section 6.3**) shared by Hydro Ottawa, CVR factors of each season were estimated to analyze the effect of voltage reduction by season. The data measured/estimated at Kanata substation can be classified by season and customer class as follows:

Table 7: Seasonal CVR factors for Energy and Power

	Summer	Falls	Winter	Spring	Average
CVR factor for Power	0.52*	0.66	0.76*	0.66	0.65
CVR factor for Energy	0.50	0.63	0.72*	0.63	0.62

*Measured and computed CVR

Table 8: CVR factors for Energy and Power per Customer Class

	CVR factor for Power (July 2019)	CVR factor for Power (average)	CVR factor for Energy (average)
Residential	0.80	0.85	0.81
Small & Medium < 50 kW	0.82	0.92	0.89
Small & Medium > 100 kW	0.44	0.56	0.55
Average CVR factor	0.52*	065	0.62

When analyzing data by season, CVR factors (Energy and Power) of Winter were found to be higher than those of Summer.

4.10. Technical Loss Reduction

Results:

Considering **3.27%** technical losses (Line Loss **1.12%**, Transformer Load Loss **1.11%** and Transformer Non-Load Loss **1.04%**) or **~10,234.1** MWh total losses out of **313,017.1 MWh** computed over the period of **June 2018 to May 2019** and **~9,102.4 MWh** total losses out of **278,403.7 MWh** computed over the period of **June 2019 to May 2020**:

- Annual reduction of overall technical losses:
  - ✓ **~372.2 MWh** (**-3.64%** of overall technical loss reduction or **3.07%** of the overall Energy Savings) estimated over the period of **June 2018 to May 2019**
  - ✓ **~413.4 MWh** (**-4.54%** of overall technical loss reduction or **3.87%** of the overall Energy Savings) estimated over the period of **Sep 2018** to **Aug 2019**
- Annual reduction of line losses due to PF improvement thanks to ENGO units (copper loss reduction):
  - ✓ Technical Loss Reduction of **~20.0 MWh (-0.20%** of overall technical loss reduction) estimated over the period of **June 2018 to May 2019**

  Or

  - ✓ Technical Loss Reduction of **~17.6 MWh** (**-0.17%** of overall technical loss reduction) estimated over the period of **June 2019 to May 2020**
- Annual reduction of technical losses due to CVR 24/7/365 (copper and core loss reduction)
  - ✓ Technical Loss Reduction of **~352.2 MWh** saved **(-3.44%** of overall technical loss) over the period of **June 2018 to May 2019**

    or

  - ✓ Technical Loss Reduction of **~395.7 MWh** saved (**-4.35%** of overall technical loss) estimated over the period of **June 2019 to May 2020**

4.11. Consumer Benefits:

Results:

- Annual Consumption Reduction due to Visibility and MV System Upgrade/ENGOs of **~11,745.6 MWh** (**96.93%** of overall Energy Savings) estimated over the period of **June 2018 to May 2019**
- Annual Consumption Reduction due to Visibility and MV System Upgrade/ENGOs of **~12,147.29 MWh** (**96.71**% of overall Energy Savings) estimated over the period of **June 2019 to May 2020**

4.12. Environmental Benefits:

Results:

- Annual CO2 reduction due to visibility and MV System Upgrade/ENGOs of **~1,938.8** Tonnes (**~12,117.6 MWh**) or **~2,367.1** Tonnes (average **1,962kW**) estimated over the period of **June 2018 to May 2019**
- Annual CO2 reduction due to visibility and MV System Upgrade/ENGOs of **~2,009.7** Tonnes (**12,560.5 MWh**) or **~2,353.0** Tonnes (average **1,984kW**) estimated over the period of **June 2019 to May 2020**

Note 6: "There are two components to the calculation of GHG reductions due to reductions in electricity usage resulting from CVR. These are computed based on the metrics for tonnes CO2e/MWh saved (0.160) and tonnes CO2e/MW saved (995), calculated by Ontario's Independent Electricity System Operator (IESO) for 2015 as reported in the Conservation Framework Mid-Term Review – Climate Change - Discussion Draft Discussion Slides prepared by Navigant (document CF-2017020-Climate-Change-Summary), Slide 27"

4.13. Project Results Summary Data:

Note 7: All costs and benefits showed in the report are in CAD.

Table 9: Field Test Results using June 2018 to May 2019 data

Engineering Calcs		
Annual Technical Loss Reduction	372.2	MWh
Avoided Wholesale Energy Purchases	12,117.7	MWh
Avoided Retail Electricity Sales	11,745.5	MWh
Customer peak capacity reduction	2.379	MW
Average System Peak reduction	1.397	MW
Annual Substation Energy Consumption Billed	302,783.1	MWh
Asset Life Extension Benefit	2,345.6	$
Power Quality Benefit	800.0	$
Annual CO2 reduction	1,938.83	tonnes
Annual NOx reduction	0.36	tonnes
Annual SOx reduction	0.61	tonnes
NPV Feeder Revenue Requirement	38,400,695,896	$

Table 10: Field Test Results using June 2019 to May 2020 data

Engineering Calcs		
Annual Technical Loss Reduction	413.4	MWh
Avoided Wholesale Energy Purchases	12,560.7	MWh
Avoided Retail Electricity Sales	12,147.3	MWh
Customer peak capacity reduction	2.366	MW
Average System Peak reduction	1.614	MW
Annual Substation Energy Consumption Billed	269,301.3	MWh
Asset Life Extension Benefit	2,345.6	$
Power Quality Benefit	800.0	$
Annual CO2 reduction	2,009.71	tonnes
Annual NOx reduction	0.38	tonnes
Annual SOx reduction	0.63	tonnes
NPV Feeder Revenue Requirement	34,154,348,389	$

5. Economic Use Case

5.1. Economic Evaluation Approach

Following financial information were considered for the Economic Use Case:

- Energy cost inflation rate of **2.0%** per year
- After-tax discount rate of **6.02%** per year (WACC)
- Utility return on equity of **8.98%** per year
- Effective Tax Rate of **26.50%**
- 2021 average retail rate before HST with Ontario electricity rebate is around **$12.74** cts/kWh considering the customer distribution at the Kanata substation
- 2021 marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) is around **$10.82** cts/kWh considering the customer distribution at the Kanata substation

5.2. Project Costs

An overall cost of **$497,802** (asset deployment and 15-year O&M costs) was considered for the medium voltage (replacement of 4 service transformers and tap changes) and the low voltage (GEMS+ENGO solution) Volt VAr control assets. No O&M expenses were considered for the ENGO devices as it does not require any preventive maintenance (no moving parts). The annual GEMS hosted subscription and GEMS apps/ENGO cellular comm are considered over 15 years ($194,532).

Table 11: Deployment and O&M Costs at Kanata MTS

Cost Calculations		
GEMS Software	$	194,532
ENGO Hardware	$	161,410
GEMS + ENGO Professional Service Costs	$	43,426
ENGO Install + Prof Service Costs (HOL)	$	78,747
MV Hardware + Install Costs (HOL)	$	19,687

An overall Hydro Ottawa project costs of **$78,747** for the ENGO deployment as well as **$19,687** for the MV System Upgrades has been considered (**$98,433**). An overall GEMS+ENGO cost of $399,368 is considered.

<u>**Note 9**</u>: We assume a GEMS Hosted Solution (above costs of $194,532 are for a 15-year operation) for the EUC calculation. However***, a GEMS on-premise solution might be more cost effective when Hydro Ottawa decides to go full-scale***. It will reduce the overall cost of the solution meaning it will reduce the LCOE and LCOC numbers presented in the following sections.

5.3. Energy Savings and Capacity Reduction Economics Using June 2018-May 2019

Considering all costs of the project (ENGOs and MV System Upgrades) and all benefits (Net Present Value NPV avoided energy of **$12,843k**, NPV technical (transformer and line) loss reduction of **$394k** and NPV O&M of **$32k** over **15** years), the Ratepayer Impact Measure (RIM) Test BCR is **0.86** (discounted) or **0.87** (undiscounted).

The deployed MV System Upgrade/ENGOs solution delivers a Levelized Cost of Energy (LCOE) Saved of **$3.65**/MWh or **$0.365** cts/kWh (to be compared with the 2021 marginal purchase energy rate of **$10.82** cts/kWh).

The Total Resource & Utility Cost (TRC/UCT) Tests BCR is **30.92** (discounted) and the IRR Internal Rate of Return is **434%** (to be compared to **6.02%** WACC or **8.98%** ROE).

Table 12: Energy Cost Effectiveness Tests of Kanata MTS Project (considering all costs)

Project Summary	
12,117.6	Annual MWh Saved
1.396	Annual MW Saved (considering July 2018 only)
$3.65	LCOE (Levelized Cost of Energy) $/MWh
$30.21	LCOC (levelized Cost of Capacity) $/kW-Yr
-3.87%	Change in Usage
-3.33%	Minimum change in Electrical Bills

Lifetime Costs and Benefits	*Discounted*				*Undiscounted*	
Cost Tests	Net Benefit	BC Ratio	IRR	Payback Yrs	Net Benefit	BC Ratio
RIM (RATEPAYER IMPACT MEASURE)	$(2,119,425)	0.86	N/A	N/A	$(3,125,598)	0.87
TRC/UCT (TOTAL RESOURCE & UTILITY COST TEST)	$12,839,446	30.92	434%	1	$20,132,180	41.44
SCT (SOCIETAL COST TEST)	$13,287,217	31.97	449%	1	$20,828,377	42.84

Note 10: The societal benefits are just shown for information and only considered in the SCT (Societal Cost Test) BCR Calculation. The federal system prices pollution at a rate of **$20** per tonne of CO2 equivalent emissions in **2019** and considering that this amount will gradually rise to **$50** per tonne by 2022, the discounted BCR will increase from **31.97** (TRC/UCT) to **33.32** (SCT) including NOx and SOx reduction.

The Table 13: RIM, TRC/UCT and SCT Test (considering all costs)shows the detail costs and benefits of the RIM, TRC/UCT and SCT tests (discounted and undiscounted over 15-years):

Table 13: RIM, TRC/UCT and SCT Test (considering all costs)

RIM Test

WACC 6.02%

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	Undiscounted
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install + Prof Service Costs (HOL)	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	GEMS + ENGO Professional Service Cost	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	MV Hardware + Install Costs (HOL)	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
	Bill Savings (if sales decrease)	$ -	$1,496,995	$1,504,480	$1,512,003	$1,519,563	$1,527,160	$1,534,796	$1,542,470	$1,550,183	$1,557,934	$1,565,723	$1,573,552	$1,581,420	$1,589,327	$1,597,273	$1,605,260	$14,958,872	###########
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Bill Savings (if sales increase)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Net Cash Flow	$ (303,270)	$ (182,138)	$ (182,983)	$ (183,833)	$ (184,687)	$ (185,544)	$ (186,406)	$ (187,271)	$ (188,141)	$ (189,015)	$ (189,893)	$ (190,775)	$ (191,661)	$ (192,551)	$ (193,446)	$ (194,344)	$(2,119,425)	$(3,125,958)
	Payback	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A	Yrs to Payback
																		N/A	IRR

UCT/TRC Tests

WACC 6.02%

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	d
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install + Prof Service Costs (HOL)	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	GEMS + ENGO Professional Service Cost	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	MV Hardware + Install Costs (HOL)	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Net Cash Flow	$ (303,270)	$1,314,857	$1,321,497	$1,328,170	$1,334,876	$1,341,616	$1,348,390	$1,355,199	$1,362,041	$1,368,919	$1,375,830	$1,382,777	$1,389,759	$1,396,775	$1,403,828	$1,410,915	###########	###########
	Payback	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	Yrs to Payback
																		434%	IRR

SCT Test

WACC 6.02%

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	d
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	ENGO Hardware	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	Services	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Societal CO2	$ -	$ 96,942	$ 97,426	$ 97,913	$ 98,403	$ 98,895	$ 99,389	$ 99,886	$ 100,386	$ 100,888	$ 101,392	$ 101,899	$ 102,409	$ 102,921	$ 103,435	$ 103,952	$968,698	$ 1,506,137
	Societal NOx	$ -	$ 3,093	$ 3,109	$ 3,124	$ 3,140	$ 3,156	$ 3,171	$ 3,187	$ 3,203	$ 3,219	$ 3,235	$ 3,251	$ 3,268	$ 3,284	$ 3,300	$ 3,317	$30,910	$ 48,059
	Societal SOx	$ -	$ 2,940	$ 2,955	$ 2,970	$ 2,985	$ 3,000	$ 3,015	$ 3,030	$ 3,045	$ 3,060	$ 3,075	$ 3,091	$ 3,106	$ 3,122	$ 3,137	$ 3,153	$29,382	$ 45,683
	Net Cash Flow	$ (303,270)	$1,417,833	$1,424,987	$1,432,177	$1,439,404	$1,446,666	$1,453,966	$1,461,302	$1,468,675	$1,476,086	$1,483,533	$1,491,018	$1,498,541	$1,506,102	$1,513,701	$1,521,338	###########	###########
	Payback	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	Yrs to Payback
																		468%	IRR

As expected, the LCOE is in line in comparison with a recent study made in June 2018 by **Navigant Consulting** “**Volt/VAr Optimization and Conservation Voltage Reduction: Market Potential Assessment & Economic Metrics for the province of Ontario**”.

As reported by **Navigant**, the LCOE of energy saved via Secondary Volt-VAr optimization (VVO) technologies such as Sentient Energy’s offering is around **$1.13 cts/kWh vs. $4.71 cts/kWh** for Primary VVO only deployments. The addition of Secondary VVO reduces the overall LCOE to **$3.41** cts/kWh (to be compared with **$0.365** cts/kWh at Kanata MTS as mentioned previously).

In 2017, Navigant Consulting performed an analysis of the potential for VVO technologies to contribute to Energy Efficiency goals in Ontario (“**Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario**”). The study includes an in-depth analysis of the BCR by class of feeder across Ontario. It concluded that approximately **30%** of the feeders in the province are good candidates for VVO as showed in Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO.

Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO

Rank	Ranked Feeders by Cost-Benefit Ratio	Feeders per Cluster	Benefit-Cost Ratio	Cluster Peak Reduction (MW)	Cluster Electricity Reduction (GWh)	Cluster Line Loss Reduction (GWh)
1	12.47 kV - Heavy Suburban	305	1.45	15	106	6
2	27.6 kV - Moderate Suburban	508	1.35	34	246	5
3	27.6 kV - Moderate Urban	508	1.34	33	244	6
4	12.47 kV - Moderate Urban	1,016	1.29	44	325	8
5	12.47 kV - Moderate Suburban	711	1.17	28	207	4
6	12.47 kV - Light Suburban	508	0.80	14	104	1
7	4.16 kV - Heavy Urban	102	0.72	1	10	1
8	4.16 kV - Heavy Suburban	102	0.65	1	9	0
9	44.4 kV - Light Rural	508	0.59	39	292	3
10	4.16 kV - Moderate Urban	1,524	0.58	17	122	3
11	27.6 kV - Light Rural	508	0.53	13	97	1
12	4.16 kV - Moderate Suburban	1,524	0.52	15	111	2
13	4.16 kV - Light Suburban	1,321	0.48	12	90	1
14	12.47 kV - Light Rural	508	0.38	7	49	1
15	4.16 kV - Light Rural	508	0.17	2	12	0

Source: Navigant analysis

The lowest performing feeders are all the 4.16 kV feeders and some of the lightly loaded 12.47 kV feeders as shown above in Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO. These feeders have a negative NPV and are not cost-effective largely because the line loss savings achieved through phase balancing are relatively small (in proportion to the feeder load) and do not justify the costs required. Recent deployments in Ontario have shown that by deploying ENGO devices at targeted location (low voltage outliers) and optimizing the MV assets, it was demonstrated that 4.16kV – light rural feeder could be turned to become eligible for VVO deployment.

Considering the Kanata MTS (27.6kV Heavy Suburban), a TRC BCR of **1.45** would have been expected as reported by Navigant study (to be compared with **30.92 (!)** achieved at the Kanata MTS).

Overall, the LCOE and IRR of the Kanata MTS project are in line with LDC's financial (Utility Return on Equity of **8.98%** vs. **434%** IRR and 2021 marginal purchase energy rate of **$10.82** cts/kWh vs. LCOE of **$0.365** cts/kWh saved) as well as the LCOE reported in 2017 Navigant's study (e.g., **$5.20** cts/kWh saved).

As shown in

Table 15: LCoE / LCoC by Feeder for VVO, the LUEC for Energy (Levelized Unit Electricity Cost) or LCOE for IFMC deployment across 15-feeders (from 4.16kV to 27.6kV, from light rural to heavy urban) ranges from **$5.20** cts/kWh and **$19.8** cts/kWh saved. An LCOE of **$5.20** cts/kWh saved is reported for a 12.47kV – Heavy Suburban feeder (to be compared to **$3.65** cts/kWh saved achieved at the Kanata MTS).

As shown in

Table 15: LCoE / LCoC by Feeder for VVO, the LUEC for Demand or LCOC ranges from **$422** and **$3,352/kW-Yr** shaved. An LCOC of **$710/kW-Yr** is reported for a 12.47kW – Heavy Suburban

feeder (to be compared to **$30.21/kW-Yr** shaved achieved at the Kanata MTS or **$120.85/kW**-Summer Time).

Table 15: LCoE / LCoC by Feeder for VVO

Prototypical Feeder	LUEC ($/kWh)	LUEC ($/kW)
4.16kV - Heavy Urban	$0.105	$777
4.16 kV - Moderate Urban	$0.131	$984
4.16 kV - Heavy Suburban	$0.117	$866
4.16 kV - Moderate Suburban	$0.144	$1,087
4.16 kV - Light Suburban	$0.157	$1,188
4.16 kV - Light Rural	$0.443	$3,352
12.47 kV - Moderate Urban	$0.059	$441
12.47 kV - Heavy Suburban	$0.052	$388
12.47 kV - Moderate Suburban	$0.065	$487
12.47 kV - Light Suburban	$0.094	$710
12.47 kV - Light Rural	$0.198	$1,502
27.6 kV - Moderate Urban	$0.056	$424
27.6 kV - Moderate Suburban	$0.056	$422
27.6 kV - Light Rural	$0.143	$1,084
44.4 kV - Light Rural	$0.128	$970

Source: Navigant analysis

Considering the Rate Payer Impact (RIM) test, a BCR of **0.87** (discounted) is shown below:

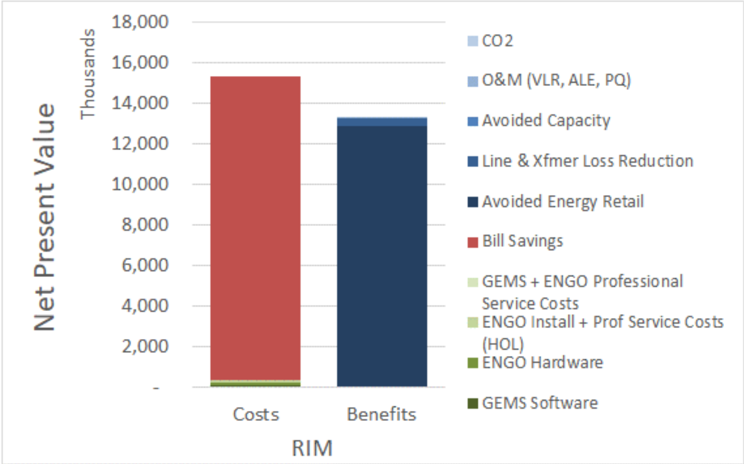


Figure 2: RIM Test Results

Based on the project measured results and financial provided by Hydro Ottawa, a reduction in energy usage of **3.87%** at Kanata MTS corresponds in a change in consumer electrical bill of **3.33%**

Considering the Total Resource Cost/Utility Cost Test TRC/UCT test, a BCR of **30.92** (discounted) is shown, which implies a decrease of the total energy expenditures (BCR>1).

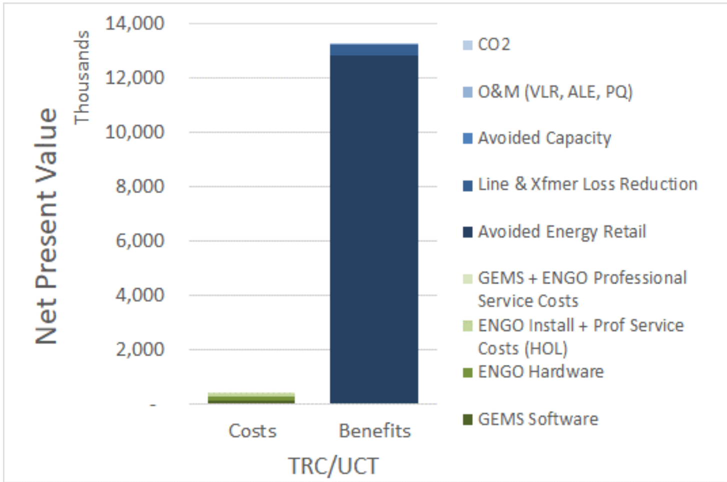


Figure 3: TRC/UCT Test Results

5.4. Energy Savings and Capacity Reduction Economics Using June 2019-May 2020

The Economics are summarized in Table 16: Economics Summary Using June 2019-May 2020.

Table 16: Economics Summary Using June 2019-May 2020

Project Summary	
12,561	Annual MWh Saved
1.615	Annual MW Saved (considering July 2019 only)
$3.52	LCOE (Levelized Cost of Energy) $/MWh
$26.16	LCOC (levelized Cost of Capacity) $/kW-Yr
-4.51%	Change in Usage
-3.89%	Minimum Change in Electrical Bills

Lifetime Costs and Benefits	*Discounted*				*Undiscounted*	
Cost Tests	**Net Benefit**	**BC Ratio**	**IRR**	**Payback Yrs**	**Net Benefit**	**BC Ratio**
RIM (RATEPAYER IMPACT MEASURE)	$(2,117,950)	0.87	N/A	N/A	$(3,123,664)	0.88
TRC/UCT (TOTAL RESOURCE & UTILITY COST TEST)	$13,352,586	32.12	451%	1	$20,930,011	43.04
SCT (SOCIETAL COST TEST)	$14,419,190	34.61	486%	1	$22,588,374	46.38

Using the billing data of August 2019 shared by Hydro Ottawa (see section 6.3) and June 2019-May 2020 SCADA-data, Sentient Energy estimated the electrical bill reduction based on customer class:

- **Residential Customers:**
  - Prior to CVR implementation, the monthly consumption is **786** kWh per customer or **9,430** kWh annually
  - CVR implementation has a negligeable impacts on LDC revenue (Fixed Monthly Service Charge + kWh-based LV Charges) that corresponds to $(170.56) over 12-months for **5,926** customers
  - For an average **7.29%** voltage reduction (**0.81** CVR factor for Energy), residential customers will see a reduction of their electrical bill by **4.56% ($71.69** annually before HST & Rebate or **$65.82** annually with HST & Rebate) while their energy usage will reduce by **5.90%**

Residential	Rates Effective January 1, 2021					
	Consumption @ 55880027 kWh			Consumption @ 52580377 kWh (5% Voltage Reduction)		
Charge Description	kWh	Rates	Customer Charge	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$40,533.84		$0.57	$40,533.84
Monthly Service Charge		$29.32	$2,085,003.84		$29.32	$2,085,003.84
Distribution Volumetric Rate	55,880,027	$0.0000	$0.00	52,580,377	$0.0000	$0.00
Low Voltage Charges	57,768,772	$0.00005	$2,888.44	54,357,594	$0.00005	$2,717.88
Adjusted Consumption	1,888,745			1,777,217		
Off-Peak	1,208,797	$0.085	$102,747.72	1,137,419	$0.085	$96,680.59
Mid-Peak	339,974	$0.119	$40,456.92	319,899	$0.119	$38,067.98
On-Peak	339,974	$0.176	$59,835.44	319,899	$0.176	$56,302.23
Network Charge	57,768,772	$0.0081	$467,927.05	54,357,594	$0.0081	$440,296.51
Connection Charge	57,768,772	$0.0050	$288,843.86	54,357,594	$0.0050	$271,787.97
Electricity Charge	55,880,027			52,580,377		
Off-Peak	35,763,217	$0.085	$3,039,873.47	33,651,441	$0.085	$2,860,372.50
Mid-Peak	10,058,405	$0.119	$1,196,950.18	9,464,468	$0.119	$1,126,271.67
On-Peak	10,058,405	$0.176	$1,770,279.25	9,464,468	$0.176	$1,665,746.34
Wholesale Market Service Rate	57,768,772	$0.0030	$173,306.32	54,357,594	$0.0030	$163,072.78
Capacity Based Recovery	57,768,772	$0.0004	$23,107.51	54,357,594	$0.0004	$21,743.04
Rural Rate Protection Charge	57,768,772	$0.0005	$28,884.39	54,357,594	$0.0005	$27,178.80
Standard Supply Service Charge		$0.25	$3.00		$0.25	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate			**$9,320,641.22**			**$8,895,778.97**
Ontario Electricity Rebate		21.2%	$1,975,975.94		21.2%	$1,885,905.14
Total before HST with Rebate			**$7,344,665.28**			**$7,009,873.82**
HST 13%		13%	$1,211,683.36		13%	$1,156,451.27
Total with HST/Rebate			**$8,556,348.64**			**$8,166,325.09**

- **Small Commercial Customers (<50kW):**
  - Prior to CVR implementation, the monthly consumption is **3,494** kWh per customer or **41,933** kWh annually
  - With the CVR implementation, LDC revenue will see a decrease by **5.31%** of its revenue if no rate adjustment is made (Fixed Monthly Service Charge + kWh-based Distribution Volumetric Rate) = $(20,128.31) over 12-months for **289** customers
  - For an average **7.29%** voltage reduction (**0.89** CVR factor for Energy), small commercial customers will see a reduction of their electrical bill by **6.25% ($417.99** annually before HST & Rebate or **$383.71** annually with HST & Rebate) while their energy usage will reduce by **6.49%**

Small and Medium General Service < 50 kW	**Rates Effective January 1, 2021**					
	Consumption @ 12118560.069646 kWh **Demand (on peak): 6 kW or 6.7 kVA**			**Consumption @ 11332298 kWh (5% Voltage Reduction)** **Demand (on peak): 6 kW or 6.7 kVA**		
	Voltage < 5 kV			**Voltage < 5 kV**		
Charge Description	**kWh**	Rates	Customer Charge	**kWh**	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$1,976.76		$0.57	$1,976.76
Monthly Service Charge		$19.7600	$68,527.68		$19.7600	$68,527.68
Distribution Volumetric Rate	12,118,560	$0.02560	$310,235.14	11,332,298	$0.02560	$290,106.83
Low Voltage Charges	12,528,167	$0.00005	$626.41	11,715,330	$0.00005	$585.77
Adjusted Consumption	409,607			383,032		
Off-Peak	262,149	$0.085	$22,282.64	245,140	$0.085	$20,836.92
Mid-Peak	73,729	$0.119	$8,773.79	68,946	$0.119	$8,204.54
On-Peak	73,729	$0.1760	$12,976.36	68,946	$0.1760	$12,134.44
Network Charge	12,528,167	$0.0076	$95,214.07	11,715,330	$0.0076	$89,036.51
Connection Charge	12,528,167	$0.00480	$60,135.20	11,715,330	$0.00480	$56,233.58
Electricity Charge	12,118,560			11,332,298		
Off-Peak	7,755,878	$0.085	$659,249.67	7,252,671	$0.085	$616,477.01
Mid-Peak	2,181,341	$0.119	$259,579.56	2,039,814	$0.119	$242,737.82
On-Peak	2,181,341	$0.1760	$383,915.98	2,039,814	$0.1760	$359,007.20
Wholesale Market Service Rate	12,528,167	$0.0030	$37,584.50	11,715,330	$0.0030	$35,145.99
Capacity Based Recovery	12,528,167	$0.0004	$5,011.27	11,715,330	$0.0004	$4,686.13
Rural Rate Protection Charge	12,528,167	$0.00	$6,264.08	11,715,330	$0.00	$5,857.66
Standard Supply Service Charge		0.2500	$3.00		0.2500	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate			**$1,932,356.11**			**$1,811,557.86**
Ontario Electricity Rebate*		21%	$409,659.50		21%	$384,050.27
Total before HST with Rebate			**$1,522,696.61**			**$1,427,507.59**
HST 13%		13%	$251,206.29		13%	$235,502.52
Total with HST			**$1,773,902.91**			**$1,663,010.11**

- **Small & Large C&I Customers (General Services >50kW to 1,599kW):**
  - Prior to CVR implementation, the monthly consumption is **184,343** kWh per customer or **2,212,118** kWh annually
  - With the CVR implementation, LDC revenue will see a decrease by **7.29%** of its revenue if no rate adjustment is made (Fixed Monthly Service Charge + kWh-based Distribution Volumetric Rate) = $(93,712.48) over 12-months for **91** customers
  - For an average **7.29%** voltage reduction (**0.55** CVR factor for Energy), small & large C&I customers will see a reduction of their electrical bill by **4.07% ($14,377.05** annually before HST & Rebate or **$13,198.14** annually with HST & Rebate) while their energy usage will reduce by **4.01%**

Rates Effective January 1, 2021						
Small and Medium General Service 50 to 1,499 kW	Consumption @ kWh			Consumption @ 0 kWh (5% Voltage Reduction)		
	Demand (on peak): 100 kW or 111 kVA			Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV			Voltage < 5 kV		
Charge Description	Usage	Rates	Customer Charge	Usage	Rates	Customer Charge
Monthly Service Charge		$200.00	$218,400.00		$200.00	$218,400.00
Distribution Volumetric Rate	30,982	$5.2905	$1,966,941.98	29,506	$5.2905	$1,873,229.56
Low Voltage Charges	30,982	$0.0196	$7,301.91	29,506	$0.01964	$6,954.02
Network Charge	30,982	$3.1059	$1,154,734.92	29,506	$3.1059	$1,099,719.06
Connection Charge	30,982	$1.9644	$730,339.44	29,506	$1.9644	$695,543.36
Electricity Charge	208,106,781	$0.01825	$3,797,948.75	199,762,764	$0.01825	$3,645,670.44
Global Adjustment	208,106,781	$0.11261	$23,434,904.57	199,762,764	$0.11261	$22,495,284.81
Wholesale Market Service Rate	208,106,781	$0.0030	$624,320.34	199,762,764	$0.0030	$599,288.29
Capacity Based Recovery	208,106,781	$0.0004	$83,242.71	199,762,764	$0.0004	$79,905.11
Rural Rate Protection Charge	208,106,781	$0.0005	$104,053.39	199,762,764	$0.0005	$99,881.38
Standard Supply Service Charge		$0.25	$3.00		$0.25	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate		0.0000	**$32,122,191.02**			**$30,813,879.02**
Ontario Electricity Rebate*		21.2%	$6,809,904.50		21.2%	$6,532,542.35
Total before HST with Rebate			**$25,312,286.52**			**$24,281,336.67**
HST 13%		13%	$4,175,884.83		13%	$4,005,804.27
Total with HST			**$29,488,171.36**			**$28,287,140.94**

5.5. Economics Conclusion

Benefits of CVR accrue primarily to the utility and customers. The CVR benefit with the largest and clearest payback, and hence of most interest to Hydro Ottawa, was Capacity Reduction and Energy Savings and loss reduction are other benefits.

CVR enables Hydro Ottawa to either achieve a significant reduction:

- in energy (**3.87%** in **June 2018-May 2019 or 4.51%** in **June 2019 – May 2020**)
  - The Kanata MTS project demonstrated a potential annual consumer bill reduction (CVR 7/24/365) in the range of **$71.69** to **$14,377** (before HST & Ontario electricity rebate) per consumer class without requiring any change in consumer behavior nor participant costs in comparison with traditional demand-side management program

  - VVO/CVR is beneficial to all consumers (low, mid, or high-income) and is considered as In-Front-of-the-Meter Conservation technology or also named supply-side management
  - Levelized Cost of Energy Saved is in the range of **$0.365** and **$0.352** cts per kWh saved
  - Considering the marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) of **$10.82** cts/kWh, the project demonstrated that energy savings is cheaper than making and transmitting energy
  - 2021 marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) is around **$10.82**

and/or

- in capacity (**~1.40 MW** - July 2018 Peak - to **~2.38 MW** - January 2019 Peak- shaved from **June 2018** through **May 2019**) **or** (**~1.61 MW** - July 2019 Peak- to **~2.37 MW** - January 2020 Peak - shaved from **June 2019** through **May 2020**)
  - The Kanata MTS project demonstrated a potential Voltage Reduction by 5%-6% without impacting customers through load shedding or major equipment investments
  - The proposed MV upgrades/ENGO deployment as a Non-Wires Alternatives solution can offset distribution investment by deferring or replacing the need for specific equipment upgrades such as T&D lines or power transformers by reducing load / demand at a substation or circuit level (CAPEX Deferral).
  - CVR is a cheap solution to reduce demand or increase substation/line capacity with a Levelized of Capacity Cost (LCOC) shaved in the range of **$26.15** and **$30.21** per kW-Yr

The deployed technology at Kanata MTS enables greater savings without compromising power quality and grid reliability and demonstrates cost-effectiveness thresholds higher than initially reported by Navigant considering only medium voltage or primary VVC equipment (i.e., Line Voltage Regulator, Switched Cap Banks etc.). The addition of Low Voltage or secondary VVC equipment such as ENGO devices reduces the overall LCOE and LCOC and increases the BCR and the number of eligible VVO feeders versus primary VVC only.

As mentioned earlier, the quantified benefit of reduced greenhouse gas (GHG) emissions was not considered in RIM or TRC/UCT BCR calculation. Any monetized benefits related to the reduction of GHG would be added to the annual consumer bill reduction.

6. Kanata MTS Overview

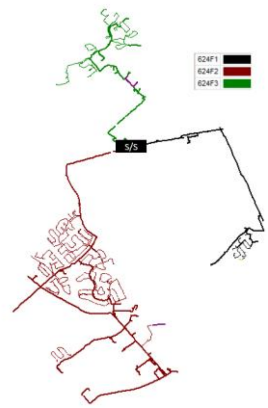
6.1. One Line Diagram and Circuit Information

The Kanata MTS is in Kanata, Ontario, Canada. The Kanata MTS has two transformer banks T1 and T2 feeding a total of five (5) feeders. Figure 4 shows the one-line diagram for the feeders connected to transformer T1 and transformer T2 obtained from the CYME model.

The circuit operates at 27.6 kV (L-L) and it is controlled by a single LTC or AVR (Automatic Voltage Regulator). The two transformer T1 and T2 are connected using a tie-switch under normal operation. However, under emergency peak conditions when the total real power flow through both the transformer banks exceeds 60.5 MW, the tie-switch is opened, and the two banks are manually controlled while the LTC is offline.

Model Specs of Kanata Substation Transformer T1:

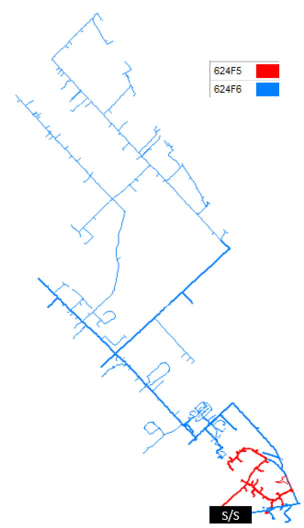
- Nominal: 27.6 kV (L-L), 15.9 kV (L-N)
- LTC SP: CB = 122V, BW = 4V
- 3 Feeders: 624F1, 624F2, 624F3
- Total 28 MW, 11.9 MVAr, PF = 91%
  - F1: 12.89 MW, 5.48 MVAr
  - F2: 13.8 MW, 5.87 MVAr
  - F3: 1.34 MW, 0.57 MVAr
- 0 Line Cap banks and 0 LVRs
- Maximum length from substations ≈ 8.96 km
- 389 service transformers



T1 Bank

Model Specs of Kanata Substation Transformer T2:

- Nominal: 27.6 kV (L-L), 15.9 kV (L-N)
- Two Step Down Transformers: 27.6 kV (L-L) / 12.43 kV (L-L)
- LTC SP: CB = 122V, BW = 4V
- 2 Feeders: 624F5, 624F6
- Total 20.3 MW, 8.75 MVAr, PF = 91.8%
  - F5: 12.6 MW, 5.46 MVAr
  - F6: 7.78 MW, 3.29 MVAr
- 0 Line Cap banks and 0 LVRs
- Maximum length from substations ≈ 22.3 km
- 486 service transformers

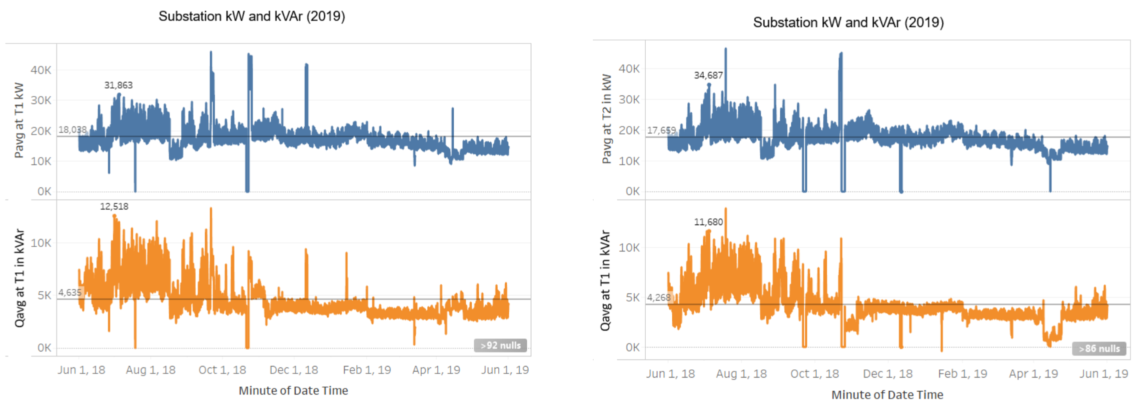


T2 Bank

Figure 4: Kanata MTS Circuit One-line Diagram for all Feeders Connected to Transformer Banks T1 and T2

6.2. Historical Kanata MTS Power Flow

Figure 5 shows the Kanata MTS load (real power P and reactive power Q) at the two transformer banks T1 and T2 between June 2018 and May 2019. The summer peak of 31.9 MW on T1 and 34.7 on T2 happens around July. In comparison, the CYME model for the two transformers has peaks of 28MW and 20.3MW, respectively.



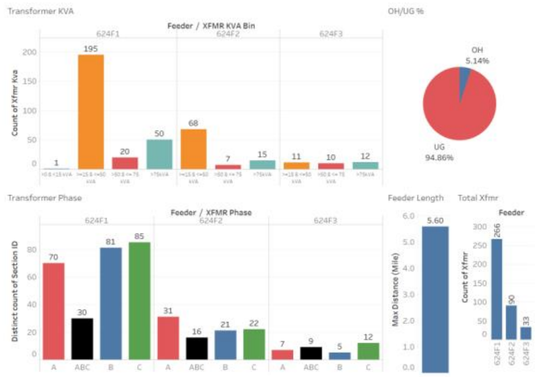
T1 Bank T2 Bank

Figure 5: Kanata MTS MW and MVAr Flow in 2018-2019

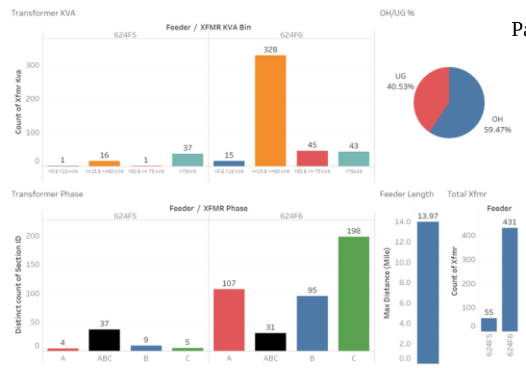
6.3. Load Type / Mix and Customer Class

Figure 6 depicts the metrics for service transformers on banks T1 and T2 on the Kanata MTS. The first plot shows the distribution of service transformers by kVA ratings across the different feeders. The second plot shows the percentage of overhead and underground sections.

The third plot shows the distribution of service transformers by phase (A, B, C, ABC) and the final plot shows the feeder length and the number of service transformers per feeder. It is seen that for T1 most sections are underground (~95%) while for T2 the majority is overhead (~60%). Further, a load report is run in CYME to obtain the type (residential, commercial, industrial etc.) and the combined connected kVA ratings of the service transformers is used to calculate the ratio of commercial and industrial load to residential load. Kanata MTS is found to have a high ratio of C&I customers as compared to Residential customers (Ratio C&I: Residential 2.22 for T1 and 2.48 for T2).



T1 Bank



T2 Bank

Figure 6: Kanata's Service Transformer Metrics

Hydro Ottawa shared with Sentient Energy the billing data of August 2019 to give a rough snapshot of the consumption/demand in the Kanata MTS area. The account match represents **87%** of residential customers, **88%** of small commercial customers (<50kW) and **90% of** small & large customers (General Service >50 to 1,599kW).

- Number of customers serviced in Kanata:
  - ✓ Residential - **5,330**
  - ✓ Small Commercial <50kW - **263**
  - ✓ Commercial - **85**
- Total kWh consumed per rate class based on the accounts match (see above):
  - ✓ Residential - **3,904,088** kWh (**17**%)
  - ✓ Small Commercial <50kW - **915,915** kWh (**4**%)
  - ✓ Commercial - **17,819,987** kWh (**79**%)
- Total kW when applicable per rate class
  - ✓ Commercial Demand - **31,183 kW** (Represents **43** Commercial Customers)

Based on the above data, **22,639,990** kWh have been billed to those customers. Considering a technical loss of **3.27%**, **23,405,222** kWh have been purchased by Hydro Ottawa (to be compared with **24,662,112** kWh reported by the SCADA system).

Therefore, Sentient Energy scaled the billing data of August 2019 per customer class to match 1-year of SCADA data (from June 2019 to May 2020 = **278,404** MWh) and 100% of the customer consumption/demand:

- Residential Customers
  - ✓ **5,926** customers (vs. 5,330)
  - ✓ **4,340,287** kWh in Aug 2019 (vs. 3,904,088 kWh)
  - ✓ Average monthly load of **786** kWh over 12-months (**732** kWh considering Aug 2019)
  - ✓ Average monthly electrical bill of $**120.32** over 12-months with Ontario Electricity Rebate and HST ($**114.01** considering Aug 2019)

Table 17: Monthly Electrical Bill of Residential Customers

	Consumption @ 4340287 kWh		
Charge Description	**kWh**	**Rates**	**Customer Charge**
Smart Metering Entity Charge		$0.57	$3,377.82
Monthly Service Charge		$29.32	$173,750.32
Distribution Volumetric Rate	4,340,287	$0.0000	$0.00
Low Voltage Charges	4,486,989	$0.00005	$224.35
Adjusted Consumption	146,702		
Off-Peak	93,889	$0.085	$7,980.57
Mid-Peak	26,406	$0.119	$3,142.35
On-Peak	26,406	$0.176	$4,647.51
Network Charge	4,486,989	$0.0081	$36,344.61
Connection Charge	4,486,989	$0.0050	$22,434.94
Electricity Charge	4,340,287		
Off-Peak	2,777,784	$0.085	$236,111.60
Mid-Peak	781,252	$0.119	$92,968.94
On-Peak	781,252	$0.176	$137,500.29
Wholesale Market Service Rate	4,486,989	$0.0030	$13,460.97
Capacity Based Recovery	4,486,989	$0.0004	$1,794.80
Rural Rate Protection Charge	4,486,989	$0.0005	$2,243.49
Standard Supply Service Charge		$0.25	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$735,982.81**
Ontario Electricity Rebate		21.2%	$156,028.36
Total before HST with Rebate			**$579,954.45**
HST 13%		13%	$95,677.77
Total with HST			**$675,632.22**

Table 18: Annual Electrical Bill of Residential Customers

	Consumption @ 55880027 kWh		
Charge Description	**kWh**	**Rates**	**Customer Charge**
Smart Metering Entity Charge		$0.57	$40,533.84
Monthly Service Charge		$29.32	$2,085,003.84
Distribution Volumetric Rate	55,880,027	$0.0000	$0.00
Low Voltage Charges	57,768,772	$0.00005	$2,888.44
Adjusted Consumption	1,888,745		
Off-Peak	1,208,797	$0.085	$102,747.72
Mid-Peak	339,974	$0.119	$40,456.92
On-Peak	339,974	$0.176	$59,835.44
Network Charge	57,768,772	$0.0081	$467,927.05
Connection Charge	57,768,772	$0.0050	$288,843.86
Electricity Charge	55,880,027		
Off-Peak	35,763,217	$0.085	$3,039,873.47
Mid-Peak	10,058,405	$0.119	$1,196,950.18
On-Peak	10,058,405	$0.176	$1,770,279.25
Wholesale Market Service Rate	57,768,772	$0.0030	$173,306.32
Capacity Based Recovery	57,768,772	$0.0004	$23,107.51
Rural Rate Protection Charge	57,768,772	$0.0005	$28,884.39
Standard Supply Service Charge		$0.25	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$9,320,641.22**
Ontario Electricity Rebate		21.2%	$1,975,975.94
Total before HST with Rebate			**$7,344,665.28**
HST 13%		13%	$1,211,683.36
Total with HST/Rebate			**$8,556,348.64**

- ✓ Annual Purchased Energy: **57,768,772** kWh
- ✓ Annual Billed Energy: **55,880,027** kWh
- ✓ Peak Load: **9,380** kW (July 2019)
- ✓ CVR factor for Energy: **0.81 (average) + 0.74 (July 2019)**
- ✓ CVR factor for Power: **0.85 (average) + 0.80 (July 2019)**

- Small and Medium General Service < 50 kW
  - ✓ **289** customers (vs. 263)
  - ✓ **1,005,395** kWh in Aug 2019 (vs. 915,915 kWh)
  - ✓ Average monthly load of **3,165** kWh over 12-months (**3,479** kWh considering Aug 2019)
  - ✓ Average monthly electrical bill of $**499.65** over 12-months with Ontario Electricity Rebate and HST ($**509.32** considering Aug 2019)

Table 19: Monthly Electrical Bill of Small Commercial Customers (<50kW)

Small and Medium General Service < 50 kW	Consumption @ 1005395.1701427 kWh Demand (on peak): 6 kW or 6.7 kVA		
	Voltage < 5 kV		
Charge Description	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$164.73
Monthly Service Charge		$19.7600	$5,710.64
Distribution Volumetric Rate	1,005,395	$0.02560	$25,738.12
Low Voltage Charges	1,039,378	$0.00005	$51.97
Adjusted Consumption	33,982		
Off-Peak	21,749	$0.085	$1,848.64
Mid-Peak	6,117	$0.119	$727.90
On-Peak	6,117	$0.1760	$1,076.56
Network Charge	1,039,378	$0.0076	$7,899.27
Connection Charge	1,039,378	$0.00480	$4,989.01
Electricity Charge	1,005,395		
Off-Peak	643,453	$0.085	$54,693.50
Mid-Peak	180,971	$0.119	$21,535.56
On-Peak	180,971	$0.1760	$31,850.92
Wholesale Market Service Rate	1,039,378	$0.0030	$3,118.13
Capacity Based Recovery	1,039,378	$0.0004	$415.75
Rural Rate Protection Charge	1,039,378	$0.00	$519.69
Standard Supply Service Charge		0.2500	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$160,340.64**
Ontario Electricity Rebate*		21%	$33,992.22
Total before HST with Rebate			**$126,348.43**
HST 13%		$0.1300	$20,844.28
Total with HST			**$147,192.71**

Table 20: Annual Electrical Bill of Small Commercial Customers (<50kW)

Small and Medium General Service < 50 kW	Consumption @ 12118560.069646 kWh Demand (on peak): 6 kW or 6.7 kVA		
	Voltage < 5 kV		
Charge Description	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$1,976.76
Monthly Service Charge		$19.7600	$68,527.68
Distribution Volumetric Rate	12,118,560	$0.02560	$310,235.14
Low Voltage Charges	12,528,167	$0.00005	$626.41
Adjusted Consumption	409,607		
Off-Peak	262,149	$0.085	$22,282.64
Mid-Peak	73,729	$0.119	$8,773.79
On-Peak	73,729	$0.1760	$12,976.36
Network Charge	12,528,167	$0.0076	$95,214.07
Connection Charge	12,528,167	$0.00480	$60,135.20
Electricity Charge	12,118,560		
Off-Peak	7,755,878	$0.085	$659,249.67
Mid-Peak	2,181,341	$0.119	$259,579.56
On-Peak	2,181,341	$0.1760	$383,915.98
Wholesale Market Service Rate	12,528,167	$0.0030	$37,584.50
Capacity Based Recovery	12,528,167	$0.0004	$5,011.27
Rural Rate Protection Charge	12,528,167	$0.00	$6,264.08
Standard Supply Service Charge		0.2500	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$1,932,356.11**
Ontario Electricity Rebate*		21%	$409,659.50
Total before HST with Rebate			**$1,522,696.61**
HST 13%		13%	$251,206.29
Total with HST			**$1,773,902.91**

- ✓ Annual Purchased Energy: **12,528,167** kWh
- ✓ Annual Billed Energy: **12,118,560** kWh
- ✓ Peak Load: **2,154** kW (July 2019)
- ✓ CVR factor for Energy: **0.89 (average) + 0.76 (July 2019)**
- ✓ CVR factor for Power: **0.92 (average) + 0.82 (July 2019)**

- Small and Medium General Service > 100 kW
  - ✓ **91** customers (vs. 85)
  - ✓ **19,819,583** kWh in Aug 2019 (vs. 17,819,987 kWh)
  - ✓ Average monthly load of **3,191,695** kWh over 12-months (**210,677** kWh considering Aug 2019)
  - ✓ Average monthly electrical bill of $**29,022.20** over 12-months with Ontario Electricity Rebate and HST ($**30,895.31** considering Aug 2019)

Table 21: Monthly Electrical Bill of Small & Large Commercial Customers (>50kW to 1,599kW)

Small and Medium General Service 50 to 1,499 kW	Consumption @ 19171583.6471221 kWh		
	Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV		
Charge Description	**Usage**	**Rates**	**Customer Charge**
Monthly Service Charge		$200.00	$18,200.00
Distribution Volumetric Rate	35,983	$5.2905	$190,368.06
Low Voltage Charges	35,983	$0.01964	$706.71
Network Charge	35,983	$3.1059	$111,759.60
Connection Charge	35,983	$1.9644	$70,685.01
Electricity Charge	19,819,583	$0.01825	$361,707.39
Global Adjustment	19,819,583	$0.11261	$2,231,883.26
Wholesale Market Service Rate	19,819,583	$0.0030	$59,458.75
Capacity Based Recovery	19,819,583	$0.0004	$7,927.83
Rural Rate Protection Charge	19,819,583	$0.0005	$9,909.79
Standard Supply Service Charge		$0.25	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$3,062,606.65**
Ontario Electricity Rebate*		21.2%	$649,272.61
Total before HST with Rebate			**$2,413,334.04**
HST 13%		13%	$398,138.86
Total with HST			**$2,811,472.91**

Table 22: Annual Electrical Bill of Small & Large Commercial Customers (>50kW to 1,599kW)

Small and Medium General Service 50 to 1,499 kW	Consumption @ 201302747.823564 kWh		
	Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV		
Charge Description	**Usage**	**Rates**	**Customer Charge**
Monthly Service Charge		$200.00	$218,400.00
Distribution Volumetric Rate	41,278	$5.2905	$2,620,580.77
Low Voltage Charges	41,278	$0.01964	$9,728.42
Network Charge	41,278	$3.1059	$1,538,467.41
Connection Charge	41,278	$1.9644	$973,040.14
Electricity Charge	208,106,781	$0.01825	$3,797,948.75
Global Adjustment	208,106,781	$0.11261	$23,434,904.57
Wholesale Market Service Rate	208,106,781	$0.0030	$624,320.34
Capacity Based Recovery	208,106,781	$0.0004	$83,242.71
Rural Rate Protection Charge	208,106,781	$0.0005	$104,053.39
Standard Supply Service Charge		$0.25	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$33,404,689.51**
Ontario Electricity Rebate*		21.2%	$7,081,794.18
Total before HST with Rebate			**$26,322,895.33**
HST 13%		13%	$4,342,609.64
Total with HST			**$30,665,504.97**

- ✓ Annual Purchased Energy: **208,106,781** kWh
- ✓ Annual Billed Energy: **208,106,781** kWh
- ✓ Peak Load: **41,278** kW (July 2019)
- ✓ Average Peak Load: **30,982** kW

- ✓ CVR factor for Energy: **0.55 (average) + 0.43 (July 2019)**
- ✓ CVR factor for Power: **0.56 (Summer) + 0.44 (July 2019)**

6.4. GEMS+ENGO Deployment

An initial analysis was performed by Sentient Energy based on the CYME models provided for both T1 and T2. The results of this analysis for T1 showed that a deployment of 3 Pole-ENGO units for visibility was sufficient. While, for T2 there was a need to deploy 40 Pole-ENGO units to achieve maximum incremental voltage improvement.

A plot Figure 7 shows the voltage profile at the secondary side of the service transformer comparing voltages without and with ENGO deployment on Kanata T2 under peak load. The voltage improvement achieved with 40 Pole-ENGO devices at the optimal locations is 5.4V (4.5%). The final list of ENGO deployment is shown in Appendix. Also, the deployment map of ENGO devices on the CYME model is shown in Figure 8.

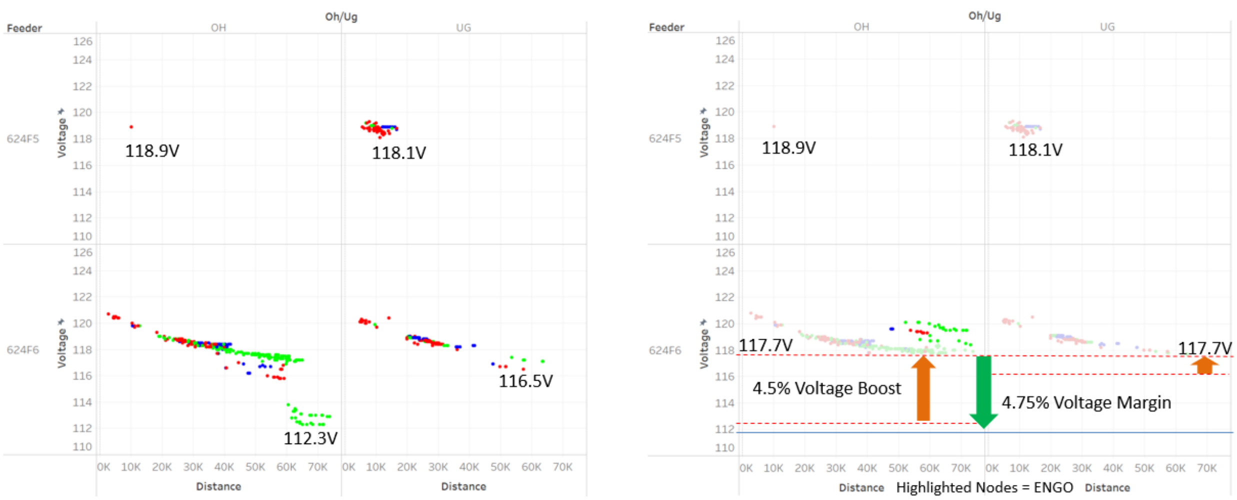


Figure 7: Initial analysis performed prior to contract signature to find the estimated number of ENGO devices and their locations in Kanata MTS

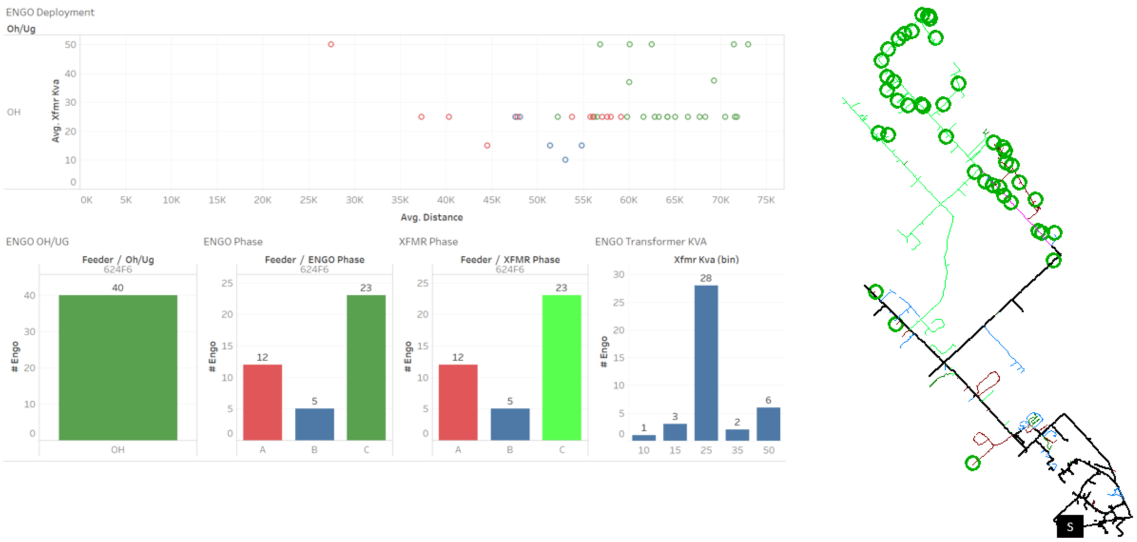


Figure 8: The final ENGO locations on a one-line diagram of feeders connected to bank T2 as per the initial analysis performed

However, due to practical constraints several pole locations identified in the initial study were not feasible for deployment. Therefore, a re-analysis was performed where Sentient Energy provided a priority list of alternative ENGO locations with the assumption that the overall voltage improvement would reduce. For this analysis, Sentient Energy relied on AMI data that was shared post the first analysis. A priority list of units based on the AMI analysis is shown in the Appendix. Hydro Ottawa chose the alternative locations from this list based on feasible pole locations. Sentient Energy also recommended some transformer upgrades that would help boost the system performance.

The final voltage profile with the alternative locations is shown in Figure 9. The voltage improvement without and with ENGO deployment as per CYME model analysis is also provided. As expected, the voltage improvement reduces due to the locations chosen as alternatives and the fact that not all are at the optimal locations. However, a healthy 3.1V (2.6%) improvement is still achieved with the 40 Pole-ENGO devices. The ENGO deployment locations on the CYME model is shown in Figure 10.

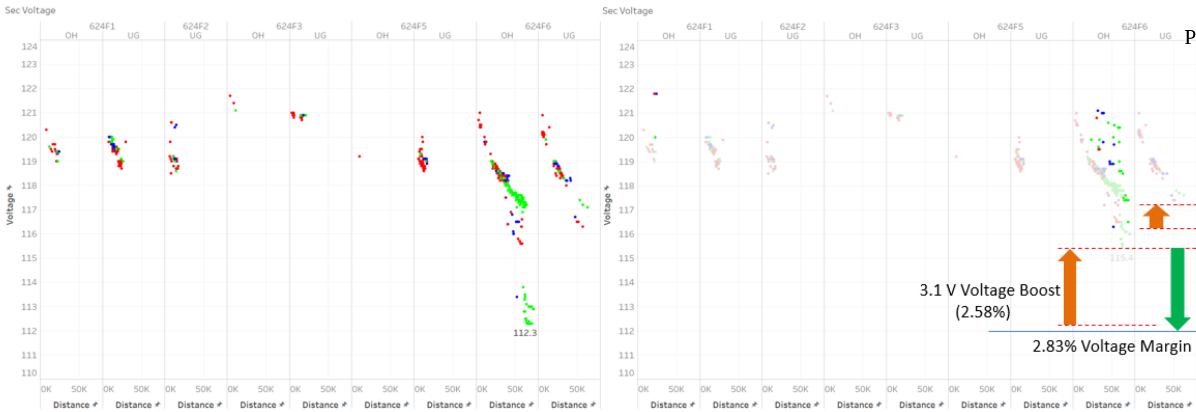


Figure 9: Analysis performed after Hydro Ottawa completed the pole survey. As several locations from the initial analysis were infeasible for deployment, a list of alternative locations was generated using AMI data. The voltage improvement estimates were found using CYME for the final locations.

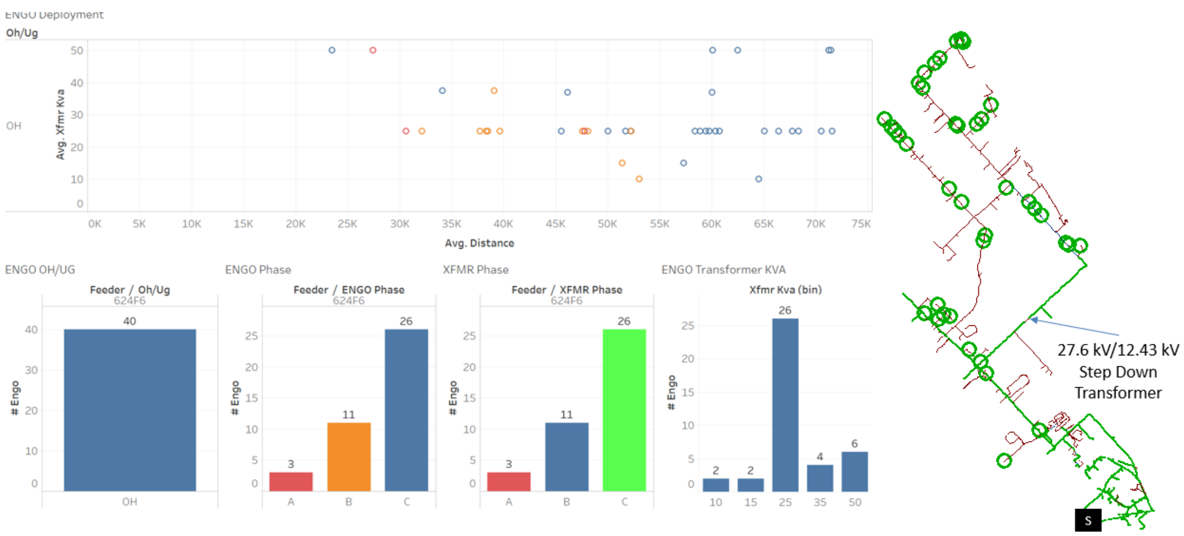


Figure 10: The final ENGO locations on a one-line diagram of feeders connected to bank T2 as per the final analysis performed

The installation of 43 ENGO units was completed on 4th May 2020 and the GEMS software was also commissioned and operational since 10th February 2020.

Table 23 below summarizes ENGO unit deployment by phase:

Table 23: Summary of Kanata ENGO Unit Deployment

	Kanata T1			Kanata T2		Total by Phase
Feeder	**624F1**	**624F2**	**624F3**	**624F5**	**624F6**	
Phase A	1	0	0	0	3	**4**
Phase B	1	0	0	0	11	**12**
Phase C	1	0	0	0	26	**27**
Feeder Total	3	0	0	0	40	**43**

7. ENGO EM&V Test Plan

The test plan and the project timeline are shown in Table 24. It is followed by brief definitions of each type of testing.

Table 24: Testing Schedule

Project Segment	Objectives	Duration	Date Range
Kanata MTS Testing			
• ENGO Install & Monitoring	Baseline Monitoring	6 Weeks	April/May 2020
• ENGO On/Off Testing	Core Metrics	2 Weeks	May/June 2020
• CVR Capacity Reduction Testing	Capacity Reduction (2.5%)	6 Weeks	July/Aug 2020
• CVR Capacity Reduction Testing	Capacity Reduction (5%)	2 Weeks	Sept 2020
• Energy Savings Testing	Energy Saving	6 Weeks	Nov/Dec 2020

7.1. Test Procedure 1 – ENGO DAY ON/OFF Test:

In this test procedure, all ENGO devices are turned ON and OFF on alternate days. During the DAY ON/OFF test, the FHR Set-Point is fixed. The Day ON/OFF testing demonstrates the benefits to improve voltage margin and grid edge voltage support provided by ENGO units. In general, 20 days daily toggling of ENGO unit VAR injection helps us measure:

- **Voltage Control Margin**: Percentage voltage control available without and with ENGO
- **Voltage Improvement**: Percentage voltage boost that is provided by ENGO devices at the weakest location on the system

7.2. Test Procedure 2 – Peak Demand Reduction Testing

In this test, the LTC setpoint is switched between nominal setpoint and CVR setpoint during the peak load hours on alternate days. The ENGO setpoint is adjusted to match the LTC setpoint. This test measures:

- **Maximum Voltage Reduction**: maximum voltage reduction with ENGO without causing any CSA violations
- **CVR Factor for Power**: Based on the voltage transitions measured whenever the LTC setpoint is toggled from nominal to CVR setpoint, the CVR factor for power can be measured.
- **Demand Reduction**: Using the measured CVR factor and the voltage reduction measured in the field, the demand reduction can be computed for the test duration.
- **Technical Loss Reduction**: As a result of reducing the voltage across the entire feeder, the transformers are energized with lower voltage which tends to reduce the core losses on the transformer. This reduction in core losses can be estimated during this test. Further, there is a general power factor improvement that leads to lower line and transformer copper losses.

7.3. Test Procedure 3 – Energy Savings Testing

In this test, the LTC setpoint is switched between nominal setpoint and CVR setpoint (24-hour intervals) on alternate days. The ENGO setpoint is adjusted to match the LTC setpoint. This test measures:

- **Maximum Voltage Reduction**: maximum voltage reduction with ENGO without causing any CSA violations
- **CVR Factor for Energy**: Based on the voltage transitions measured whenever the LTC setpoint is toggled from nominal to CVR setpoint, the CVR factor for energy can be measured.
- **Reduction in Energy Consumption**: Using the measured CVR factor and the voltage reduction measured in the field, the energy savings can be computed for the test duration.
- **Technical Loss Reduction**: As a result of reducing the voltage across the entire feeder, the transformers are energized with lower voltage which tends to reduce the core losses on the transformer. Further, there is a general power factor improvement that leads to lower line and transformer copper losses.
- **Environmental Benefits**: Annual CO2 emission reduction can be estimated using the energy saved metrics.
- The Energy Savings Test will continue over the months of November and December 2020 and the $CVR_{f\ Energy}$ will be calculated. This report contains the MWh Energy Saving and Environmental Benefit metrics using the CVR factor for power which was calculated as part of the capacity reduction test.

8. EM&V Test Metrics

8.1. Impact of System Upgrades and ENGO Voltage Improvement

Hydro Ottawa upgraded the rating of an overloaded transformer (X07487) recommended by Sentient Energy. This led to a significant voltage improvement in the system. Further, ENGOs provided a voltage improvement on top of the improvement obtained from the system upgrade. The proof of this improvement is shown in Figure 11: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field from an initial low voltage of 104.6V to a final minimum voltage of 114.9V. It can be seen that prior to May 6th, 2020, the minimum voltage recorded by ENGOs is 104.6V. Around May 7th the limiting transformer was replaced with an upgraded bank and the ENGO units were in the auto-toggle ON/OFF schedule, therefore on May 9th, 2020, the minimum voltage recorded a jump up to 114.9V. Therefore, the overall effect of Sentient Energy recommended system upgrades and ENGO devices in the system allowed an effective voltage increase from 104.6V to 114.6V (8.3%) – demonstrating no CSA violations.

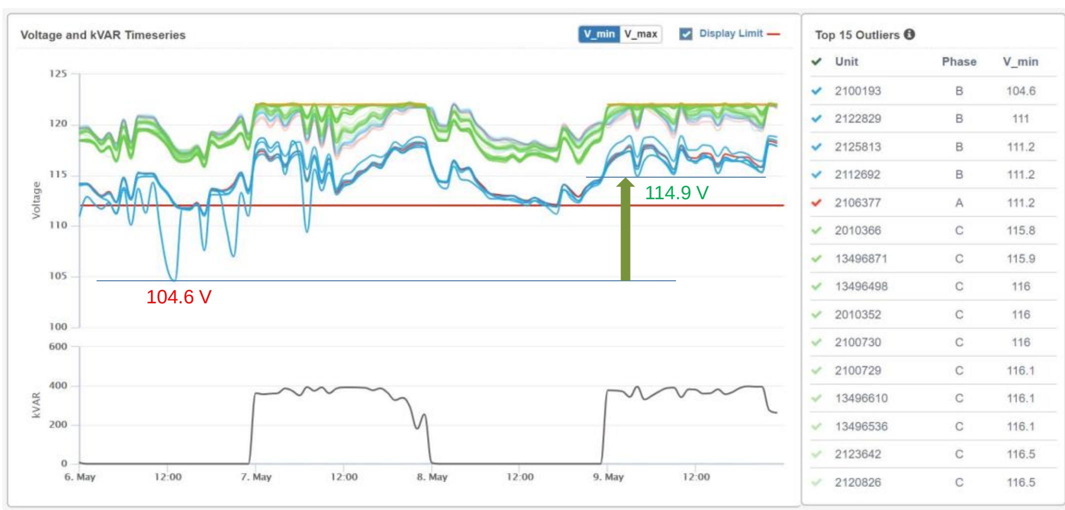


Figure 11: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field from an initial low voltage of 104.6V to a final minimum voltage of 114.9V

Based off the success of system upgrades combined with ENGO voltage support, a study was conducted to identify outliers that would enable performing a 5% reduction at the LTC. Five transformers are selected for tap setting changes (X07491, X07487) and connected kVA rating upgrades (X07484, X50916, X07508). These enhancements were incorporated over the months of July and August boosting the available voltage margin for load reduction and energy savings. The minimum voltage recorded jumps up to 118V+ providing a 6V-7V margin for CVR (CSA voltage threshold of 111V-112V at the distribution transformer).

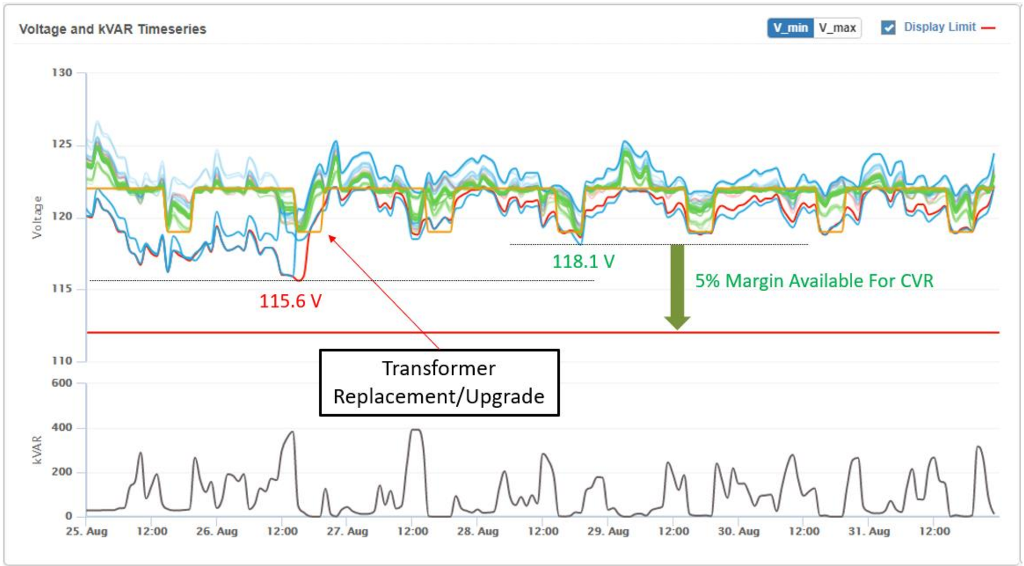


Figure 12: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field boosting voltage to a final minimum of 118.1V

8.2. ENGO ON/OFF Testing Result

8.2.1. Substation Loading and Voltage Profile

The loading at Kanata MTS for both the transformer banks T1 and T2 is shown in Figure 13. It can be seen that the AVR was fixed around June 5th, 2020 and bank T2 was brought online and the load was shared between T1 and T2. Further, if we look at Figure 14 which shows the voltage per phase at the substation, it is seen that prior to June 5th in the absence of regulation the swing in substation voltage was large (~117V to ~126V) and the average substation voltage was around 122V. After the AVR fix, the voltage is much more controlled and swings within the bandwidth of the AVR. Also, the average voltage is around 124V after the AVR fix.

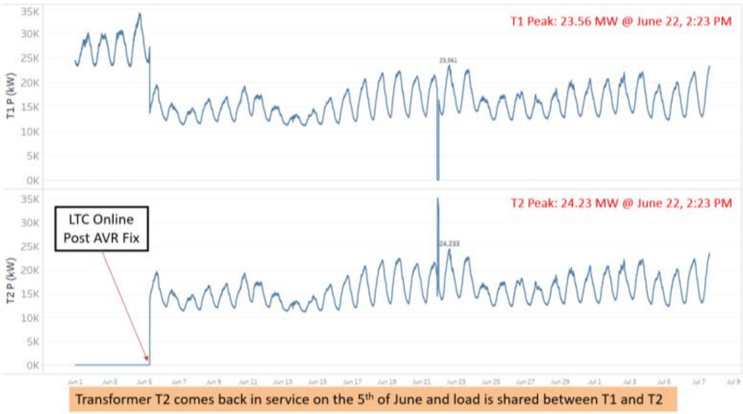


Figure 13: Substation MW loading on both banks T1 and T2 shows that the AVR was fixed around June 5th consequently the power is shared between the two banks

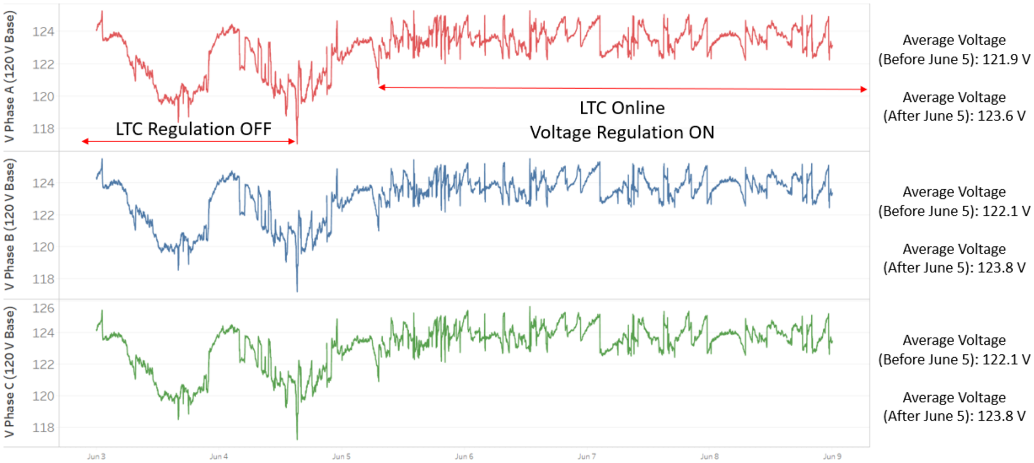


Figure 14: Data per phase voltage indicates that after the AVR fix the voltage are well regulated with an average voltage of ~124V

8.2.2. Voltage Improvement Due to ENGO Units

The ENGO ON/OFF test was conducted for 20 days (from 6/8/2020 to 7/3/2020) the ENGO units were deployed. Subsequently, voltage measurement and analysis of installed ENGO nodes was completed. The minimum voltage recorded when ENGO devices are OFF is 110.6V at a peak load of 22.8 MW (T2), while the minimum voltage recorded when ENGO devices are ON is 113.7V at 24.2MW (T2). The overall voltage improvement is ***3.1V during peak load of 24.2MW***. *Please note that this is a minimum voltage improvement as if the loading on ENGO OFF days was the same as ENGO ON days (which was not the case as the peak load during ENGO OFF days was 22.8MW while during ENGO ON days was 24.2MW), then the voltage on ENGO OFF days would have been even lower giving us a higher voltage improvement value.*

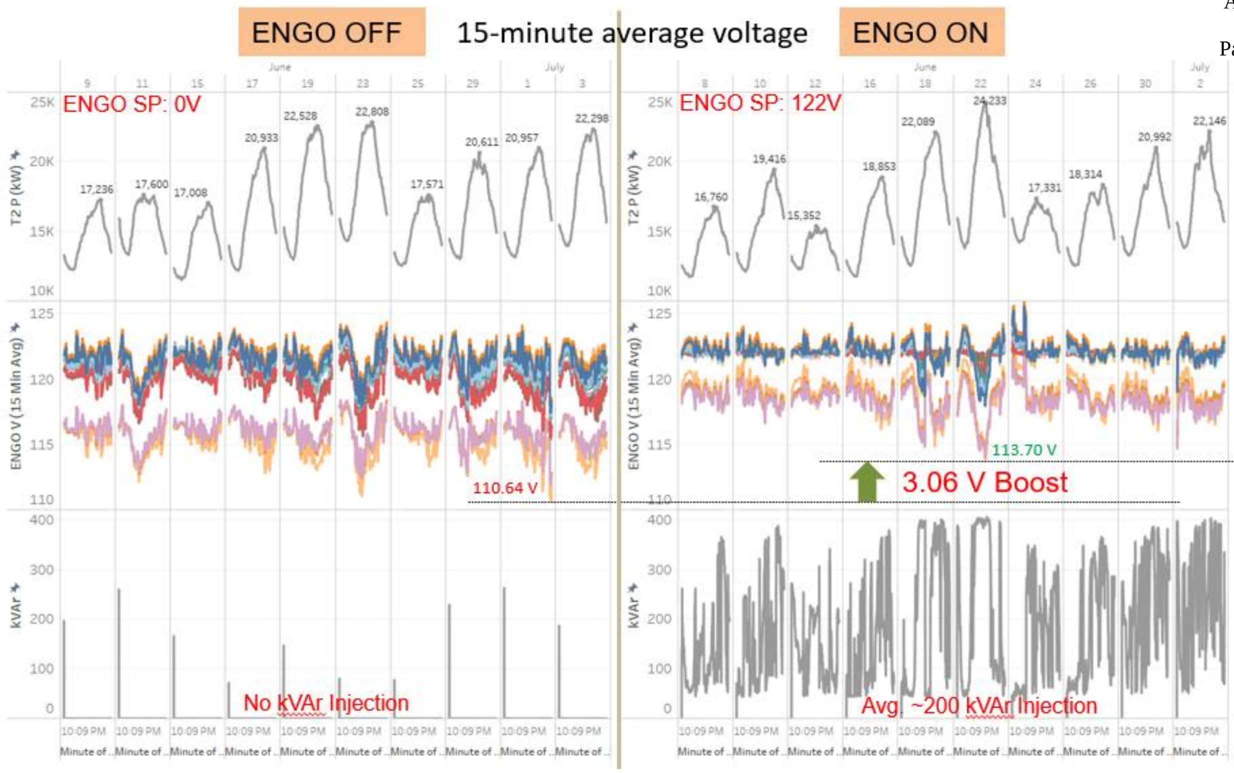


Figure 15: ENGO voltage time series data during ON/OFF testing along with circuit loading condition

Deployed ENGOs help improve the power factor at the substation from 0.9478 to 0.9503 and help reduce the line losses by 0.53%.

Another way of representing the time series plot comparison between ENGO OFF and ENGO ON days is through a voltage versus distance profile where the voltage is the minimum voltage observed over the entire duration. This voltage profile is shown in Figure 16. If we take a 2V drop (conservative value) along the secondary line from the service transformer to the service entrance, then during ENGO OFF days under peak load, the CSA limit is violated. However, with ENGOs ON, no CSA violations are seen and in fact a voltage margin for voltage reduction is observed. ***This shows that voltage reduction on Kanata MTS is not possible without ENGO***.

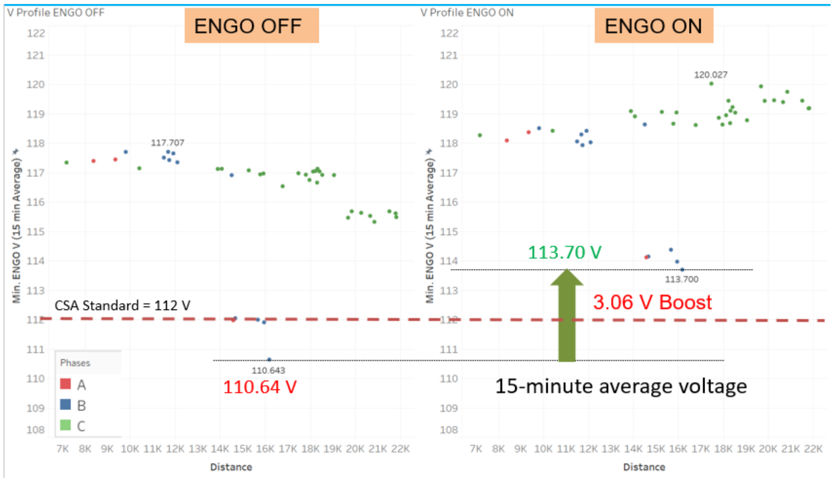


Figure 16: ENGO voltage profile as a function of distance during ON/OFF testing

The values computed for voltage improvement from ENGO is nearly the same as that obtained from the final CYME analysis. But please note that as per initial CYME analysis, the lowest recorded voltage at peak of 20.4 MW (T2) was supposed to be 115.7V while that obtained from the field at a peak of 24.2MW is 113.7V. Hence, there is a gap or error between the analysis performed in CYME and that obtained from field that needs to be accounted for and has been performed in the section on *System Error Calculation.*

8.2.3. Voltage Margin Curve

In order to estimate voltage margin, demand reduction and system error calculation at Kanata, a curve between %Voltage Margin and substation MW was created using field measurements collected during the ON/OFF testing. This curve was created for ENGO ON days to compare with the CYME based curve. Please note that to compute the voltage margin, a difference of minimum voltage and 112V was computed and converted to a percentage value.

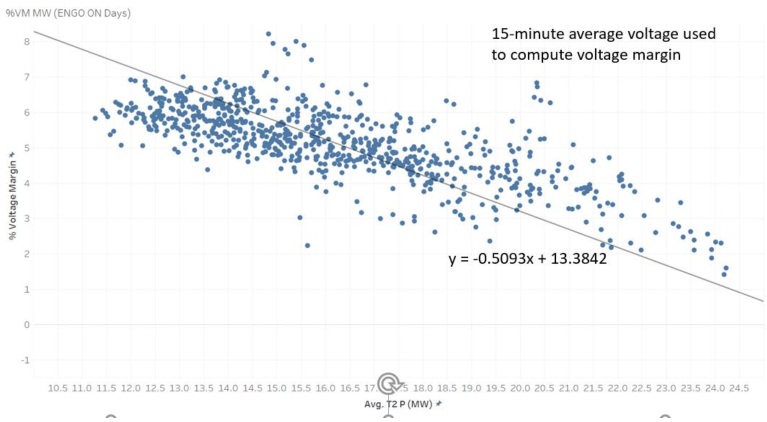


Figure 17: A Curve between Voltage Margin and Substation MW with ENGO ON

9. System Error Calculation as per Contract

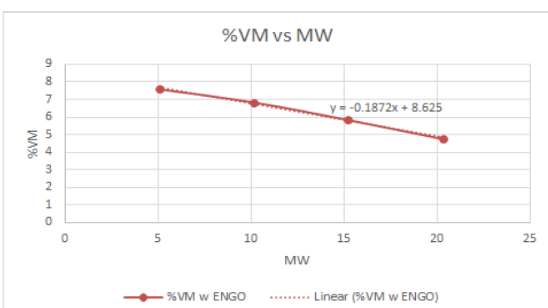
Generally, engineering analysis performed using software such as CYME may have errors and the results obtained may differ from what is observed in reality in the field. These errors arise as the model may not accurately represent the field data.

A performance-based incentive/penalty structure has been proposed as part of the contract which is based on the voltage reductions achieved at the ENGO locations at Kanata T2. Due to the existing healthy voltage margin, no penalty/incentive structure for Kanata T1 was proposed.

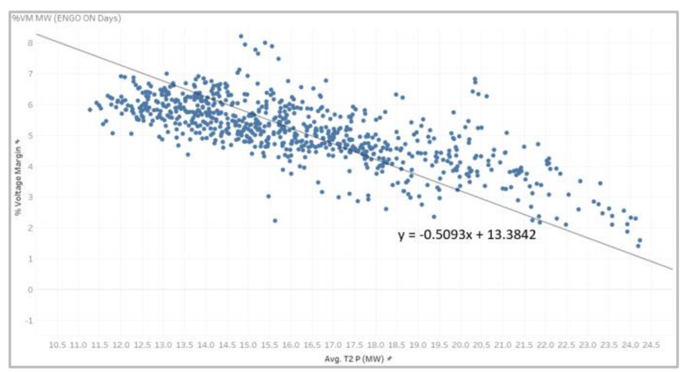
System error calculation for Kanata T2 feeders (F5, F6) was proposed as part of the contract to ensure that when we compare results between CYME and field data, both are aligned together and we are able to account for the incremental value provided by the ENGO units alone.

In this section, we provide the methodology used for computing system error as per the contract. Data considered for computing the system error for the T2 circuits, is over the period of June during which ENGO ON/OFF testing took place.

The first step to finding the system error is to compare the regression model between %Voltage Margin and MW loading obtained from CYME with the same regression model obtained from the field results. These two plots are shown in Figure 18. These plots are obtained for the ENGO ON periods as ultimately, we want to analyze the impact of ENGO units alone without the system error impact.



CYME



Field Data

Figure 18: A comparison between regression model obtained from CYME and field data. Regression model is between %Voltage margin and MW loading (Kanata T2)

The corresponding linear regression model obtained from CYME is

$$\%VM = -0.1872MW + 8.625$$

While the linear regression model obtained from field data captured over the period of June is

$$\%VM = -0.5093MW + 13.3842$$

The difference between these two linear regression models provide us with the system error as a function of MW loading. Doing this gives us the following equation for system error

$$\%SystemError = 0.3221MW - 4.7592$$

As an example of how to use this system error, consider the peak day in June that was recorded on June 22nd (ENGO ON day) with a peak of 22.4MW, the system error can be calculated for this one day as follows

$$\%SystemError = 0.3221(22.4MW) - 4.7592 = 3.05\%$$

The above calculation tells us that for June 22nd there was a system error between the CYME model-based analysis and the field data-based measurements of 3.05% and this system error needs to be considered before we can compare results from the CYME model with field results.

As per the contract, we need to consider the top 10 peak MW values recorded over the ON/OFF test duration. Considering the top 10 peak MW values, we get the results shown in Figure 19.

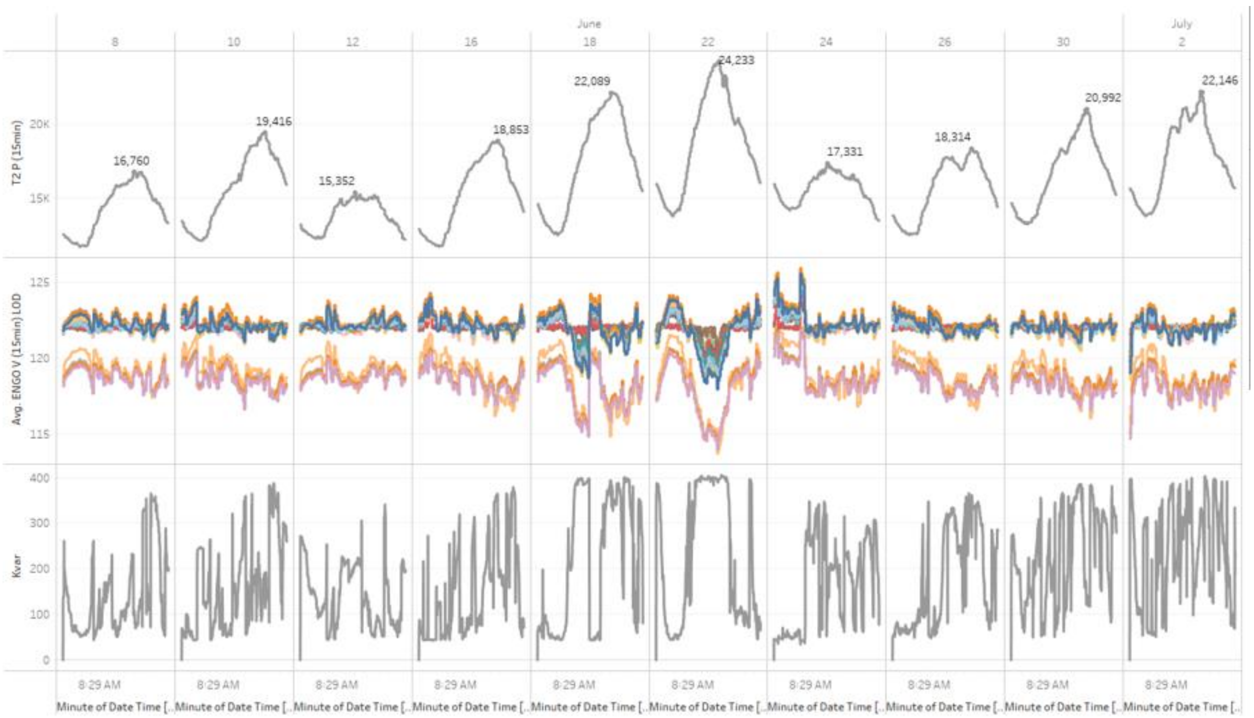


Figure 19: Ten instances of peak in June with ENGO ON captured to compute system error metrics

The Figure 19: Ten instances of peak in June with ENGO ON captured to compute system error metrics shows MW loading at the transformer bank T2 on top, the ENGO voltages in the middle and the kVArs injected by the ENGO to support the voltage at the bottom. Using this plot, we created a table that shows the peak MW and the lowest voltage measured by the ENGO at that point in time which allowed us to then compute the corresponding system error for each sample. A total of 10 samples are collected and at the end an average of the system error and the minimum voltage measured by ENGO is computed.

Table 25: Ten instants of peak MW captured during June with ENGO ON used to compute system error metrics

Peak MW Time Stamp	Peak MW Load (T2 Only)	System Error %	Min Voltage Recorded
6/22/2020 14:30	24.233	3.05	113.92
6/22/2020 15:45	23.296	2.74	116.14
6/22/2020 16:00	23.126	2.69	116.22
7/2/2020 16:00	22.261	2.41	116.70
6/18/2020 17:00	22.117	2.36	116.69
6/18/2020 17:45	22.047	2.34	116.88
6/18/2020 18:00	21.904	2.30	116.06
6/18/2020 18:30	21.534	2.18	116.29
6/18/2020 19:00	21.237	2.08	117.14
6/18/2020 19:30	20.401	1.81	116.43
Average		**2.39%**	**116.24V**

To compute the final metrics that can then be used for comparison with the Penalty structure table provided in the contract and shown below in Table 26, we do the following:

- *Using the average minimum voltage recorded on ENGO ON Days, the %VM computed = 3.53% (116.24V – 112V)*
- *Adjusting for sys_error = 3.53% + 2.39% =* ***5.92%***
- *Voltage reduction for penalty/bonus table =* ***5.92%****. This corresponds to highest bonus based on performance exceeding 110%.*

These calculations simply prove that after accounting for system error, the ENGO units perform as promised during the CYME analysis phase.

Please note that this 5.92% voltage margin is not the actual voltage margin by which the LTC can be reduced under peak. It is a metric that is used to compare results with the penalty/bonus table for convenience.

No penalty/incentive structure was proposed for Kanata Transformer T1 since we have a healthy margin available for voltage reduction and 3 pole mount ENGO devices were placed for visibility only.

Table 26: Penalty/Bonus computation reference table obtained from the contract document. Based on the calculation for system error we provide the highest performance and get the maximum bonus

Min 15-min Voltage Measured by ENGO	Voltage Reduction due to ENGO (min 112V, VM% 120V base)	Weighted Achieved Performance	Total $ Due
Less than 114.4V	Less than 2%	Performance less than 50%	$138,835 - $17,544 = $121,291
114.9V - 117.1V	2.38% - 4.28%	=50% up to 90%	$138,835 - $11,696 = $127,139
117.1V - 117.4V	4.28% - 4.51%	=90% up to 95%	$138,835 - $5,848 = $132,987
117.4V - 118V	4.51% - 4.99%	=95% up to 105%	$138,835 + 11,640 = $150,475
118V - 118.3V	4.99% - 5.23%	=105% up to 110%	$138,835 + $17,460 = $156,295
Greater than 118.3V	5.23%	Performance greater than 110%	$138,835 + $23,280 = $162,115

10. Peak Demand Reduction Testing Results

In order to estimate the load reduction capacity, it is imperative to compute the CVR factor for Power. The System Entropy Method (SEM) developed by Sentient Energy uses natural variation in the substation voltage due to the LTC change and a method of aggregation that reduces the error in calculation of the CVR factor.

- SEM works as follows:
  - We compute the voltage transitions and capture the corresponding changes in power
  - In order to estimate the error present in our computation due to natural variation in power, we create a distribution of the natural variation in Power
  - Using this natural variation in Power we estimate the distribution of error in CVRf-power
  - Using an aggregation of events captured, we reduce the variance of the error distribution around the CVRf-power
  - The mean of valid events captured through all the single transitions provide the final estimate of CVRf-power and the standard deviation of the natural variation helps us compute the error band around this CVRf-power

$$Single\ Event\ CVR_{f-Power} = \frac{\left(\frac{P[i]-P[i-1]}{P[i-1]}\right)}{\left(\frac{V[i]-V[i-1]}{V[i-1]}\right)} \qquad Estimated\ CVR_{f-power} = \frac{1}{N}\sum_{Valid} Single\ Event\ CVR_{f-Power}$$

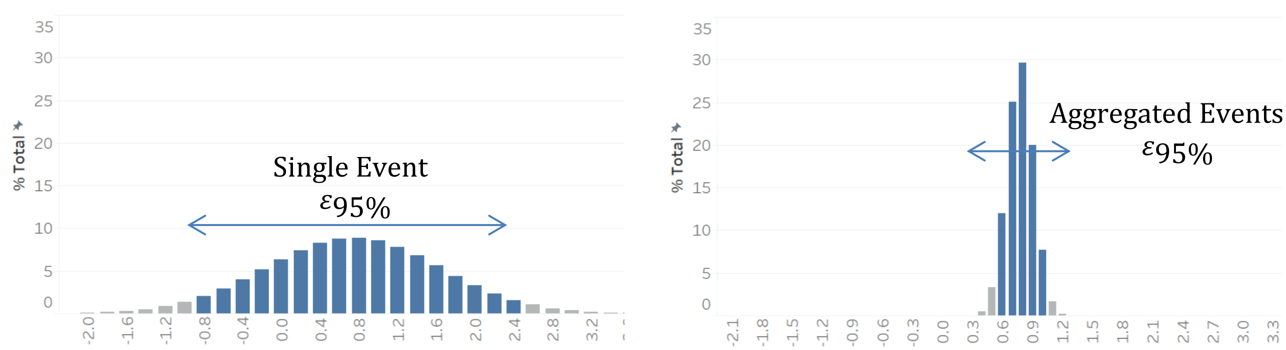


Figure 20: CVR Factor Computation for Power

Peak demand reduction tests are run over three months July (2.5% CVR), August (2.5% CVR) and September (5% CVR) and 27 events (54 transitions) are recorded to calculate an average **CVRfp of 0.52+/- 0.03** (95% confidence). Being a majority C&I customer feeder, the CVRfp is expected to be in the 0.3-0.6 range. **No CSA violations are observed (GEMS) or reported (AMI/Customer Call) during the tests.**

Applying this metric to calculate the total peak shaving on September 23rd (5% CVR Day), a 900kW reduction in load is observed.

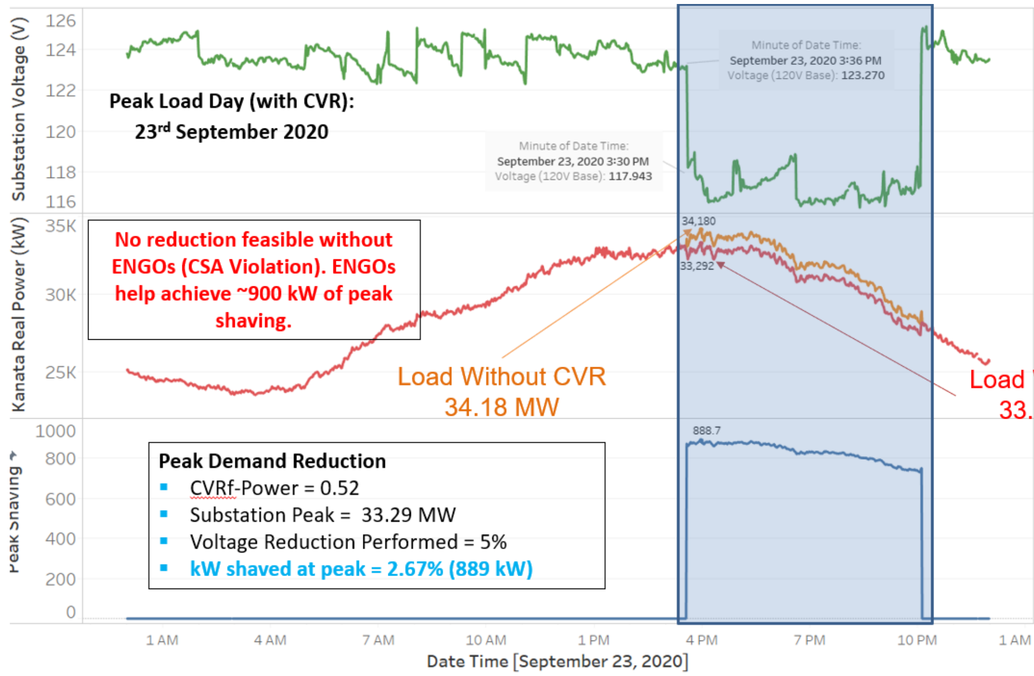


Figure 21: Peak Shaving on September 23rd, 2020 (5% CVR Day)

Similarly, applying the calculated CVRfp to the yearly peak of 50.53 MW (July 2020) a potential reduction of 1.3 MW – 1.6 MW is deemed possible.

Peak Demand Reduction

- CVRf-Power = 0.52
- Substation Peak (Without Reduction) = 50.53 MW
- Load Reduction Possible with **5% CVR** (if CVR was performed): 50530*0.05*0.52 = ***1314 kW (2.60%)***
- Load Reduction Possible with **6% CVR** (if CVR was performed): 50530*0.06*0.52 = ***1577 kW (3.12%)***

Figure 22: Peak Reduction Estimate by 5% and 6% CVR Day

The expected 2.6% - 3.1% peak demand reduction is a promising metric in line with the expected results from the CYME simulation proving the efficacy of Sentient Energy's ENGO solution.

11. Voltage Improvement Story (Voltage Visibility)

Sentient Energy performed analysis using CYME model and AMI data to provide locations for ENGO devices. While performing this analysis, Sentient Energy also recommended some transformer upgrades to ensure that the overall voltage profile of the system improves and maximum incremental voltage benefits can be obtained from the deployment. Figure 23 through Figure 28: **5% CVR – Energy Savings Test – AMI Voltage Profile** shows a storyline using AMI and GEMS voltage profile of transformer nodes with ENGOs deployed and engaged in ON mode (injecting reactive VAr for voltage support; essentially a historical trend of voltage improvement as the recommended steps were followed by Hydro Ottawa. Ultimately, as a result of these upgrade and ENGO voltage regulation, CVR reduction is made possible without any CSA violations.

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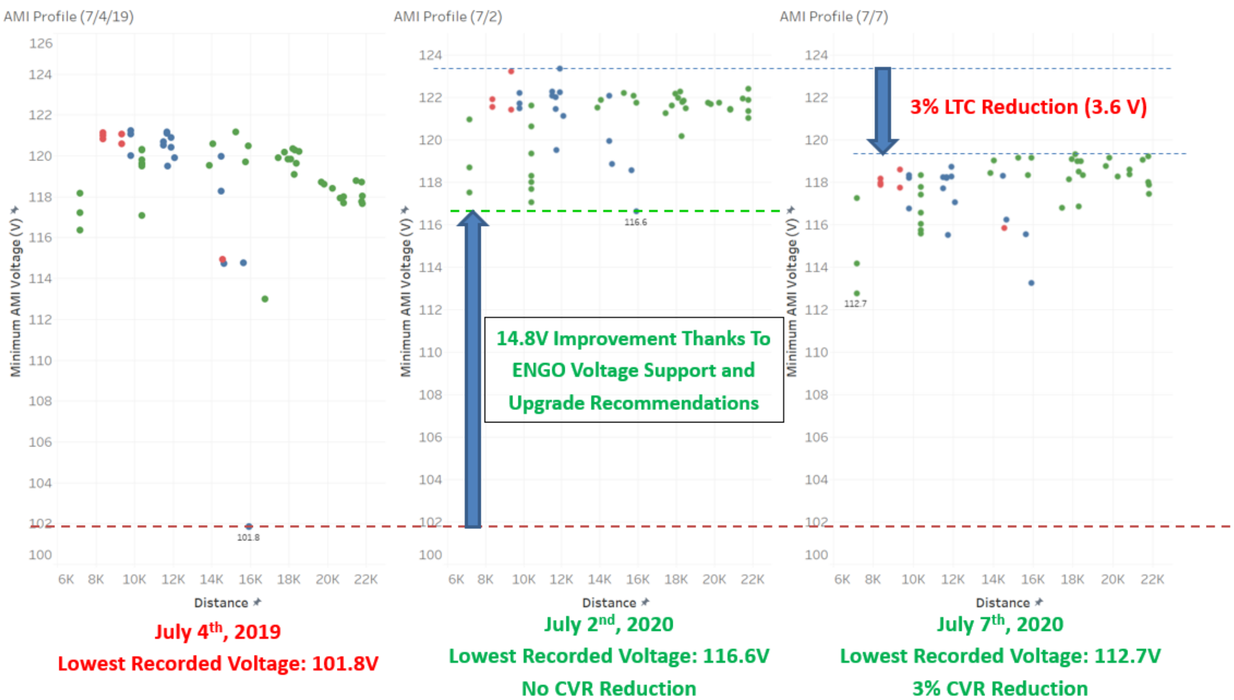
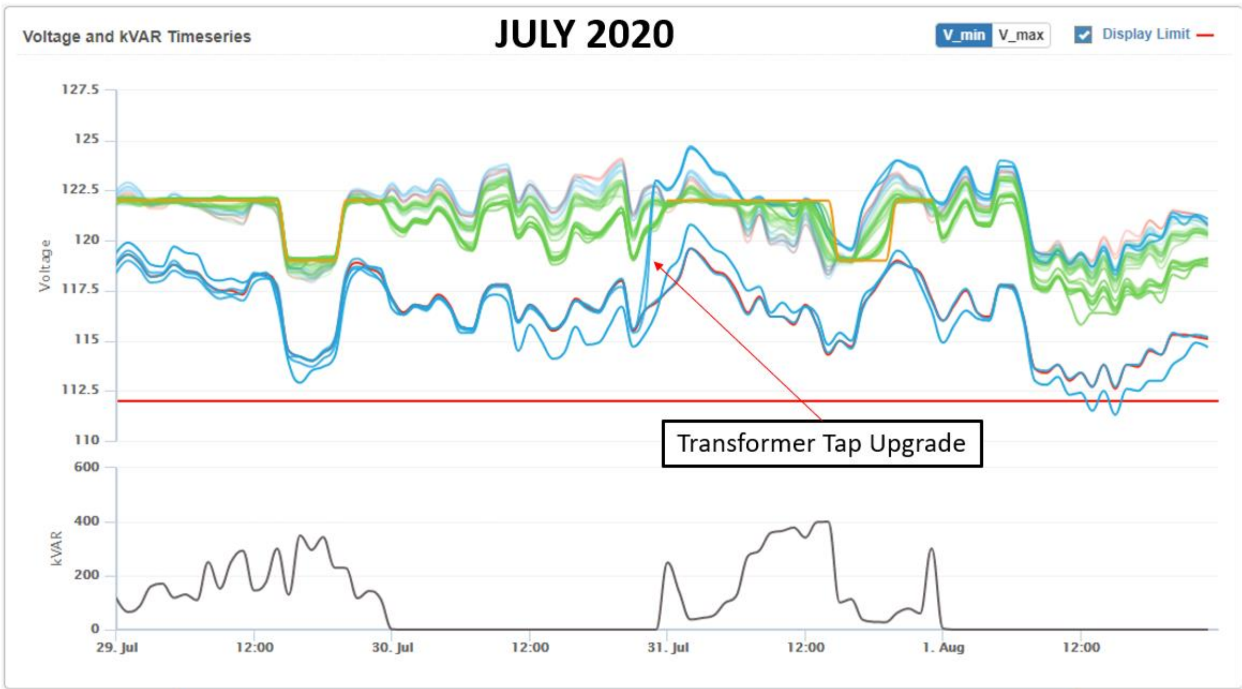


Figure 23: X07487 Transformer Replacement and ENGO ON (May-July 2020)

AMI voltage profile shown over an extended period from last year peak time to this year peak time. It is clear from this plot that after making the upgrades and adding ENGO units to the system, a CVR reduction is possible without any CSA violation which was not the case before.

Note 11:

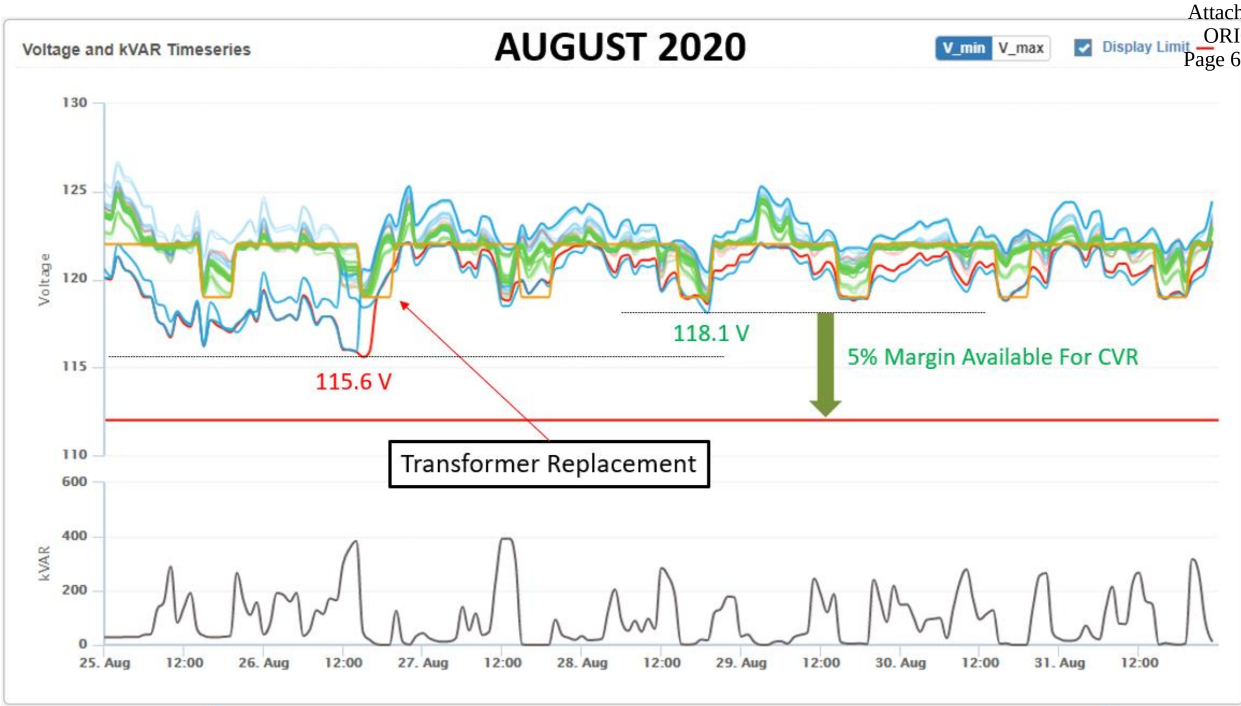
Meter [redacted] connected to Transformer X36610 is excluded for abnormal secondary voltage drop



Two transformers (X074874, X07491) were identified for tap changes resolving voltage outliers and providing margin to pursue 5% CVR

Figure 24: Limiting Voltage Transformer Upgrade (July 2020)

Figure 24: **Limiting Voltage Transformer Upgrade (July 2020)** shows a GEMS view of ENGO time series voltage from July 30th, 2020. Two transformers (X07487, X07491) were identified for tap upgrades resolving voltage outliers and providing margin to pursue 5% CVR. GEMS provides near real time visibility into operation of assets in the field at high data granularity.



Three transformers (X07484, X07508, X50916) were identified for replacement resolving voltage outliers and providing margin to pursue 5% CVR

Figure 25: Limiting Voltage Transformer Replacement (August 2020)

Figure 25: **Limiting Voltage Transformer Replacement (August 2020)** shows a GEMS view of ENGO time series voltage from August 26th, 2020. Three transformers (X07484, X07508, X50916) were identified for replacement (kVA rating upgrade) resolving voltage outliers and providing margin to pursue 5% CVR. GEMS provides near real time visibility into operation of assets in the field at high data granularity.

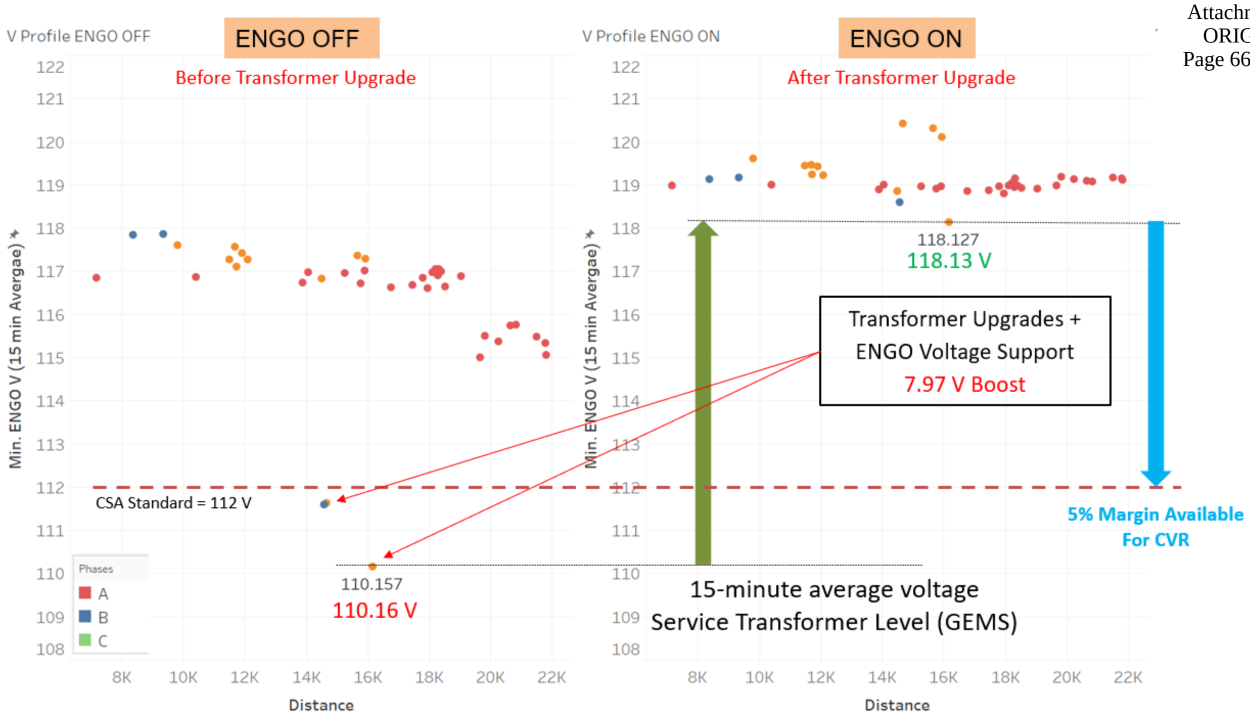


Figure 26: ENGO ON/OFF Voltage Profile (No CVR Day – August 2020)

Figure 26: ENGO ON/OFF Voltage Profile (No CVR Day – August 2020) shows the Voltage Profile (Minimum Voltage vs Distance) measured by ENGO devices before and after the transformer upgrades conducted on August 26th, 2020. With ENGOs turned OFF, there is a CSA violation and no voltage margin present for CVR (prior to system upgrades). Transformer replacement + ENGO ON provides dramatic incremental voltage improvement creating a margin for 5% (and more) CVR.

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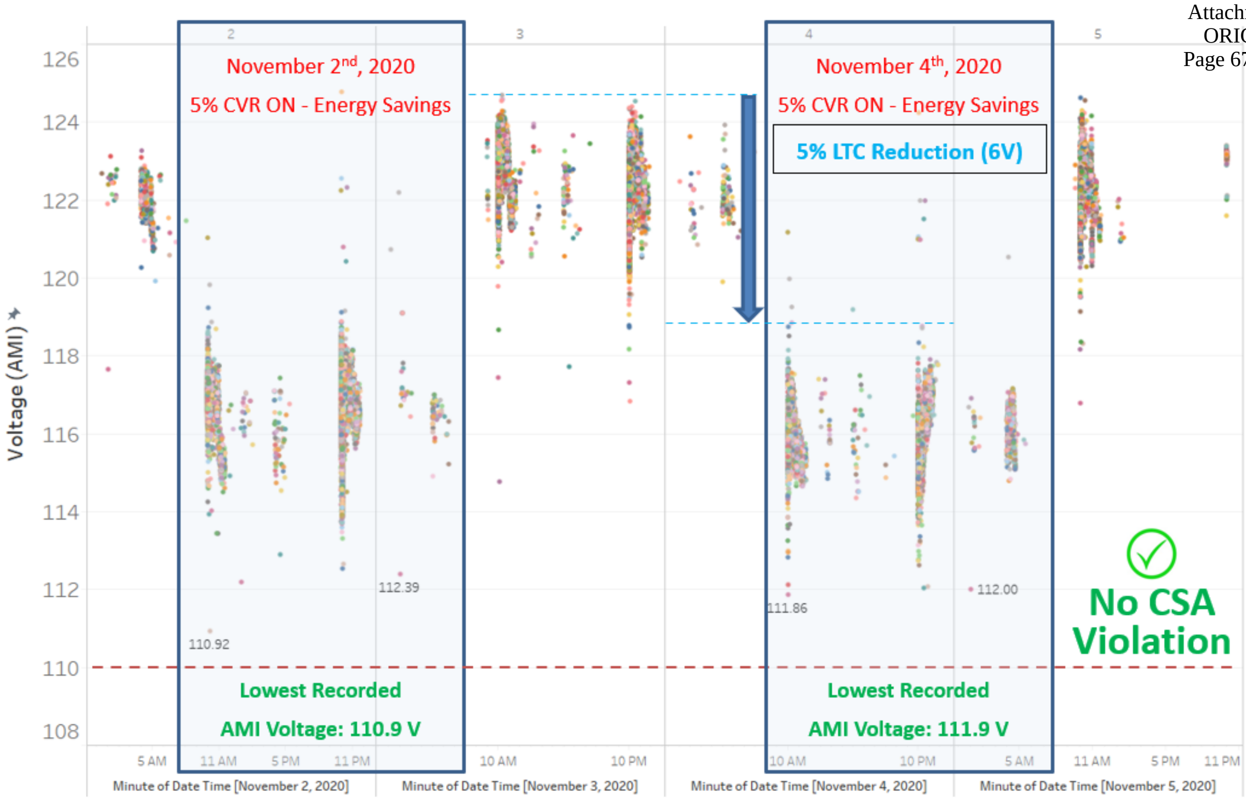

Figure 27: 5% CVR – Energy Savings Test – AMI Voltage Time Series

Figure 27: 5% CVR – Energy Savings Test – AMI Voltage Time Series shows the system-wide AMI voltage recorded during week 1 of energy savings test. 5% reduction in LTC is performed on alternate days in 24-hour intervals. No CSA violation or customer complaint detected. Lowest recorded voltage shows presence of margin for higher CVR.

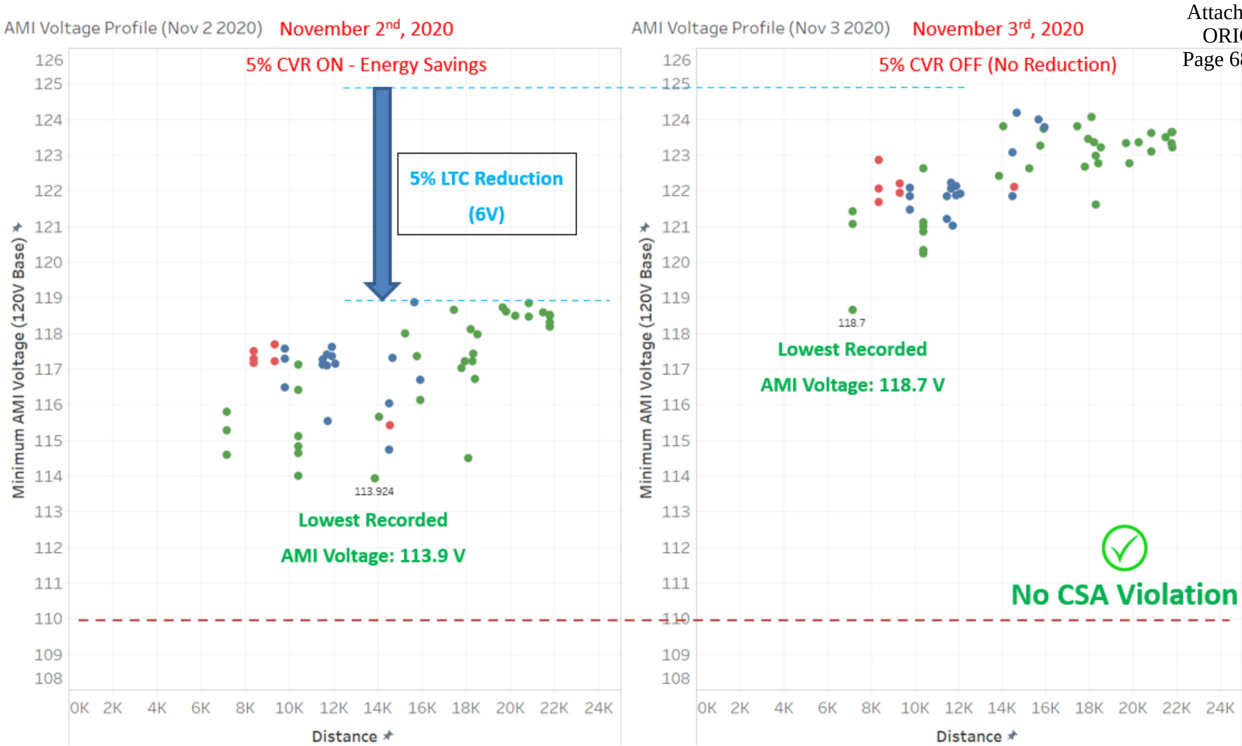

Figure 28: 5% CVR – Energy Savings Test – AMI Voltage Profile

Figure 28: 5% CVR – Energy Savings Test – AMI Voltage Profile shows the AMI Voltage (vs Distance) profile for meters connected to transformers with ENGO deployment during week 1 of energy savings test. 5% reduction in LTC is performed on alternate days in 24-hour intervals. No CSA violation or customer complaint detected.

12. Appendix A: List of ENGO Units as per First Analysis

ENGO ID	[redacted]	XFMR KVA	XFMR Phase	ENGO Phase	OH/UG	# ENGO	Distance
ENGO100	[redacted]	50	C	C	OH	1	22341.5
ENGO101	[redacted]	25	C	C	OH	1	68360.3
ENGO102	[redacted]	25	C	C	OH	1	65062
ENGO103	[redacted]	25	C	C	OH	1	71557.3
ENGO104	[redacted]	25	C	C	OH	1	70545.5
ENGO105	[redacted]	25	C	C	OH	1	66439.7
ENGO106	[redacted]	25	C	C	OH	1	67744.2
ENGO107	[redacted]	50	C	C	OH	1	71459.2
ENGO108	[redacted]	25	A	A	OH	1	47802.3
ENGO109	[redacted]	25	B	B	OH	1	48099.1
ENGO110	[redacted]	25	C	C	OH	1	59782.3
ENGO111	[redacted]	25	C	C	OH	1	52204.5
ENGO112	[redacted]	50	C	C	OH	1	62485.8
ENGO113	[redacted]	37	C	C	OH	1	60019.6
ENGO114	[redacted]	50	C	C	OH	1	60085.7
ENGO115	[redacted]	10	B	B	OH	1	53050.9
ENGO116	[redacted]	15	B	B	OH	1	51395.9
ENGO117	[redacted]	25	C	C	OH	1	58376.1
ENGO118	[redacted]	25	C	C	OH	1	60371.4
ENGO119	[redacted]	25	C	C	OH	1	58912.4
ENGO120	[redacted]	25	A	A	OH	1	30638.7
ENGO121	[redacted]	25	A	A	OH	1	21389
ENGO122	[redacted]	25	B	B	OH	1	52297.2
ENGO123	[redacted]	25	B	B	OH	1	32157.2
ENGO124	[redacted]	25	B	B	OH	1	38490.5
ENGO125	[redacted]	25	B	B	OH	1	37706.5
ENGO126	[redacted]	50	C	C	OH	1	23529.4
ENGO127	[redacted]	50	C	C	OH	1	71274.6
ENGO128	[redacted]	37.5	C	C	OH	1	34133.6
ENGO129	[redacted]	10	C	C	OH	1	64531.4
ENGO130	[redacted]	25	C	C	OH	1	45552.8
ENGO131	[redacted]	25	B	B	OH	1	38329.4
ENGO132	[redacted]	25	B	B	OH	1	39671.9
ENGO133	[redacted]	37.5	B	B	OH	1	39082.8
ENGO134	[redacted]	25	B	B	OH	1	39174.7
ENGO135	[redacted]	50	C	C	OH	1	52793.4
ENGO136	[redacted]	50	C	C	OH	1	34341.2
ENGO137	[redacted]	25	C	C	OH	1	53442
ENGO138	[redacted]	50	A	A	OH	1	33077.9
ENGO139	[redacted]	50	C	C	OH	1	32930.3
ENGO140	[redacted]	50	A	A	OH	1	34285.6
ENGO_M1	[redacted]	25	B	B	OH	1	47577.9
ENGO_M2	[redacted]	25	B	B	OH	1	24049

13. Appendix B: List of ENGO Units as per Final Analysis

ENGO ID	[redacted]	XFMR KVA	XFMR Phase	ENGO Phase	OH/UG	# ENGO	Distance
ENGO100	[redacted]	25	C	C	OH	1	68360.3
ENGO101	[redacted]	25	C	C	OH	1	65062
ENGO102	[redacted]	25	C	C	OH	1	71557.3
ENGO103	[redacted]	25	C	C	OH	1	70545.5
ENGO104	[redacted]	25	C	C	OH	1	66439.7
ENGO105	[redacted]	25	C	C	OH	1	67744.2
ENGO106	[redacted]	50	C	C	OH	1	71459.2
ENGO107	[redacted]	25	A	A	OH	1	47802.3
ENGO108	[redacted]	25	B	B	OH	1	48099.1
ENGO109	[redacted]	25	C	C	OH	1	59782.3
ENGO110	[redacted]	25	C	C	OH	1	52204.5
ENGO111	[redacted]	50	C	C	OH	1	62485.8
ENGO112	[redacted]	37	C	C	OH	1	60019.6
ENGO113	[redacted]	50	C	C	OH	1	60085.7
ENGO114	[redacted]	10	B	B	OH	1	53050.9
ENGO115	[redacted]	15	B	B	OH	1	51395.9
ENGO116	[redacted]	50	A	A	OH	1	27458.2
ENGO117	[redacted]	15	C	C	OH	1	57297.4
ENGO118	[redacted]	37	C	C	OH	1	46135.1
ENGO119	[redacted]	25	C	C	OH	1	60767.8
ENGO120	[redacted]	25	C	C	OH	1	59435.2
ENGO121	[redacted]	25	C	C	OH	1	58376.1
ENGO122	[redacted]	25	C	C	OH	1	60371.4
ENGO123	[redacted]	25	C	C	OH	1	58912.4
ENGO124	[redacted]	25	C	C	OH	1	51738.3
ENGO125	[redacted]	25	A	A	OH	1	30638.7
ENGO126	[redacted]	25	C	C	OH	1	50062.4
ENGO127	[redacted]	25	B	B	OH	1	52297.2
ENGO128	[redacted]	25	B	B	OH	1	32157.2
ENGO129	[redacted]	25	B	B	OH	1	38490.5
ENGO130	[redacted]	25	B	B	OH	1	37706.5
ENGO131	[redacted]	50	C	C	OH	1	23529.4
ENGO132	[redacted]	50	C	C	OH	1	71274.6
ENGO133	[redacted]	37.5	C	C	OH	1	34133.6
ENGO134	[redacted]	10	C	C	OH	1	64531.4
ENGO135	[redacted]	25	C	C	OH	1	45552.8
ENGO136	[redacted]	25	B	B	OH	1	38329.4
ENGO137	[redacted]	25	B	B	OH	1	39671.9
ENGO138	[redacted]	37.5	B	B	OH	1	39082.8
ENGO_M1	[redacted]	25	B	B	OH	1	47577.9
ENGO_T1_1	[redacted]	25	A	A	OH	1	18754.8
ENGO_T1_2	[redacted]	25	B	B	OH	1	24049
ENGO_T1_3	[redacted]	50	C	C	OH	1	22341.5

14. Appendix C: Lessons learned during ENGO Placement

The initial ENGO placement analysis was conducted using CYME simulations to identify voltage outlier nodes and iteratively deploy ENGO devices in the model. Phase I of the field installation gave us several insights in the process:

1. **Identified constraints during field survey of proposed locations:**

    - Customer owned poles were removed from the list
    - Poles with accessibility issues were removed from the list
    - Poles with 120V service were preferred for placement and 240V poles were removed from the list

    The lessons learnt from this exercise include:

    - Ensuring pole locations criteria is identified before analysis is completed for the final pole list
    - Pole inspections should be completed earlier in the project to confirm any pre-work or to identify the pole as not being ENGO compatible.

2. **The initial phase of ENGO deployment gave us some much-needed visibility (high granularity of recorded data in GEMS) in the field:**

    - It was observed that the voltage profile from the CYME analysis did not correlate well with the field data. This was confirmed on analyzing the AMI data which was limited by the small number of reads (two) recorded on a daily basis.
    - A fresh analysis was conducted using an AMI data-driven approach to revise the list of potential locations for ENGO placement. Performance metrics were re-evaluated and multiple options were considered for deployment and relocation.

    The lessons learnt from this exercise include using field data to verify the accuracy of the CYME model and use a hybrid model + data approach while generating the list of potential ENGO locations.

3. **Consider system topography and operating conditions while conducting analysis:**

    Kanata MTS has two transformer regions T1 (feeding circuits 624F1, 624F2 and 624F3) and T2 (feeding circuits 624F4 and 624F5) which are connected by a closed bus tie and regulated through a single LTC controller under normal operating condition. Initially the analysis was conducted on the two transformer areas as independent systems with separate improvement metrics. This was later rectified to conduct combined studies for the normal operating condition and separate analysis for the abnormal operating condition with the bus tie open.

The main takeaway from this effort was communication and clarification of all assumptions made during the study and aligning the Sentient Energy analysis to correctly reflect the HOL system state.

4. **Evaluating primary asset modifications prior to ENGO installation and ensure availability of inventory and construction material:**

   During the project, five (5) transformers were identified for connected kVA rating upgrades and tap changes to rectify voltage issues. These primary asset modifications greatly helped improve the overall voltage profile and provided margin to pursue an additional reduction in voltage.

   The lesson learned from this aspect of the project is to address primary asset issues before the ENGO analysis and be prepared with materials like mounting hardware for construction.