3/15/2024

Area Planning Study – 2025 to 2029

Algoma Power Inc.
A FORTIS ONTARIO Company

2024 Cost of Service Application

Historical Period: 2020-2024

Forecast Period: 2025-2029

Table of Contents

List of Figures

List of Tables

1. Introduction

Algoma Power Inc. (API) provides electricity distribution services in the remote areas of Northern Ontario located north and east of the City of Sault Ste. Marie. API is a wholly-owned subsidiary of FortisOntario Inc. API serves approximately 12,000 customers on a distribution system consisting of 1,861 kilometers of distribution line, with a resulting density of approximately 6.5 customers per kilometer of distribution line. The distribution system extends 93 km east and approximately 255 km north of the City of Sault Ste. Marie.

1.1. Scope and Objectives of Area Planning Study

The Area Planning Study is a vision / plan of the programs and investments required in the distribution network to ensure the system continues to operate in a safe, reliable, and efficient manner. Area Planning Study scope *includes* Load Forecast, Load Flow Study that identifies overloading, non-standard voltage, and phase imbalance, System Sensitivity Analysis that identify potential system constraints, and System Contingency Analysis that identifies components with weak N-1 contingency backup; Area Planning Study also discusses solutions for reliability improvement, integrations of DERs and EVs, and system resilience improvement. Asset replacement investment plans will be discussed on a high level rather than in detail and will focus on the assets with high criticality or requiring major capital investments.

The objectives of the Area Planning Study are as follows:

- Analyze the existing Distribution Network
- Potential Load Growth Impact
- System upgrades for sustainability & improvement
- Future Investment & Expansion
- Economic Analysis
- Reliability Plans

The following assumptions were made during the preparation of this report:

- No significant changes (other than known) to the HOSSM transmission system will occur, including Grid Intertie projects or alternate 115kV sources.
- There will be no large 'spot' loads developing in API's service territory other than those identified in this report.
- API has an obligation to serve its entire present customer base, regardless of costs incurred.

1.2. Summary of Study Results

Key findings of this Area Planning Studies are summarized as follows:

1. Based on historical peak load between 2015 and 2022, the moving-average curve-fit of the peak indicated a moderately increasing a trend. This trend may be further driven up due to the commitment to support the EV-related load growth.
2. The Load Flow study indicates that the current system under peak load conditions does have a voltage drop issue at primary side in Echo River, Batchawana, and Goulais areas.
3. Primary conductors generally do not have over-capacity issues in the peak loading simulation when reviewing thermal overloads. However, certain secondary conductors were 110% (or greater) overloaded in the peak loading simulation and may entail a further investigation on a case-by-case basis.
4. Certain number of distribution transformers and one ratio transformer exhibited 100% (or greater) overloading in the peak loading simulation and may entail a further investigation on a case-by-case basis. A few substation power transformers exceeded 50% of their nominal rating under peak condition and should be monitored closely.
5. The technical demand loss at peak load for API system is about 8.73%. The relatively high demand loss can be largely attributed to the long run of lines with low load density. Unbalanced feeder configuration and small conductor size also play a role.
6. The sensitivity analysis and contingency analysis illustrate that under moderate load growth forecast (i.e., 30% in 10-year when forecasted EV growth being incorporated) or under certain extreme contingencies (N-1 or less components in service), massive sections in Goulais-Batchawana area and the 7.2/12.5kV system of Echo River area display non-standard voltage due to load imbalance, small conductor size, or long distance. Some lines are over or close to their full capacity. Many distribution transformers are over or close to their full capacity.
7. The stress test shows that under aggressive load growth forecast when higher EV penetration rates being considered, the Batchawana-Goulais area is susceptible to the risk of voltage collapse and warrants a higher operating voltage.
8. The asset condition assessment (refer to ACA Report) indicates a variety of assets are approaching their life expectancy and may experience age-related wear. Certain categories of assets require renewal or disposal in order to meet the new standards.
9. The reliability study (refer to the Reliability Analysis Report) identifies the worst performance feeders based on historical outage event data and indices. Some feeders' reliability can be improved by deploying automated switches if they are in a loop system, others may not be easy to improve due to the remoteness and limitation of the radial configuration.

To correct present and predicted deficiencies and meet the capacity requirements for the predicted load growth, the following major work will be anticipated during the study period:

1. Rebuild the backbone sections, mainly between Goulais TS and Bachawana TS, targeting at eventually being operated at 14.4/25kV and capable of providing certain level of contingency backup between the two TS Stations.

2. Convert some non-backbone sections in Goulais-Batchawana area, where the asset conditions and configurations meet the standards and technical requirements so that conversion becomes a more cost-effective option compared to rebuild.
3. Install multiple ratio transformers at a few strategical locations within Goulais where the downstream cannot be converted and prepared to operate at 14.4/25kV. The ratio transformers will maintain the supply to these sections when the new Goulais TS is cut over.
4. Deploy an automation plan in phase to reinforce the Echo River 34.5kV loop system for an improved FLISR capability and operational flexibility. The plan includes the installation and configuration of multiple remotely controlled switches along the existing ER1-ER2 loop.
5. Improve the voltage and phase balance of East of Sault Ste. Marie 7.2/12.5kV system by a combination of multi-phase line extension, phase re-configuration and adjustment, regulator installation.
6. Retire the existing power transformer and structure at Wawa #2 and build a new DS at the same place with larger power transformer capacity.
7. Replace or reinforce a variety of assets non-compliant or near the end-of-life, including poles, distribution transformers, metering infrastructure, and communication infrastructures.
8. Improve the reliability of certain feeders with system reconfiguration or the deployment of SCADA and distribution automation measures.
9. Perform a feasibility study and potentially implement a pilot project to explore the data and control needs of Distribution Energy Resource Management Systems (DERMS) which prepares the LDC for the upcoming DER and EV integration.
10. Conduct a climate vulnerability assessment in order to be more proactive in combating climate change and improve the system resilience.
11. Review non-standard primary voltage and line thermal overload issues under a moderate load increase simulation. Perform field investigation to validate or monitor the issues. In general, if line rebuild or system reconfiguration is not practical or efficient, measures such as correcting load imbalance, installing capacitor banks and/or regulators, or replacing with larger size of conductors should be incorporated into projects whenever it is possible.

Table 1 provides a detailed breakdown and estimated timeline for the work mentioned above.

ID	D/ND	Major Capital Project Description	Category	Estimated TimeLine and Cost ($ 000's)					
				2024	2025	2026	2027	2028	2029
1	ND	East of Sault Ste. Marie 12.5kV Voltage & Phase Balance Improvement	SR		0	0	60	2655	984
2	ND	Wawa Main Substation Upgrade	SR		0	1274	512	2414	180
3	ND	Batchawana & Goulais Voltage Conversion and System Reconfiguration‡	SR	1,261	3,055	937	652	2,719	0
4	ND	EchoRiver 34.5kV Loop Reinforcement and Switching Automation	SS	177	319	232	300	0	0
5	ND	Metering Infrastructure Replacement	SR		364	369	376	381	387
6	D	Communication Infrastructure reinforcement for (smart meters)	SR		40	41	41	42	42
7	D	Transformer Replacement	SR	117	140	142	144	146	149
8	D	Distribution Automation, Reliability Improvement, & Protection Revision Program	SS	245	212	0	0	185	495
9	D	Planned and Unplanned Line Rebuild Program	SR	4,261	4,676	4,746	4.817	4,890	4,963
10	D	Miscellaneous other End-of-life Asset Replacement	SR	62	90	91	93	94	96
11	D	Misc. Grid Modernization and SCADA	SS	140	125	146	138	122	64
12	D	Misc. Engineering Studies & Investigations	SS	42	43	43	44	45	45

‡ This Table only contains some major capital projects, and each project could correspond to a consolidation of multiple projects. Please refer to DSP for the detailed budget plan.

Table 1: Major Capital Project – Cost and Timeline Estimate‡

2. Planning Criteria

The main standards and criteria that applied to in this study involved acceptable voltage range, overloading of conductors and transformers, and contingency reliability. Complete discussion on the standards, criteria, technical specifications, and procedures that will be used for API system planning is outlined in a separate internal document – "Standards for System Planning – Fortis Ontario".

The criteria / assumptions set out in this section will form the basis to analyze the existing distribution network and will identify capital investments for sustainability and improvement of distribution operations. The planning criteria also accounts for the system reliability and emergency business operations and therefore, is stringent in some cases, especially for the substation transformers.

The planning study criteria / assumptions are as follows:

- CSA CAN3-C235-83 (R2015) specifies the preferred voltage levels. Basically, under normal operating conditions, the voltage variation at service entrance is 110 to 125V (single phase, Line-to-Ground). Circuits above 1kV (Primary) should be maintained at any given point so as not to vary from nominal voltage by more than ±6% (i.e., 113 to 127V with 120V base). This study will examine the non-standard voltage issue at the primary circuits assuming that all the TS bus voltages are set as 126V (1.05PU).
- OEB Filing Requirements (2.8.9, 2020) requires an explanation of distribution losses greater than 5%. This study will examine and interpret the system demand losses.
- All current-carrying components have the ability to withstand thermal overloads to certain extent under different ambient conditions and load profile. The threshold percentage used in this study just represents a call for caution.
- Ideally, under normal operating conditions, ratio bank and substation transformers operate at up to 50% of their nominal capacity. This threshold percentage also represents a call for caution only.
- Main feeders that are over 300 A ampacity under normal configuration should be given attention. Especially, main feeders with underground feeder exits and downstream feeder dips are subject to reduced and restricted ampacity.
- Ideally, feeder imbalance should be within 15% of tolerance limit.

***Load flow simulation performed in this study was completed using Milsoft™ Engineering Analysis software Windmil Version 22.1.4.**

3. Historical Load and Load Forecast

3.1. Historical Power Consumption

API’s average system demand has maintained a moderately increasing trend over the past 8 years. No significant increase in demand has been seen over the years. The table and figure below show the trend of API’s System Demand.

Table 2: System Average and Peak Load 2015 to 2023

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2015 Actual	44,710	26,201	32,284
2016 Actual	40,591	29,413	31,617
2017 Actual	41,840	29,103	31,181
2018 Actual	44,182	34,492	35,232
2019 Actual	48,304	33,373	36,879
2020 Actual	44,860	36,660	36,273
2021Actual	45,245	36,402	38,653
2022 Actual	50,393	38,745	39,881
2023 Actual	47,551	37,735	40,128

*Winter Peak – Maximum among January – April and November – December
*Summer Peak – Maximum among May – October
*Average Peak – Average of monthly peak

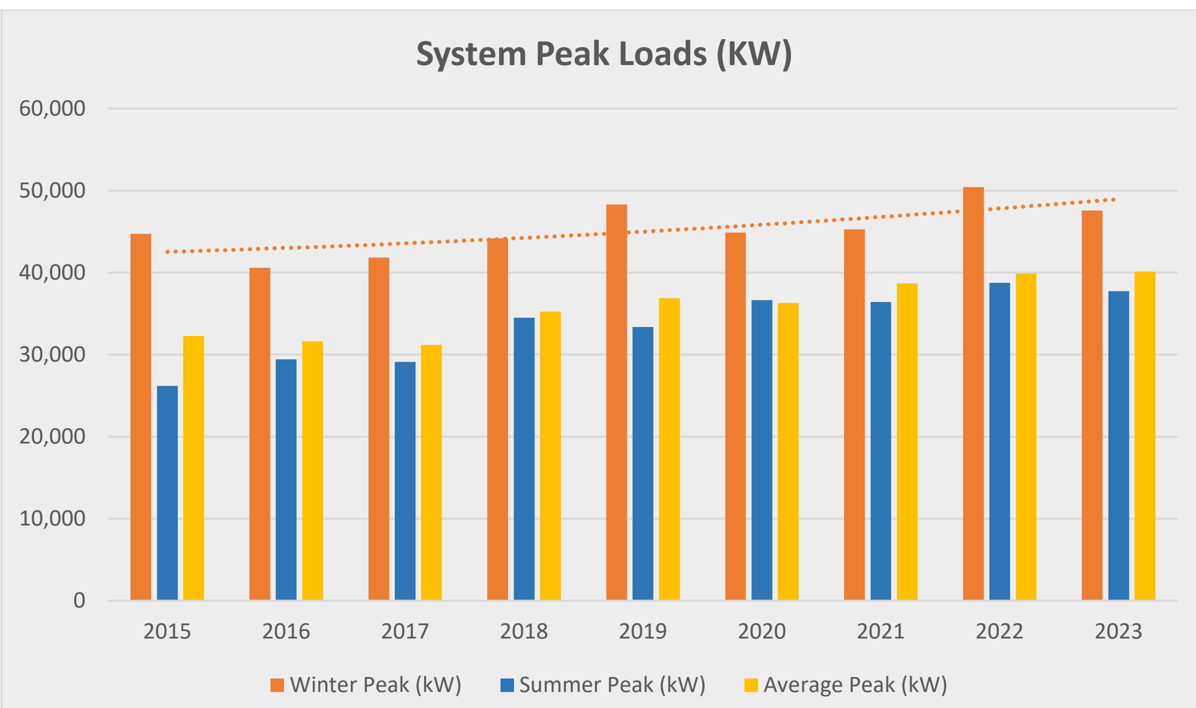

Figure 1: System Average and Peak Load 2015 to 2023

In general, the average loading of the substation power transformers are below their 50% capacity utilization although an increase has been observed over the years. The seasonal / momentary peaks observe a similar increasing trend, and some power transformers are well above their 50% capacity utilization.

The summarized capacity utilization tables and figures for substation transformers are as follows:

Table 3: Substation Transformer Capacity & Peak Loading

Distribution Substation	Transformer	HV kV	LV kV	Capacity (kVA)	# Customers	Peak Load (kVA)	% Capacity Utilized
Garden River DS	T1	34.5	12.47Y/7.2	3000	406	1010	33.6%
	T2	34.5	12.47	3000	137	509	16.9%
Bar River DS	T1	34.5	12.5	6000	1375	3231	53.8%
Desbarats DS	T1	34.5	12.5	6000/8000/10000	1141	2782	46.3%
	T2	34.5	24.94Y/14.4	5000/6667/8333	1969	4030	80.6%
Bruce Mines DS	T1	34.5	12.47	5000	1196	2563	51.2%
Goulais TS (API Transf.)	T1	25	12.5	7500	200	2276	30.3%
Wawa #1 DS	T1	34.5	8.3Y/4.792	5000/6667/8333	687	2947	58.9%
Wawa #2 DS	T1	34.5	8.3Y/4.792	5000/6667/8333	672	1674	33.5%
Hawk Junction DS	T1	44	8.3Y/4.792	1000	See Note		
Hawk Junction DS	T2	44	8.3Y/4.792	1000	147	296	29.6%
Dubreuilville Sub 86	T1	44	4.16Y/2.4	3000	221	1260	42.0%
	T2	44	4.16Y/2.4	3000	127	865	28.8%
Dubreuilville Sub 87	T1	44	4.16Y/2.4	1000	7	99	9.9%

** Note: T1 is a redundant spare within the Hawk Junction DS*

Table 4: Transmission Station - Peak Loading

Delivery Point	HV kV	LV kV	Capacity (kVA)	# Customers	Peak Load (kVA)[4]	% Capacity Utilized
Andrews TS	115	25	5000	62	369	7.4%
Batchewana TS	115	7.2[2]	4000	845	2081	52.0%
D.A. Watson TS (Wawa)[1]	115	34.5	75000	1681	9221	12.3%
Echo River TS	230	34.5	25000	6227	18433	73.7%
Goulais TS	115	12.5	15000	3184	10849	72.3%
Limer - No.4 Circuit	44	44	28000	654	27099	96.8%
Mackay TS	115	14.4	25000	9	68	0.3%
Northern Ave 34.5kV	115	34.5	26700	2	See Note 3	
Northern Ave 12kV	34.5	12	10000	6	2508	25.1%

Notes:

1. *The large available capacity of Watson TS is a result of a large amount of generation connecting at 34.5 kV.*
2. *Batchawana TS supplies only 2 phases at 7.2 kV L-N. Transformers at rated 2500 and 1500 kVA*
3. *The Northern Ave 34.5 kV feeder normally supplies <100 kVA to a single customer; however, it occasionally supplies the entire Echo River TS load.*
4. *Peak Load is extracted from the baseline scenario of Load Allocation (Section 4.1).*

3.2. Load Growth

3.2.1 Service Territory Developments

There are some potential major industrial and commercial spot loads within API's service territory. The items listed below are at different stages of development and serve the planning purpose only.

- A Customer on Limer #4 Circuit (2.5MW peak, seasonal or rarely used).
- A Township customer with new housing development.
- A hotel customer with level 2 EV charger.
- A Customer in Goulais issued an expansion plan before Covid and may follow up.
- A car dealership customer expresses the interest of building a charging station within the industrial zone along highway.
- East of Sault: a few gas stations express the interest of installing charging stations.
- A large industrial customer in Echo River area expressed interest of expansion.
- A local community expresses the interest for potential industrial development & potential community energy plan.
- Hwy17 Corridors: potential growth due to emerging EV charging stations.

3.2.2 EV Charging

Climate change has impacted the global eco systems in many different ways leading to be one of the major influencing factors towards green energy. The decarbonization has also led to improvements / changes in the transportation sector.

The Government of Canada (GoC) has set a target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100 percent sales by 2040. The GoC is setting the country on a clear path towards Canada's new 100 percent zero-emission vehicle sales goal and a prosperous net-zero emissions economy by 2050[1].

With an estimated 51,000 electric vehicles on the road in Ontario, a number expected by IESO to grow ten-fold by the end of the decade[2]. Ontario's power demand is projected to have an annual growth rate of **1.7% per year until 2042**[3] – 2021 Demand Forecast by IESO.

Growth is primarily attributed to electric vehicles (EVs), agricultural greenhouses, mining expansion, steel producer electrification in northern Ontario, and continued residential sector growth. The transportation sector demand outlook has the most significant change with an annual average growth rate of 20%. EV charging is the primary driving force behind this growth. The Annual Planning Outlook (APO) forecast aligns with the recent federal government announcement on zero-emissions vehicle sales targets, which projects 6.4 million EVs in Ontario by 2042. This increase in EVs results in an annual charging demand of 24.4 TWh and peak demand of 1,200 MW[4].

EV's may be interpreted as an energy storage resource that can be connected to the electric network and provide the desired electrical energy to the power grid and/or customers. EV's are targeted as the emerging large loads in power grids; different from the conventional loads, EV's are able to function as both energy storage resource and a distributed energy unit that, at times and if necessary, can support the power distribution grid stability, reliability, and resilience. While EV's facilitate an electrified mobility in modern power grids offering lots of flexibility and supportive benefits locally and grid-scale, there are few challenges concerning the widespread deployment of EV's, among which are the significant randomness in driving patterns and the re-charging capacities.

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[1] - - https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/ - page 26

[2] - https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.pdf Electric Vehicles – Section 2.4.5.1 - Page 23

[3] - https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.pdf - Page 2

[4] - https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.pdf Electric Vehicles – Section 2.4.5.1 - Page 23

IESO has invested $1 million in Vehicle to Grid projects[5], due to the bi-directional capability of EV chargers to support the local grid. The projects supported by the funding will test new technologies and will provide additional flexibility for EV owners and Ontario's power grid[5].

As a reference, Figure 2 shows the current EV density within API's service territory. The map is based on the EV postal code dataset provided by the Ministry of Transportation in October 2023.

[5] - https://www.ieso.ca/Corporate-IESO/Media/News-Releases/2021/11/Gearing-up-for-the-Electric-Vehicle-of-the-Future#:~:text=This%20project%20will%20test%20a,and%20backup%20power%20as%20needed.

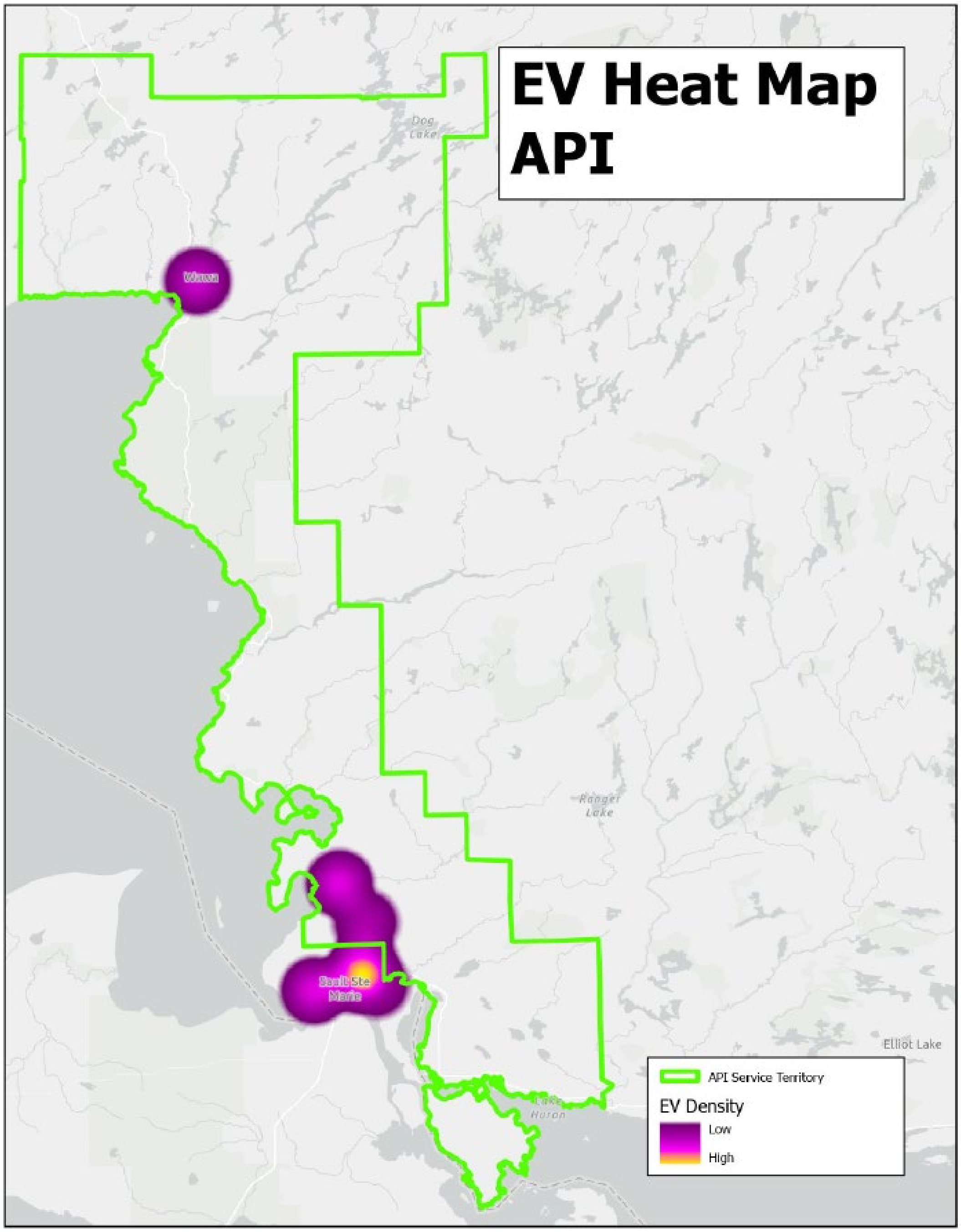


Figure 2: API EV Heat Map by 2023

3.3. Load Forecast

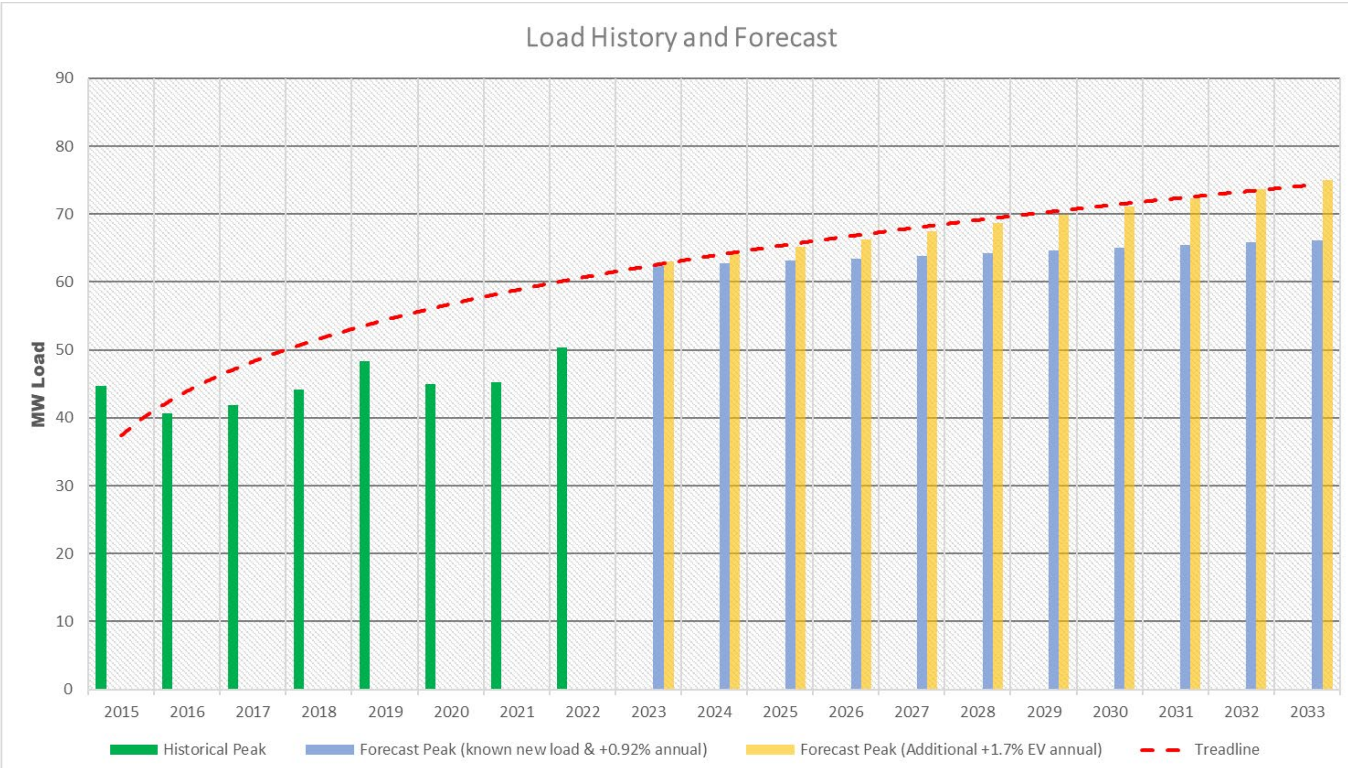


Figure 3: API Load History and Forecast 2010 to 2033

The moving-average curve-fit of the historical peak load between 2015 and 2022 indicates a moderately increasing trend. The load drops due to slow-down during Covid had been compensated by some major industrial load increases. The actual peak load of 2022 is 50.4MW. Given of the known additional 10MW loads on #4 Circuit to be gradually picked up by 2024 assuming the coincidence factor is close to 1 (which will be highly possible), the peak load of 2024 is expected to be about 60MW. Using this load as a baseline, API's peak load would be expected to increase to 66MW by Year 2033. This forecast assumes a 0.92% general load growth from year to year. If the IESO's projected annual load growth of 1.7% due to EV is taken into account, API's peak load would be expected to increase to 75MW by Year 2033. Whether the load growth follows a conservative or an aggressive path is highly depends on the pace of EV penetration.

Following the same trend, the 15-Year, 20-Year, and 25-Year load forecasts are illustrated in Figure 4 below, as compared to the 10-Year load forecast. The load levels for 10 -Year, 15-Year, 20-Year, and 25-Year load forecasts are close to the load levels of the four scenarios in Sensitivity Analysis (Section 4.6) separately. Please refer to the stress test results for potential system constraints accordingly.

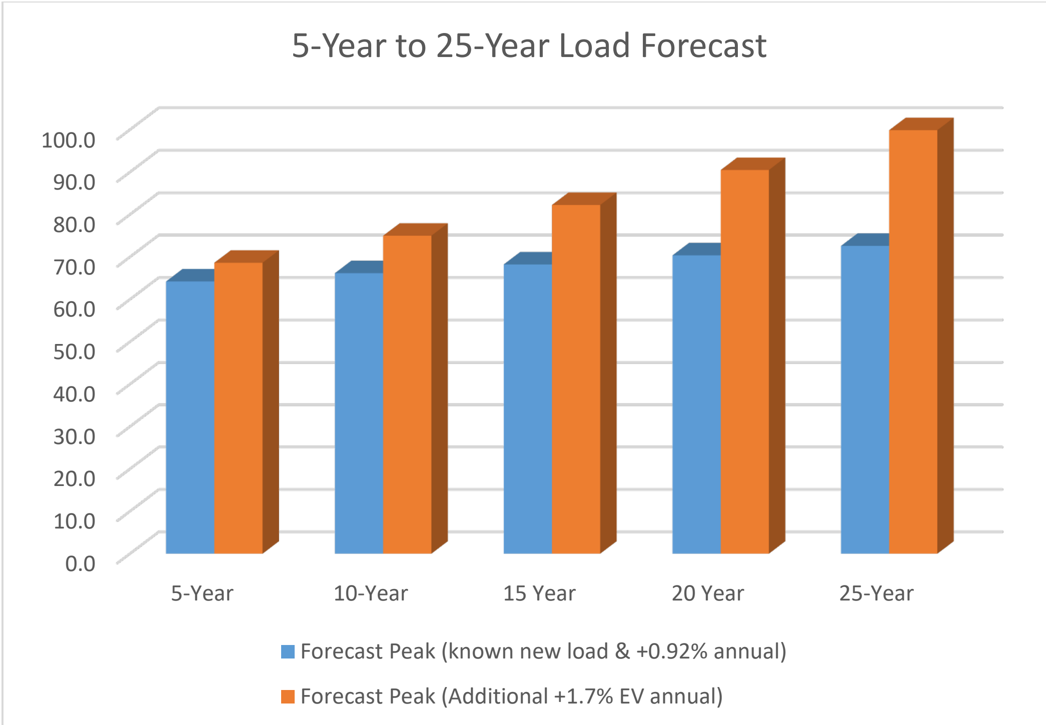


Figure 4: API 5-Year 50 25-Year Load Forecast

4. Load Flow Analysis and Results

4.1. Load Allocation

The most recent peaks when performing this study, January 15th, 2022 at 10:00am (50.4MW), and February 3rd, 2023 at 8:00pm (47.6MW), were merged and adjusted to create a pseudo snapshot of system peak. System peaks in previous years may be higher than this recent peak, however, the feeder configuration could have changed and does not match the current circuit model any more. In order to build the snapshot of the system coincident peak loading, this study takes a bottom-up load allocation approach. For residential customers and commercial customers that have AMR data, the peak load values were retrieved from MeterSense kWh readings primarily at 10:00am, January 15th, 2022. About 28 residential customers' data were retrieved from MeterSense kWh readings at 8:00pm, February 3rd, 2023. For industrial customers, the peak load values were obtained from Utilismart maximum daily billing kW demand on February 3rd, 2023; some of the industrial customers' demands were further replaced with its 2022 annual peak demands. For customers that are missing data due to meter errors or meter communication issues, its demand was assigned with a random value within a range that is reasonable for the corresponding customer type such as Residential, GS<50, SEASNL, and etc. The values for this portion of customers were adjusted so the final snapshot of system load is roughly equivalent to the recorded total demand peak on January 15th, 2022 (~50MW). In addition, the known upcoming spot loads from two mining companies – Alamos and Argonaut (about 10MW) and the significant difference between winter peak and summer peak from Ontario Trap Rock (about 2MW) had been added into the pseudo peak load allocation, which makes the total **allocated** load close to 62MW.

The load mix is approximately 33.5% residential and 66.5% general (commercial and industrial).

Table 5: Summary of System Load allocation

Supply	Total LCP (MW)	Demand Losses‡ *(%)*	Residential (MW)	Non-Residential (MW)	Allocated -R (MW)	Allocated -W (MW)	Allocated -B (MW)
Echo River	17.81	9.82%	10.61	5.53	5.21	6.70	4.23
Goulais	*9.97*	*12.33%*	*6.01*	*2.73*	*2.37*	*3.74*	*2.63*
Batchawana	*1.92*	*14%*	*1.17*	*0.48*	*0.46*	*0.015*	*1.18*
Limer	*27.09*	*7.42%*	*1.23*	*23.85*	*8.58*	*8.42*	*8.08*
Watson	*8.41*	*7.03%*	*3.68*	*4.12*	*2.63*	*2.64*	*2.55*
Andrews	*0.327*	*4.29%*	*0.019*	*0.30*	*0.076*	*0.053*	*0.19*
Mackay	*0.061*	*4.89%*	*0.001*	*0.057*	*0.058*	-	-
Northern Ave 34.5kV	*0.0315*	*3.13%*	*0.0004*	*0.03*	*0.01*	*0.01*	*0.01*
Northern Ave City Feed	*2.26*	*1.95%*	-	*2.22*	*0.74*	*0.74*	*0.74*

‡: Total losses incorporate station power transformers.

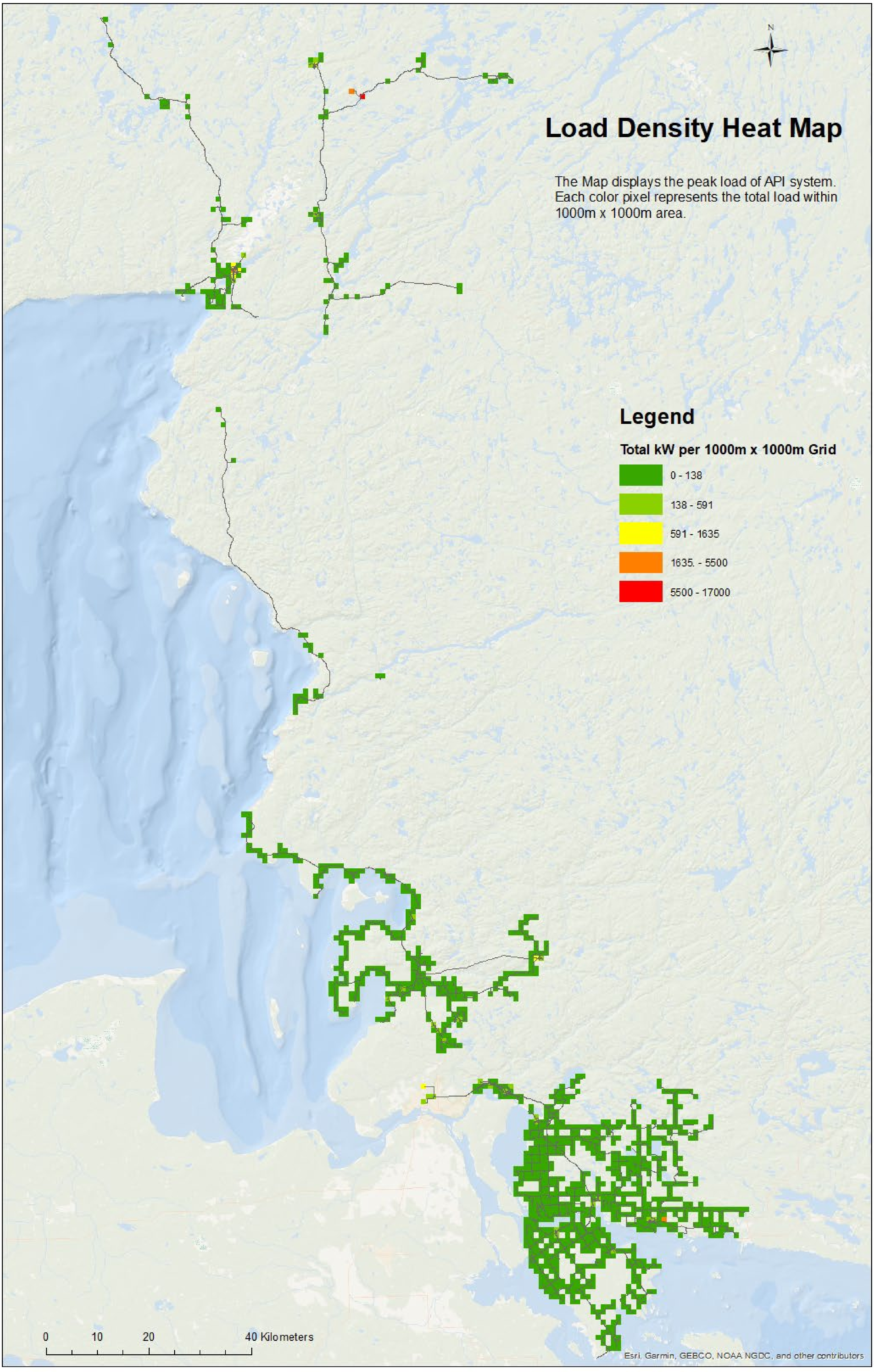


Figure 5: API Load Density Heat Map

4.2. System Losses

Load allocation analysis shows the technical demand loss at pseudo system peak is about 8.73%; given of the mix system operating voltages of 44kV, 34.5kV, 25kV, 12.47kV, 8.3kV, and 4.16kV, the relatively high demand loss can be largely attributed to the long runs of lines with low load density. For API, clustering of customers is basically limited to the community of Wawa, Dubreuilville and small communities east of Sault Ste. Marie. Otherwise, customers are sparsely located and connected by relatively long runs of primary distribution lines with customers normally connected to distribution transformers with a one-to-one ratio. Secondary distribution is rare due to geographical separation of customers. The unbalanced feeder configuration may also play a role.

Table 6 shows API energy losses between 2016 and 2012. In order to link the energy loss to the peak loss calculated from the load allocation analysis, a simplified formulae,

E% = (0.7*Load Factor + 0.3) * D%

was used in this study, in which, E% represents the average energy loss and D% represents the demand peak loss (technical losses only). This formulae is derived from the relationship between a typical distribution feeder demand loss and the load factor[2].

[2]: *Refer to "Transmission and Distribution Electrical Engineering", C. Bayliss and B. Hardy, 2012.*

Table 6: API Energy Losses 2016 - 2022

2022					2021	2020	2019	2018	2017	2016
YTD Peak Billing Demand (MW)	YTD MWh's Purchased (MWH)	YTD MWh's Sold (MWH)	YTD MWh Losses (MWH)	YTD % energy Losses	YTD % energy Losses	YTD % energy Losses	YTD % energy Losses	YTD % energy Losses	YTD % energy Losses	YTD % energy Losses
50	281,651	256,288	25,363	9.01%	7.90%	9.27%	7.93%	7.87%	8.34%	7.33%

Given that the average monthly Peak demand in 2022 is about 40MW (refer to Table 2) and the peak demand of 2022 is about 50MW, the load factor is about 0.8 across the system. The true load factor should be lower than 0.8; however, since the pseudo system peak includes the major load increases from three large industrial customers whose load factor is close to 1, assuming 0.8 as the system load factor is reasonable. As a result, the calculated energy loss will be 7.51%. Since the pseudo model incorporates the major reconductoring on Limer #4 Circuit (which is still in progress during this study), this result should already include the loss rate improvement due to conductor size upgrade.

Compared with Table 6, the real energy loss was 9.01% in 2022 and varies between 7.33% to 9.27% from 2016 to 2021. Other than the supposed improvement due to conductor upgrade mentioned above, in general, this real energy loss is supposed to be higher than the calculated energy loss and it is generally accepted that an allowance in the range 0.2% to 1.0% is appropriate to accommodate meter inaccuracy and theft (non-technical losses). With that being said, going forward, the high energy loss rate over 9% should trigger a further investigation.

4.3. Thermal Overloads

The snapshot built in load allocation above represents the system peak, which in most cases is not coincident with substation peak and feeder peak. Selected feeder peak under contingency conditions will be analyzed in Section 4.7. Table 7 below shows the loading that had been allocated for the major feeders.

Table 7: Summary of Feeder Loading Current

Supply	Operating Voltage	Feeder Identification	Feeder Loading under normal system configuration (Amps) ‡		
			R	W	B
Echo River	34.5 kV	ER1	**181**	**161**	**116**
		ER1 - DB1	**103**	**97**	**99**
		ER2	**160**	**155**	**137**
		ER2 – GR1	**22**	**28**	**28**
	25 kV	ER2 – Desbarats T2 - 3600	**83**	**121**	**87**
	12.5 kV	ER1- Desbarats T1 - 3400	**46**	**215**	**12**
		ER1- Desbarats T1 - 3510	**23**	**76**	**5**
		ER1- Desbarats T1 - C2M3510K	**12**	**13**	**15**
		ER1 - DB1 – Bruce Mines T1	**133**	**131**	**99**
		ER2 - Bar River -3210	**73**	**102**	**32**
		ER2 - Bar River -3220	**134**	**66**	**64**
		ER2 – GR1 - 3110	**33**	**36**	**76**
		ER2 – GR1 - 3120	**30**	**26**	**17**
Goulais	12.5 kV	5110	**11**	**189**	**8**
		5120	**200**	**370**	**322**
	25 kV	5130	**79**	**43**	**45**
Limer	44 kV	No.4 Cct	**363**	**332**	**322**
	8.3 kV	Hawk Junction T1 - 8100	**27**	**27**	**1**
		DS86 -T1 - 8610	**201**	**183**	**157**

	4.16 kV	DS86 - T2 - 8620	**139**	**140**	**93**
		SUB87 – T1 -8700	**3**	**14**	**0.6**
Batchawana	12.5 kV	5200	**66**	**0**	**209**
Watson	34.5 kV	Wawa No.1	**2**	**-**	**-**
		Wawa No.2	**146**	**144**	**151**
	12.5 kV	WawaSD - 9400	**105**	**119**	**64**
	8.3 kV	Wawa2-T1 - 9210	**108**	**112**	**195**
		Wawa2-T1 - 9220	**68**	**60**	**93**
		Wawa1-T1 - 9110	**197**	**170**	**149**
		Wawa1-T1 - 9120	**75**	**104**	**64**
Andrews	25 kV	7210	**6**	**4**	**14**
MacKay	25 kV	7610	**5**	**-**	**-**
Northern Ave City Feed	12.5 kV	4110	**96**	**96**	**96**
Northern Ave 34.5kV Feed	34.5 kV	4100 (NA1)	**0.5**	**0.5**	**0.5**

‡ Feeder Loading only represents one snapshot of system peak and does not necessarily coincide with the feeder historical peak.

Various current-carrying components of the distribution system are subject to thermal overloads in different ways. This study mainly focused on transformers and conductors.

Conditions must be considered when determining if a transformer is overloaded. Since this study was only simulating one snapshot of system peak, the results must be combined with a further investigation on the year-round transformer load profile.

According to related standards and manufacturer's specification, transformers can be safely overloaded 100% under hot and continuous loading and up to 140% under 4-hour overload. Overhead conductors may be overloaded up to 125% of ampacity as long as the ambient temperature remains below 0°C.

Although transformers and conductors all have over-capacity capability, in this study, transformers and conductors that were overloaded to 100% and 110% separately of their nominal rating were marked up for further investigation. This will facilitate us to take proactive measures should these transformers or conductors have been given unreasonable ratings.

Figure 6 illustrates elements that exhibit over-capacity in the simulation and need further investigation on their potential of being over-loaded. In total, 98 distribution transformers were 100% (or greater) overloaded; out of these 98 transformers, 33 were 140% (or greater) overloaded and most of these 33 transformers are rated 5kVA. A small quantity of primary conductors (UG/OH) were found overloaded, and certain amount of secondary conductors were 110% (or greater) overloaded in the peak loading simulation. Most of these secondary overloaded conductors were associated with the overloaded transformers and require further investigation. Refer to the simulation model for the details of potential overloaded transformers and secondary conductors.

Seven power transformers exceed 50% of their nominal rating under peak condition: Wawa1-T1 (79%), WawaSD9400-T1 (129%), Wawa2-T1 (83%), Desbarats -T2 (86%), Barriver -T1 (61%), Desbarats -T1 (81%), Brucemines- T1 (58%). Two three-phase ratio banks exceed 50% of their nominal rating: AP004146-T1 (52%) and AP004812-T1 (71%). One single phase step-down transformer AP000842-T1 exhibits over 100% of its rating and a further field investigation is required.

4.4. Load Imbalance

Table 7 shows that at substation and feeder level, the loads on different phases are not well balanced and in most cases the imbalance far exceeds 15%. ER2, DB1, No.4 Cct., and WawaNo.2 are the few major feeders where the phase imbalance is within FTSO standard limit of imbalance of 15%. API is located at remote northern areas and its single phase radial feeders usually have been configured to extend as far as it can to pick up loads. This practice makes phase imbalance hard to be corrected since no other phases are available in adjacent areas in many cases. Voltage-drop issues then come along with phase imbalance issue on feeders with extra stretch of reach.

The simulation suggests the following 7 feeders imbalance during peak loading exceeds 100%:

- Desbarats T1 - 3400 – 1692%
- Desbarats T1 - 3510 – 1420%
- Bar River -3210 – 219%
- Bar River -3220 – 106%
- GR1 - 3110 – 130%
- Goulais - 5110 – 2263%
- Batchawana - 5200 – 216% (The supply from Batchawana TS is currently via two single phase power transformers, i.e., the notion of “unbalance” doesn’t apply.)

A further evaluation is required to investigate the cause of imbalance and the possible remediation actions. Whenever the three or two phases are available, planners should incorporate a phase balance check for any new build or rebuild project so the phase imbalance can be fixed over the time. For areas that are on the rebuild or reinforcement agenda, the feeder configuration and system design should provide a flexibility for future phase balancing activities.

4.5. Non-standard Voltage

This study suggests that there are significant Voltage drop issues at primary circuit within Echo River, Goulais, and Batchawana supply areas, along with multiple secondary side non-standard voltage issues that are usually associated with distribution transformer overloading and small secondary conductor size (Figure 6), Assuming 112-Volt or below on a 120-Volt base will be deemed as non-standard. A further field check should be conducted at these locations with primary and/or secondary voltage issues. If confirmed, for secondary, the problem can be addressed locally by either tapping-up the corresponding distribution transformer or adjusting the downstream load. For Primary, it may require a re-configuration of the feeders so the phases can be balanced out. If that is not an option, remediation measures may include installing capacitors and/or regulators, and reconductoring with larger size of conductors.

6 capacitor banks and 9 regulators had been included in the simulation model and play a role in stabilizing the voltage. For some three-phase capacitors, certain phases may have been disconnected on purpose to avoid voltage rise due to an excessive supply of reactive power. This situation often occurs when there is an extremely imbalanced phase load, for example, in Echo River areas. Field check of the status and control of these capacitor banks is recommended.

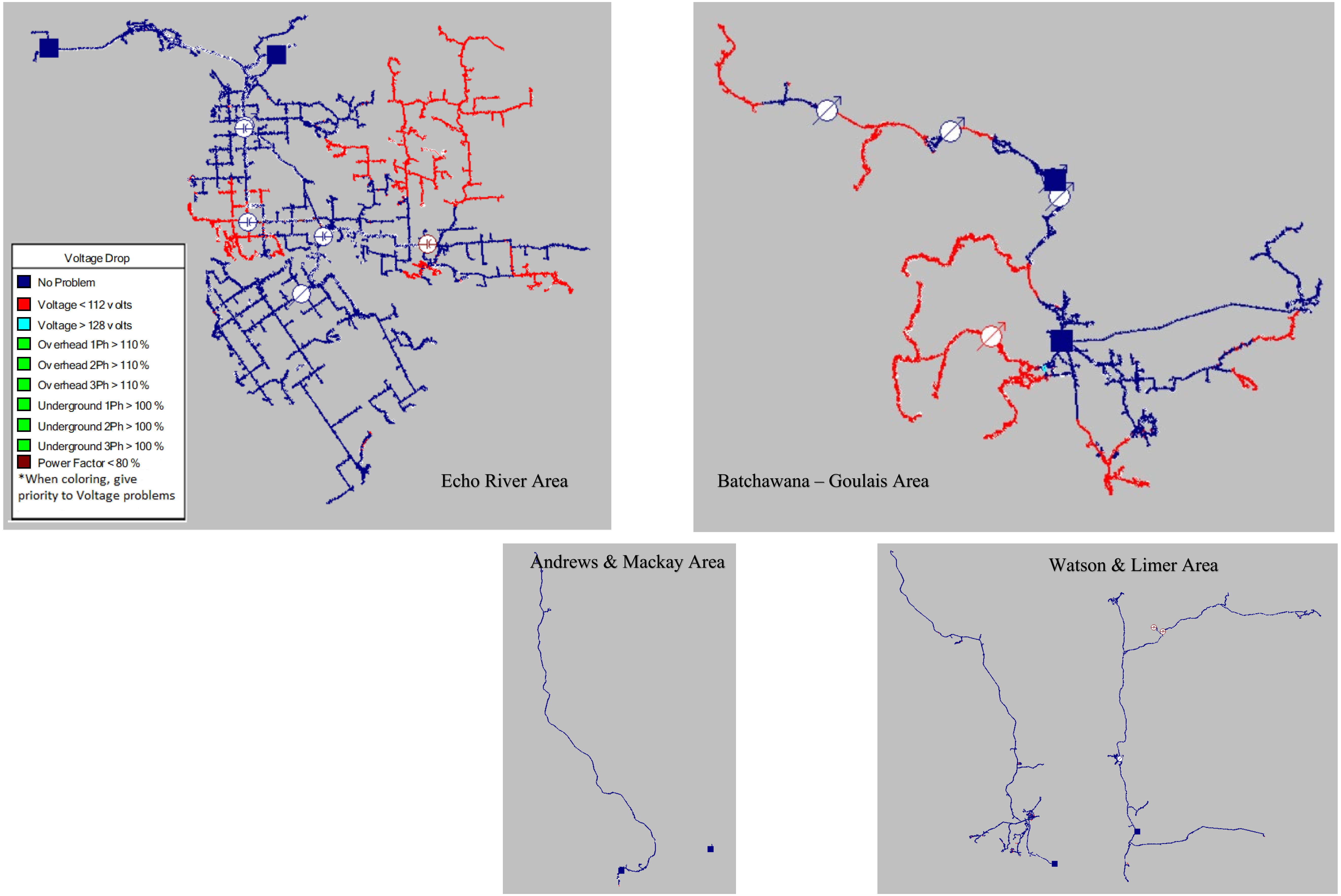


Figure 6: Peak Load Profile – Voltage Drop and Thermal Overload

4.6. Sensitivity Analysis

4.6.1 Load Growth Scenarios

The load forecast indicates a moderate load growth within the next 10 years (refer to Section 3.3). To stress-test the system, a sensitivity analysis was performed to test the robustness of the system in dealing with extreme loading conditions. This analysis is based on four peak load scenarios as follows:

a) Scenario 1 – 9.6% accumulative general load growth (0.92%/annum over 10 years) plus 18% accumulative EV growth (1.7%/annum over 10 years).
b) Scenario 2 - 20% accumulative general load growth (*1.84%/annum over 10 years*) plus 10% EV penetration rate.
c) Scenario 3 - 20% accumulative general load growth plus 20% EV penetration rate.
d) Scenario 4 - 20%accumulative general load growth plus 40% EV penetration rate.

The baseline of above load scenarios is API 2022 peak load (~50.4MW) adjusted with known industrial new loads to be gradually added after Q4, 2023 and a few other industrial loads that may had not been peaked at 2022 Winter Peak, assuming a 100% coincidence factor of the new added loads. The adjusted baseline load is about 62MW. The two mining companies' loads are capped-off based on their connection agreements and load growth has not been applied in the simulation.

Out of the four scenarios, Scenario 1 exactly corresponds to the load profile of the 10-year load forecast (Section 3.3); basically, Scenario 1 assumes the EV-related load growth is a flat rate of 1.7% per year and the simulation model treats EV-related load growth the same way as the general load growth. As a result, the EV load growth has been evened-out among all customers and its impact towards distribution transformer capacity may have been skewed and un-revealed.

In comparison, Scenario 2 to 4 includes some manipulation of the simulation model. Basically, residential customers were grouped based on their upstream distribution transformers; then 7.6kW, 11kW, or 19kW chargers were randomly simulated under different transformers by attaching the charger to an existing customer until the total number of customers who own a charger reaches roughly 10%, 20%, and 40% of total customer counts. When manipulating data in the simulation, 7.6kW charger was considered as the most popular one, 11kW charger was less popular, and 19kW charger was added sporadically to capture those "faster" charger. No commercial DC charging stations had been simulated.

4.6.2 Potential System Constraints

Table 8 summarizes the load allocation, the number of potential overloaded distribution transformers, and the possibility of primary conductor sections (UG/OH) with voltage drop or capacity issues under each stress-test load growth scenarios.

As Figure 7-10 illustrate, **Batchawana & Goulais** systems failed all four stress tests. Given the intensity of voltage drop issue in these two areas even with today's peak loading (Refer to **Section 4.5**), it is imperative to rebuild and reconfigure the distribution network in these areas. Both systems are extremely sensitive to any new load growth and the potential for voltage collapse is enormous if the systems are left as is. This potential risk had been identified in previous studies and thus had triggered some regional collaboration with HOSSM. Through this effort and as part of HOSSM's refurbishment plans for the Transmission stations in Batchawana and Goulais, API has requested they refurbished to permit operating at a higher voltage, i.e., 14.4/25kV, and the available capacity will be increased significantly from transmission perspective. API will implement a voltage conversion and rebuild project following HOSSM's new TSs. Based on the latest updates from HOSSM, the new Batchawana TS will be in-service in 2024 while the new Goulais TS project can only be initiated as early as 2025, but not be placed into service until 2028-2029. Considering the vulnerability the two systems have presented, an immediate remediation measure that can be further adopted in the long-term rebuild & voltage conversion plan is warranted.

For the first two stress-test scenarios, the **Echo River** distribution system displays similar constraints as suggested in today's peak loading, i.e., the system suffers from the extremely long stretch of a specific phase at 7.2kV level, causing voltage drop issues in the far ends of these single-phase radial lines and a non-standard phase balance at distribution substation transformers. When the general load growth reaches 20% and the EV penetration rate reaches 20%, the system shows some voltage converging symptoms which requires a holistic correction at the system level, including the addition of voltage regulation devices, var compensation devices and the reconductoring. In addition, it will likely exceed the current TS transformer capacity of 25MVA. Due to the vast expanse of the API service territory and the geographic dispersion of its customer, API's system has been designed following an atypical approach in which, long runs of a specific phase lines and lack of three-phase tap are very common. However, the customers in Echo River area are more clustered and the average load density is higher than those areas with sparsely connected customers. It will be beneficial to extend the reach of three-phase backbone gradually to warrant a better flexibility for phase allocation and adjustment. In addition, the load density in Echo River area justifies the introduction of certain level of automation and control scheme since it will significantly reduce the power restoration time and improve the overall reliability of API system.

The **Limer and Watson** areas illustrate a great capability to handle the load growth and EV penetrations; in general, both systems won't encounter primary voltage drop or conductor over-capacity issue until Scenario 4. It may require the adjustment of tap changers on some power transformers or ratio banks and the reconductoring of a few primary sections, but the required work is manageable and minor. For Watson area, the potential areas with voltage drop issues in Scenario 4 are mainly located along the 12.47kV Harbour Circuit (an Express Line). No immediate actions are required but the study results should be revisited in the next area planning study to evaluate if any remediation measure is necessary.

The remaining areas, including **Andrews, Mackay, and Northern Ave.,** are in a good shape for all the four scenarios voltage-wise and capacity-wise.

In general, all areas show an increasing number of overcapacity distribution transformers as they go through the four scenarios with ascending load growth. API still has 1147 distribution transformers that size 15KVA or below, including 57 5KVA transformers. That represents over 22% of API's total count of distribution transformers. A further analysis is required to investigate the age, condition, and location of each of the non-standard size of transformers. It is recommended to differentiate those transformers based on their locations, and factor-in the other asset conditions to determine whether the transformers should be "running to fail" or be replaced following a well-structured plan. The over-all strategy also depends on OEB's expectation and guidance with respect to the recovery of costs related to efforts of addressing system constraints for EV load increase.

Other than a variety of distribution level of issues caused by rapid EV penetration and load growth, the system will also be facing a significant challenge on transmission supply points.

In summary, Figure 10 illustrates that when the general load growth reaches 20% and the EV penetration rate reaches 40%, the system encounters a large scale of voltage drop and over-capacity issues and requires an overhaul. To be noted, the total allocated load under this scenario reaches about 105 MW; if the time window is limited to 10-years, this forecasted load will be higher comparing to the forecast calculated based on the average IESO-estimated 1.7% annual EV load growth. In reality, 40% penetration rate means over 3,000 API residential customers will own or install a charger in their garage, whether it is 7.2 ~ 7.6kW, 11kW, 19kW, or others. Even those customers won't plug the chargers at the same time and a reasonable coincidence factor needs to be applied, the load growth is significant. Unless there is a methodology available to efficiently manage who and when those EVs can be charged, the system will be facing a challenge to tackle the situation caused by a high EV penetration rate.

Table 8: Stress-test Load Growth Scenarios and Potential System Constraints

Scenario	Substation	Total Load to Allocate (MW)	Voltage Drop Converged (Yes/No)	Primary Conductor Non-standard Voltage (Yes/No)	# of Overloaded Transformers	Primary Conductor Thermal Overloading (Yes/No)
Scenario 1	Echo River	20.89	Yes	Yes	87	No
	Goulais	11.32	No	Yes	58	Yes
	Batchawana	2.13	No	Yes	11	No
	Limer	25.85	Yes	No	6	No
	Watson	10.14	Yes	No	64	No
	Andrews	0.40	Yes	No	6	No
	Mackay	0.076	Yes	No	2	No
	Northern Ave 34.5kV	0.039	Yes	No	0	No
	Northern Ave City Feed	2.86	Yes	No	0	No
	Total of Scenario 1 is about 73.7 MW					
	Echo River	24.44	Yes (with Capacitor and	Yes	158	No

Scenario 2			Regulator addition or adjustment)			
	Goulais	13.42	No	Yes	104	Yes
	Batchawana	2.97	No	Yes	15	Yes
	Limer	26.27	Yes	No (with multiple ratio transformers' tap adjustment)	12	No
	Watson	10.90	Yes	No (Set WawaSD9400 tap at 95%)	80	No
	Andrews	0.44	Yes	No	6	No
	Mackay	0.078	Yes-	No	2	No
	Northern Ave 34.5kV	0.056	Yes	No	0	No
	Northern Ave City Feed	2.65	Yes	No	0	No
	Total of Scenario 2 is about 81.22 MW					
Scenario 3	Echo River	29.26	No	Yes	394	Yes
	Goulais	16.05	No (Voltage collapse on Feeder 5120)	Yes	229	Yes
	Batchawana	3.89	No (Voltage Collapse)	Yes	48	Yes
	Limer	26.85	Yes	No (with multiple adjustments)	22	No
	Watson	11.60	Yes	Yes	96	No
	Andrews	0.48	Yes	No	7	No
	Mackay	0.085	Yes	No	2	No
	Northern Ave 34.5kV	0.075	Yes	No	0	No
	Northern Ave City Feed	2.65	Yes	No	0	No
	Total of Scenario 3 is about 90.94 MW					
	Echo River	36.20	No (Voltage Collapse)	Yes	565	Yes
	Goulais	19.94	No (Voltage Collapse)	Yes	272	Yes

Scenario 4	*Batchawana*	5.17	No (Voltage Collapse)	Yes	73	Yes
	Limer	27.74	Yes	Yes	50	No
	Watson	12.81	Yes	Yes	113	No
	Andrews	0.54	Yes	No	7	No
	Mackay	0.093	Yes	No	4	No
	Northern Ave 34.5kV	0.075	Yes	No	0	No
	Northern Ave City Feed	2.66	Yes	No	0	No
	Total of Scenario 4 is about 105.23 MW					

** Scenario 1 treats EV-related load increase the same way as the general load growth, while Scenario 2 to 4 manipulates to add different size of chargers randomly downstream of distribution transformers.*

**Refer to detailed simulation model and reports for the potential overloaded transformers and primary sections that have voltage drop or over-capacity problem.*

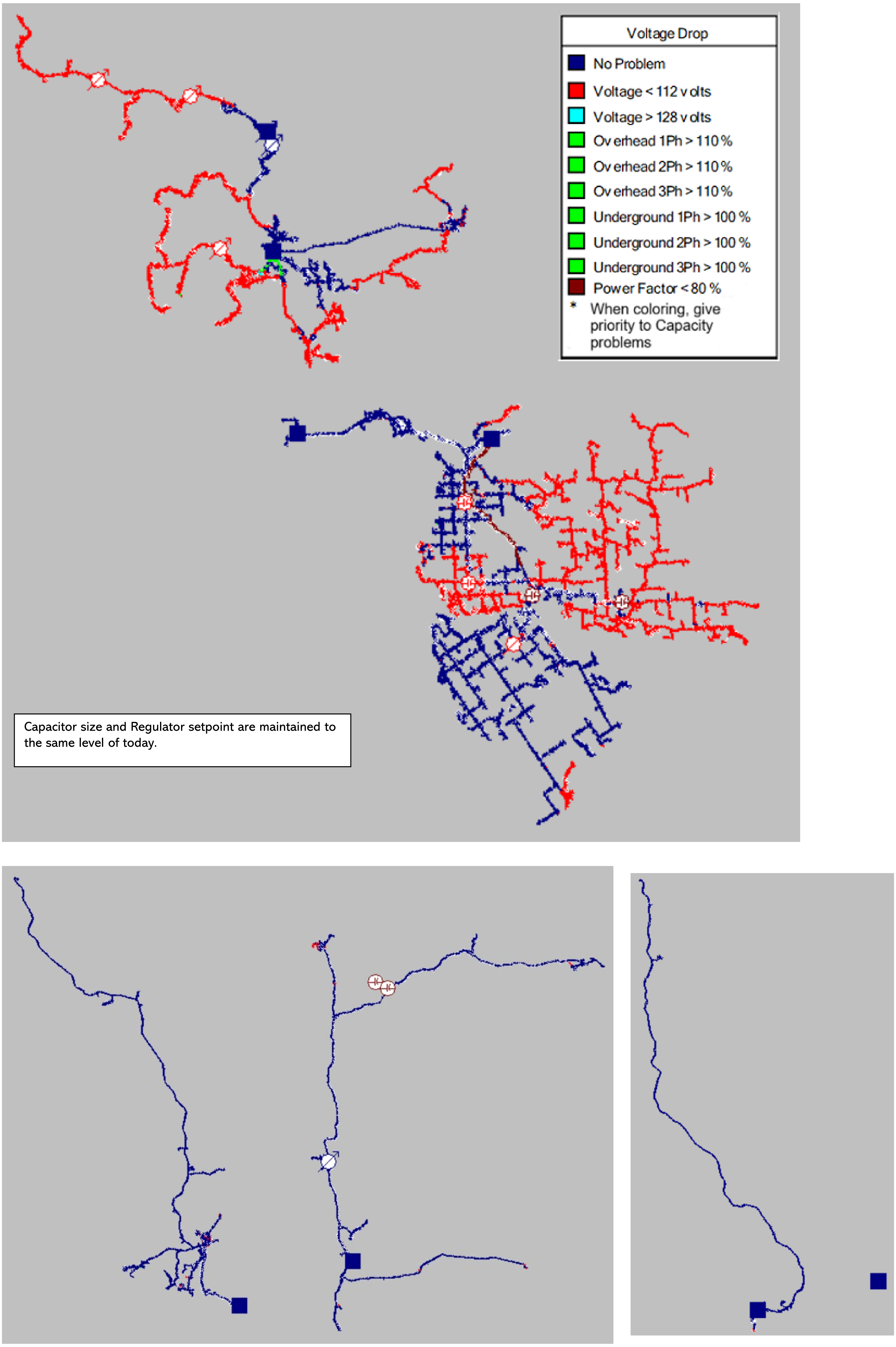


Figure 7: Load Profile Scenario 1 - Voltage Drop and Thermal Overload Map

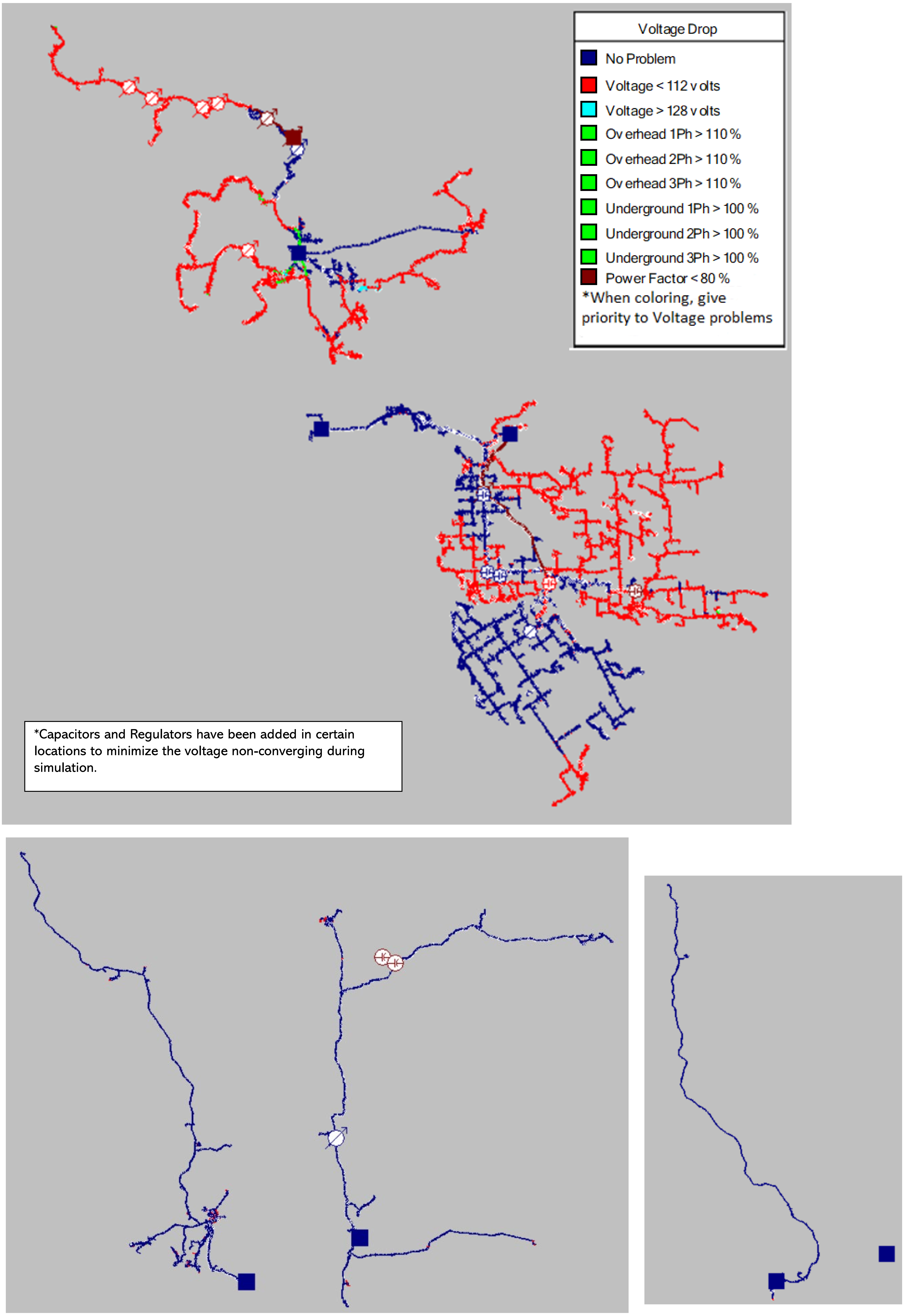


Figure 8: Load Profile Scenario 2 - Voltage Drop and Thermal Overload Map

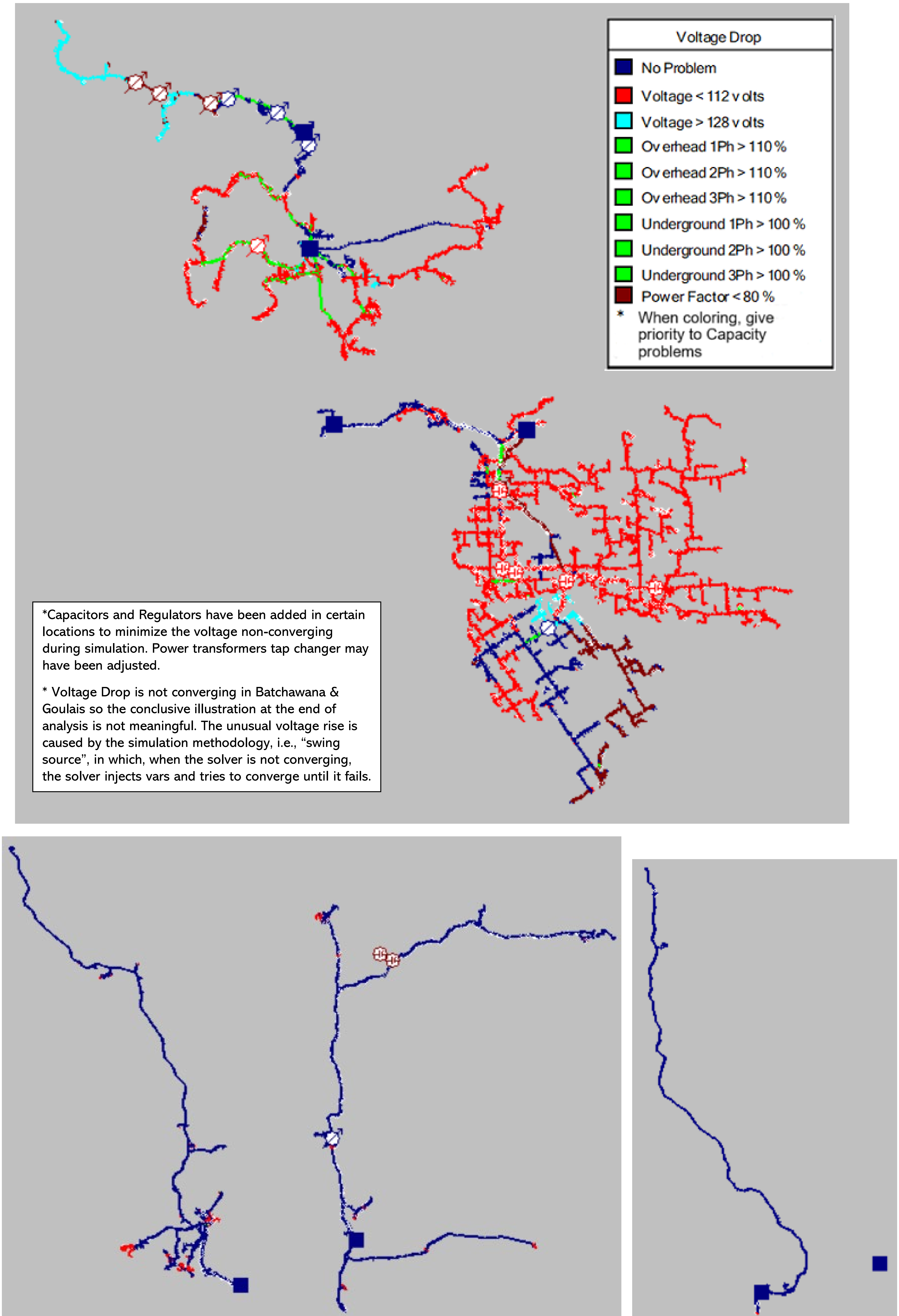


Figure 9: Load Profile Scenario 3 - Voltage Drop and Thermal Overload Map

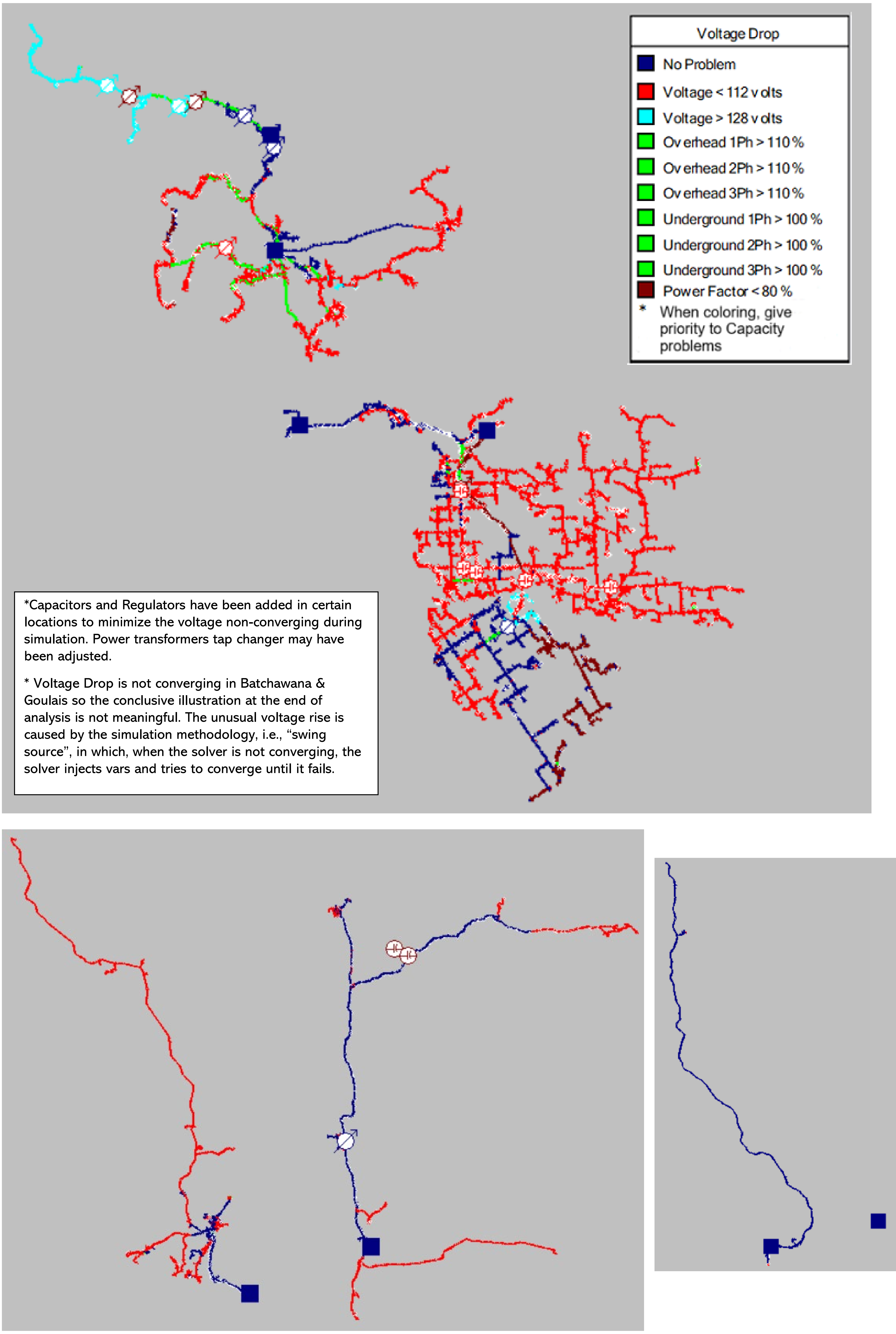


Figure 10: Scenario 4 - Voltage Drop and Thermal Overload Map

4.7. Contingency Analysis

This section examines if the system can still meet its design requirements assuming one of the components fails (i.e. N-1 components in service).

4.7.1 Contingency – Transmission Supply

From **s**upply perspective, API continues working collaboratively with Hydro One Sault Ste. Marie (HOSSM) to reduce the risks associated with "loss of supply", especially when the customer count or reliability requirements in that area justifies the investment.

Echo River

Echo River TS is currently supplied by a single transformer unit, i.e., the two 34.5 kV feeders, ER1 and ER2, are supplied with the same transformer. Based on the last DSP, HOSSM is in the process of installing a second power transformer in Echo River TS that would allow restoration of the supply at full capacity within 24-48 hours following a failure of the existing transformer.

Batchawana

HOSSM is in progress with Batchawana TS refurbishment (as a single unit) and it will be ready for connection in 2024. There is no contingency supply from Transmitter, however HOSSM has included in its refurbishment plan a proposal to expand the station to permit the connection of their Mobile Unit Substation. API has also planned on future rebuilding of the distribution backbone between Batchawana TS and Goulais TS to back up the power supply.

Goulais

HOSSM is planning to refurbish Goulais TS as 25kV by 2028 or later.

- It is currently supplied by a 3 x 5MVA transformer bank; HOSSM can set up a mobile unit within 24 to 48 hours if one unit of the transformer bank fails.
- Rebuilding the distribution backbone between Batchawana TS and Goulais TS will provide certain back-up for the power supply.

Limer

Limer #4 Circuit is supplied by a loop 44kV configuration that are fed from HOSSM's Hollingsworth TS and Anjigami TS. With the increased loads from the two mining companies, according to IESO's SIA, HOSSM will need to upgrade the LV switches in its Hollingsworth TS so the loop configuration can be maintained. At today's configuration and operating mode, if there is a power supply disruption in either of the two TSs or along the loop supply 44kV lines, it will require a manual switching procedure to break the loop and restore the power from the healthy side.

Watson

Watson TS provides two 34.5 kV Feeders, Wawa No.1 and Wawa No.2. These two feeders can fully backup each other.

Andrews and Mackay

Both have no readily available backup. However, their customer count is minimal, and the majority of customers are seasonal.

Northern Ave City Feed & Northern Ave. 34.5kV Feed

These two feeds supply a few industrial customers, and the contingency plan requires input from customers. The Northern Ave. 34.5kV Feed will lose the backup from Echo River should the 34.5kV lines in between be retired. API is currently exploring a feasible alternative backup plan, including introducing a new connection to HOSSM's Third Line TS.

4.7.2 Contingency – Distribution Substation

For a distribution substation, ideally, there are sufficient feeder interties and feeder capacity to perform load transfers to fully restore power in the event of a substation or feeder outage, i.e., each feeder should be evaluated against the following criteria:

- Each feeder shall have an intertie to a feeder from an alternate substation and/or an intertie to a feeder supplied from the alternate bus of the same station.
- This feeder shall be readily accessible and gang-operated.

Single Transformer Substations (Wawa #1, Wawa #2, Wawa SD9400, Dubreuilville #3)

This contingency covers the loss of an entire Single Transformer Station in which it is assumed that entire station and all feeders are unavailable.

For **Wawa DS #1** and **Wawa DS #2,** each distribution station has a power transformer that operates at the 8.3kV level to supply the Town of Wawa load. Under normal operating conditions the town load is shared between the two stations. In the event of a catastrophic event at either station, the entire town load can be served by the remaining station.

For **Wawa SD9400**, it contains 3 x 667KVA 34.5kV to 12,47kV ratio transformers. There is no readily available contingency source nearby that is operating at this voltage. The contingency plan relies on the availability and logistic support of spare equipment.

For **Dubreuilville #3,** it hosts a 1000KVA 44kV to 4.16kV ratio transformer. The substation is located at the end of #4 Circuit and there is no contingency source available nearby. The contingency plan relies on the availability and logistic support of spare equipment.

Dual Transformer Substations (Bruce Mines, Dubreuilville DS #2, Desbarats, Garden River, Bar River)

In this contingency, it is assumed that half a two-transformer station is unavailable. The remaining half of the station (or a Ratio Bank) and associated breakers are assumed to be in service.

For **Bruce Mines**, it is currently a single transformer DS; however, with the new dual-transformer substation to be built in 2024, it will become a fully redundant DS operating at 12.5 kV.

For **Bar River DS**, with the new ratio bank that had been installed and commissioned in 2023, it is now fully redundant.

For **Desbarats DS**, there are two single power transformers; T2 operates at 34.5 to 25 kV to feed St. Josephs Island and T1 operates at 34.5 to 12.5 kV to feed the local Desbarats area. There is currently no transformer redundancy at this DS. However, with the new ratio bank to be installed in 2024, the configuration at the substation supply side to be upgraded in 2023, and the design, duct system, and switching procedures to be in-place, Desbarats T1 and T2 will be deemed as units with a full backup. If T1 fails, the new ratio bank will be able to pick up today's loads; if T2 fails, T1's load will be transferred to the new ratio bank and T1 itself will be operating at 25 kV via its dual voltage tap.

For **Garden River DS,** the dual 34.5kV supplies will be reduced to one since the Feeder NA1 (supplied from Northern Ave TS) will be retired, and the two substation transformers will be supplied one feeder from Echo River TS. Garden River DS itself is a fully redundant, dual transformer DS operating at 12.5kV.

4.7.3 Contingency – Distribution Feeders and Express Lines

From a general **distribution** perspective, API's feeder configuration is a radial, with little or no redundancy built into the system at the feeder level, is very common in rural Ontario setting. No three-phase ties exist among feeders are common as well. Some feeders are identified as "express lines" which were originally constructed when resource industries such as mining and forestry were developed in the region. Examples include Limer #4 Circuit, Goulais Searchmont Circuit, Wawa Harbour Circuit, and so on. These express lines are usually purely radial, extending through a vast expanse of wilderness and supplying a variety of communities including seasonal customers. As the system evolves over time, some rural feeders extend radially out into remote areas that are far away from roads. This situation does pose a significant challenge on accessibility and response time for repair.

Given the remoteness and limited access of the express lines, it is not practical to change the radial nature itself; instead, the lines should be constructed and maintained to a higher standard due to the criticality of the lines and the contingency plans should be focusing on the improvement of availability and logistic support of spare equipment.

As the system evolves over time, some rural feeders extend radially out into remote areas that are far away from roads. This situation does pose a significant challenge on accessibility and response time for repair.

There are radial submarine cables supplying islands such as St. Joseph Island. A failure to one of these cables may require more than 8 hours to restore. However, submarine cables are generally considered an acceptable exception to the 8-hour restoration rule, and the spare cable installed makes restoration within 8-hours achievable under optimum scenario.

4.7.4 Contingency Case Study – Failure of Feeder ER1

This case assumes Echo River feeder ER1 fails during peak loading conditions under the 10-Year load forecast scenario (Refer to Scenario 1 of Section 4.6). The total demand load to be allocated is assumed to be 20.89 MW.

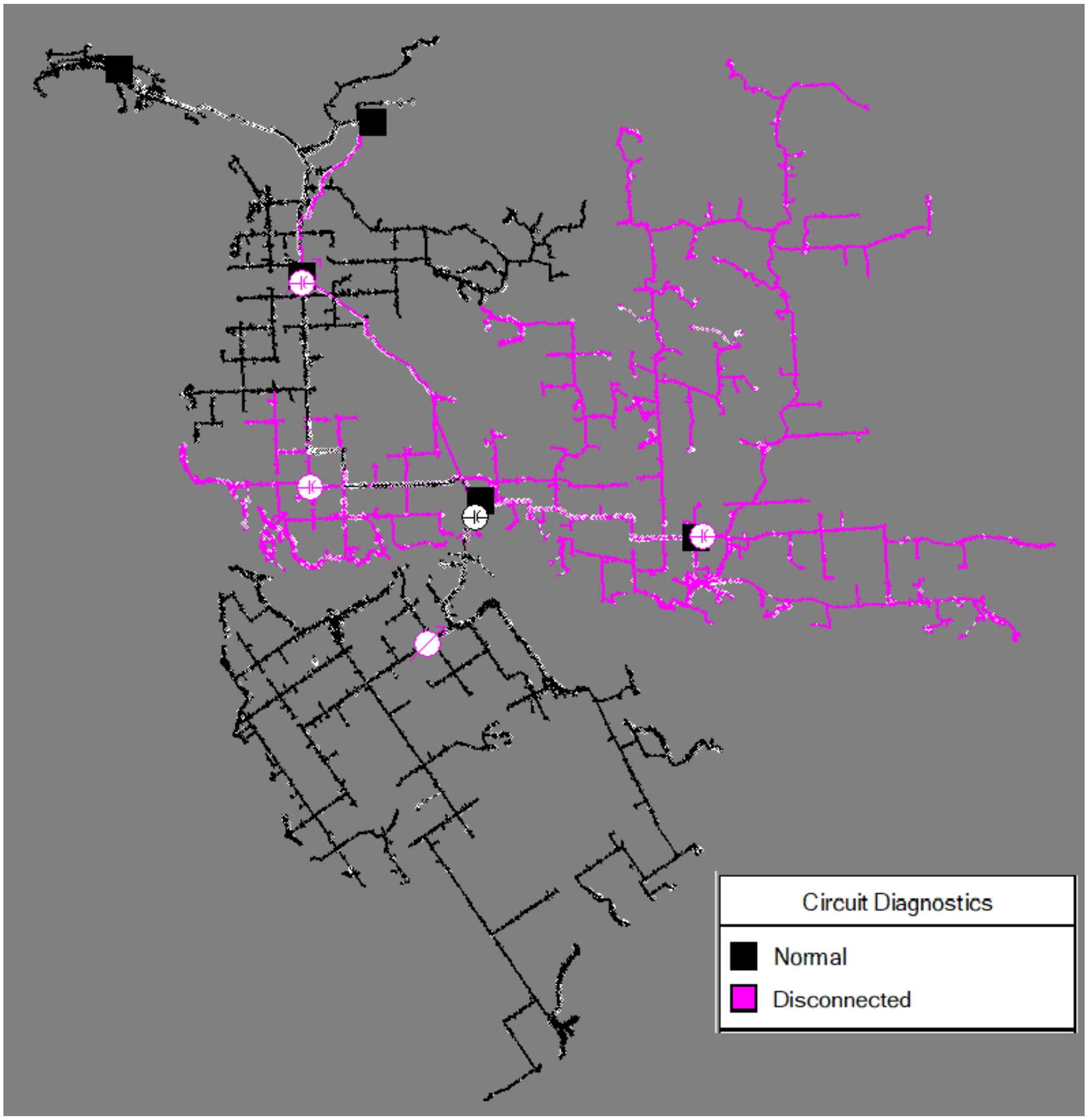


Figure 11: Failure of Echo River Feeder ER1

As one of the two 34.5 kV feeders exiting from Echo River TS, ER1 is normally backed up from the only other 34.5 kV feeder ER2. This study only examines the switching via feeder ties while a specifical section on ER1 needs to be isolated and doesn't include discussions on the back-up via station bus.

When ER1 is interrupted, Desbarats T1 and Bruce Mines T1 will lose the supply (Figure 11). ER1 can be restored via either the gang-operated tie switch SW023 at Bar River Substation or the gang-operated tie switch SW2007 at Desbarats Substation.

When ER1 is restored via SW023, other than the similar voltage drop issues illustrated in Section 4.6, the feeder loading at ER2 would exceed 400 Amps (specifically on Phase A and B). The loss rate increases significantly as well. In order to deliver 20.89 MW, ER2 will have 24.23 MW go through at the feeder level and thus the loss rate is about 14.6%. In this case, the ~3.9km 3/0 ACSR from the tap at Echo Lake Road and along Pioneer Road needs to be upgraded to a larger size of conductor and a very short section just outside of Bar River Substation requires a conductor upgrade as well (*refer to the black oval circles in Figure 12 below*).

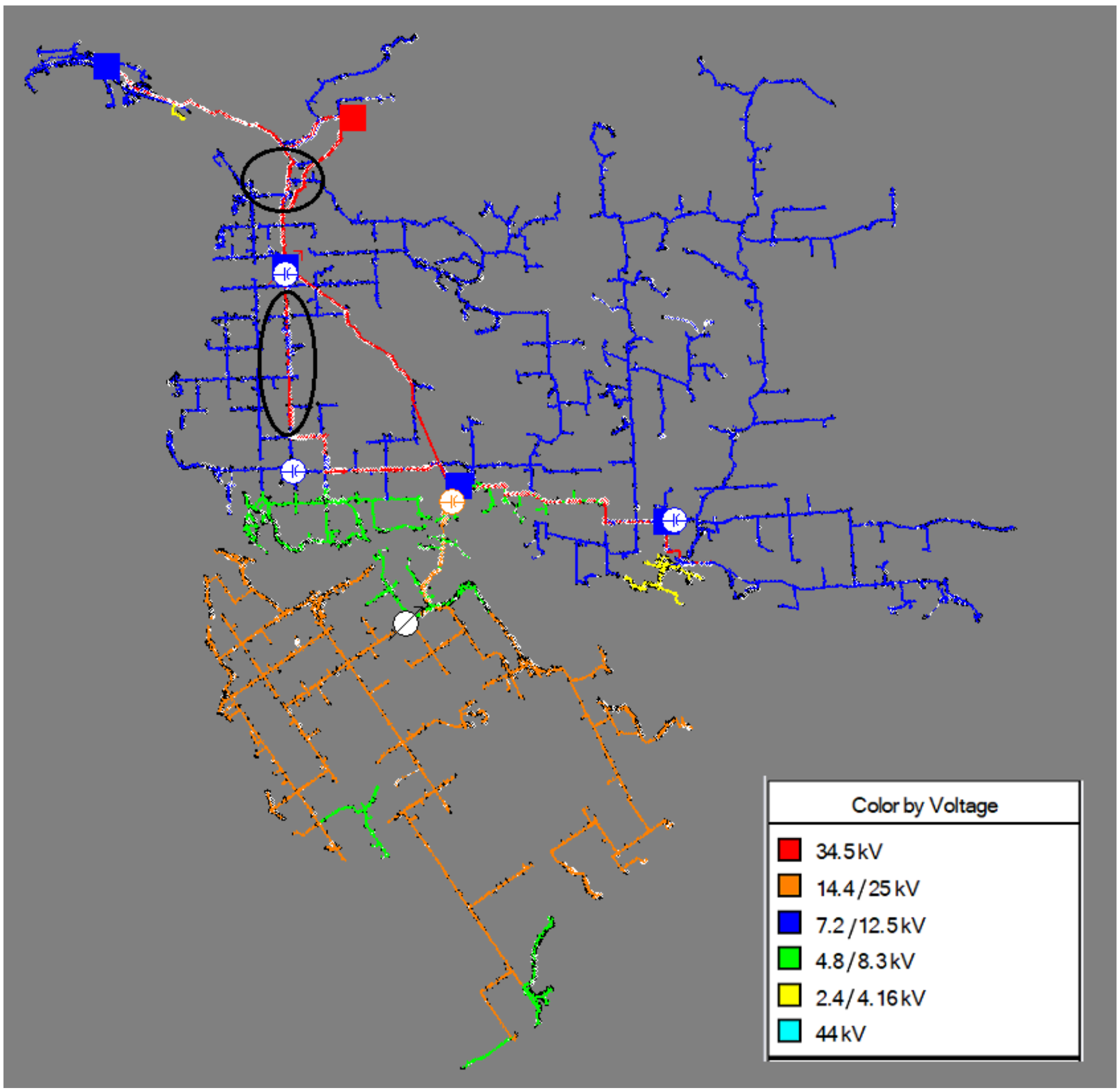


Figure 12: Sections required to upgrade under ER1 contingency

When ER1 is restored via SW2007 since it takes a longer distance to deliver the power, the voltage drop encounters a converging issue and the summed kvar losses differ from subtracted losses by 6.2% which suggests the system requires further reactive power compensation. In addition, the ~3.9km 3/0 ACSR from the tap at Echo Lake Road and along Pioneer Road needs to be upgraded to a larger size of conductor; and the ~9km 3/0 ACSR between Bar River Substation to Rydall Mill Rd along Government Road also requires a conductor upgrade.

Table 9: ER2 Phase currents under ER1 contingency

Feeder From	Feeder to	Red (Amps)	W(Yellow) (Amps)	Blue (Amps)
ER1	ER2	493	433	352

Since ER2 is the only available backup and there is no way to sectionalize and transfer, if the system load has ever reached the assumed level, it will pose a challenge to the contingency plan as of today's configuration.

The following action items are recommended:

- Upgrade the 3/0 ACSR sections mentioned above under both switching situations. It is recommended to consider a size of minimum 477 AAC or ACSR to accommodate future load growth.
- Install a Capacitor Bank somewhere along the 34.5kV loop to boost voltage if necessary.
- Correct the phase imbalance whenever possible on the 7.2/12.5kV feeders and this will reduce the capacity constraints on 34.5kV lines under contingency situation.

5. Major Project Analysis and Recommendations

5.1. Goulais & Batchawana Voltage conversion and feeder reconfiguration

As per Section 4.5 and Section 4.6, Goulais & Batchawana area presents non-standard voltage at the pseudo baseline peak load. Since the load flow simulation only corresponds to one snapshot of the system, the duration for the non-standard voltage to sustain is unknown. In reality, API has not received low-voltage complaints from customers but is aware that this system is highly sensitive to even a small percentage of load growth and subject to the potential risks of voltage collapse. This study reinforces the conclusion from previous studies, i.e., the area needs to be operated at a higher voltage (25kV) to sustain a further load growth and improve the primary voltage levels approaching feeder ends.

To address this known issue, API has coordinated with HOSSM on the rebuild of both Goulais TS and Batchawana TS. A preliminary refurbishment plan which involves the voltage conversion and feeder reconfiguration has already been developed and discussed. As of the time of this report, the new Batchawana TS with a single unit of 7.5/10/12.5MVA, 12.5kV x 25kV dual-voltage power transformer is planned to be ready for connection in Q4 of Year 2024; the new Goulais TS, originally planned to be refurbished and placed into service in 2026, has opted to be delayed due to capital constraints of HOSSM.

Figure 13 shows the existing feeder configuration and voltage support devices. Based on the ultimate vision plan, eventually, the system will be re-configured as follows:

- The ~20km lines between Batchawana TS and Goulais TS along Highway 17 will be re-rebuilt as three-phase and re-conducted with 336ASC. This section will become the backbone 3-phase tie between the two TS's to provide certain level of contingency. This line section used to be single phase and the rebuild has been in progress. As of today, about 5-kilometer line rebuild has been completed.
- The new Batchawana TS will have one breaker position with the feeder splitting into a north feed and a south feed just outside the station fence. The feeder extents will be roughly the same as today, but with a better three-phase availability and upgraded design standard.
- The new Goulais TS will have two feeder breakers and the feeders will split into four directions a short distance from the station fence. The feeder extents will roughly match the feeder distribution today. The 1 kilometer single-circuit section towards the south, where the three feeders tap off from today, will be rebuilt with a second circuit on the west side of the highway to improve the reliability and operational flexibility.
- Over the time, all lines in the Goulais & Batchawana area will be rebuilt or quickly converted to eventually operate at 14.4/25kV.

Although the "**ultimate vision plan**" mentioned above will relieve the constraints in this area, it is not feasible to achieve this goal within 5 years bearing in mind the intensive resources required and technical challenges imposed by fully converting this area to another operating voltage. As a result, it is imperative to develop an approach to bring the system from today's configuration to this ultimate-vision configuration.

Once the approach is determined, the plan can be implemented in multiple stages and across multiple rate application periods.

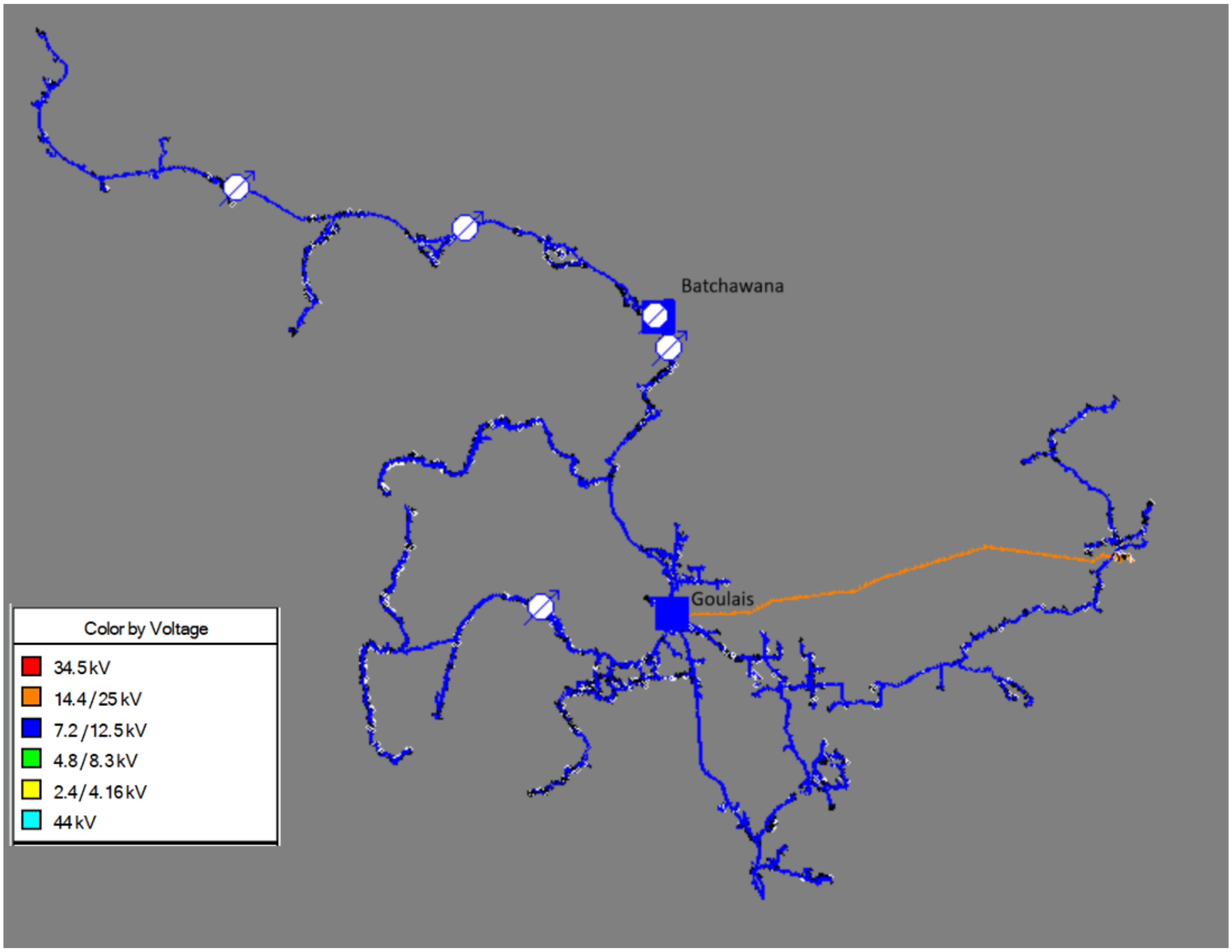


Figure 13: Batchawana & Goulais Area - Existing Feeder Configuration and Regulators

This study compares two alternative approaches that could potentially facilitate the system reconfiguration towards the ultimate goal. Both alternatives can be deemed as an "interim solution" before the ultimate vision plan can be fully achieved. As a clarification, in this study:

"Line Rebuild" refers to a situation when majority of construction work involves pole replacement, re-conductor, and hardware upgrade.

"Quick Conversion" refers to a situation when majority of construction work only involves hardware (such as insulators and arresters) upgrade. In addition, under "Quick Conversion" scenario, the existing distribution transformers will be replaced by new transformers equipped with a primary dual voltage tap. When the new TS is ready for a cut-over, field crew can quickly adjust the distribution transformer taps to minimize the outage duration. The goal of "Quick Conversion" is to ensure the system readiness with minimal costs so the system can be switched to a new operating voltage when the 25kV source becomes available.

“Cut Over” refers to a moment when the new TS puts in service of the new power transformer that operating at the 25kV. Multiple crews need to be dispatched to different sections and work simultaneously to adjust the distribution transformer dual-voltage tap and replace the transformer lightning arresters (if necessary). The work must be completed within one-day to minimize the power interruption.

5.1.1 Alternative A: Convert Goulais with Ratio Transformers and Partially rebuild Batchawana

This alternative will complete the rebuild of the main trunk between the two TSs, allow Batchawana to still operate at 7.2/12.5kV to minimize the conversion activities in Batchawana, and make-it-ready for Goulais system to operate at 25kV when Goulais TS Refurbishment is completed. The main drive for this alternative is to avoid requesting the dual voltage power transformer at Goulais TS. API originally requested a similar dual-voltage power transformer configuration as Batchawana TS. With the refurbishment delay, it is now feasible for API to pursue a voltage conversion so the system will be ready to operate at the targeting 25kV once the Goulais TS refurbishment is completed around or after 2029. This will avoid the requirement for HOSSM to purchase and install a power transformer with a reconfigurable secondary winding (i.e., dual-voltage) and thus save the associated incremental cost that API would be required to pay. Another benefit is to eliminate the requirement to construct a smaller station to house the existing 12.5 kV to 25kV autotransformer that supplies the Searchmont 25kV circuit.

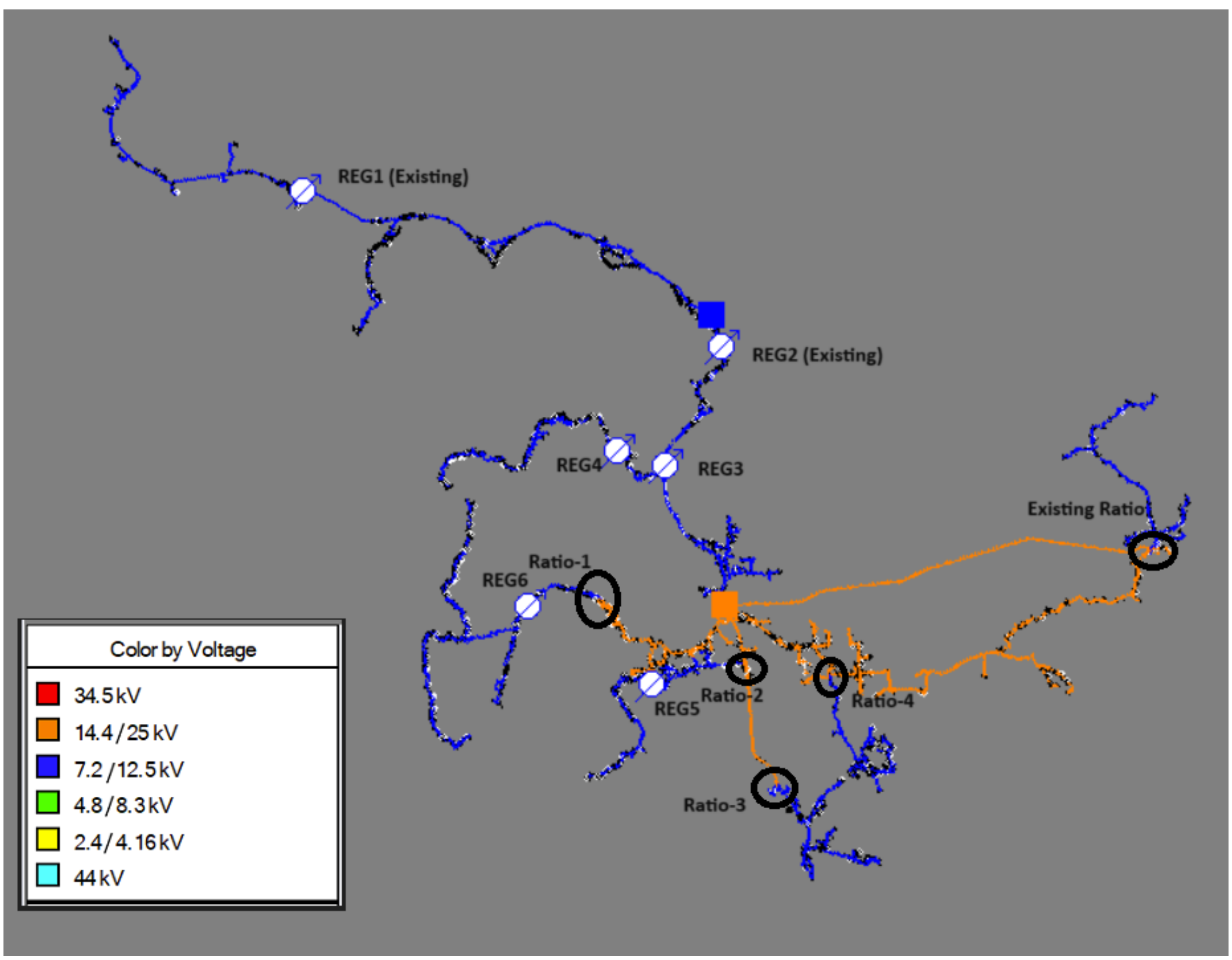


Figure 14: Alternative A - Interim Feeder Configuration, Ratio Transformers, and Regulators

This alternative proposes various tasks to be performed to reach an interim system configuration as Figure 14 illustrates. These tasks include:

- Install three single-phase ratio transformers (3) and one three-phase ratio bank (1) at the strategic locations to step down the voltage from 14.4/25kV to 7.2/12.5kV
- Rebuild 21km main-trunk lines between two TSs with new conductors, new poles (majority), and upgraded voltage rating.
- Upgrade 7.3km Batchawana lines from two-phase to three-phase
- Upgrade 12.9km Batchawana lines from single phase to two-phase
- Quick Conversion of about 50km Goulais lines to upgrade their voltage rating.
- Install 4 regulators at the strategic locations to boost voltage (or relocate existing regulators if feasible)
- At the end of this study period (Year 2029), Batchawana will operate at 7.2/12.5kV and its Feeder 5210 will pick up the load of Goulais Feeder 5110. Goulais will operate at 14.4/25kV, or at 7.2/12.5kV, but ready to switch to 25kV whenever the new Goulais TS is ready for a cut-cover.

The study simulates the proposed system changes and applies the 10-year forecast load scenario to test the feasibility. The load allocation result suggests, with the new system configuration, a combined of 14.73 MW load is allocated and the demand loss rate is about 8.69%. Out of this 14.73 MW, Batchawana allocates 4.11 MW and Goulais allocates 10.62MW (Feeder 5110 loads to be picked up by Batchawana). The simulation shows no primary voltage standard violation under this load scenario after the proposed tasks have been taken in place.

In order to examine the detailed tasks, the area is divided into sections. For each section, Table 10 provides its length, number of distribution transformers, allocated load and phase current under 10-year forecast load scenario, and the proposed tasks to be performed. The study did not test other stress load scenarios since the system is still vulnerable to further load growth beyond the 10-year forecast load due to voltage collapse.

Table 11 provides a high-level cost estimate for Alternative A. The estimate is for planning purpose only and subject to changes with detailed engineering.

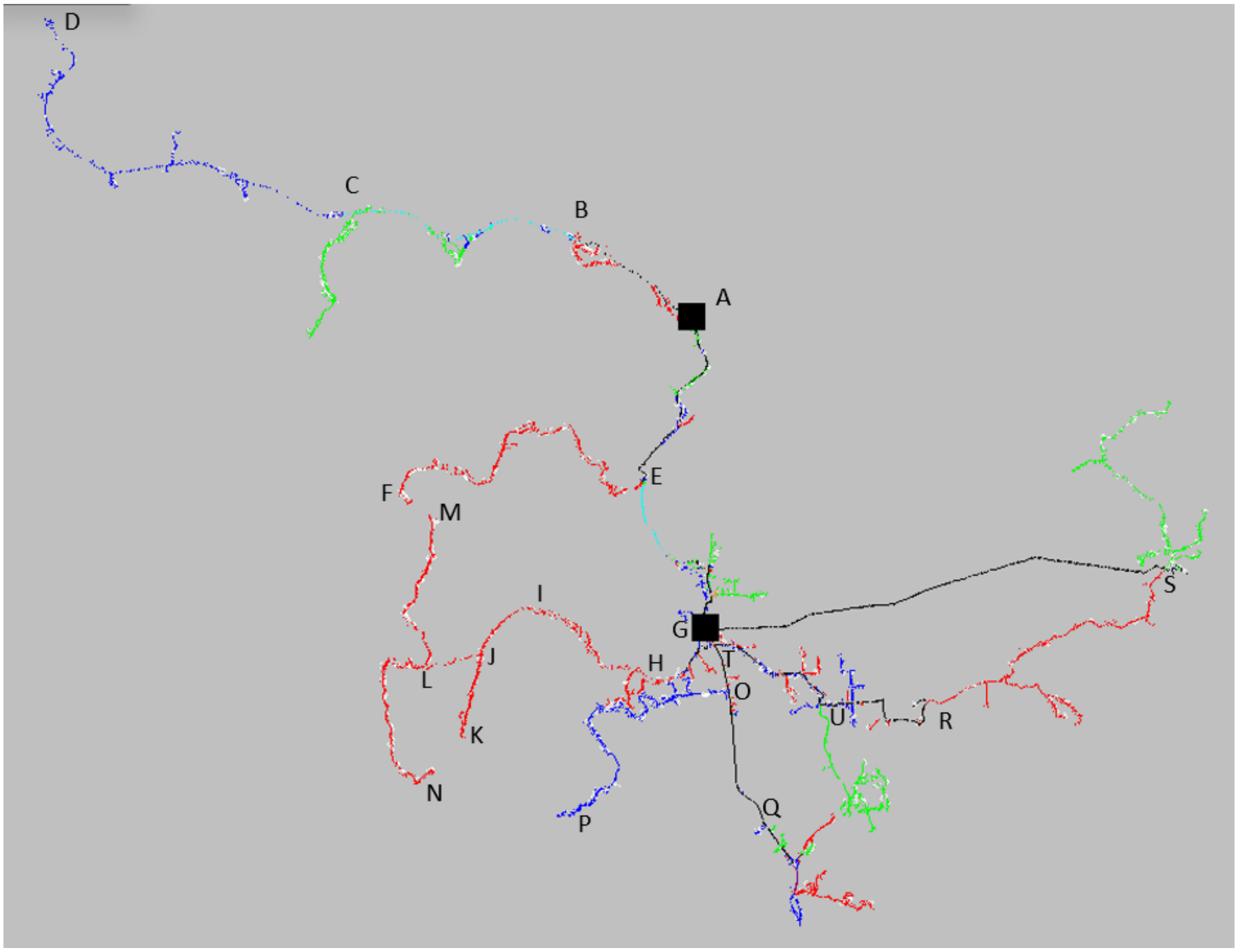


Figure 15: Goulais-Batchawana voltage conversion area - Section Illustration

Table 10: **Summary of Load Allocation Result, Section Statistics, and Proposed System Changes**

Section	Existing phasing	Proposed Phasing	# of distribution transformers	Length (meter)	Ratio Bank KVA	Operating Voltage (L-G kV)	Thru kW	A-Phase Current	B-Phase Current	C-Phase Current	Proposed Tasks
A-E	ABC to C(majority)	ABC	68	10288	-	7.2	2795	88	248	67	• Rebuild as 3-phase. • Add 1 regulator near point E (total 2);
E-G	ABC to B(majority)	ABC	110	10114	-	7.2	618	49	6	32	Rebuild as 3-phase backbone
E-F	B	B	156	19658	-	7.2	1097	-	154	-	Install 1 Regulator
G-T	ABC	ABC	6	963	-	14.4	7665	98	243	200	Build a 2nd 3-phase circuit to make this section as double-circuit
T-H	ABC	ABC	30	3335	-	14.4	2098	0.64	141	9	Quick Conversion‡
H-I	B	B	73	6744	-	14.4	1881	-	137	-	Quick Conversion
I-Tap	B	B	214	19656 (longest Branch N-I)	**1500#**	7.2	1289	-	187*	-	• Install a Step-down Transformer • Install 1 Regulator
T-O	ABC	ABC	9	2388	-	14.4	3621	48	60	150	Quick Conversion
O-P (O-Tap)	C	C	115	15843	**1500**	7.2	1230	-	-	172*	• Install a Step-down Transformer • Install 1 Regulator
O-Q	ABC	ABC	14	7413	-	14.4	2288	47	56	61	Quick Conversion
Q-Tap	ABC	ABC	137	8575 (longest branch)	**1000 x 3**	7.2	2151	93*	109*	114*	Install Step-down Transformers
T-U	ABC	ABC	79	7042	-	14.4	1912	50	41	41	Quick Conversion
U-R	ABC	ABC	52	8018	-	14.4	684	0.32	30	17	Quick Conversion
U-Tap	A	A	86	10492	**1000**	7.2	696	99*	-	-	Install a 1000KVA Step-down transformer
R-S	B	B	72	15991	-	14.4	383	-	27	-	Quick convert from point R towards point S, using existing 500KVA ratio

											bank to supply the load during conversion.
G-S	ABC	ABC	9	25453	-	14.4	2950	104	55	59	-
S-Tap	A	A	85	12922 (longest branch)	Existing 500kVA	7.2	502	71*	-	-	-
A-B	AC	ABC	68	7287	-	7.2	1315	90	45	50	Upgrade 2/0 2PH to 336 3PH
B-C	C	AC	111	12918	-	7.2	963	90	-	50	Upgrade single phase to two-phase
C-D	C	C	71	22945	-	7.2	278	-	-	42	-

**Ratio Bank Secondary current*

‡ Quick Conversion only replaces insulators and transformers (with a primary due-voltage unit); usually, it doesn't need re-conductoring. Quick conversion may be performed section by section using fully insulated UG Cable to bridge the supply. If no transformer needs to be replaced, live-line work could be an option as well (may need temporary measures to set the line aside).

[#] *As per existing best practice, the largest size of single-phase transformer that is feasible for overhead platform-mounting is1000KVA. It will require detailed engineering for the 1500KVA ratio transformer installation. As a sidenote, 1000KVA is sufficient for all the taps based on today's peak load scenario.*

Table 11: Alternative A – Cost Estimate

Item	Description	Quantity	Unit Cost	Total Cost
1	Ratio Bank Installation (Engineering & Material & Labour)	4 (including one 3-phase Bank)	$80,000	$320,000
2	Regulator Installation (Engineering & Material & Labour)	4	$30,000	$120,000
3*	3-Phase Line Rebuild & Voltage Conversion (km)	18 (total 28km minus 10km to be completed before 2025)	$180,000	$3,240,000
4	2-Phase Line Rebuild & Voltage Conversion (km)	13	$120,000	$1,560,000
5	1-Phase Line Quick Voltage Conversion without pole replacement (km)	50	$40,000	$2,000,000
6	Voltage Cut Over for 344 distribution transformers (labour only)	10 crews (10 hours)	$8,000	$80,000
7	Dual-voltage Distribution transformer material cost	344	$3,000	$1,032,000
7	System Resilience Improvement for Rebuild along HYW17 (incremental on design & build)	1	$30,000	$30,000
Total Estimated Cost				**$8,382,000**

**Line rebuild is in progress and certain km will be already completed before 2025*

5.1.2 Alternative B: Fully convert Batchawana and install voltage support devices for Goulais

This alternative will complete the voltage conversion of Batchawana service territory and rebuild the 20km main trunk lines between the two TSs. At the end of this targeting study period (Year 2029), Batchawana can operate at 14.4/25kV. Goulais Feeder 5110 will be still supplied by Goulais TS. API will request a similar 12.5kV x 25kV dual-voltage power transformer configuration for Goulais TS and follow a similar conversion approach as Batchawana service territory. With the uncertainties associated with Goulais TS Refurbishment, an interim stage when Batchawana operates at 14.4/25kV while Goulais TS still operates at 7.2/12.5kV will probably last for 5 to 8 years. As a result, Goulais will need reactive power support and voltage regulation support to deliver the load level in the 10-year load forecast, which is in the range of 10 to 12 to 13 MW for Goulais area.

Shunt capacitor installation has relatively smaller costs compared to the voltage regulators; however, at least three regulators that are currently installed in Batchawana area can be relocated. This study manipulated the quantity, size, and locations in the simulation model with the 10-year forecast load profile being applied, until no primary voltage violation is identified. The analysis indicated that a total of eight capacitors and three regulators (in addition to the existing one regulator) will be required in Goulais.

Figure 16 illustrates the interim feeder configuration and locations of regulators and capacitors. REG1 is an existing regulator which is not required after the voltage conversion and line rebuild is completed following the original refurbishment plan. However, considering the long run of the single-phase feeder, REG1 is left and by-passed in the simulation, just in case of future need. REG2 is also an existing regulator that can be by-passed but left as is for the future feeder backup between Batchawana and Goulais.

Figure 16 also notifies the necessary line rebuild, reconductor, phase adjustment, ratio transformer tap adjustment that will be progressing in parallel with the deployment of voltage support measures. The simulation assumes:

- Load profile is the 10-year Load Forecast
- Adjustment includes adding 8 Capacitors and relocating 3 regulators
- Rebuild 21km main-trunk lines between two TSs with new conductors, new poles (majority), and upgraded voltage rating.
- Rebuild 7.3km Batchawana lines from two-phase to three-phase
- Rebuild 12.9km Batchawana lines from single phase to two-phase
- Quick conversion of 23km Batchawana lines
- Phase change from A to B at SW5123A-193
- Ratio Transformer T5123A 001 (AP004703-T1) tap changer to be set at 97.5%
- Conductor size to be upgraded to 336 along the 3-phase trunk of Feeder 5110, 5120B and 5121 (near the full capacity of existing 3/0 or 2/0); UG section maintains as 2/0 AL
- #4 ACSR and #6 ACSR still exist in this area near the far end

The following size of capacitors have been used in the simulation. It is expected that detailed engineering studies will be carried out before shunt capacitor deployment and voltage regulator relocation. Further studies will ensure no power quality violations for end customers will be caused by those devices.

- CAP1: 400 Kvar
- CAP2: 600 KVar
- CAP3: 600 Kvar
- CAP4: 600 KVar
- CAP5: 3-phase 3 x 400 Kvar
- CAP6: 600 KVar
- CAP7: 200 Kvar
- CAP8: 200 KVar

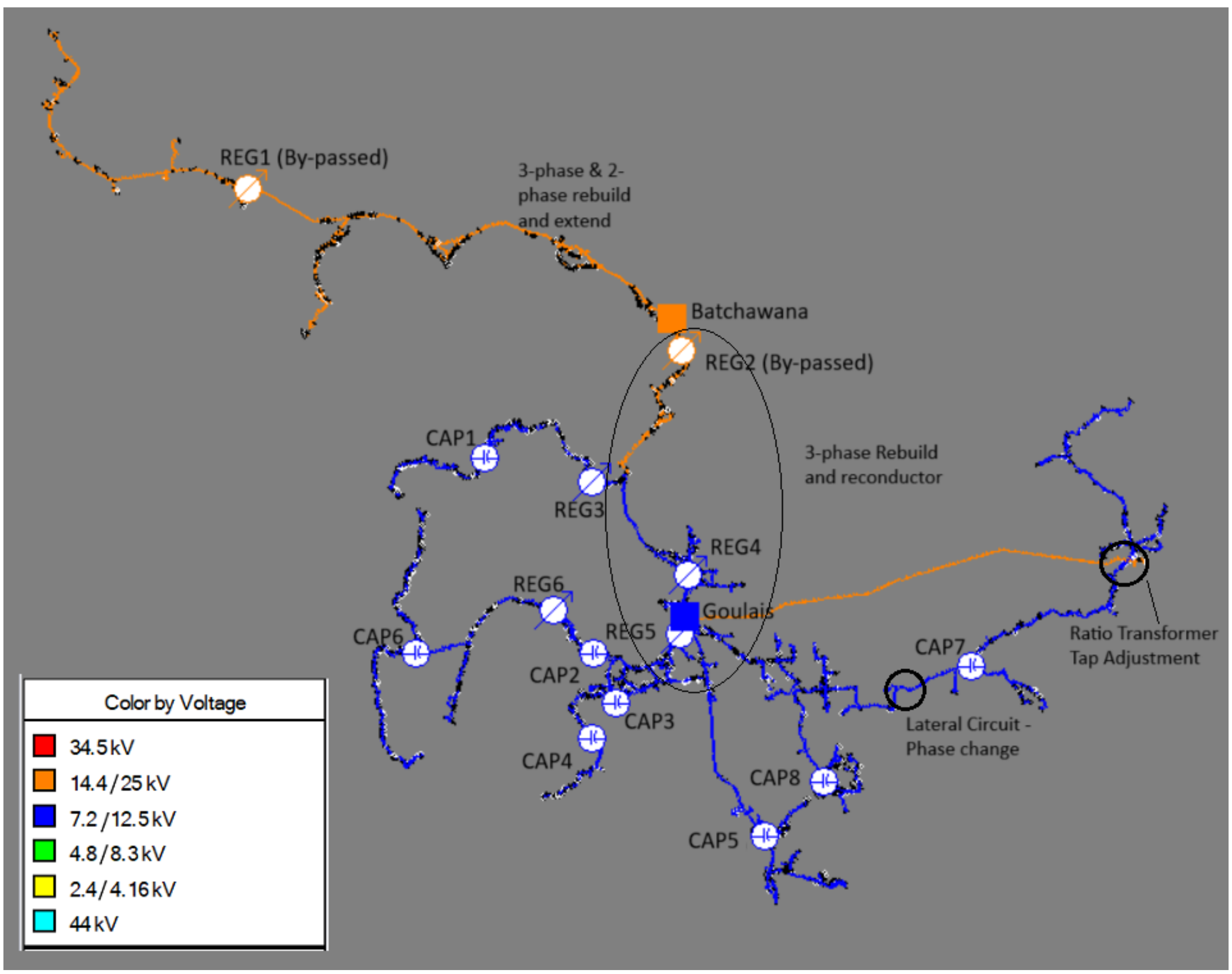


Figure 16: Alternative B - Interim Feeder Configuration, Capacitors, and Regulators

Figure 17 below suggests that no primary voltage violation after all necessary temporary measures have been in place. Secondary non-standard voltages still present in some location which will require further field investigation for wire size and transformer tap position.

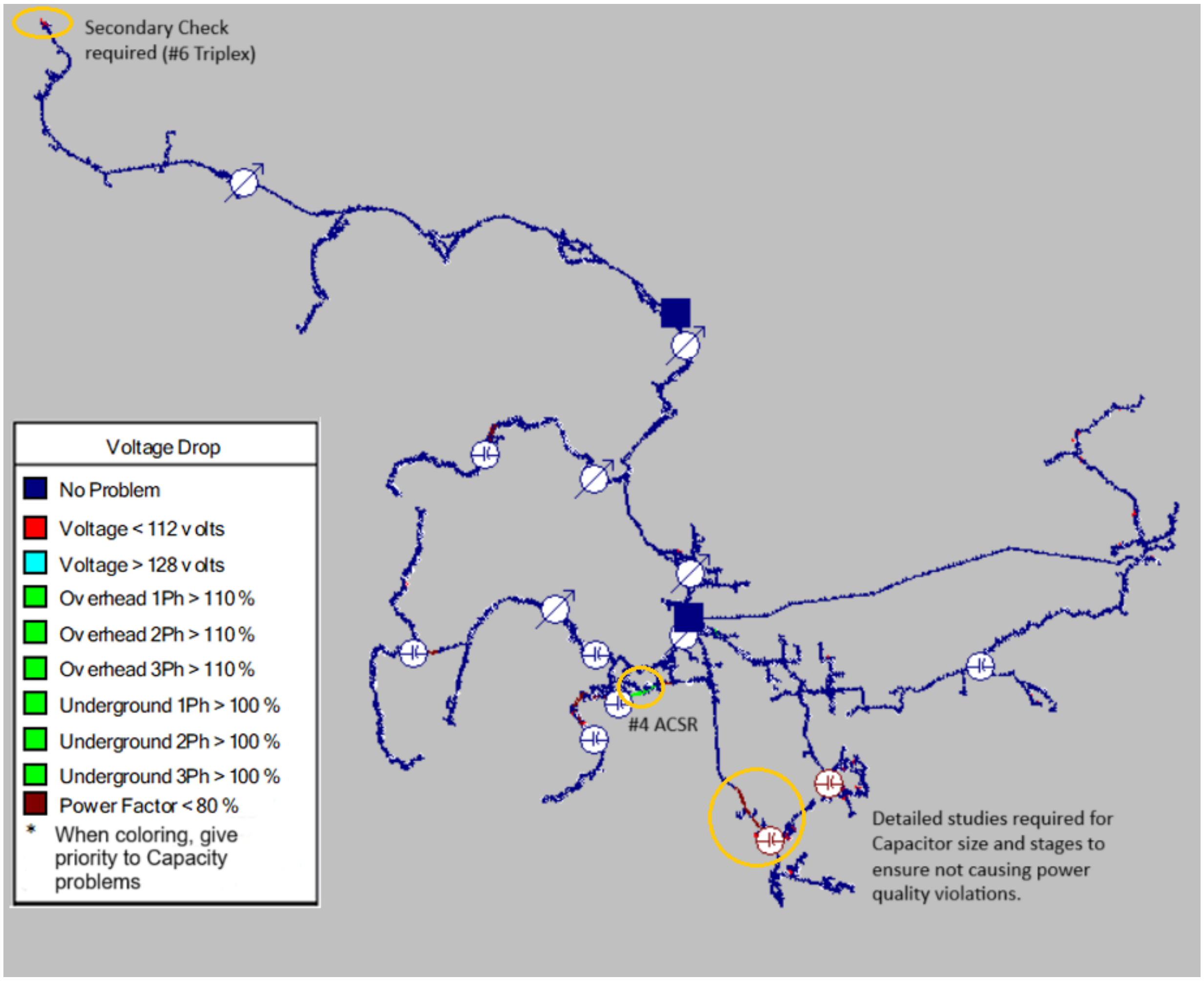


Figure 17: Alternative B – Voltage Drop for Interim Feeder Configuration with 10-Year Forecast Load Scenario

Table 12: **Alternative B – Cost Estimate**

Item	Description	Quantity	Unit Cost	Total Cost
1	Capacitor Installation (Engineering & Material & Labour)	8	$90,000	$720,000
2	Regulator Installation (Engineering & Material & Labour)	3	$30,000	$90,000
3*	3-Phase Line Rebuild & Voltage Conversion (km)	18 (total 28km minus 10km to be completed before 2025)	$180,000	$3,240,000
4	2-Phase Line Rebuild & Voltage Conversion (km)	13	$120,000	$1,560,000
5	1-Phase Line Quick Voltage Conversion without pole replacement (km)	23	$40,000	$920,000
6	Dual-Voltage Transformer material costs	318	$3,000	$954,000
7	Voltage Cut-over for 318 distribution transformers	10 crew (10 hours)	$8,000	$80,000
8	System Resilience Improvement for Rebuild along HYW17 (incremental on design & build)	1	$30,000	$90,000
9	Incremental cost to pay HOSSM for Goulais TS dual-voltage secondary winding	1	$150,000	$150,000
10	Incremental cost for the construction of substation to house the Searchmont step-up transformer	1	$1,200,000	$1,000,000
Total Estimated Cost				**$8,804,000**

**Line rebuild is in progress and certain km of lines will be completed before 2025.*

5.1.3 Recommended Solution

Both Alternative A and Alternative B will only make the system have the capability to supply the 10-year forecast load. The ultimate goal is to fully convert Batchawana and Goulais, operating at 14.4/25kV. This study applied all the three-stress test load profiles (Refer to Scenario 2 to 4 in Section 4.6) to verify if the final configuration is robust enough for at least another 10 to 15 years beyond the 10-year load forecast.

It requires a further study to bring the system from the interim configuration of Alternative A or Alternative B to the ultimate configuration; particularly, to determine the optimal location, quantity, size, and mix of the voltage supporting devices.

Figure 18 represents one possible final configuration after voltage conversion has been completed. In order to supply the load level of Scenario 4 stress test, the system will require some capacitors and regulators to be in place to support the voltage under this high load scenario.

The remaining section of 7.2kV, which is supplied by a 14.4 to 7.2kV 500KVA Ratio Transformer T5123A, is recommended to be converted to 14.4kV since the ratio transformer will reach its 100% capacity limit beyond the 10-year load forecast. Further load growth will also require voltage support in addition to the maximum 5% voltage boost that transformer tap changer can provide.

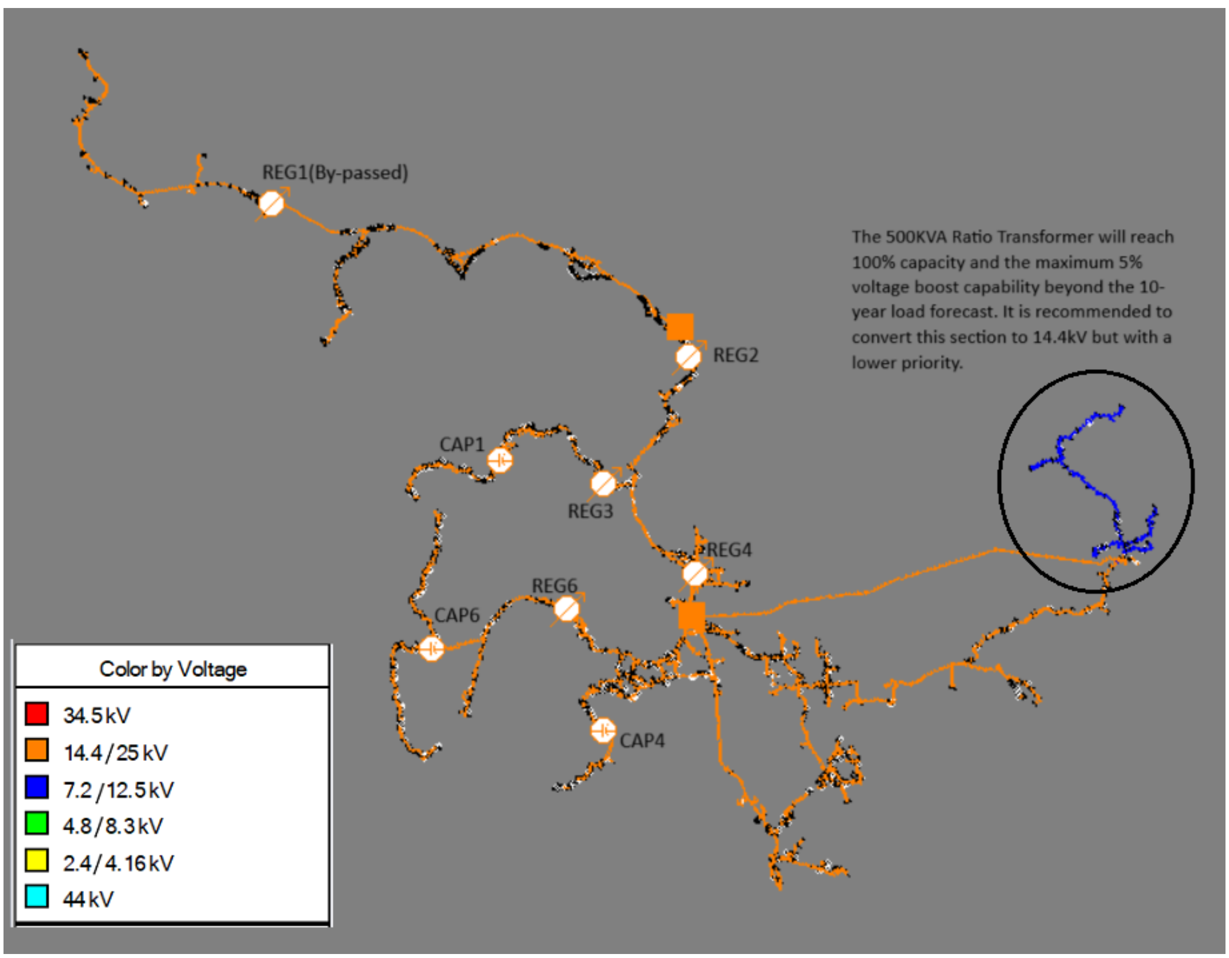


Figure 18: Final Configuration with Capacitors and Regulators required for Load Profile Scenario 4

When the system is fully operating at 14.4/25kV, as the load profile changes from Scenario 4 to Scenario 1 (from high to low), the necessities for the regulators and capacitors reduce gradually. Figure 19 below shows under Scenario 3 load level, there is no voltage violation as long as REG3 and REG6, or alternatively, CAP1 and CAP6 are in place. When load profile Scenario 2 is applied, only REG6, or alternatively CAP6, is in place. When load profile Scenario 1 (the 10-year load forecast) is applied, all the capacitors and regulators can be by-passed under normal condition.

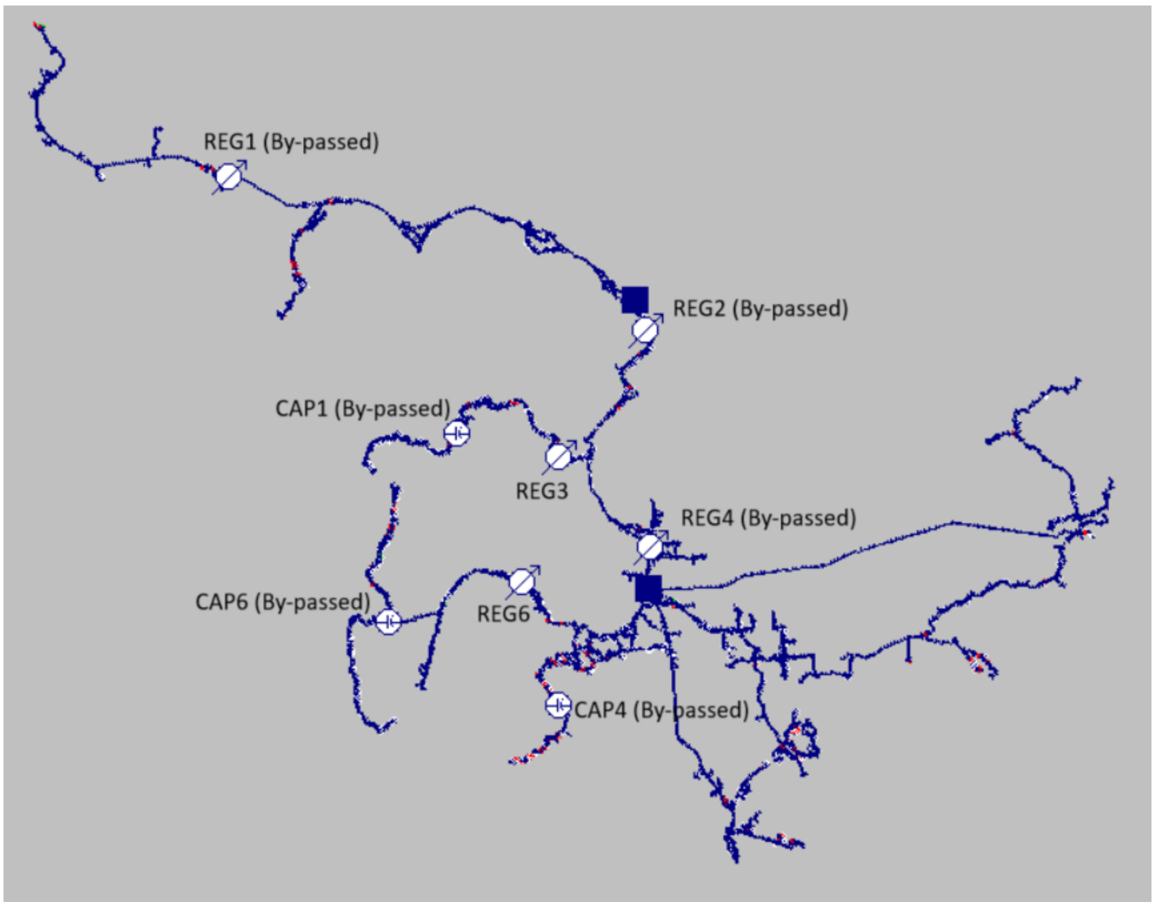
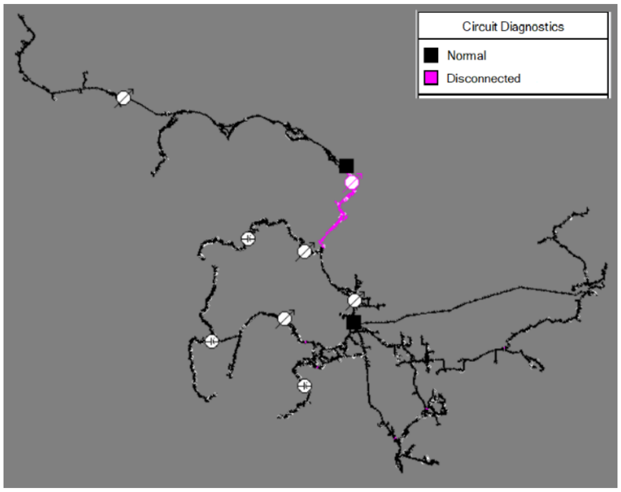
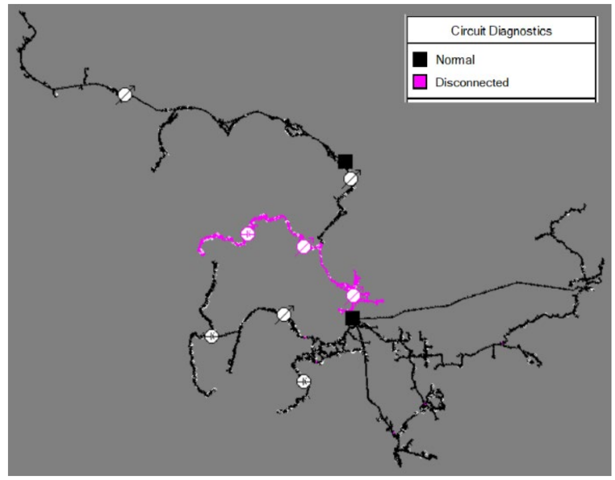


Figure 19: Voltage Drop for Final Feeder Configuration with Scenario 3 Load Profile

The study examined two contingency cases (Figure 20 below) to check the capability of backup between Batchawana TS and Goulais TS, assuming voltage conversion and all necessary line upgrade has been completed and Load profile – Scenario 4 is applied. Under both contingency cases, there is no violation of primary voltage when REG2 and REG4 are in place. Under this load profile, 5MW load can be switched between these two TS (as illustrated in Figure 20 below).



Contingency Case – loss of Batchawana 5210



Contingency Case – loss of Goulais 5110

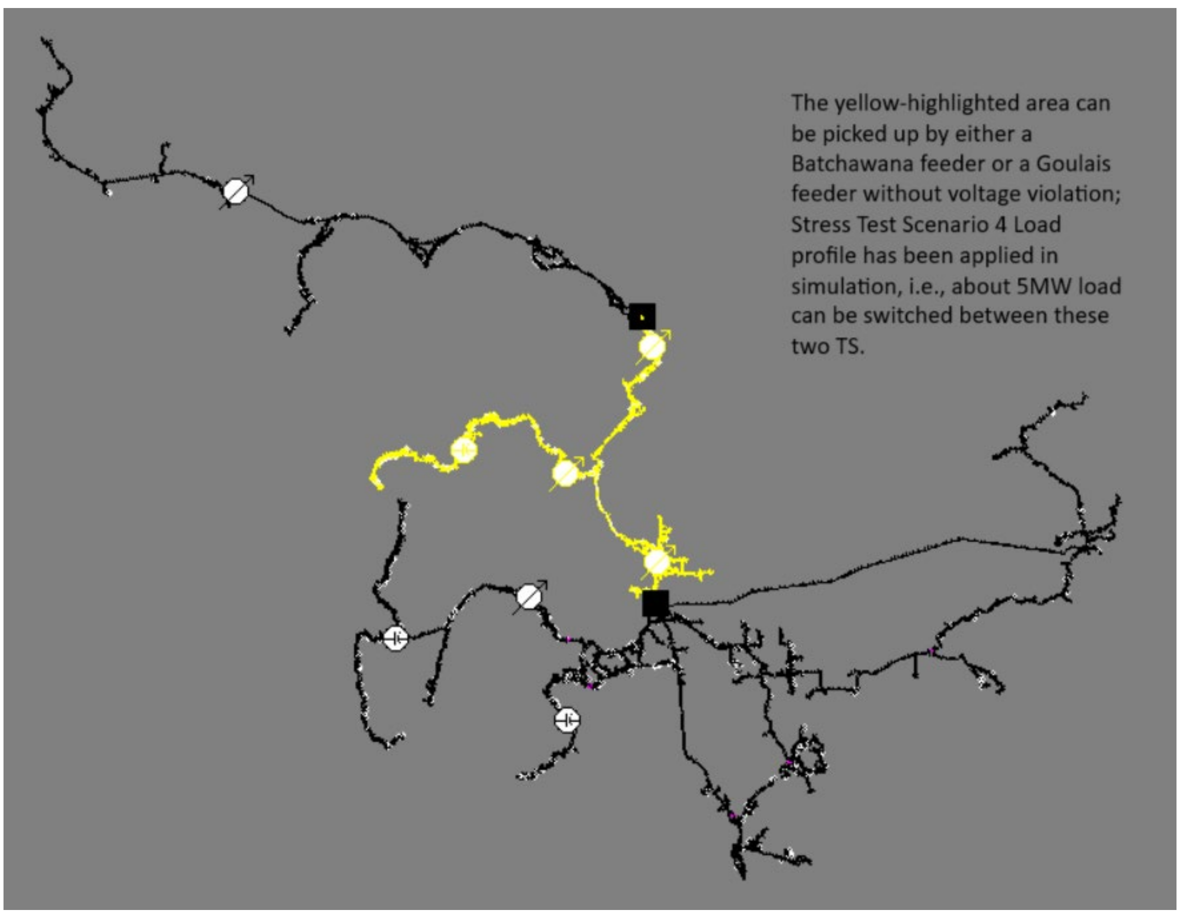


Figure 20: Contingency Backup between Batchawana TS & Goulais TS

The analysis concludes that the ultimate configuration will be robust enough to sustain the load growth and improve the reliability in this area. As a result, the comparison between taking Alternative A or Alternative B to reach that ultimate goal should be focusing on the overall timeline, engineering efforts, implementation complexity, resource required, and project life-cycle costs.

From backbone construction perspective, both Alternative A and Alternative B intend to complete the rebuild section between two TSs. However, the "quick conversion" Alternative A intends to complete will double the length achieved by Alternative B.

Another drawback for Alternative B is that the final cut-over from 7.2/12.5kV to 14.5/25kV will pose a big challenge due to the large and dispersed service territory of Goulais. Tasks performed in Alternative A, for example, installing ratio transformers, may also be necessary to facilitate a smooth cut-over for Alternative B.

Write-off is also an issue associated with Alternative B. The new mini "substation" that is required to accommodate the Searchmont step-up transformer will become useless once the whole area operates at 25kV. The multiple voltage supporting devices may not be required any more at the end of conversion, not to mention the intensive engineering efforts required to coordinate and set up those multiple voltage supporting devices.

In conclusion, Alternative B forecasts a slightly higher cost, but achieves less. It will take longer time and more resource to reach the ultimate configuration for Alternative B. As a result, Alternative A is the recommended interim solution and serves the basis for the development of the detailed implementation plan outlined in Section 4.5 for this rate application period.

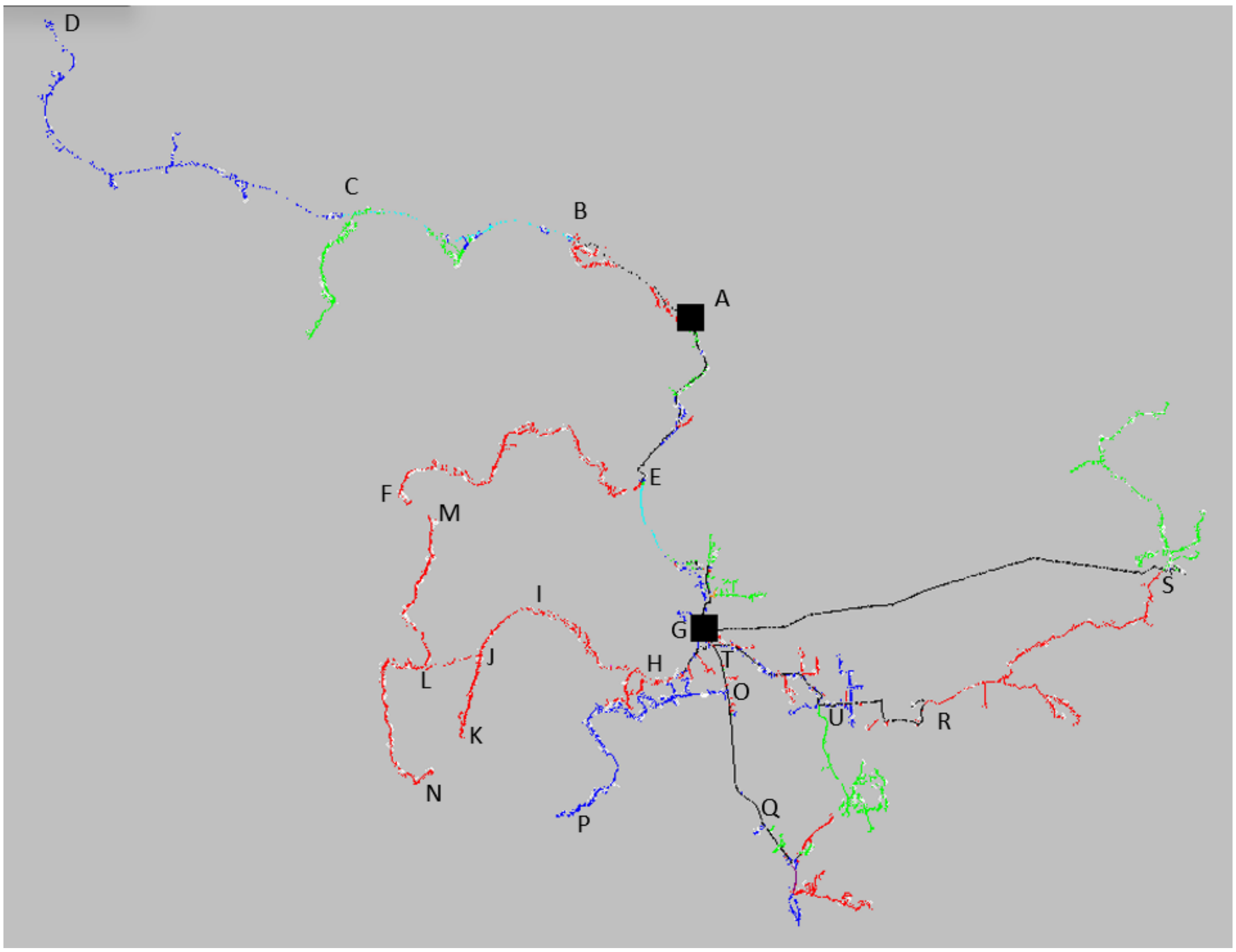
5.1.4 Detailed Implementation Plan for Goulais – Batchawana Voltage Conversion

Over the seven-year period 2015 to 2022, the Goulais TS was identified as the worst performing station in the Algoma Power service territory in terms of Customer-Hours of duration caused by loss of supply. Customers served by the two 12.5 kV feeders and single 25 kV feeder suffered about 137,000 customer-hours of outages over the seven-year period (Table 28 – Algoma Power Inc Reliability Study).

The Section 4.2 – Loss of Supply, 2023 Algoma Power Inc. Reliability Study describes how seven of the eight largest Loss of Supply events since 2017 have impacted the customers fed from Goulais TS. The existing load transfer capabilities between Goulais TS and Batchawana TS are limited by system configuration (only a single-phase tie between the stations), voltage (currently operating at 12.5 kV) and distance (station fence to station fence is about 20 km).

System load flow studies have determined that to facilitate load transfers between these two stations and maintain acceptable system voltages will require three things: (1) the voltage of both station transformers will have to be converted to 25 kV, (2) the 20 km of line between the station will have to be upgraded to operate at three phase, 25/14.4 kV with a minimum of 336 Al conductor and (3) the load area of each station will have to be rebuilt to operate at 25 /14.4 kV or with ratio transformers to step the voltage down to 12.5/7.2 kV. The justification for alternatives considered are found in Sections 5.1.1 to 5.1.3 above.

A detailed, project by project voltage conversion plan for all relevant line sections within the Goulais TS service is described below. Assumptions used in the cost estimates for each section are similar to Table 11 but following a different approach with regard to unit costs. The sum of costs for all detailed projects, including both line rebuilds and voltage conversions, is roughly the same as the total estimated cost in Table 11.



Goulais-Batchawana voltage conversion area – Section Illustration G

**Same as Figure 15 - Labels are used to define voltage conversion line segments below.*

<u>Complete the Three-Phase Tie Line between Batchawana TS and Goulais TS</u>

As of the date of this document, November 2023, the three-phase interconnection line between Batchawana TS and Goulais TS is completed as follows.

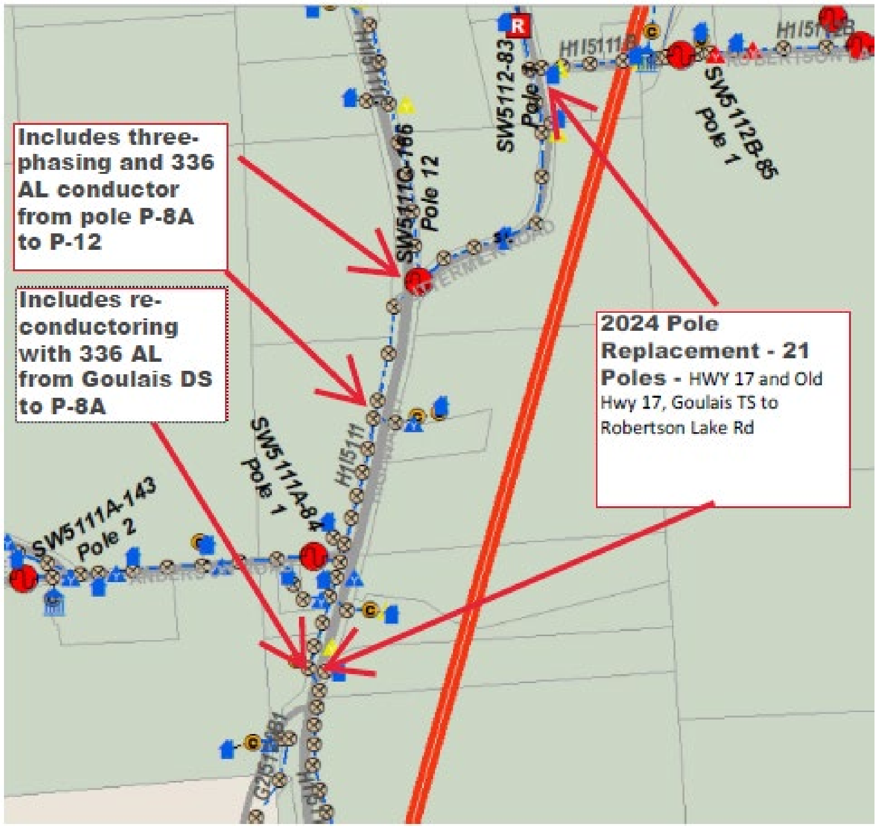
- Three-phase rebuilt to the 25 kV standard with 336 AL conductor is complete from Batchawana TS southerly to Harmony Beach Road – Pole 88.
- Three-phase built to the 15 kV standard with 336 AL conductor is complete from Goulais TS northerly to Anglican Church Road – Pole 15.
- There is a three-phase, built to the 25 kV standard with 336 AL conductor GAP from Goulais TS/Anglican Church Road - Pole 15 to Harmony Beach Road – Pole 88… a distance of about 14 kilometers.

The Major Project List includes the following 2024 projects that will provide partial completion of the gap:

- In 2024 – Line Rebuild – Robertson Road – 40 poles - $332,000
  - It is assumed that the Robertson Rd rebuild includes all elements required to complete a Quick Conversion.
  - Includes Rose Road and McGaughin Road east of the 115 kV line.
- Complete the three-phase line rebuild between Harmony Bay and point E in above Figure.

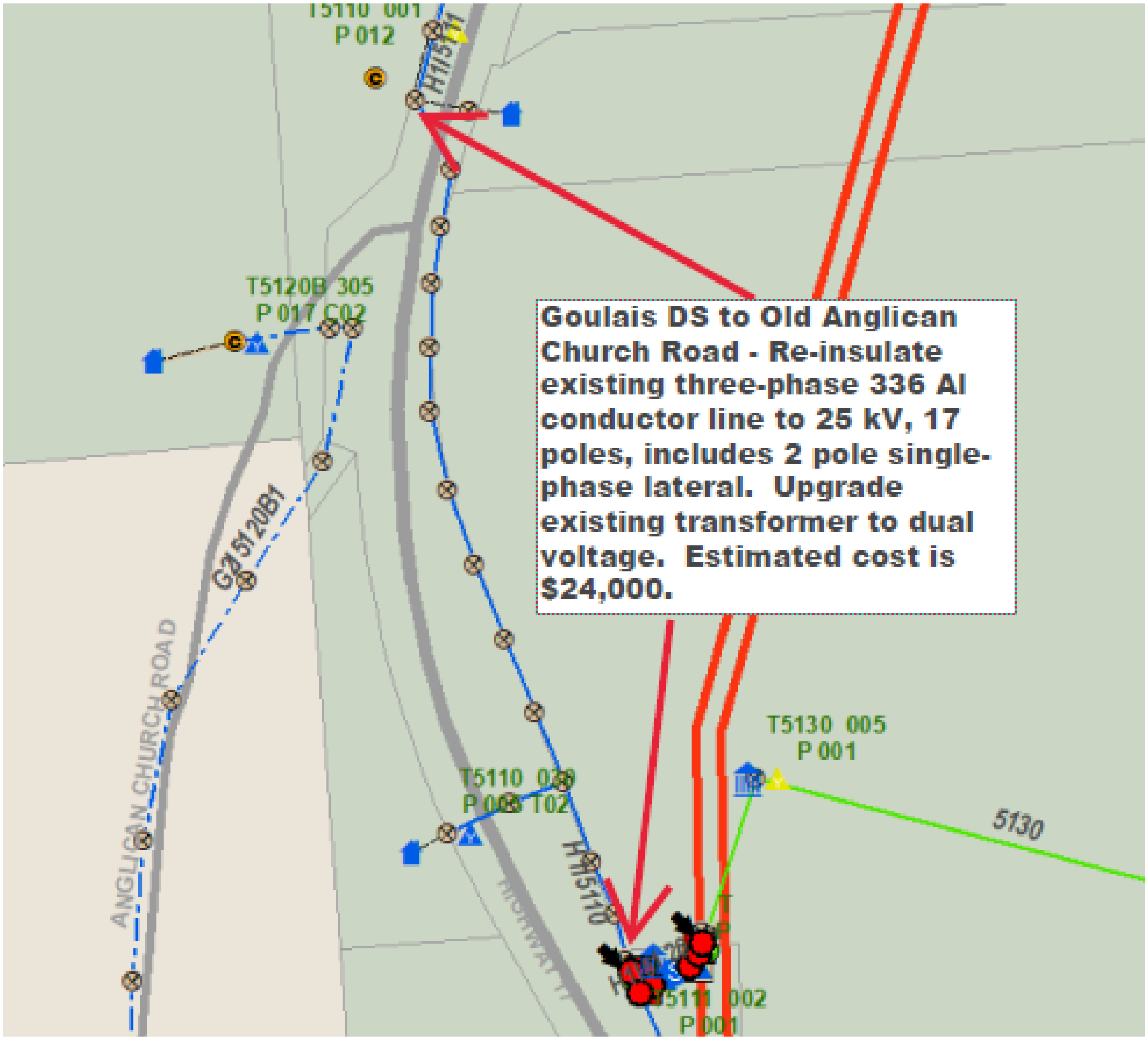
<u>Voltage Conversion Projects – Section G to E</u>

- In the line rebuild budget API has committed to rebuild the line along new HWY 17 and Old Hwy 17N Road from just south of Anderson Rd to Robertson Lake Rd – 21 poles - $176, 915
  - Interpretation of the description is illustrated below.
  - Includes reconductoring to 336 Al and three-phasing from P-8A to P-12 inclusive.
  - Includes Quick Conversion of Old Highway 17N to Robertson Road and five (5) dual voltage transformers.

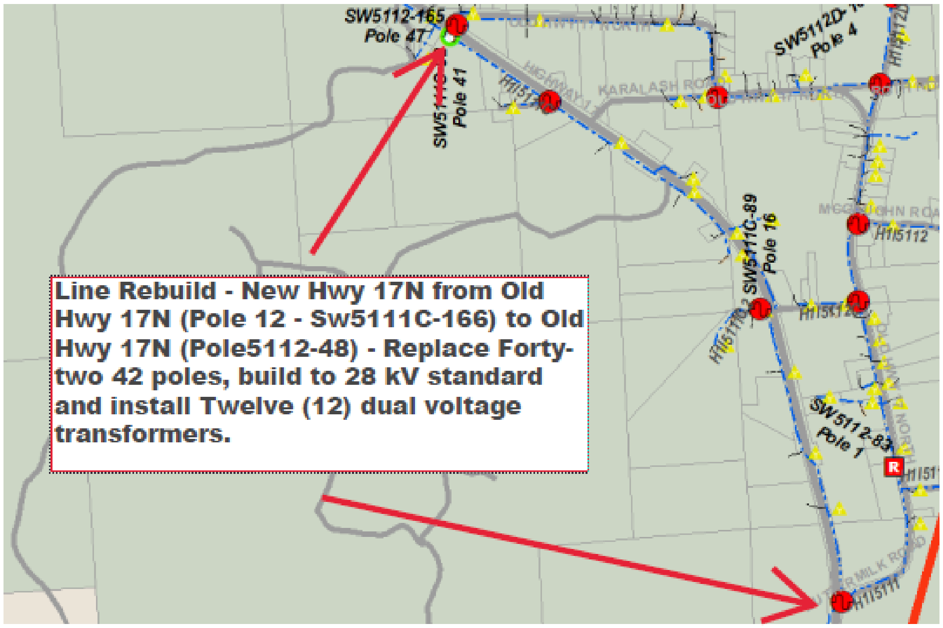


- It is unclear if the proposed three-phase tie line between Batchawana TS and Goulais TS is built along new Highway 17 North or along Old Highway 17N Rd. For purposes of this Area Planning Study, it is assumed the tie line will be built along new Highway 17 North.

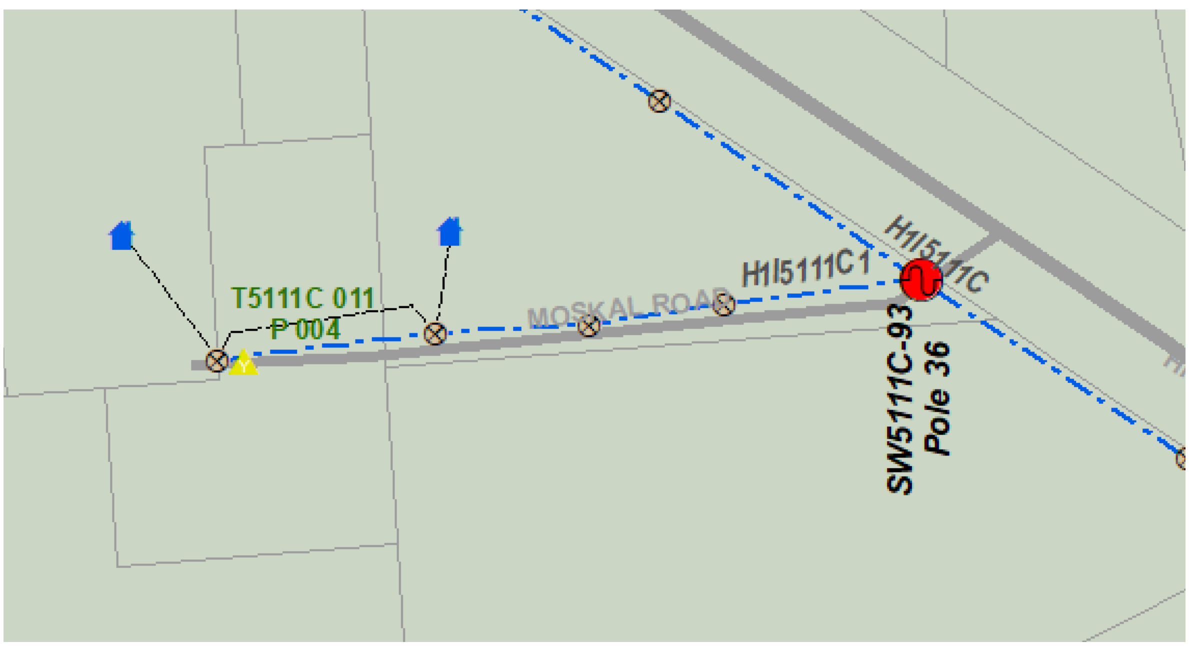
- Voltage conversion of the existing three-phase line from Goulais TS to the end of the existing three-phase line just south of Anderson Road requires that the line be re-insulated from Goulais TS to Old Anglican Road P15 – a total of seventeen (17) poles, which includes a two-pole, single-phase lateral at P-5.



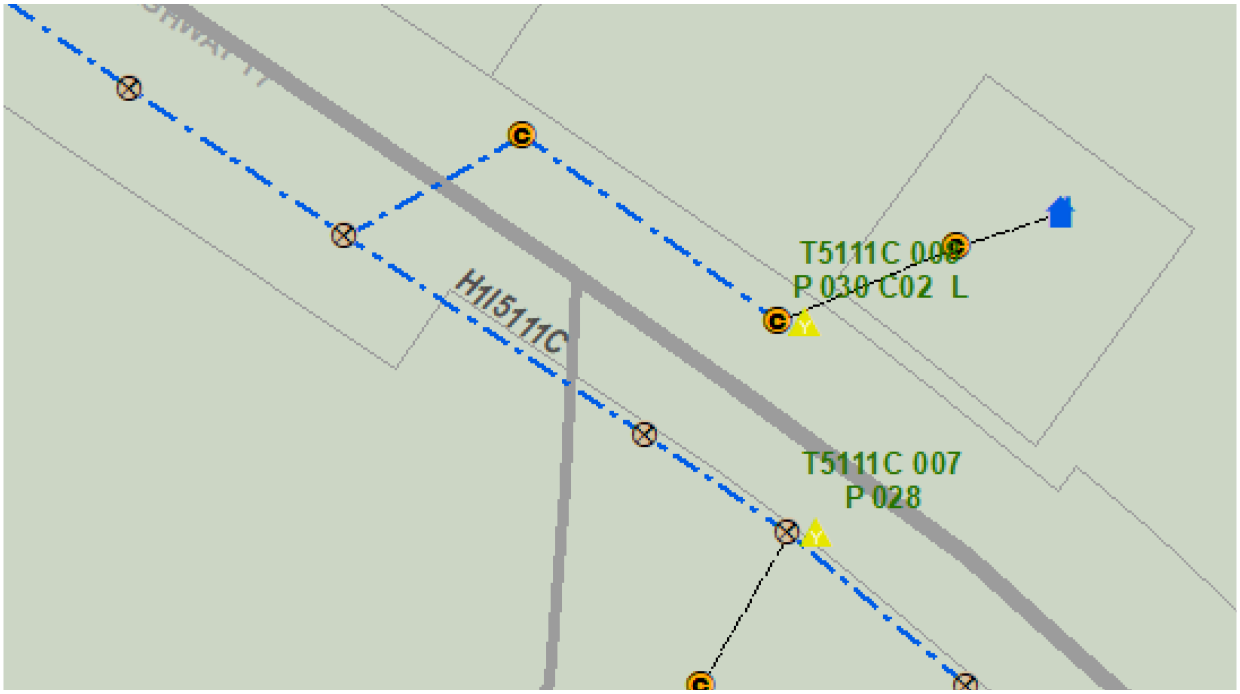
- Line Rebuild - New Hwy 17N from Old Hwy 17N (Pole 12 - Sw5111C-166) to Old Hwy 17N (Pole5112-48) - Replace Forty-two 42 poles, build to 28 kV standard and install Twelve (12) dual voltage transformers.



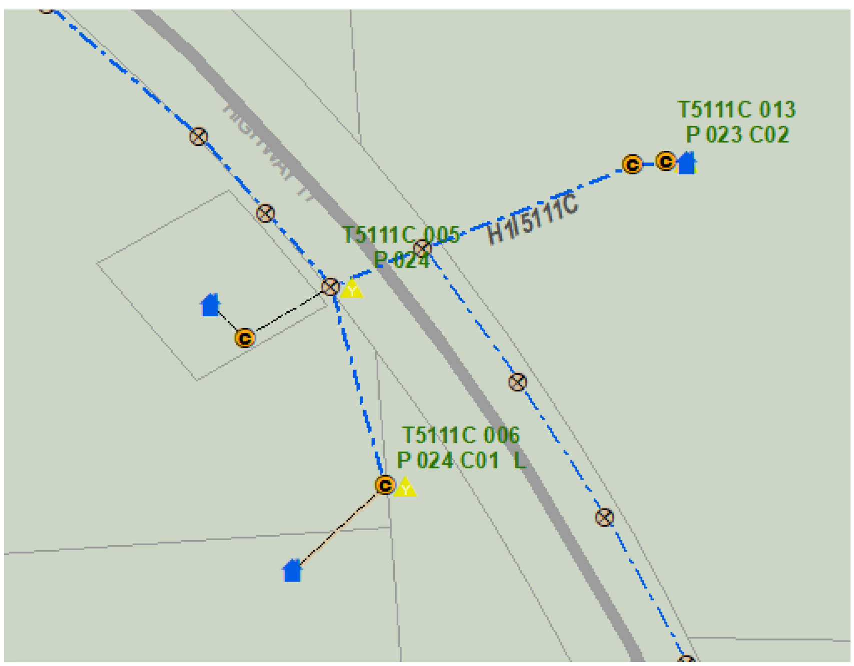
- Moskal Road - An API owned four (4) pole single-phase lateral at P-36.



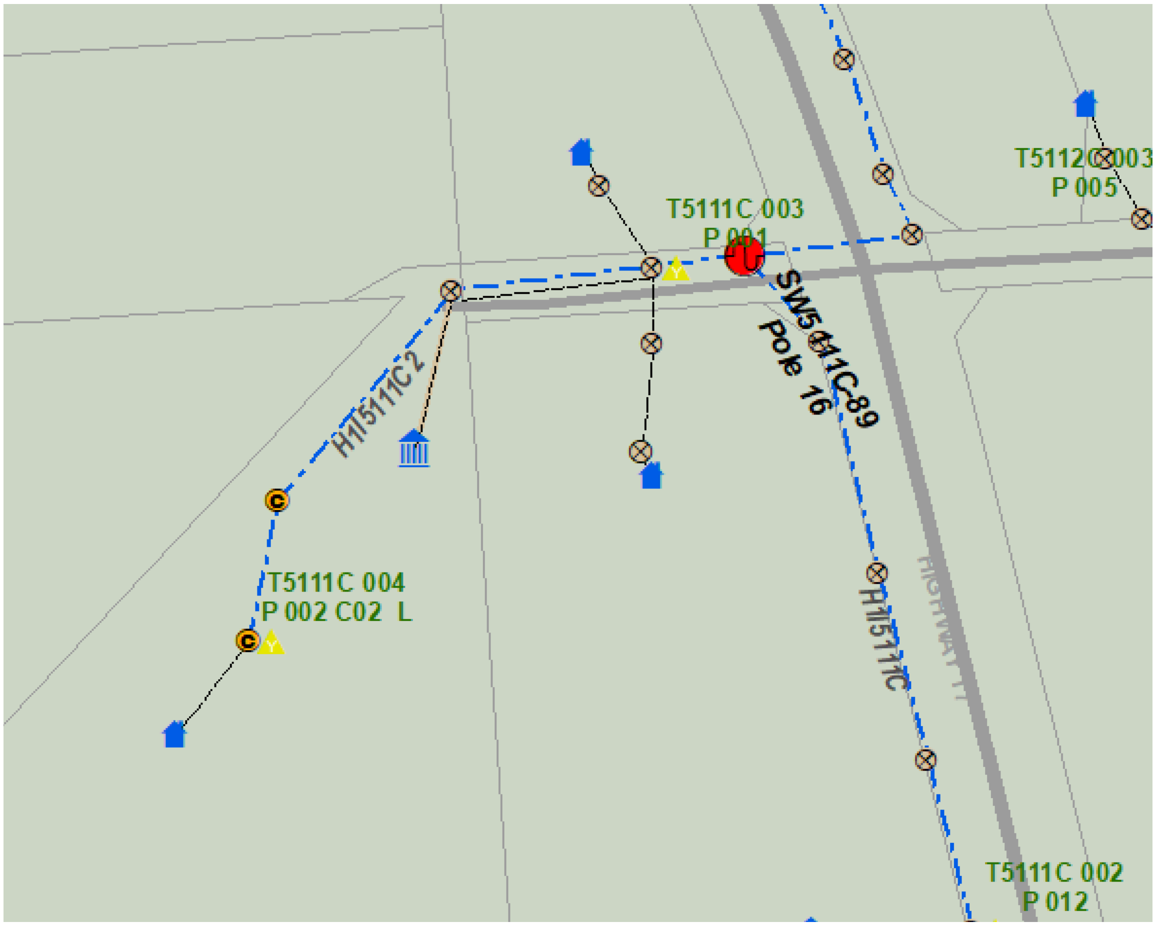
- 4154 Hwy 17 N - A Customer Owned two (2) pole single-phase lateral at P-30.



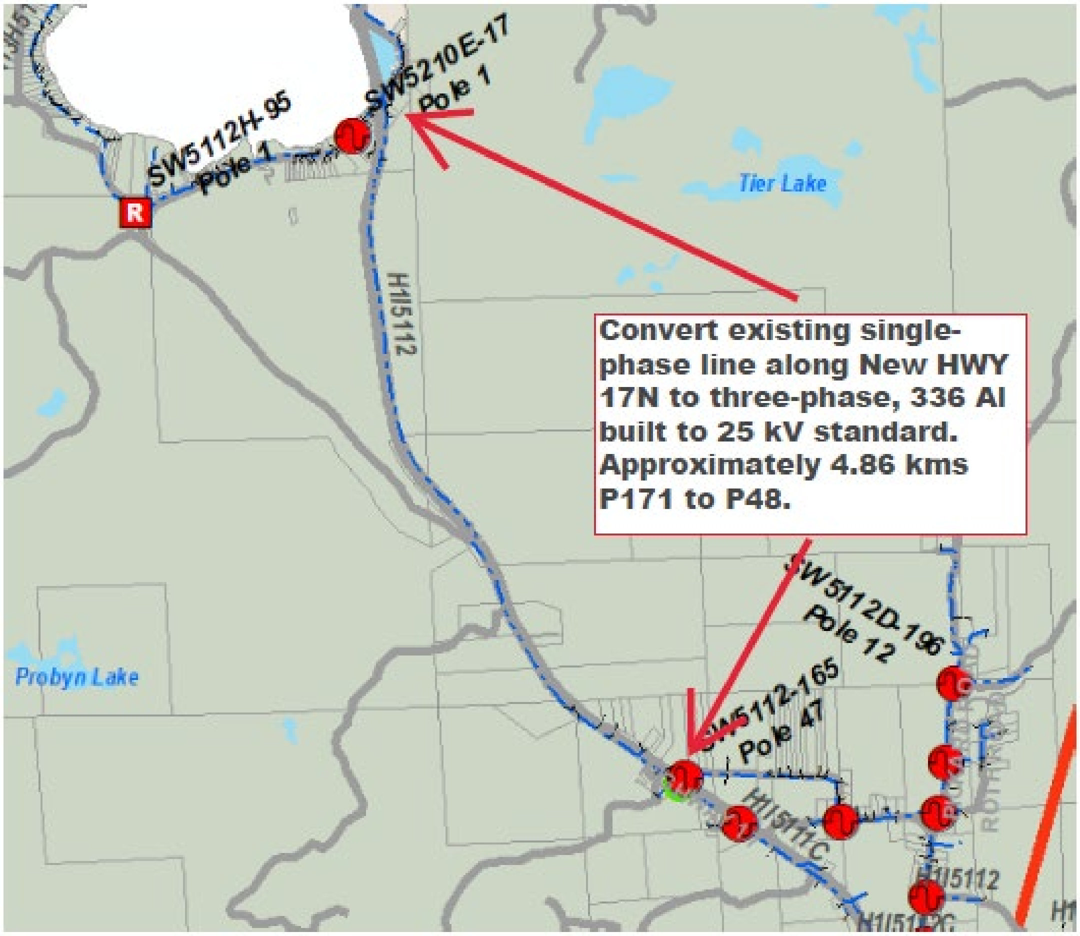
- 40 Mahler Road - A Customer Owned one (1) pole single-phase lateral at P-24 and a Customer Owned one (1) pole single-phase lateral at P-23.



- 103Yourchuk Road - An API Owned two (2) pole single-phase lateral at SW5111C-89 – Pole 16 that feeds a Customer Owned two pole (2) pole single-phase lateral.



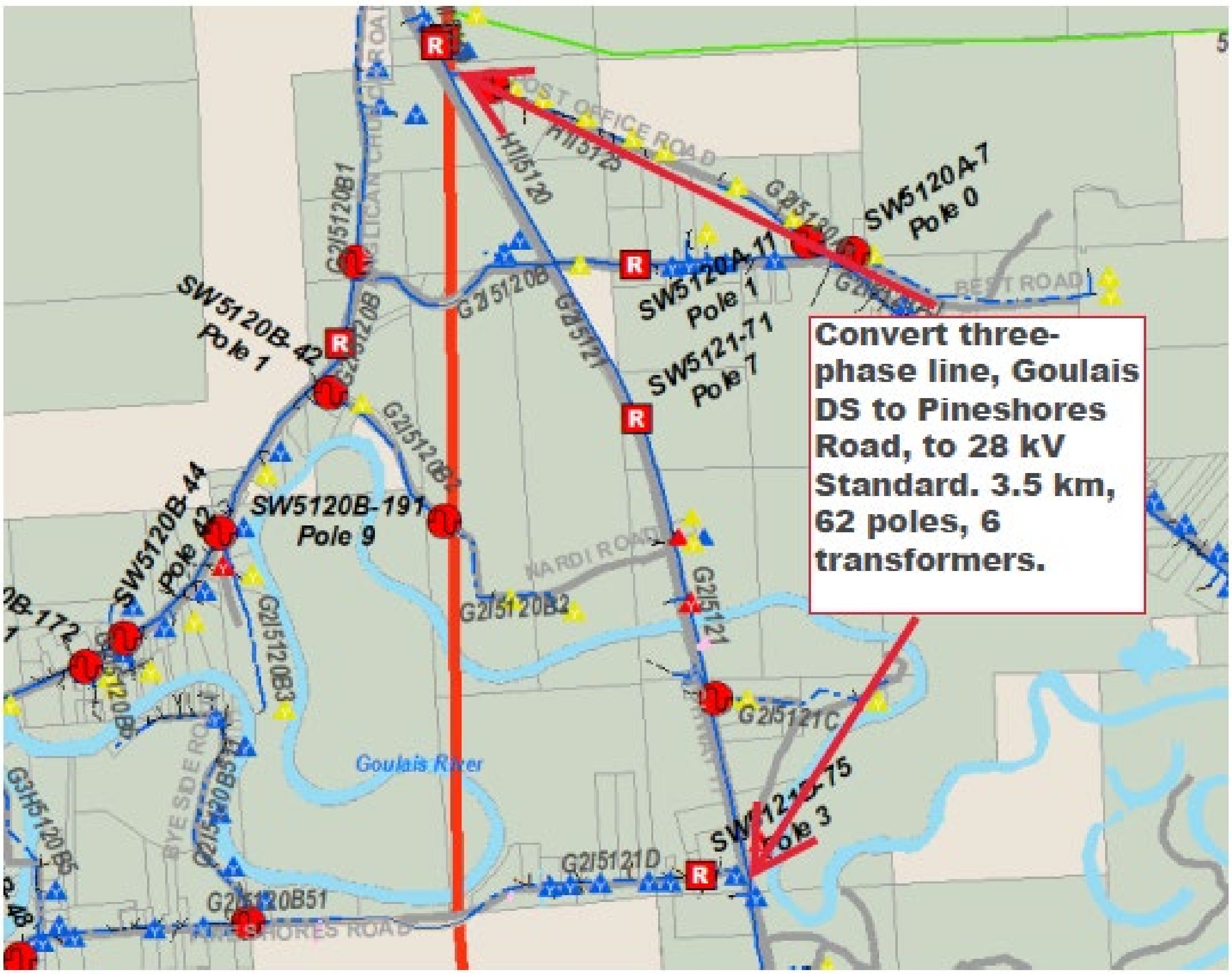
- Rebuild the single-phase line from Havilland Shores Drive (SW 5210-18A, Pole 215210-170) south along Highway 17 to Old Highway 17 North Road (Pole 5112-48), a distance of about 4.86 km involving 73 poles as a three-phase line with 336 AL conductor. There are eight (8) transformers along the route that require dual voltage transformers. Estimated rebuild cost is $1,148,473.
        - At P5112-53 – primary single-phase lateral quick convert road crossing pole at P5112-165
    - At P5112-49 – primary single-phase lateral quick convert south from highway, 3 poles – quick convert


SW5112H-95
Pole 1
SW5210E-17
Pole 1
Tier Lake
H1I5112
Convert existing single-phase line along New HWY 17N to three-phase, 336 Al built to 25 kV standard. Approximately 4.86 kms P171 to P48.
SW5112D-196
Pole 12
SW5112-165
Pole 47
Probyn Lake
H1I5111C
H1I5112

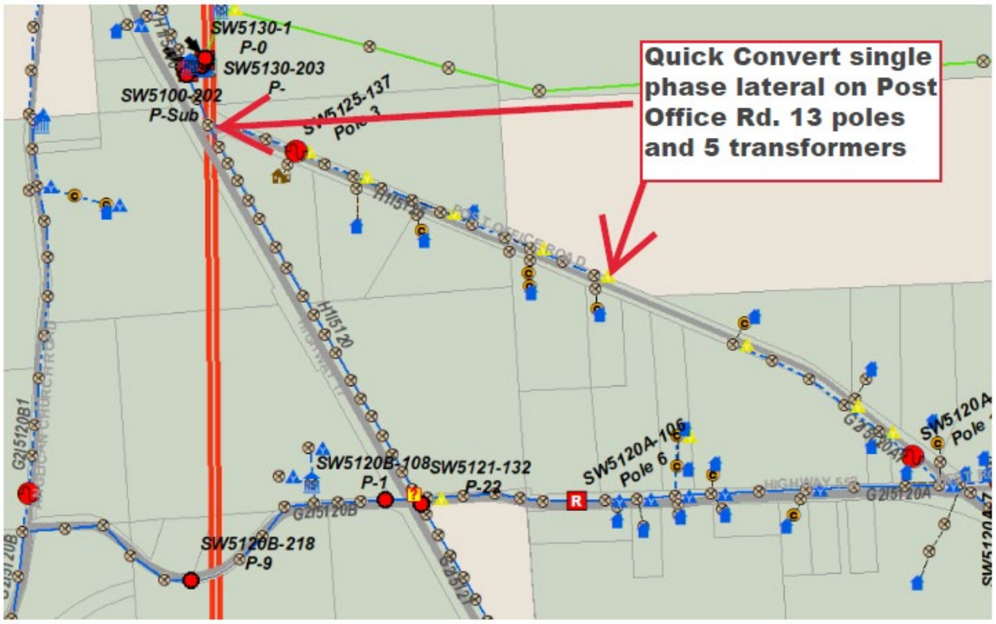
__Voltage Conversion Projects – Goulais DS – G to O__

- Complete line build described in Section 7.1 – Recommended solution to Improve the Reliability of Goulais 5120 Feeder – 22 poles

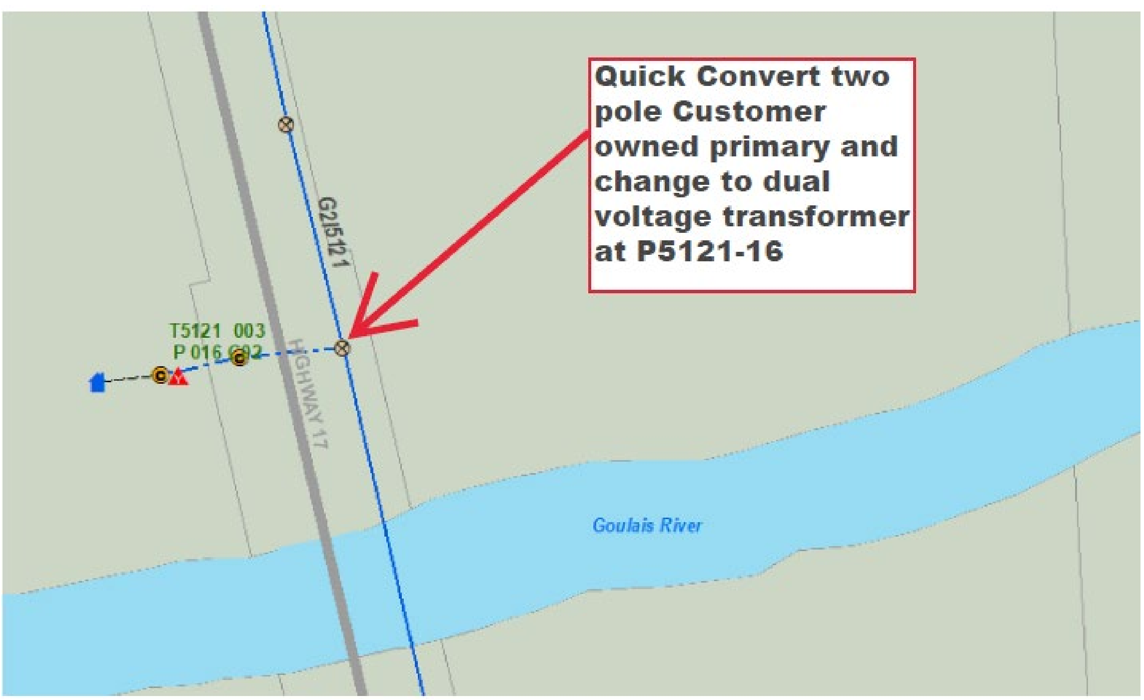
Rebuild the three-phase line G to O from Goulais TS (SW 5100-202 P-Sub, Pole 5120-2) south along Highway 17 to Pineshores Road (Pole 5121-29), a distance of about 3.5 km involving 62 poles as a three-phase line with 336 AL conductor. There are six (6) transformers along the route that require dual voltage transformers.



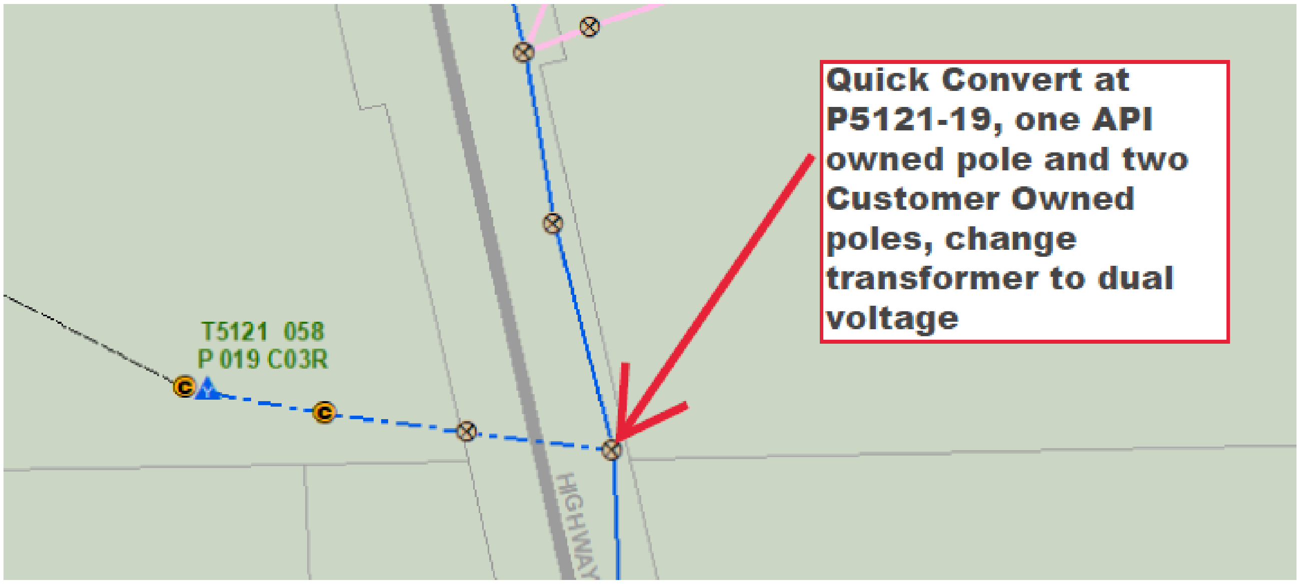
- Quick Convert single-phase lateral on Old Post Office Rd- 13 poles, 5 transformers



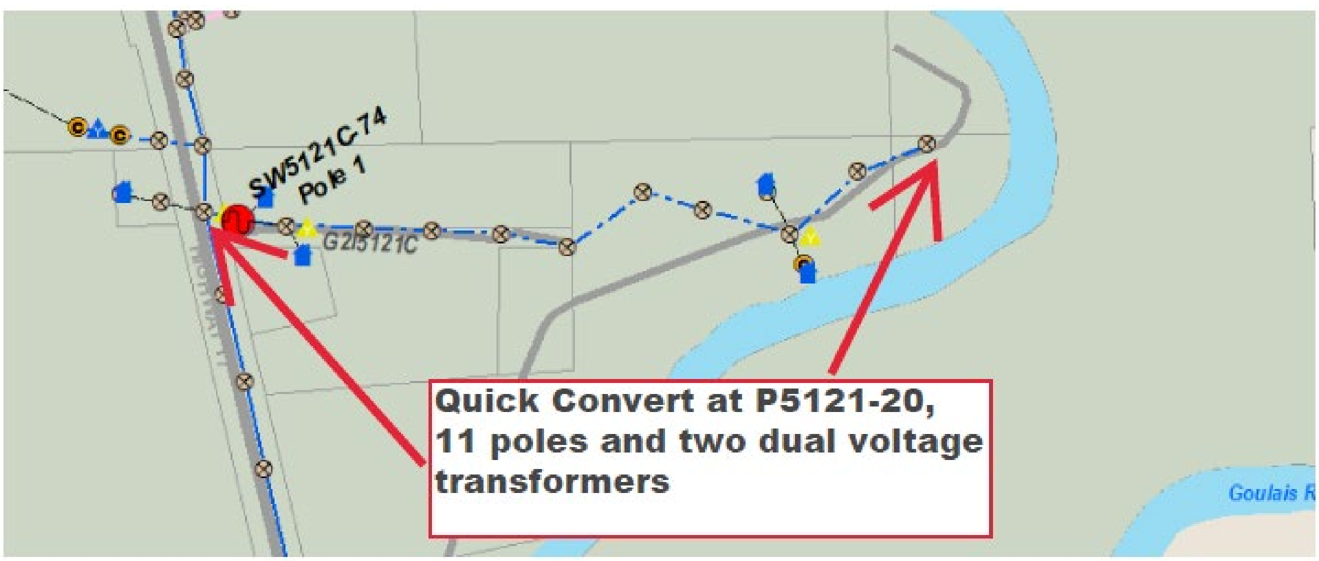
- Quick Convert small single-phase lateral, two (2) customer owned poles and a dual voltage transformer at P5121-16.



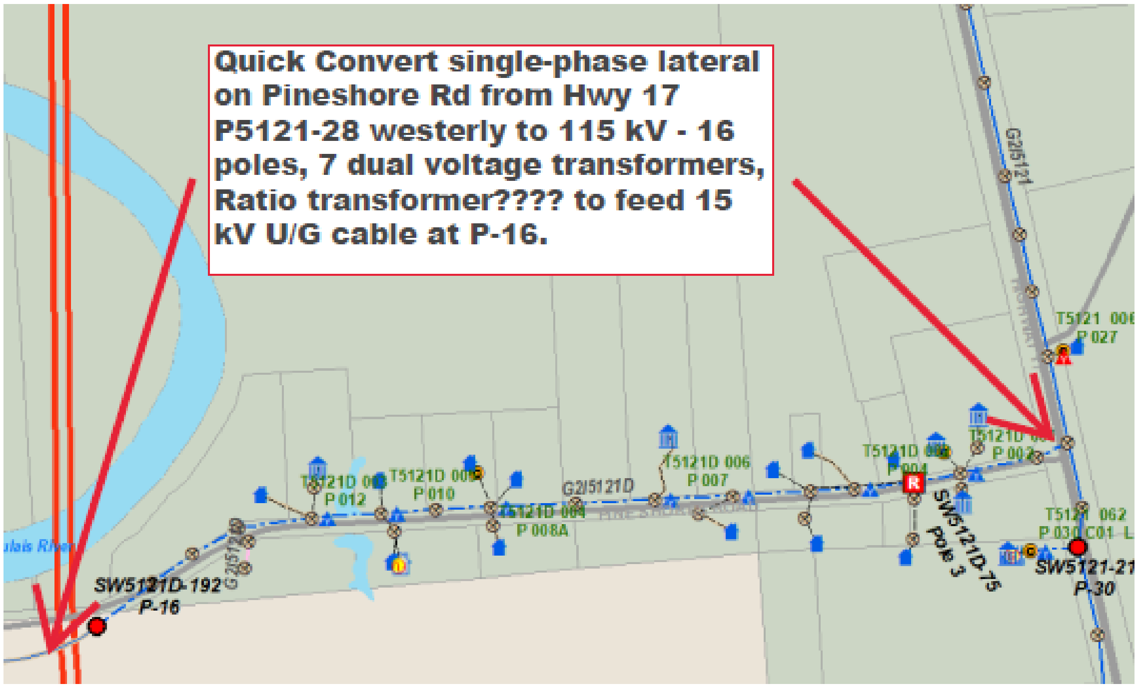
- Quick Convert small single-phase lateral, one (1) API owned pole, two (2) customer owned poles and a dual voltage transformer at P5121-19.



- Quick Convert small single-phase lateral, eleven (11) API owned poles and two (2) dual voltage transformers at P5121-20.



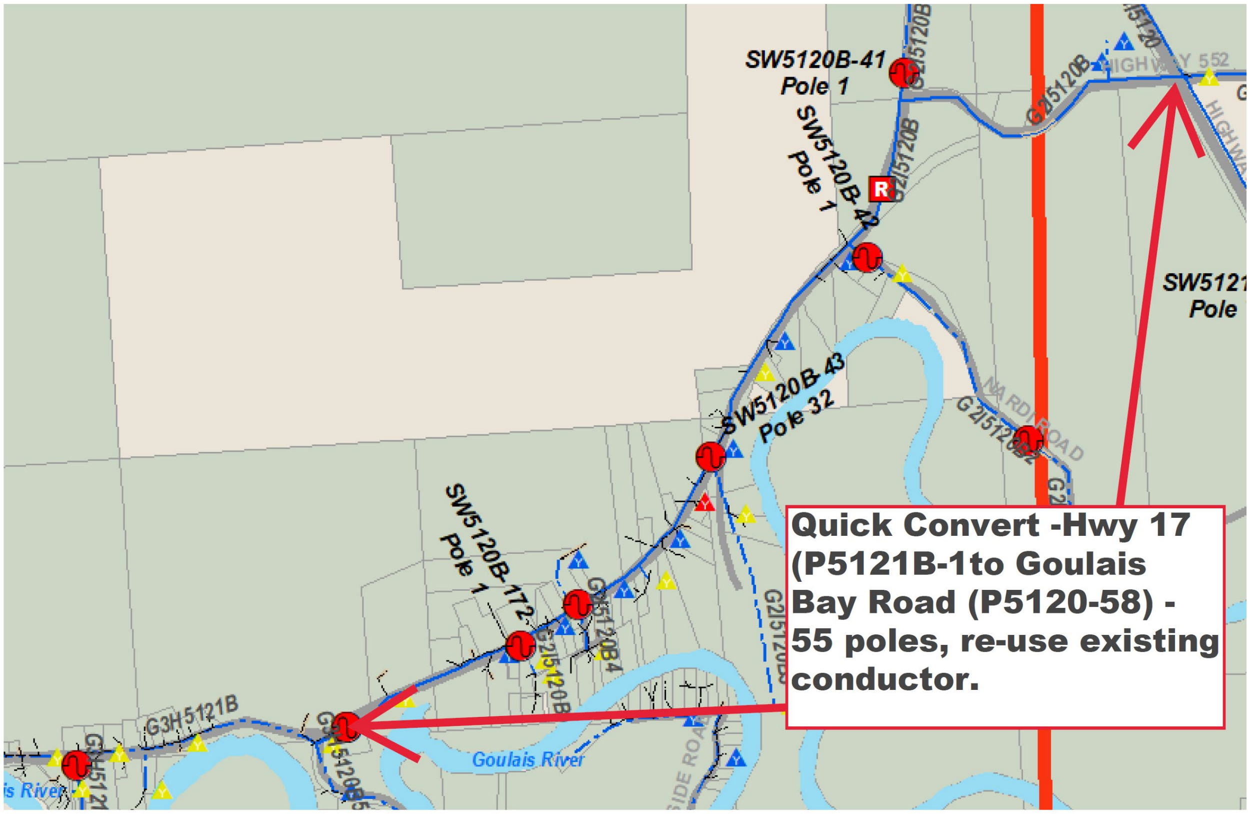
- Quick Convert single-phase lateral on Pineshore Rd westerly from Hwy 17 at P5121-28 to 115 kV line where line dips U/G to a 15 kV rated cable. QC sixteen (16) API owned poles and seven (7) dual voltage transformers and a Ratio Transformer.



<u>Voltage Conversion Projects – Goulais DS – Section G to H</u>

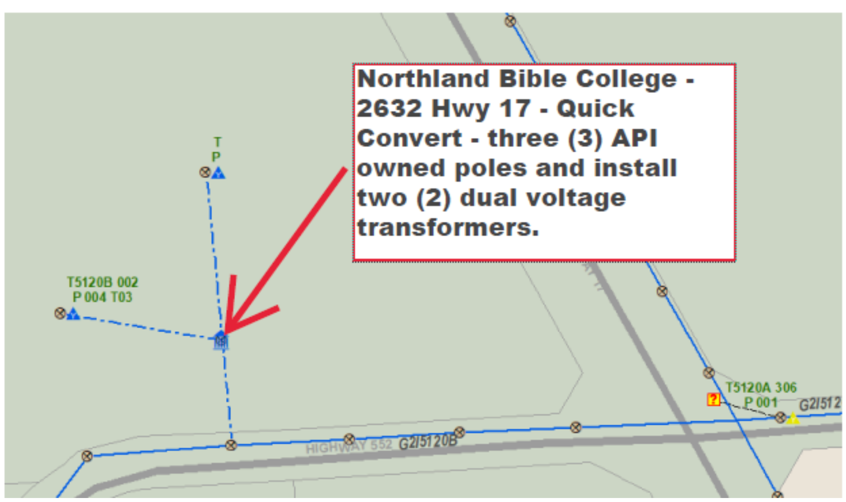
- Rebuild the three-phase line - G to H - Hwy 552 west from Hwy 17 Rd (P5120B-1) to the Intersection of Goulais Mission Rd/Grant Rd /Hwy 552 (P5121B-35) - Total of 93 Poles.
  - Section 1 from Hwy 17 (P5121B-1) to Goulais Bay Rd (P5120B-58) - Quick Convert 55 poles re-use existing 3/0 ACSR.
  - Section 2 from to Goulais Bay Rd (P5120B-58) to the Intersection of Goulais Mission Rd/Grant Rd /Hwy 552 – (P5121B-35) - Quick convert for 38 poles re-use existing conductor..

Section 1 – Goulais DS G to H – Hwy 552 from Hwy 17 to Goulais Bay Rd

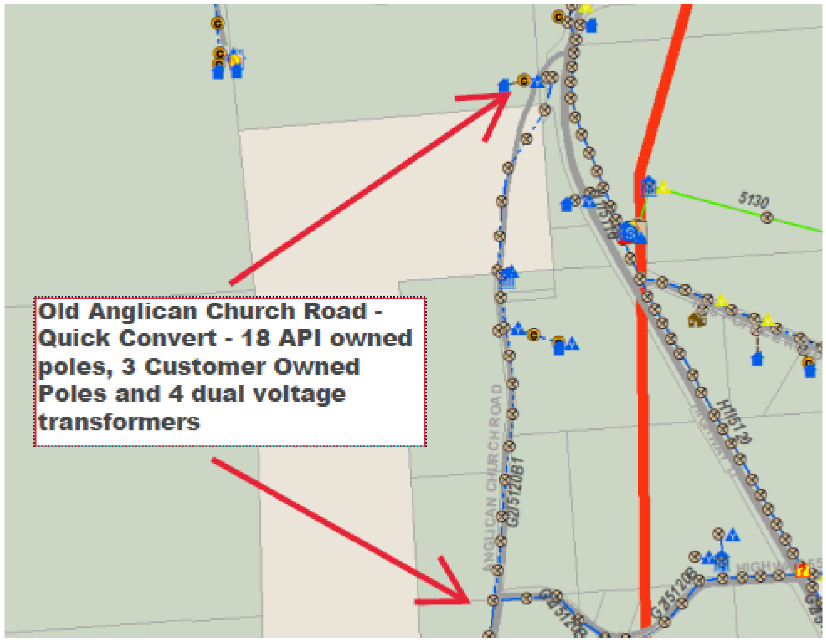


Section 1 – Single-Phase laterals on Hwy 552 west from Hwy 17 (P5120B-1) to Goulais Bay Rd (P5120B-58)

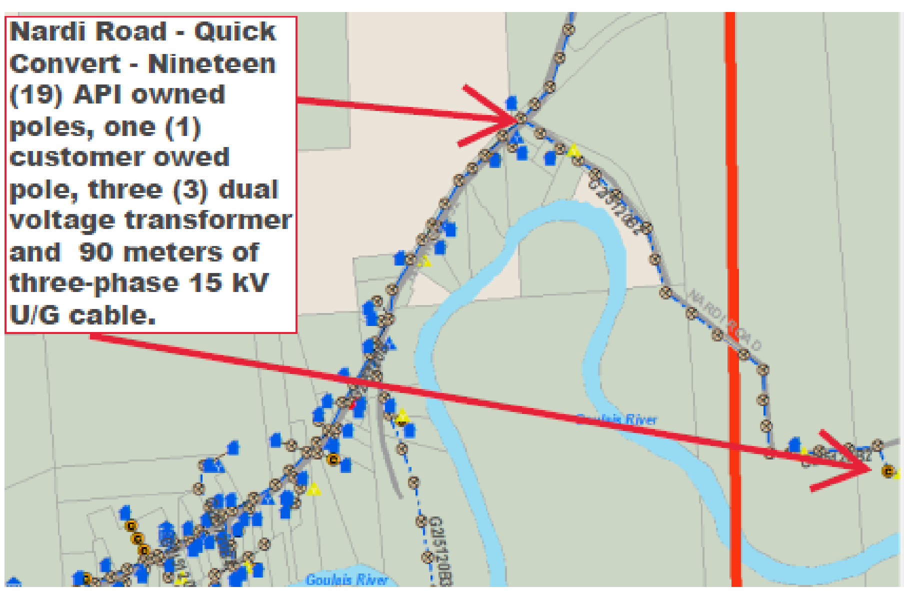
- Quick Convert - Small single-phase laterals within rebuild G to H - Hwy 552 west from Hwy 17 (P5120B-1) to the Intersection of Goulais Mission Rd/Grant Rd /Hwy 552 (P5121B-35).
  - Northland Bible College -2632 Hwy 17 – Fed from P5120B-4 - Quick Convert three (3) poles and install two (2) Dual Voltage Transformers.
  - This is a primary metered service that will need to be upgraded to 25/14.4 kV.



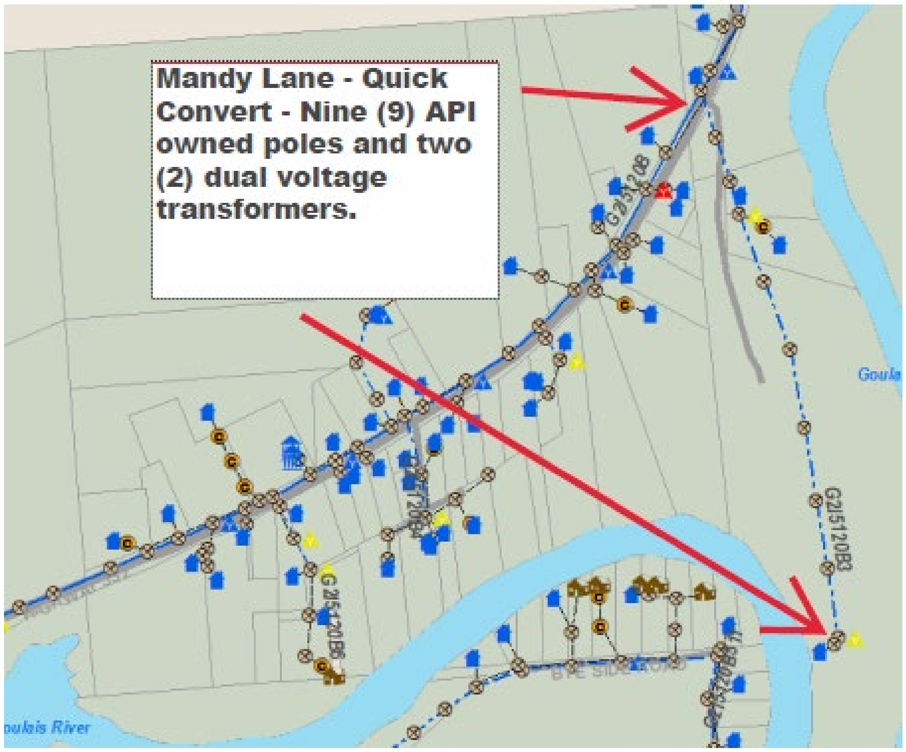
- Old Anglican Church Road – Quick Convert - reinsulate eighteen (18) API owned poles, three (3) Customer owned poles and four (4) dual voltage transformers.



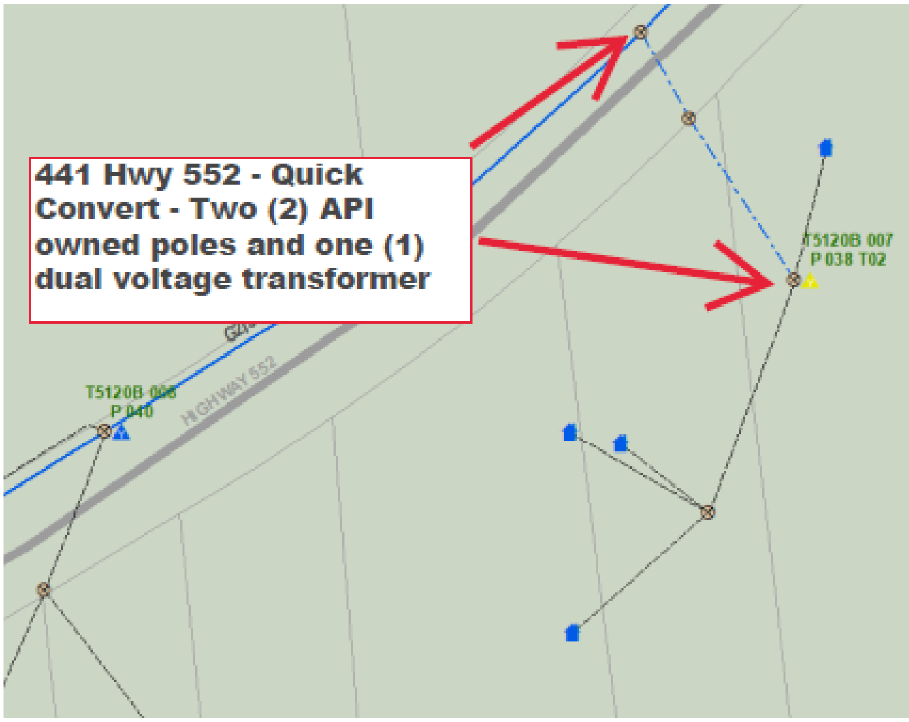
- Nardi Road – Quick Convert - Nineteen (19) API owned poles, one (1) customer owed pole, three (3) dual voltage transformer and 90 meters of three-phase 15 kV U/G cable.



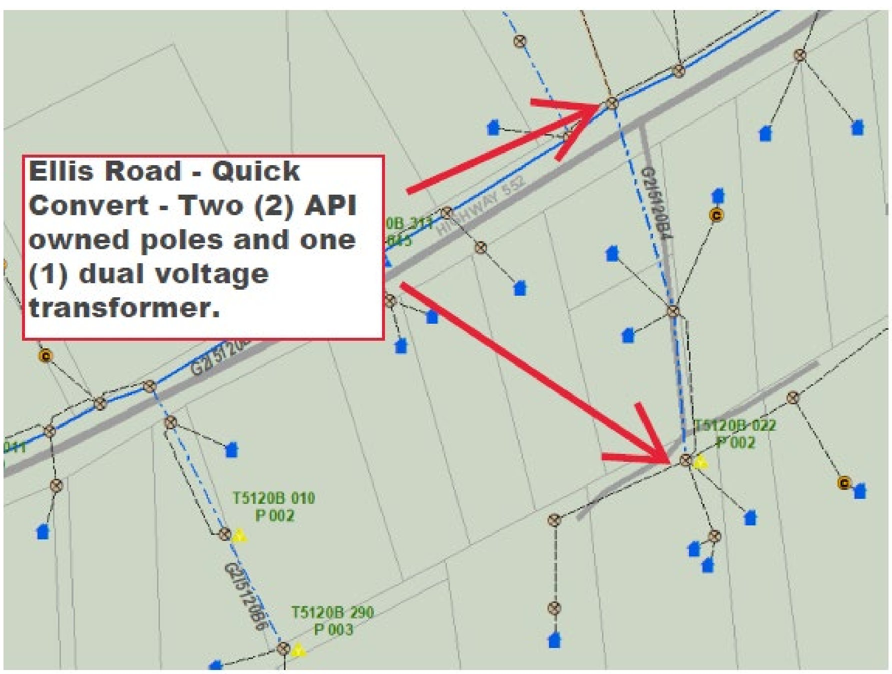
- Mandy Lane – Quick Convert - Nine (9) API owned poles and two (2) dual voltage transformers.



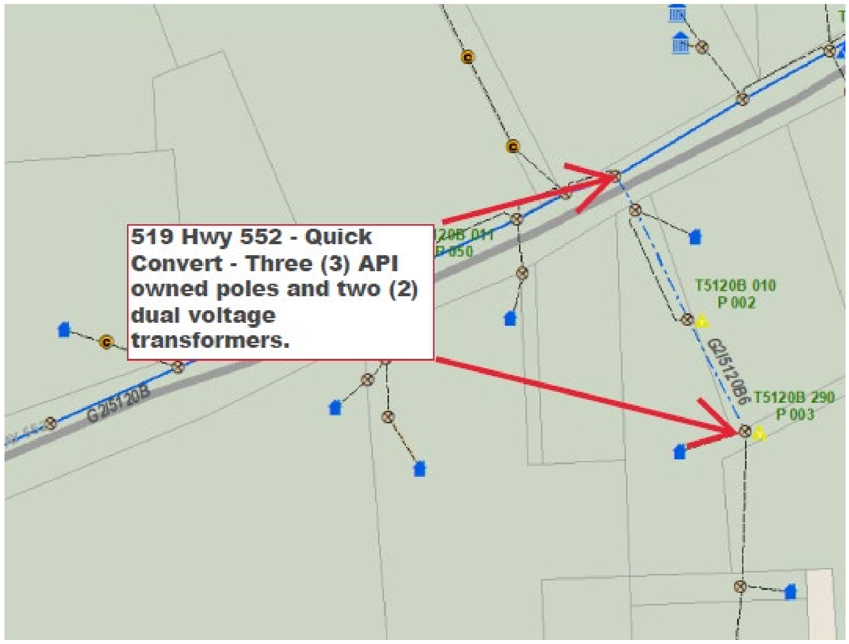
- 441 Hwy 552 - Quick Convert - Two (2) API owned poles and one (1) dual voltage transformer.



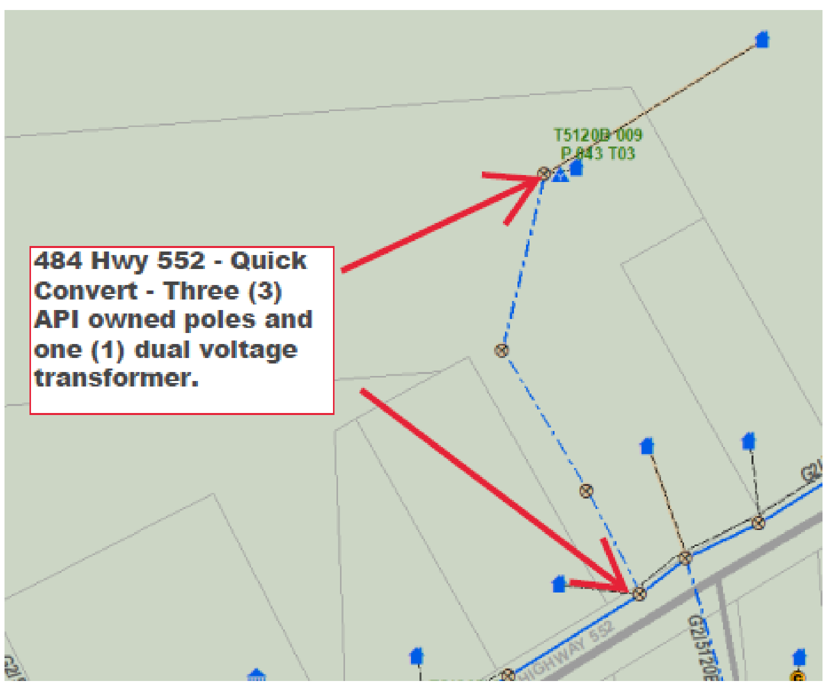
- Ellis Road – Quick Convert - Two (2) API owned poles and one (1) dual voltage transformer.



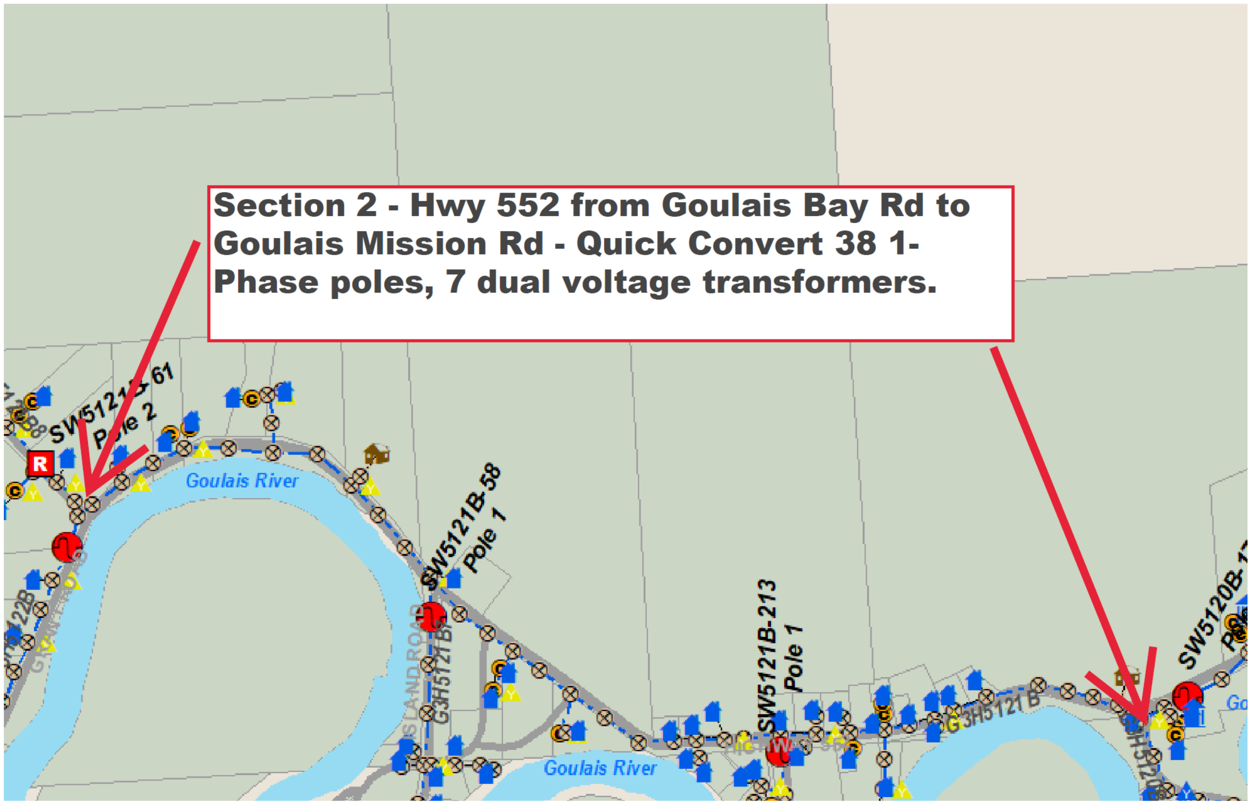
- 519 Hwy 552 - Quick Convert - Three (3) API owned poles and two (2) dual voltage transformers.



- 484 Hwy 552- Quick Convert - Three (3) API owned poles and one (1) dual voltage transformer.

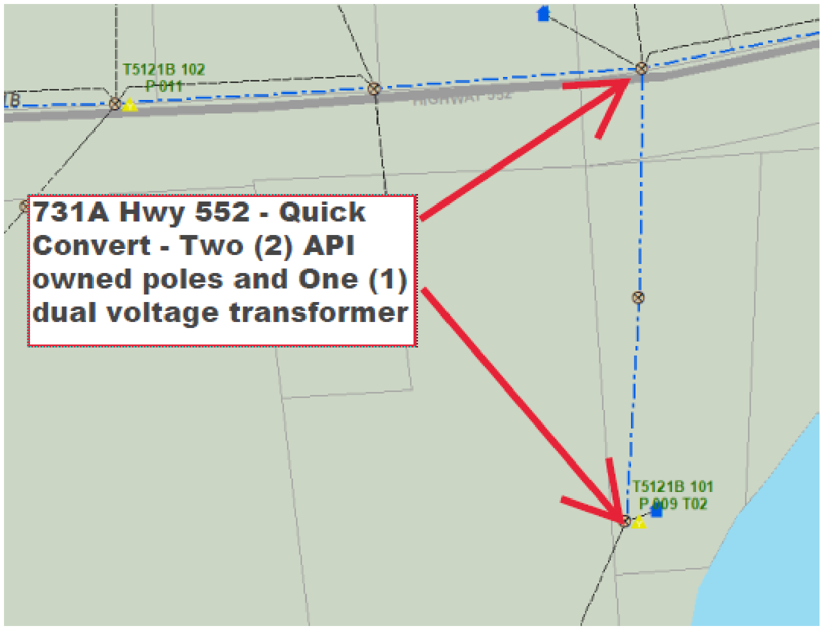


Section 2 – Hwy 552 from Goulais Bay Road to Goulais Mission Road

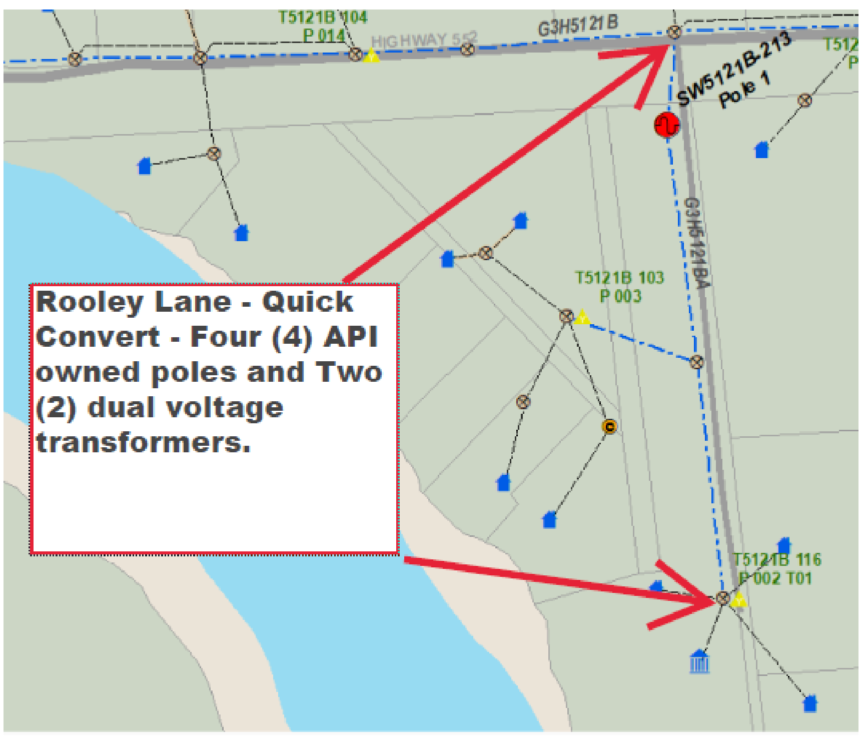


Section 2 – Single-Phase laterals on Hwy 552 west from Goulais Bay Rd (P5120B-58) to the Intersection of Goulais Mission Rd/Grant Rd /Hwy 552 – (P5121B-35).

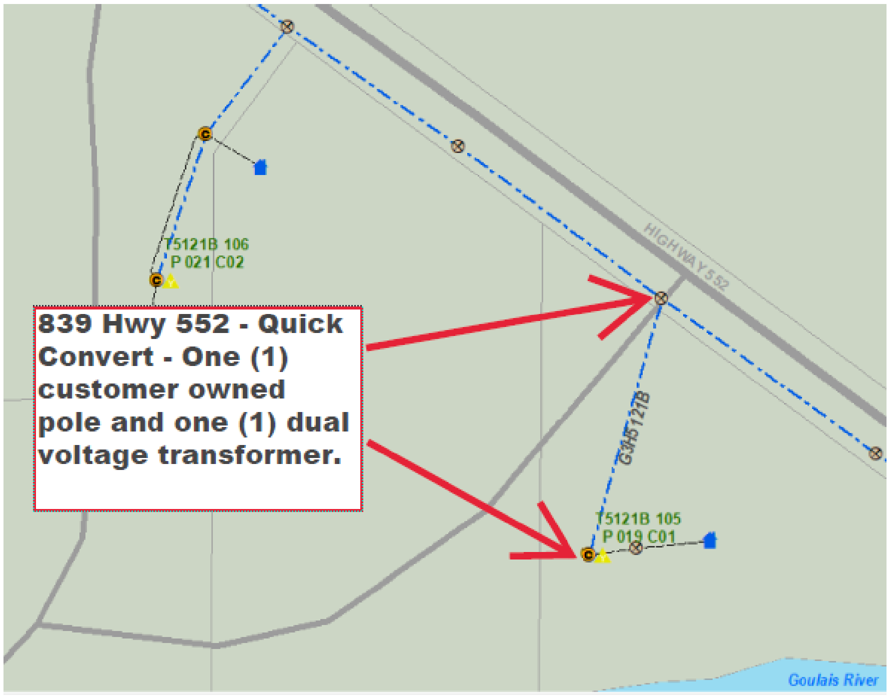
- 731A Hwy 552 - Quick Convert - Two (2) API owned poles and One (1) dual voltage transformer.



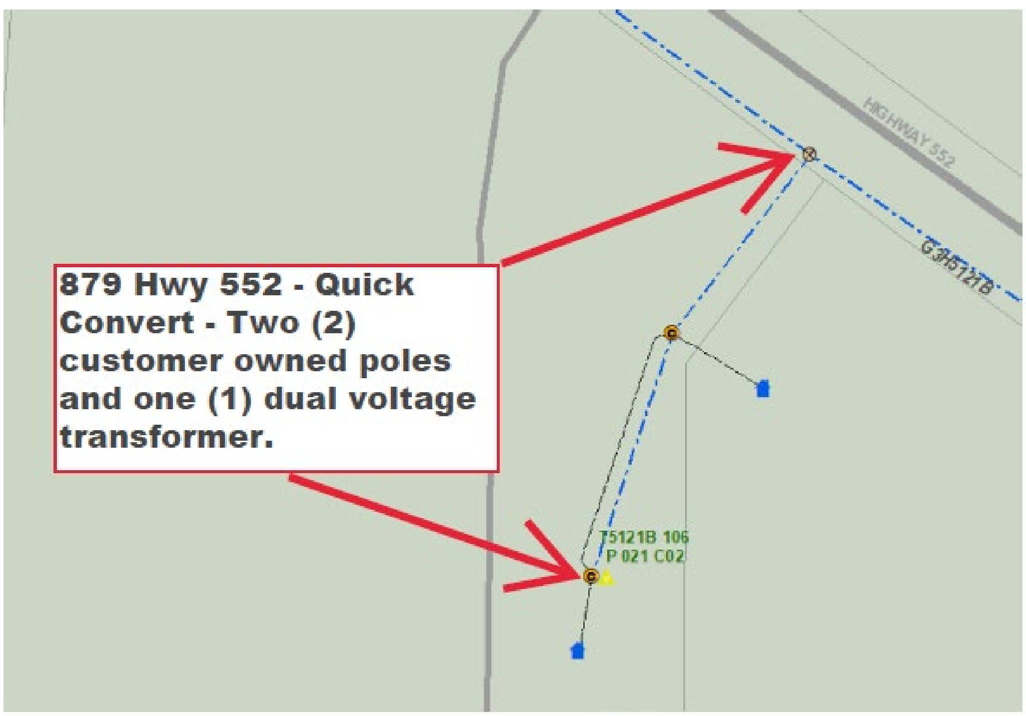
- Rooley Lane - Quick Convert - Four (4) API owned poles and Two (2) dual voltage transformers.



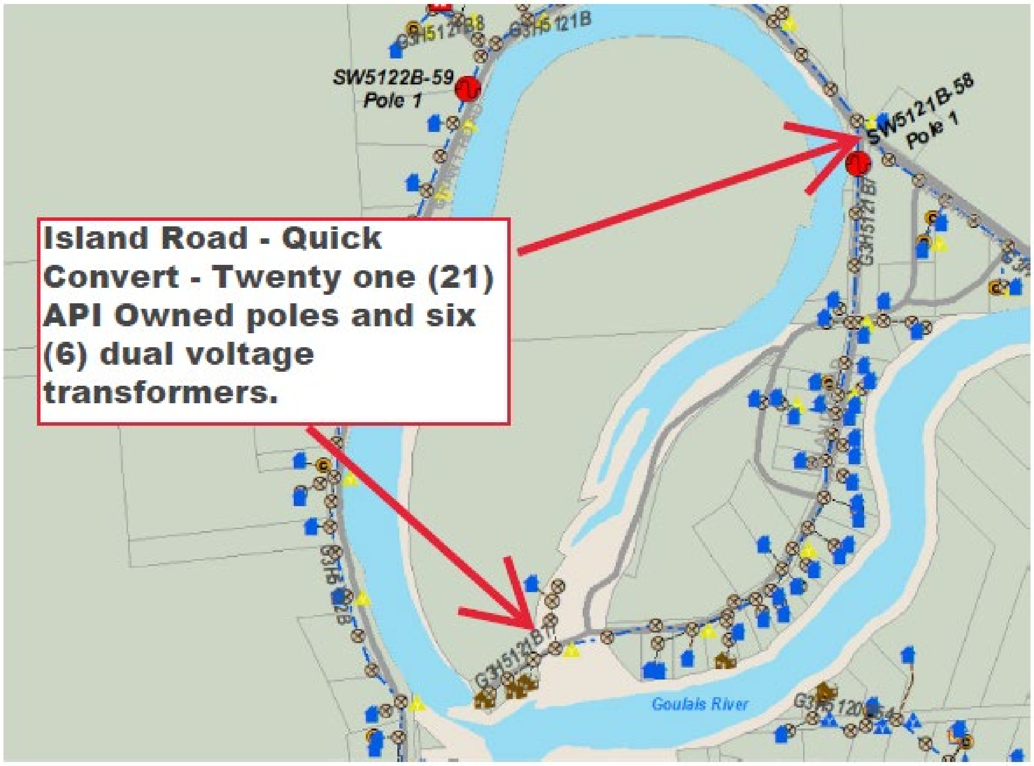
- 839 Hwy 552 - Quick Convert - One (1) customer owned pole and one (1) dual voltage transformer.



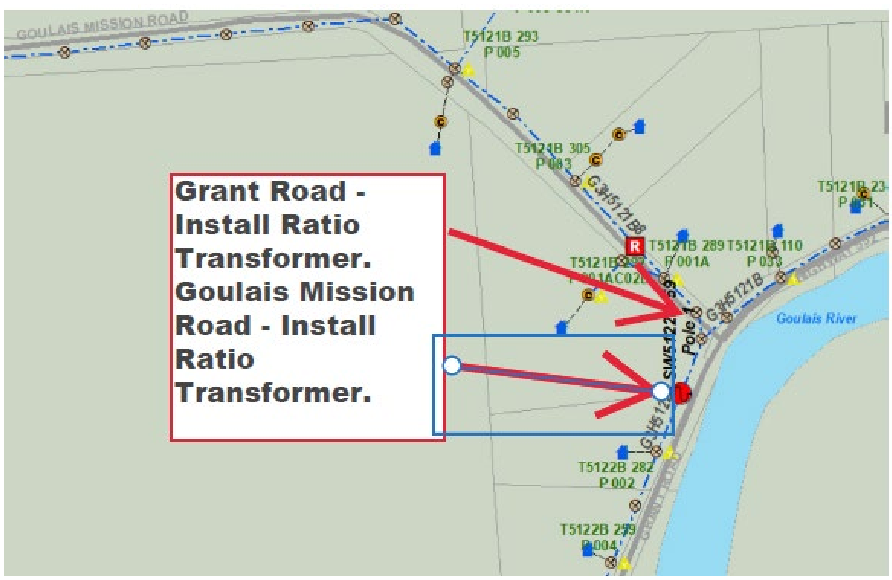
- 879 Hwy 552 - Quick Convert - Two (2) customer owned poles and one (1) dual voltage transformer.



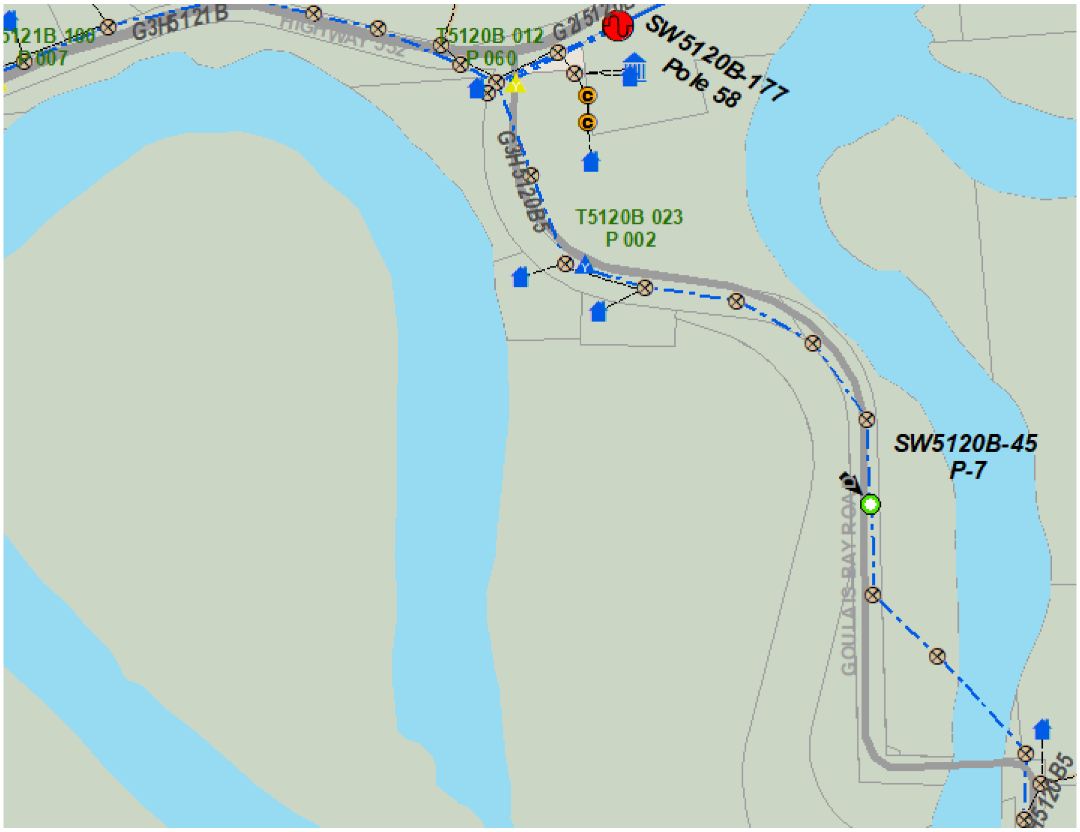
- Island Road - Quick Convert - Twenty-one (21) API Owned poles and six (6) dual voltage transformers.



- Grant Road and Goulais Mission Road – Install a Ratio transform on each road to feed single-phase load.



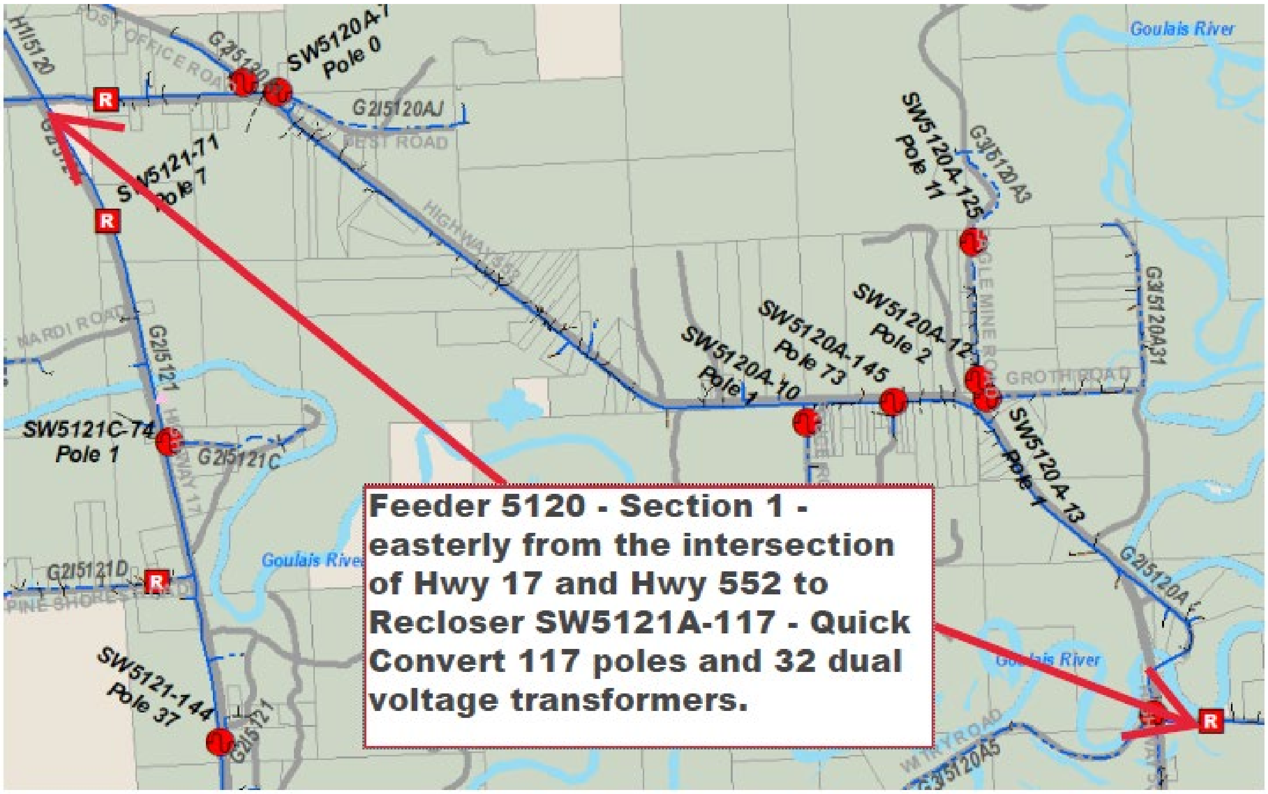
- Goulais Bay Road – Quick Convert – seven (7) API Owned poles and one (1) dual voltage transformer.



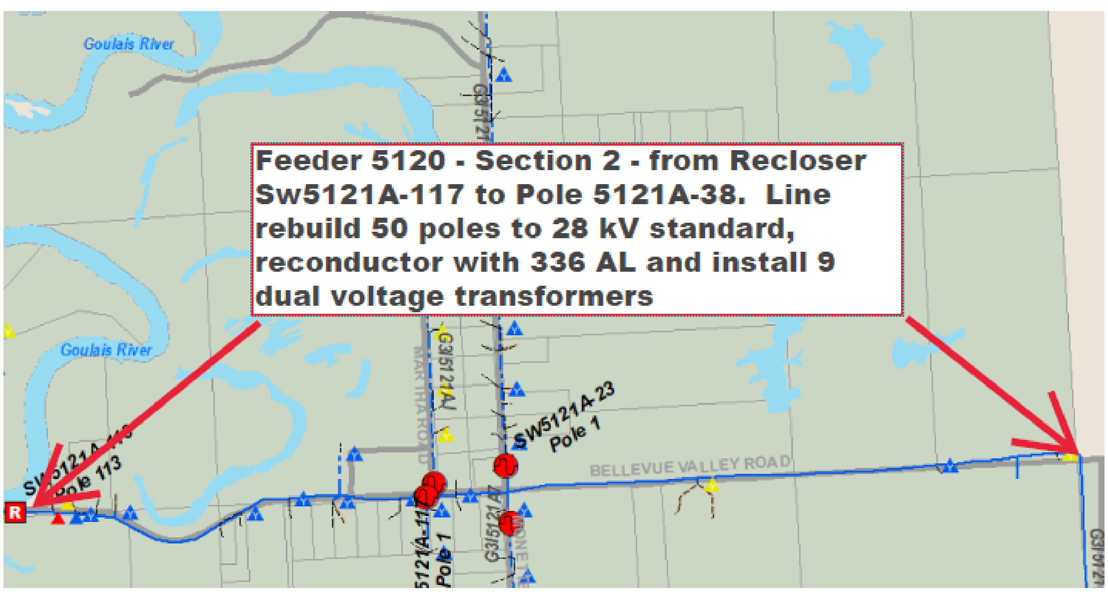
Voltage Conversion Projects – Goulais DS – Section G to R

- Rebuild the three-phase line G to R from Goulais DS TS (SW 5100-202 P-Sub, Pole 5120-2) east along Highway 552 to the Nav Canada Tower – Bellevue (Pole 5122A-37T10), a distance of about 15 km involving approximately 250 poles. The line is to be reinsulated to the 28 kV standard and conductor smaller than 4/0 ACSR is to be replaced.

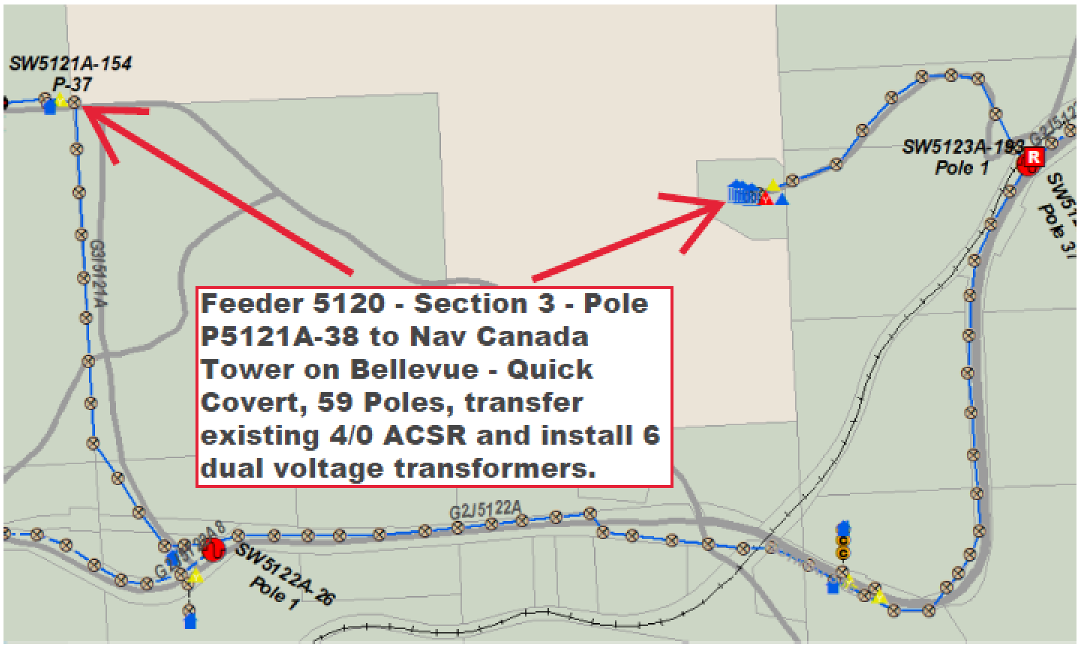
Section 1 – Intersection of Hwy 17 and Hwy 552 easterly on Hwy 552 to Recloser SW5121A-116 located on Bellevue Valley Road just east of Hwy 552. Line length is approximately 7.3 km, has 117 poles and 32 dual voltage transformers. There are multiple small single-phase laterals off the main feeder.



Feeder 5120 - Section 2 – Is that part of the 5120 feeder from Recloser SW5121A-116 located on Bellevue Valley Road to Pole P5121A-38 where the line turns 90 degrees and heads south across country towards Hwy 556. Line length is approximately 3.0 km, has 50 poles and 9 dual voltage transformers. There are multiple small single-phase laterals off the main feeder.

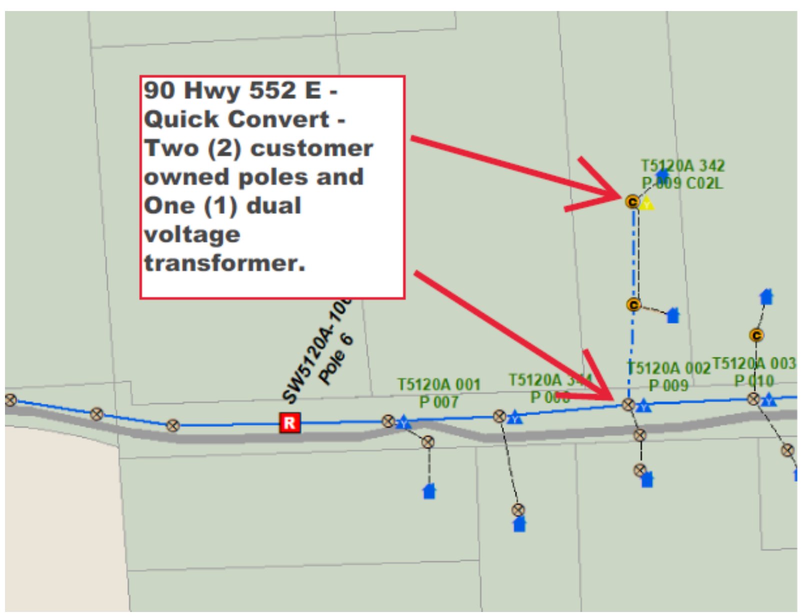


Feeder 5120 - Section 3 – Is that part of the 5120 feeder from Pole P5121A-38 where the line turns 90 degrees and heads south across country towards Hwy 556 to the Nav Canada Tower – Bellevue (Pole 5122A-37T10). Line length is approximately 4.7 km, has 59 poles and 6 dual voltage transformers. There are a few small single-phase laterals off the main feeder.

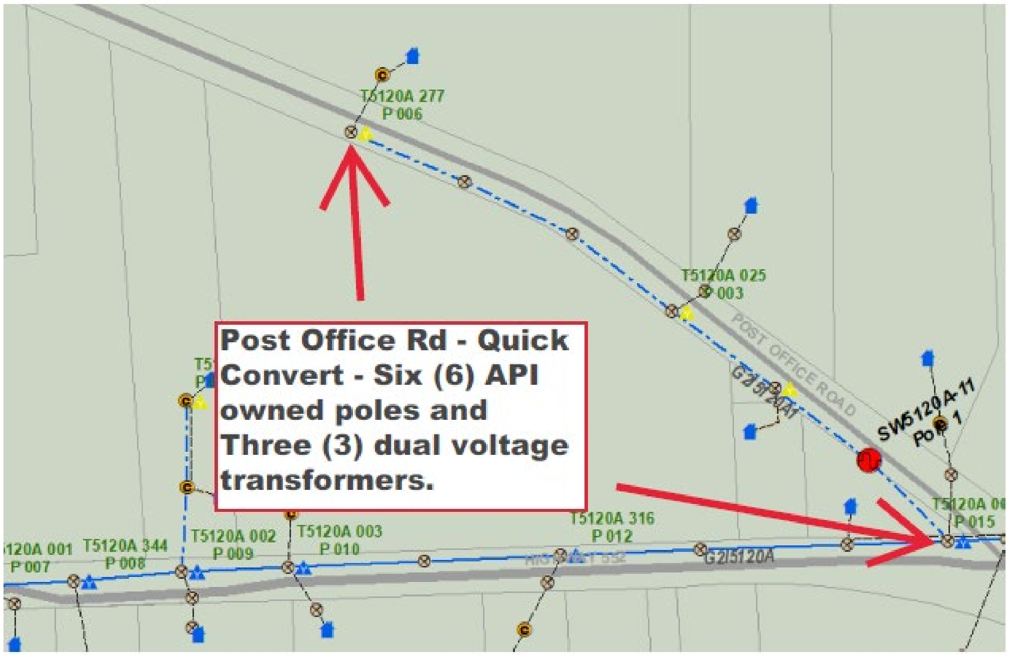


<u>Feeder 5120 – Section 1 – Small Single-Phase Laterals</u>

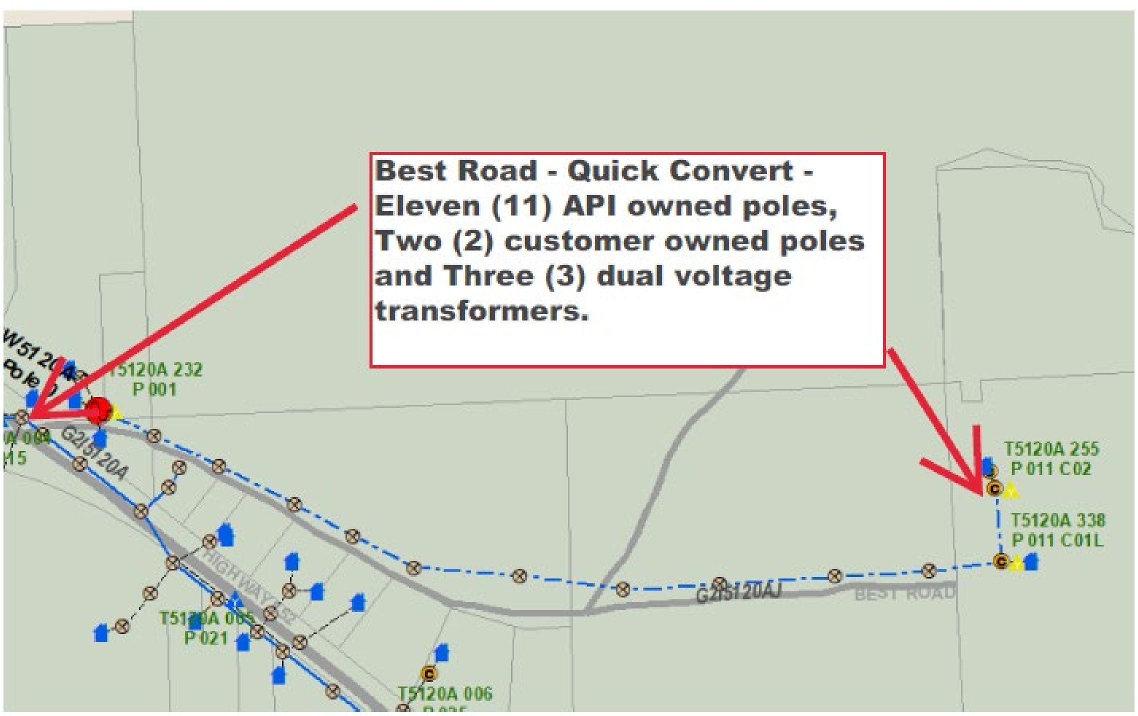
- 90 Hwy 552 E – Quick Convert - Two (2) customer owned poles and One (1) dual voltage transformer.



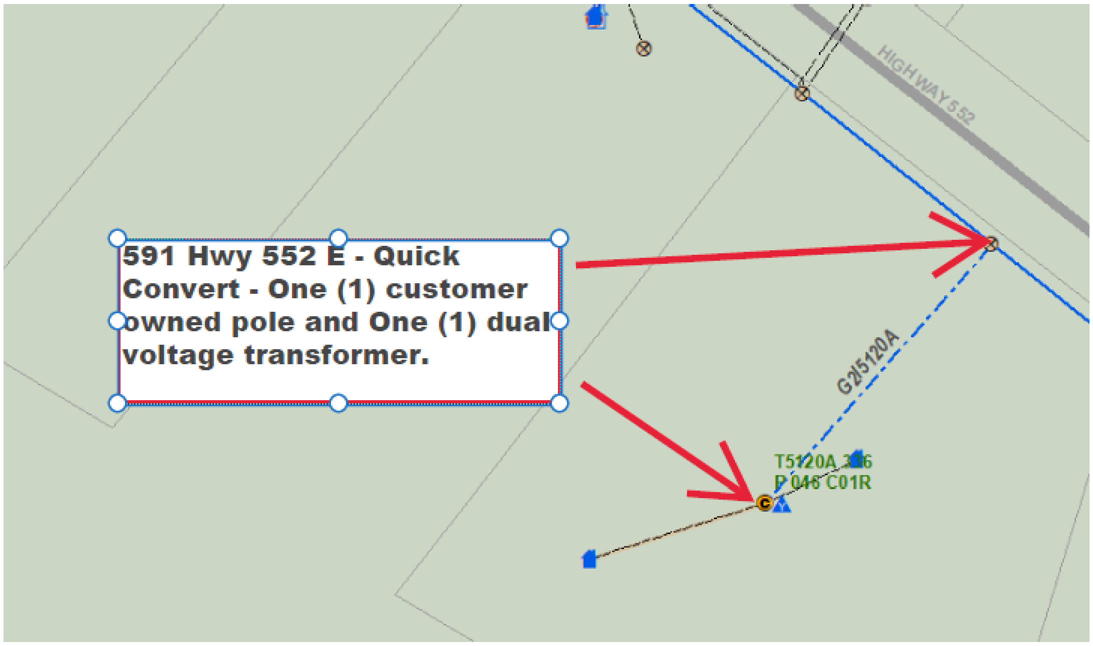
- Post Office Road - Quick Convert - Six (6) API owned poles and Three (3) dual voltage transformers.



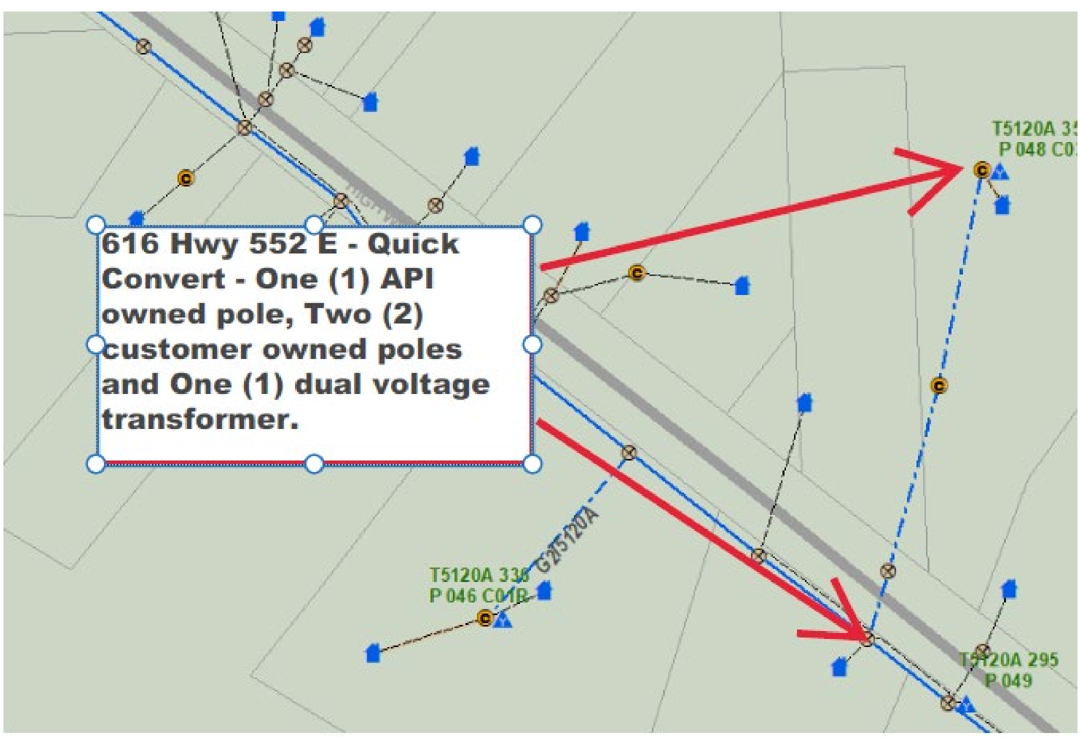
- Best Road - Quick Convert - Eleven (11) API owned poles, Two (2) customer owned poles and Three (3) dual voltage transformers.



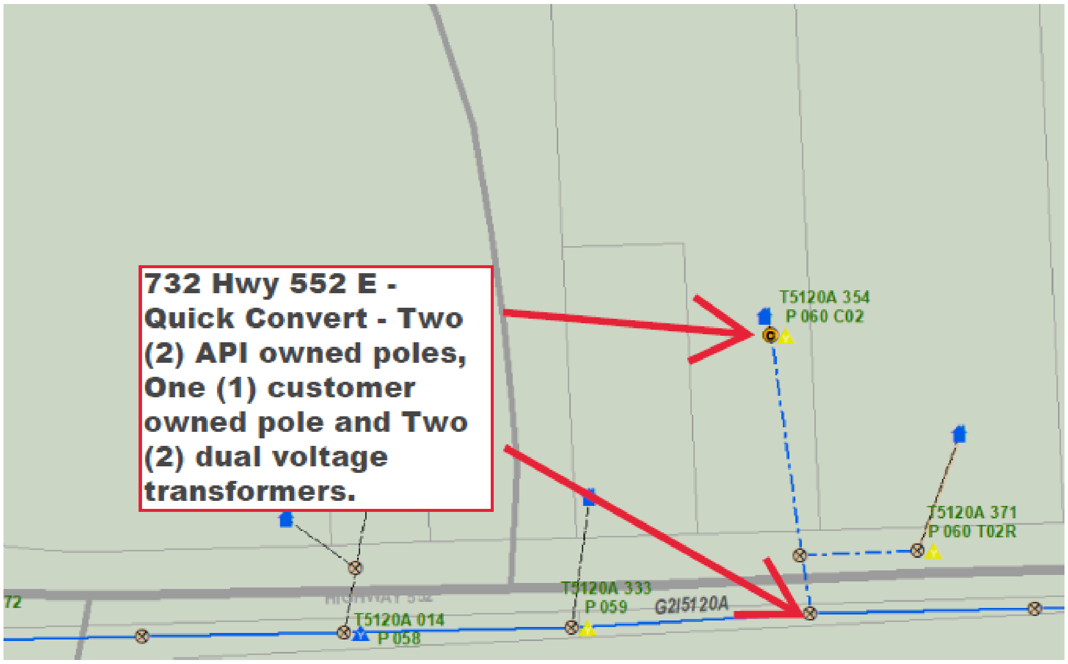
- 591 Hwy 552 E - Quick Convert - One (1) customer owned pole and One (1) dual voltage transformer.



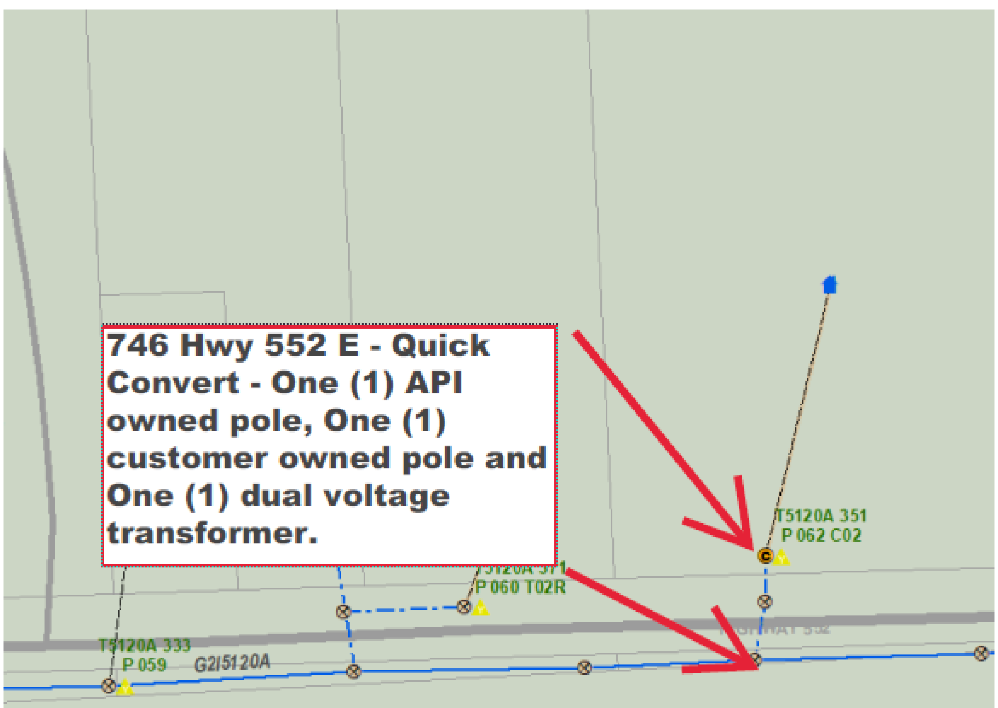
- 616 Hwy 552 E - Quick Convert - One (1) API owned pole, Two (2) customer owned poles and One (1) dual voltage transformer.



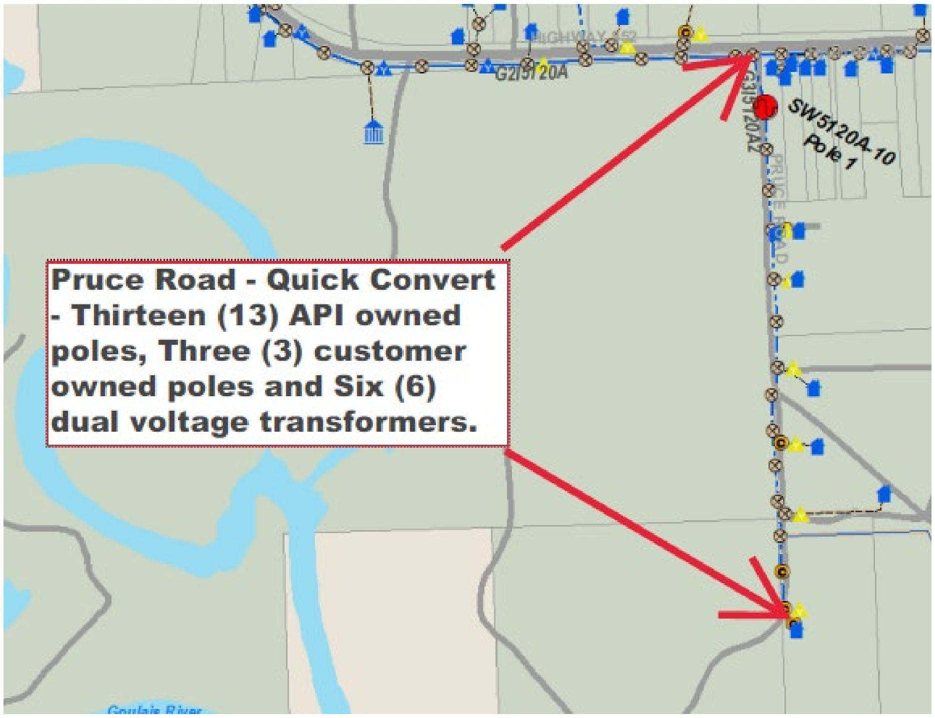
- 732 Hwy 552 E - Quick Convert - Two (2) API owned poles, One (1) customer owned pole and Two (2) dual voltage transformers.



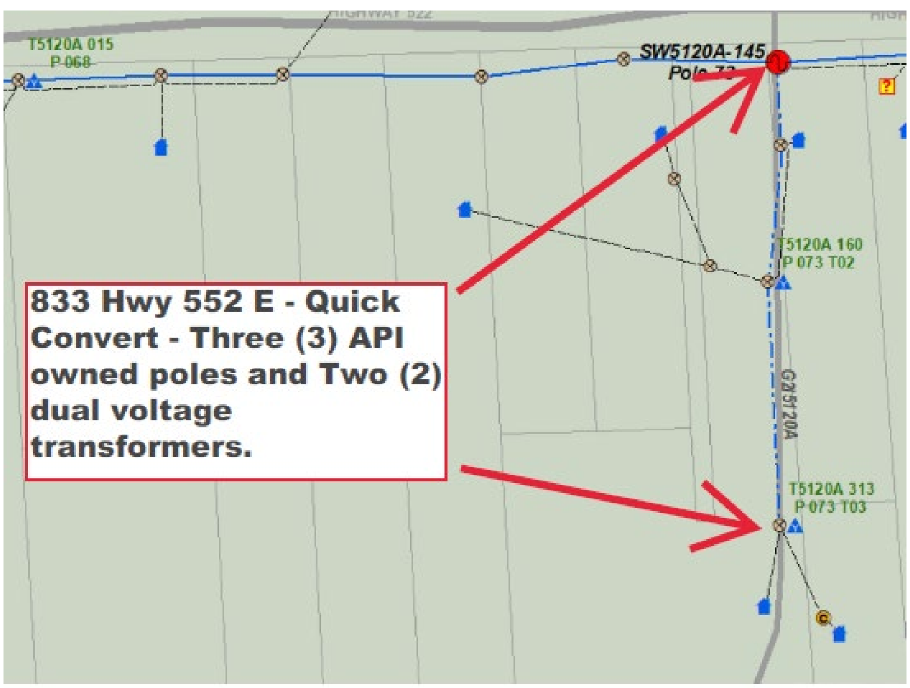
- 746 Hwy 552 E - Quick Convert - One (1) API owned pole, One (1) customer owned pole and One (1) dual voltage transformer.



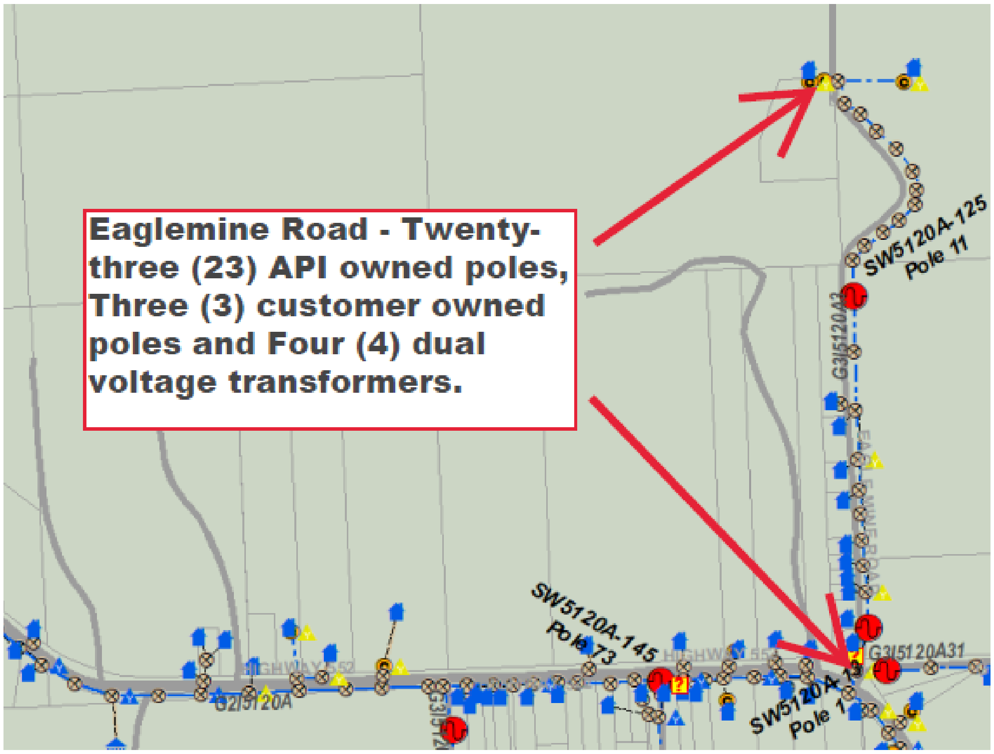
- Pruce Road - Quick Convert - Thirteen (13) API owned poles, Three (3) customer owned poles and Six (6) dual voltage transformers.



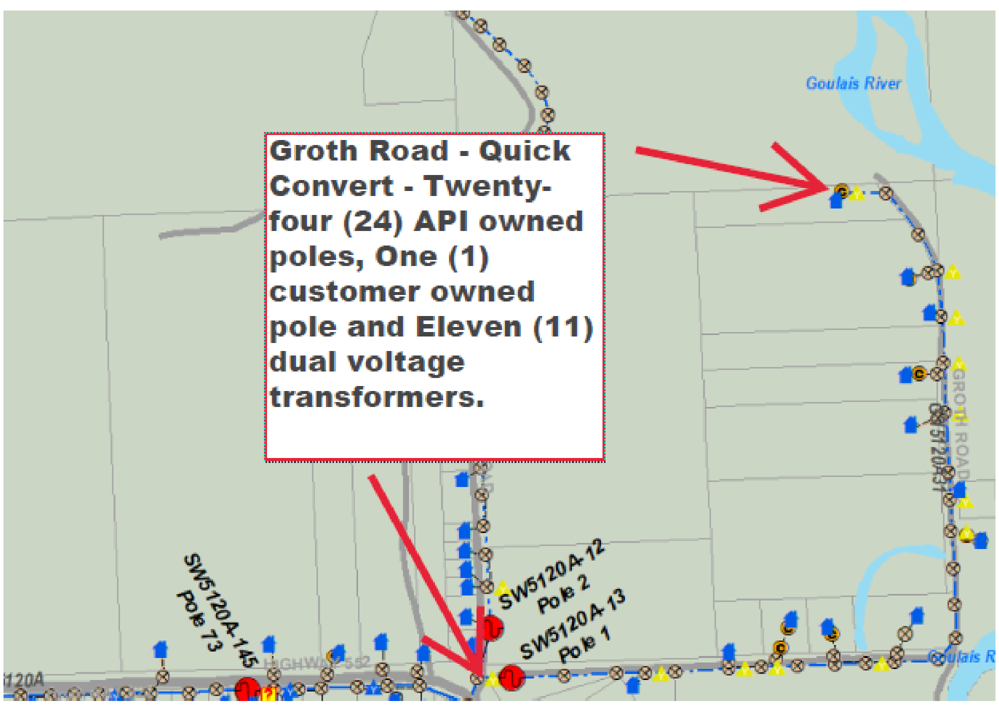
- 833 Hwy 552 E - Quick Convert - Three (3) API owned poles and Two (2) dual voltage transformers.



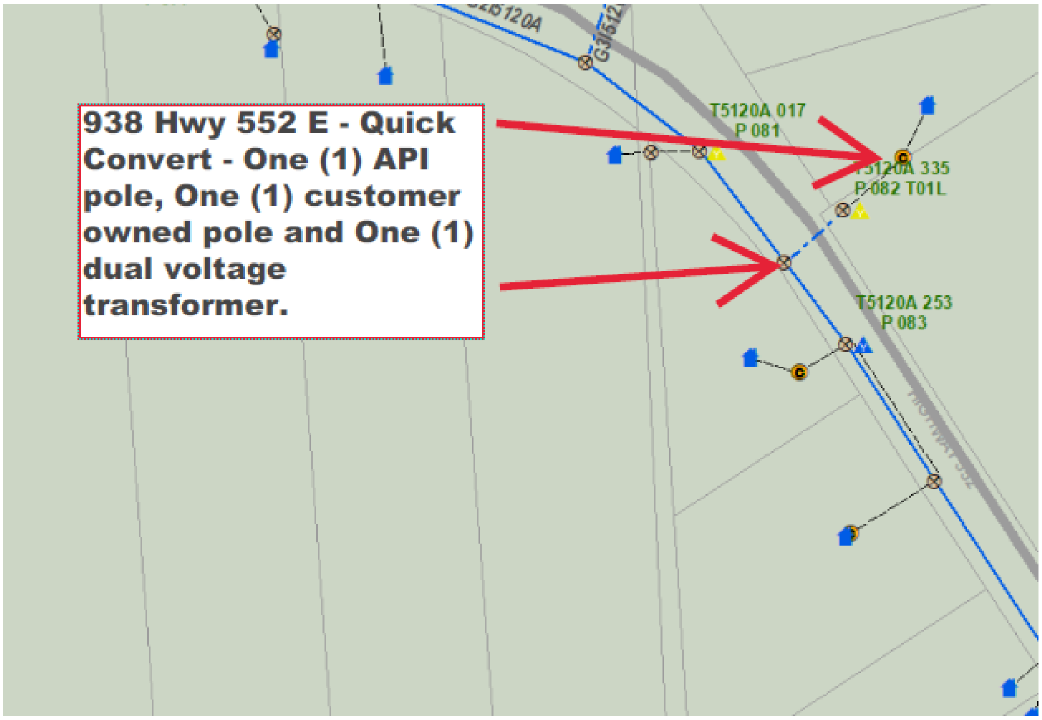
- Eaglemine Road - Twenty-three (23) API owned poles, Three (3) customer owned poles and Four (4) dual voltage transformers.



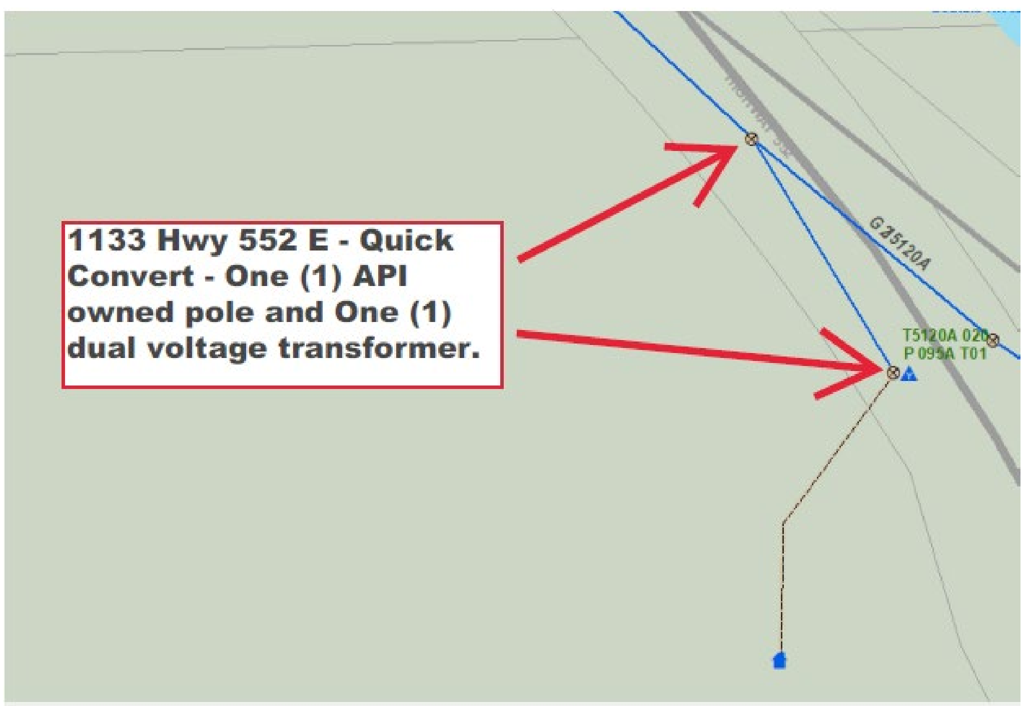
- Groth Road - Quick Convert - Twenty-four (24) API owned poles, One (1) customer owned pole and Eleven (11) dual voltage transformers.



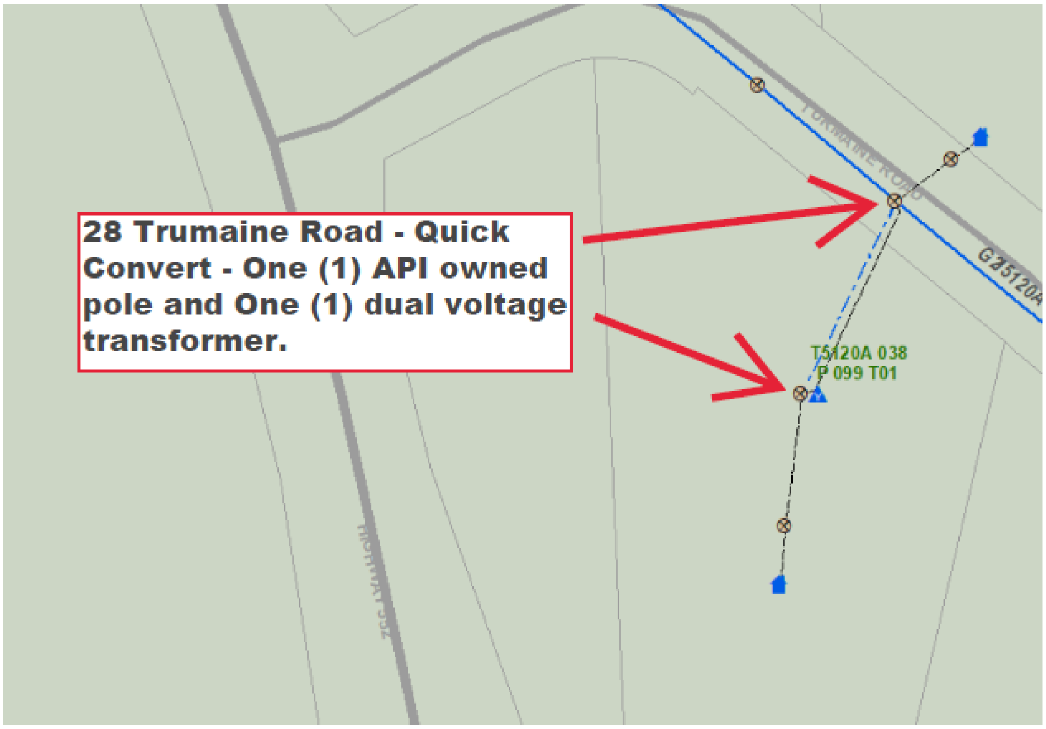
- 938 Hwy 552 E - Quick Convert - One (1) API pole, One (1) customer owned pole and One (1) dual voltage transformer.



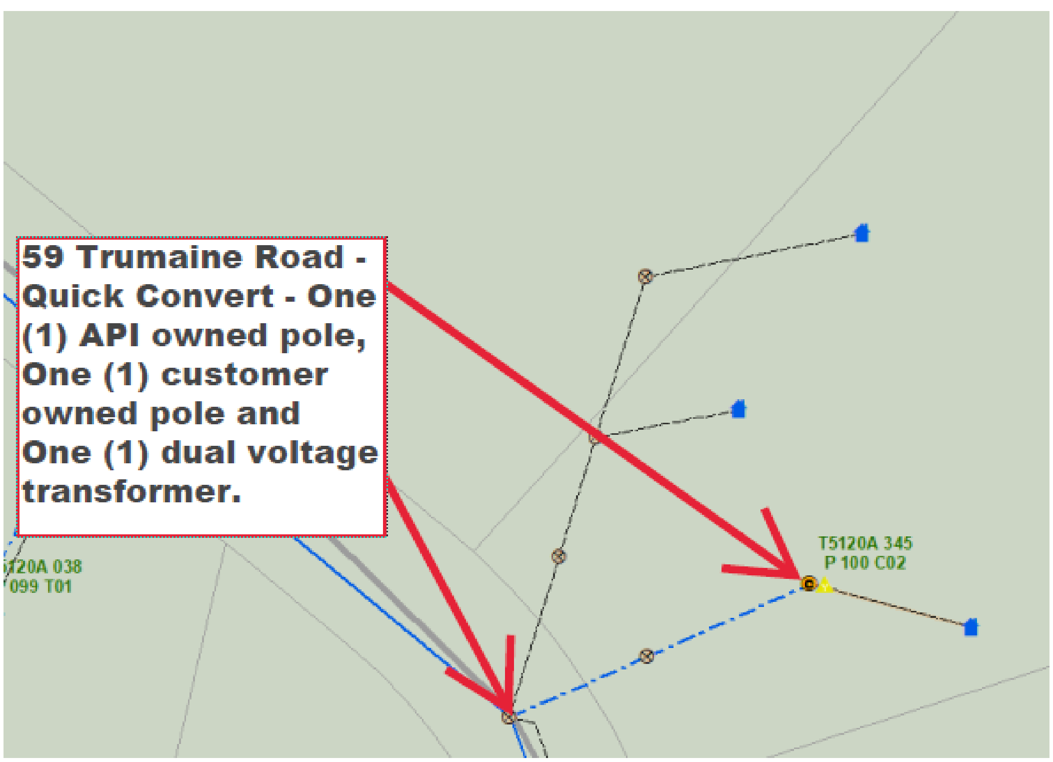
- 1133 Hwy 552 E - Quick Convert - One (1) API owned pole and One (1) dual voltage transformer.



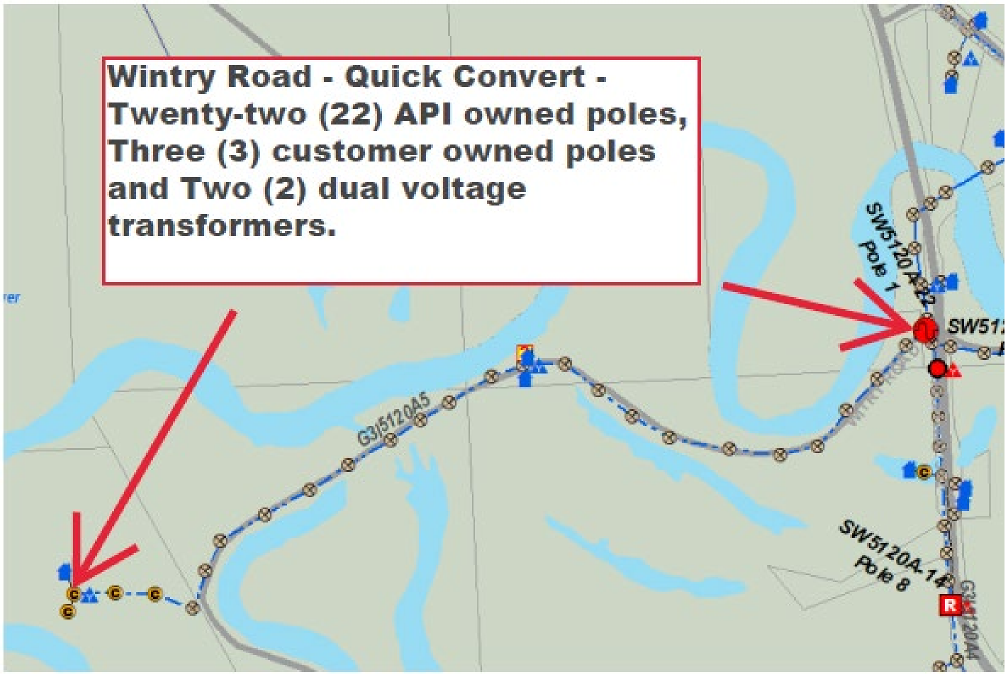
- 28 Trumaine Road - Quick Convert - One (1) API owned pole and One (1) dual voltage transformer.



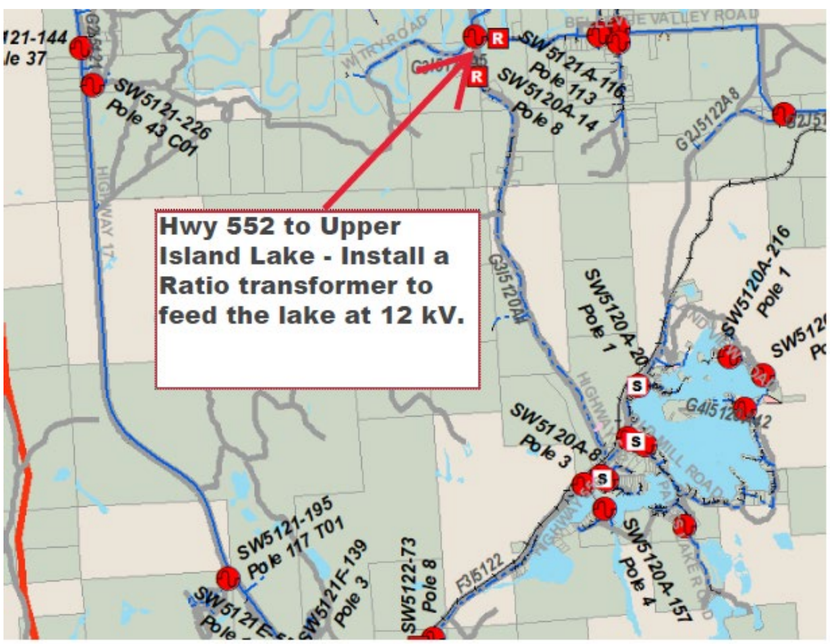
- 59 Trumaine Road - Quick Convert - One (1) API owned pole, One (1) customer owned pole and One (1) dual voltage transformer.



- Wintry Road - Quick Convert - Twenty-two (22) API owned poles, Three (3) customer owned poles and Two (2) dual voltage transformers.

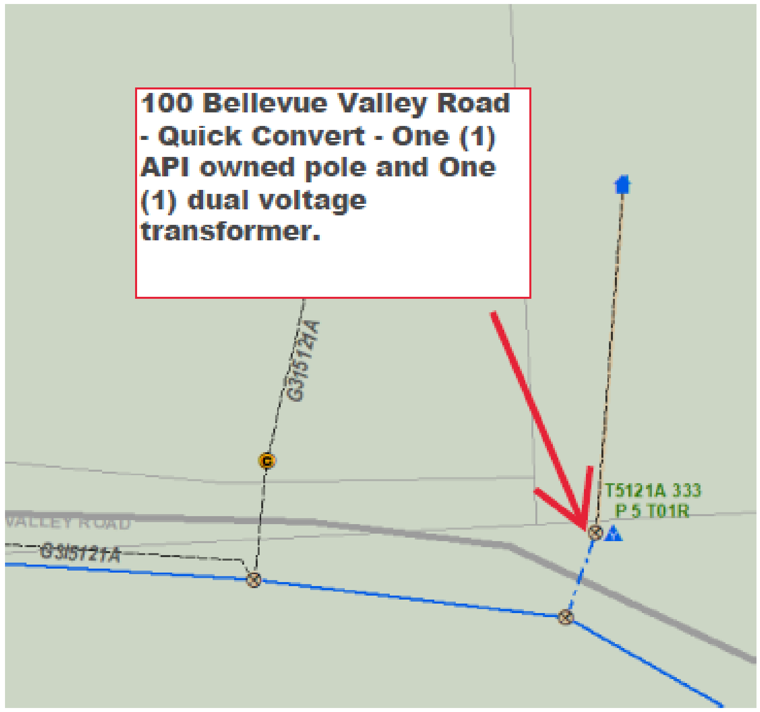


- Hwy 552 to Upper Island Lake - Install a Ratio transformer to feed the lake at 7.212 kV.

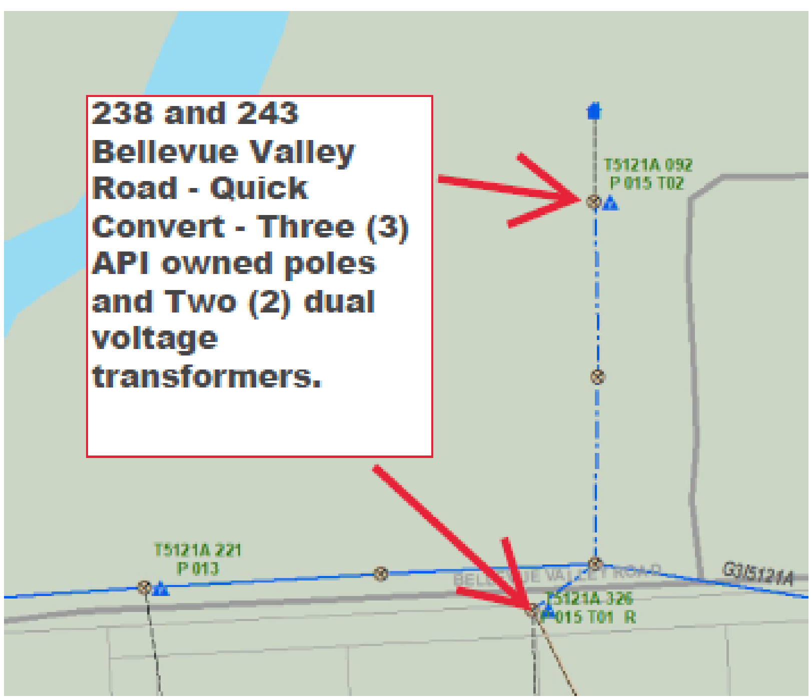


Feeder 5120 – Section 2 – Small Single-Phase Laterals

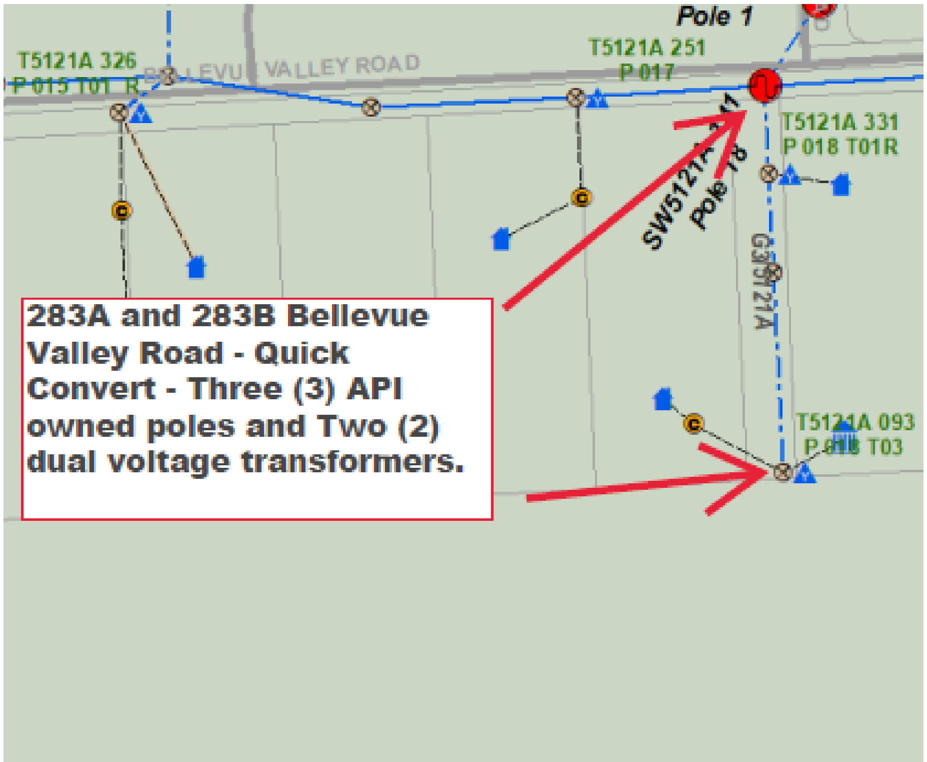
- 100 Bellevue Valley Road - Quick Convert - One (1) API owned pole and One (1) dual voltage transformer.



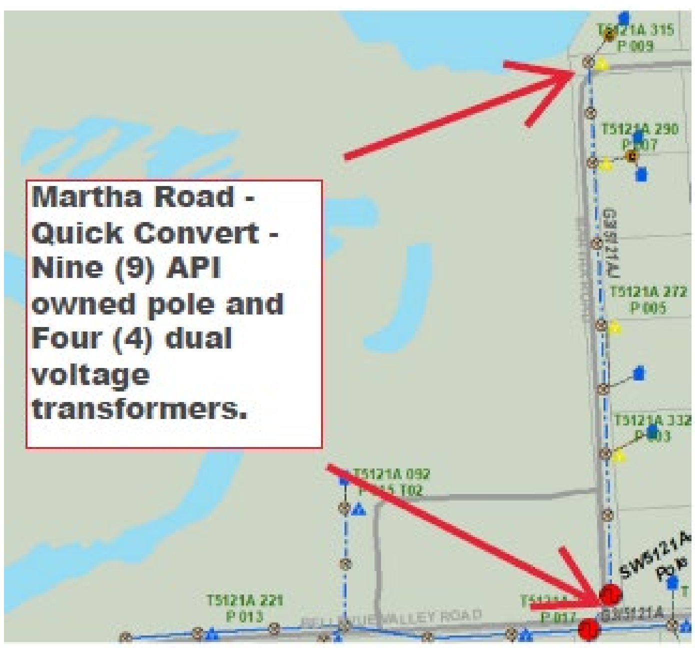
- 238 and 243 Bellevue Valley Road - Quick Convert - Three (3) API owned poles and Two (2) dual voltage transformers.



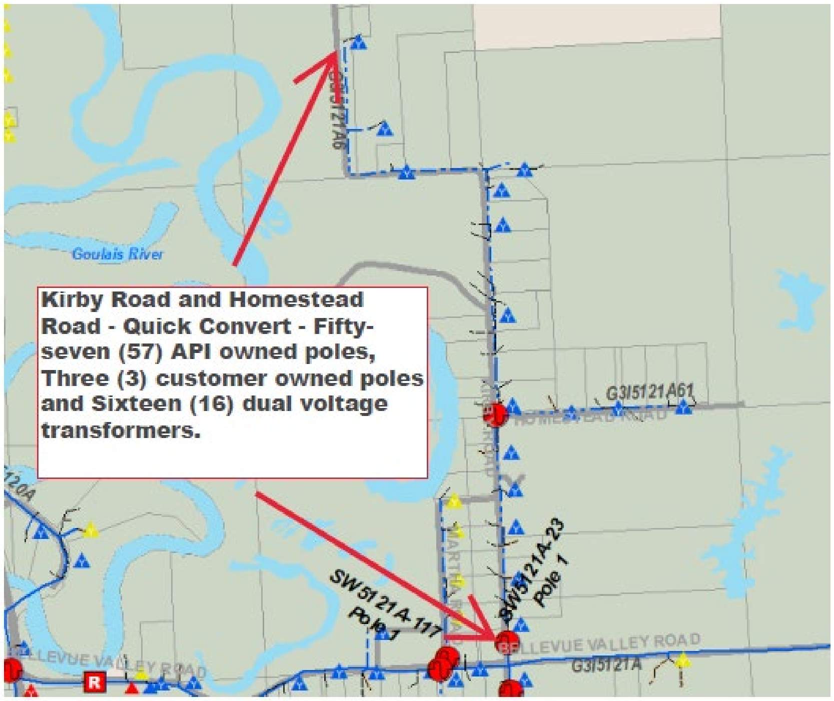
- 283A and 283B Bellevue Valley Road - Quick Convert - Three (3) API owned poles and Two (2) dual voltage transformers.



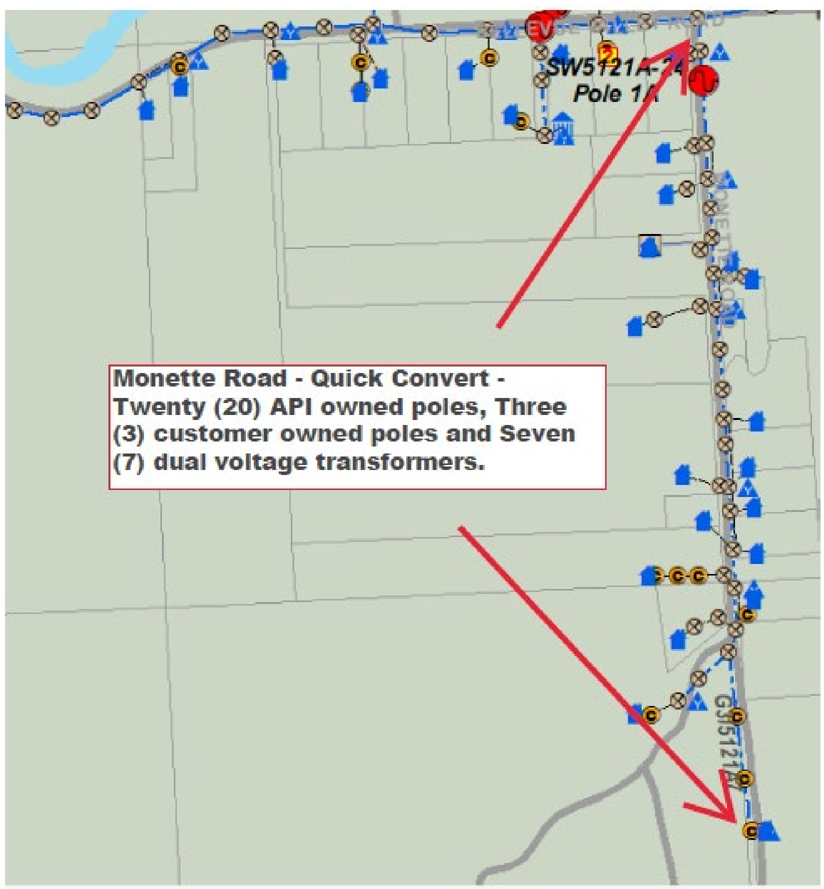
- Martha Road - Quick Convert - Nine (9) API owned pole and Four (4) dual voltage transformers.



- Kirby Road and Homestead Road - Quick Convert - Fifty-seven (57) API owned poles, Three (3) customer owned poles and Sixteen (16) dual voltage transformers.

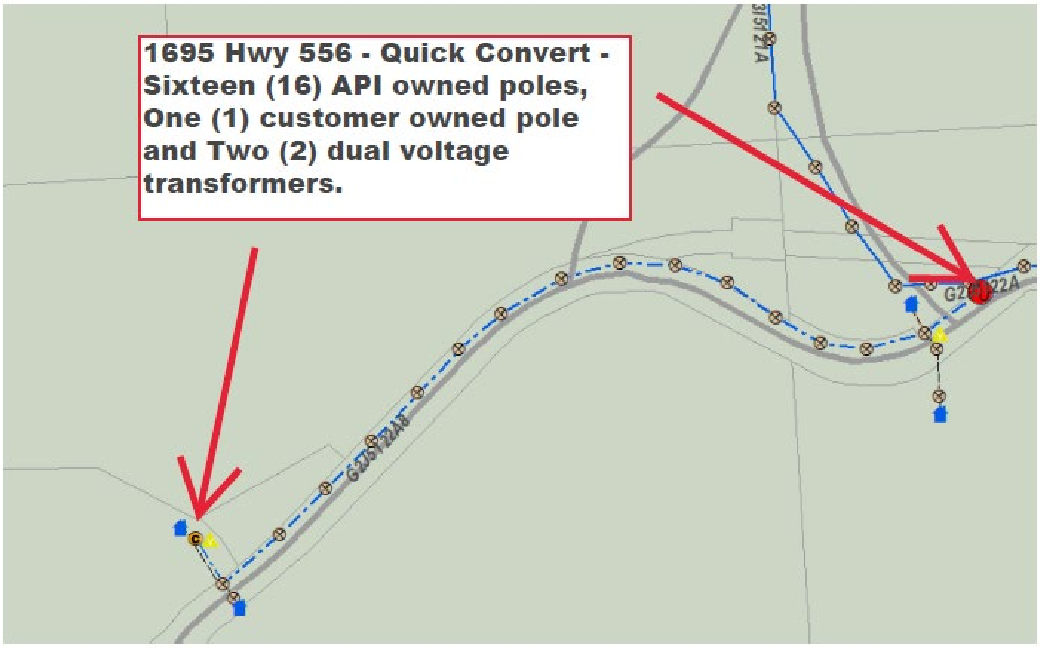


- Monette Road - Quick Convert - Twenty (20) API owned poles, Three (3) customer owned poles and Seven (7) dual voltage transformers.

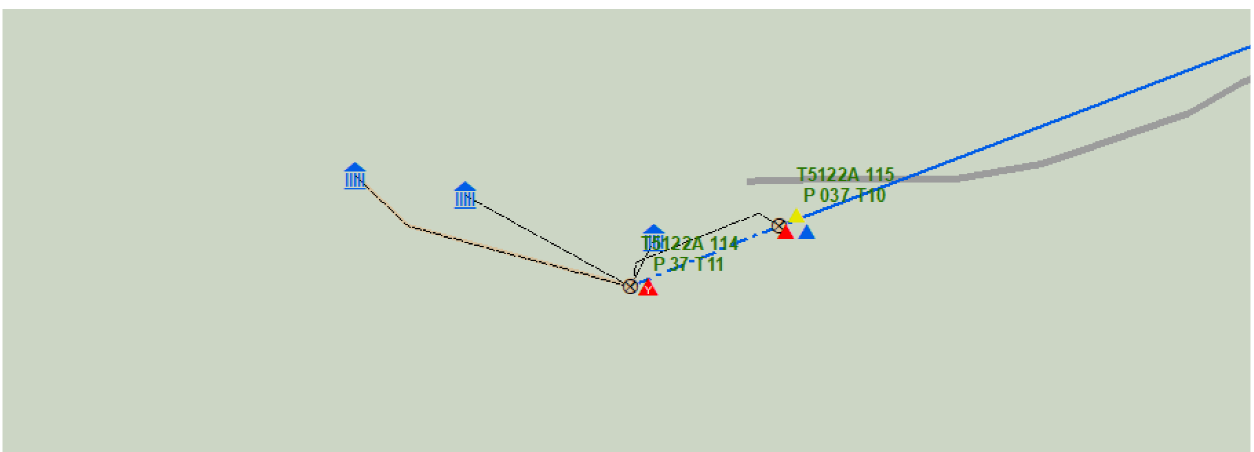


Feeder 5120 – Section 3 – Small Single-Phase Laterals

- 1695 Hwy 556 - Quick Convert - Sixteen (16) API owned poles, One (1) customer owned pole and Two (2) dual voltage transformers.



- Nav Canada Tower Bellevue - Quick Convert - One (1) API owned pole and Four (4) dual voltage transformers.



Voltage Conversion Projects – Goulais DS – O to P

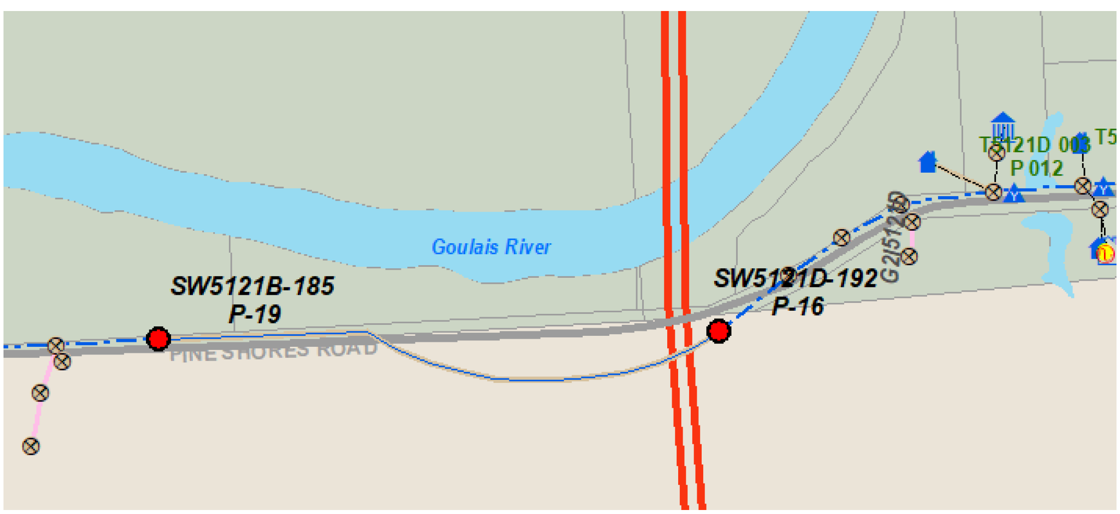
- 1-Phase line Easterly on Pineshores Road from Hwy 17 to Goulais Bay Road

    - Section 1 – Single-Phase overhead from Hwy 17 easterly to the 115 kV line.

Quick Convert single-phase line on Pineshore Road easterly from Highway 17 to where it dips underground at the 115 kV line. Re-use existing 1/0 ACSR. Line length is approximately 1.2 kilometers, has 16 poles (replace one 1971 pole) and seven (7) API owned dual voltage transformers. Replace existing recloser with 25 kV unit.

- Section 2 – Single-Phase underground line under 115 kV line.

Based on discussions with API staff it is assumed that the cable installed is 28 kV 2/0 Al and therefore no action required, except perhaps to change lightning arresters at each dip pole if applicable.

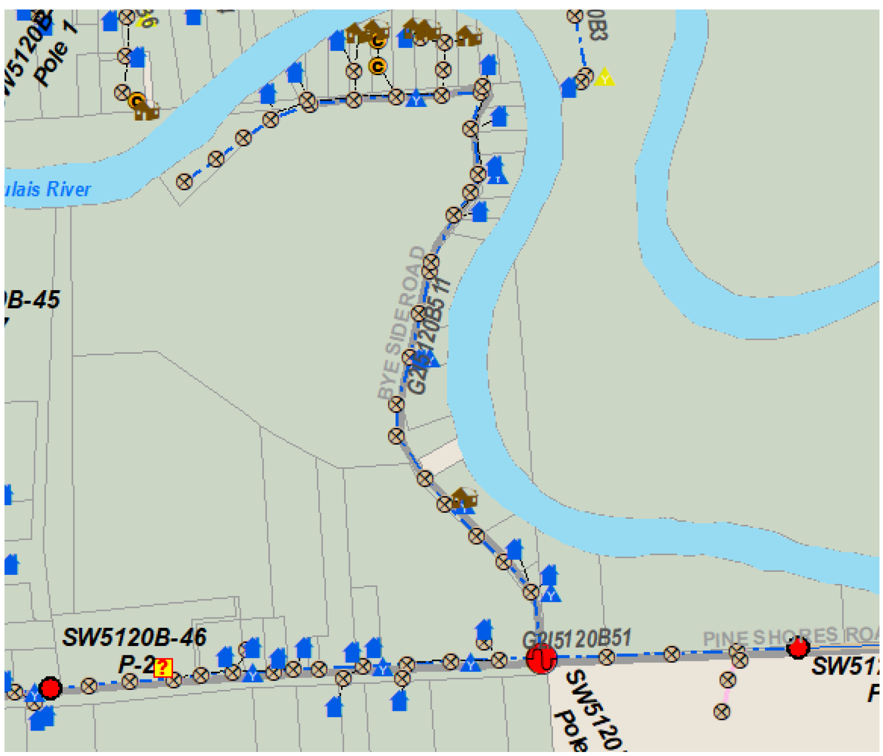


- Section 3 – Single-Phase overhead easterly on Pineshores Road from 115 kV line to Goulais Bay Road.

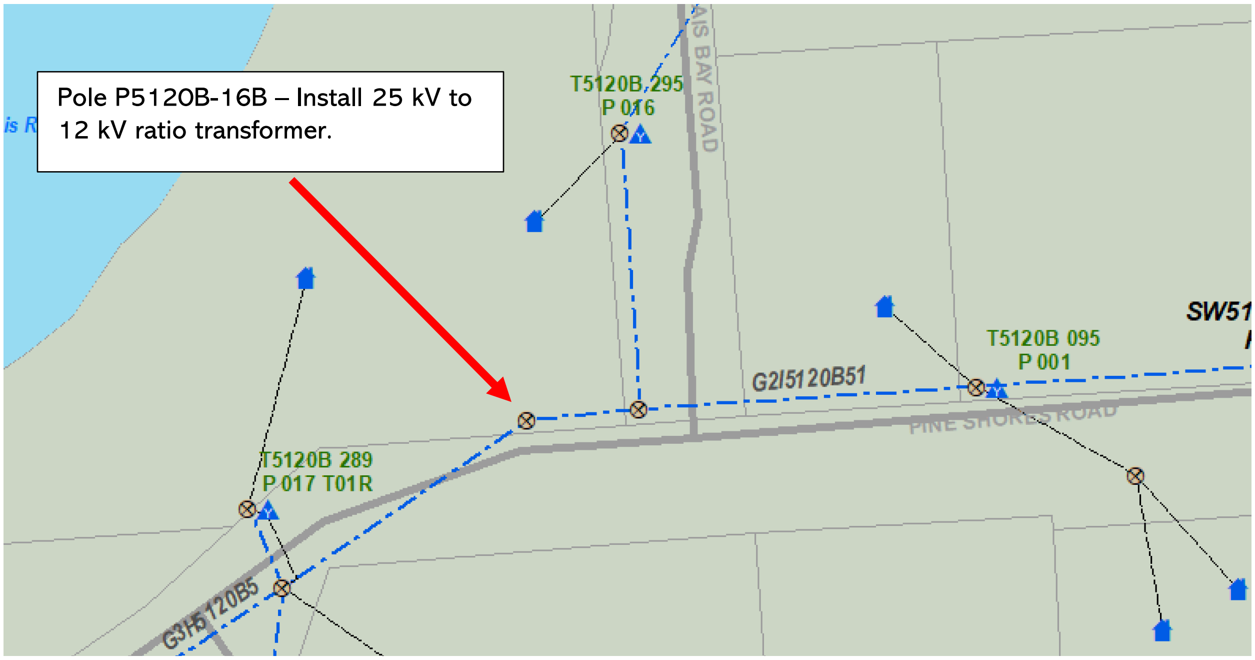
Quick Convert single-phase line on Pineshore Road from Highway 17 easterly to where it intersects with the existing single-phase line on Goulais Bay Road. Re-use existing 1/0 ACSR. Line length is approximately 1.5 kilometers, has 19 poles (replace seven 40+ year old poles) and four (4) API owned dual voltage transformers. There is one single-phase lateral off the main feeder.

- Single Phase Lateral – Bye Side Road

Quick Convert single-phase line on Bye Side Road. Re-use existing 1/0 ACSR. Line length is approximately 1.4 kilometers, has 24 poles (replace four 40+ year old poles) and five (5) API owned dual voltage transformers. There is one single-phase lateral off the main feeder.



- Pole 5120B-16B – Pineshores Road just east of Goulais Bay Road Hwy 17 – Install 25kV to 12 kV ratio transformer.

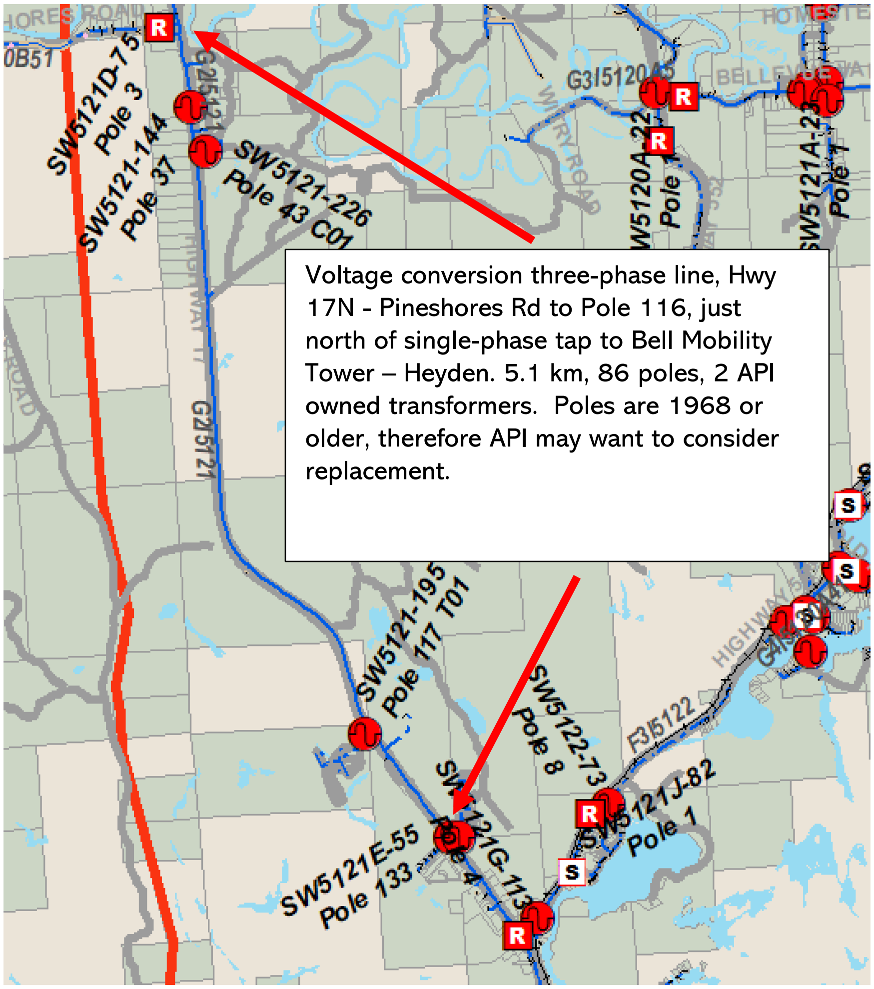


Voltage Conversion Projects – Goulais DS – O to Q

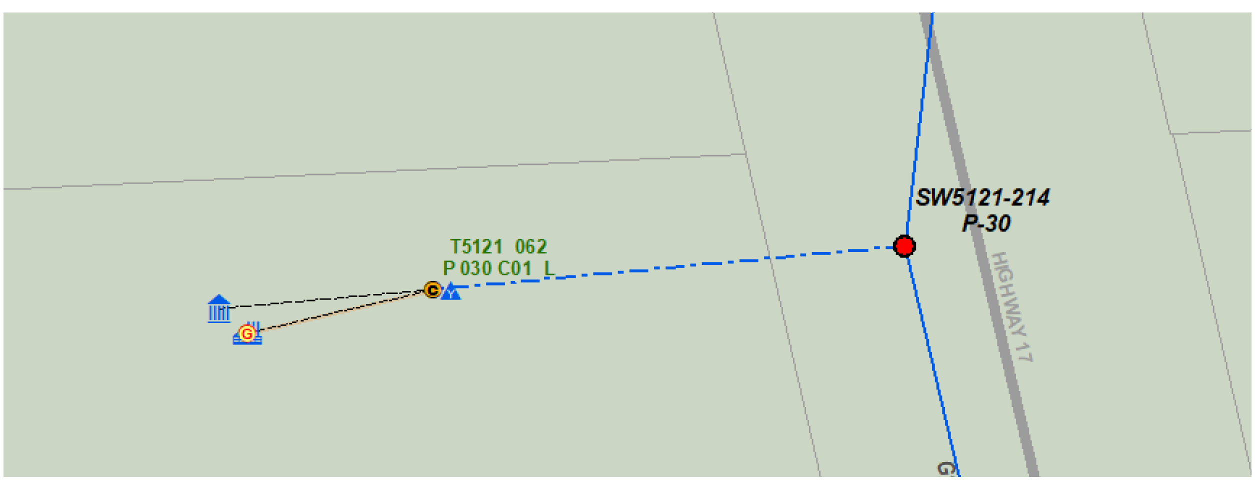
- 3-Phase line from Southerly on Hwy 17 from Pineshore Rd to Pole 116

Quick Convert three-phase line on Highway 17 south from the intersection of Pineshore Road to pole 116, just north of the single-phase tap to the Bell Mobility Tower at Heyden. Line length is approximately 5.1 kilometers, has 86 poles and two (2) API owned dual voltage transformers. There are multiple small single-phase laterals off the main feeder.

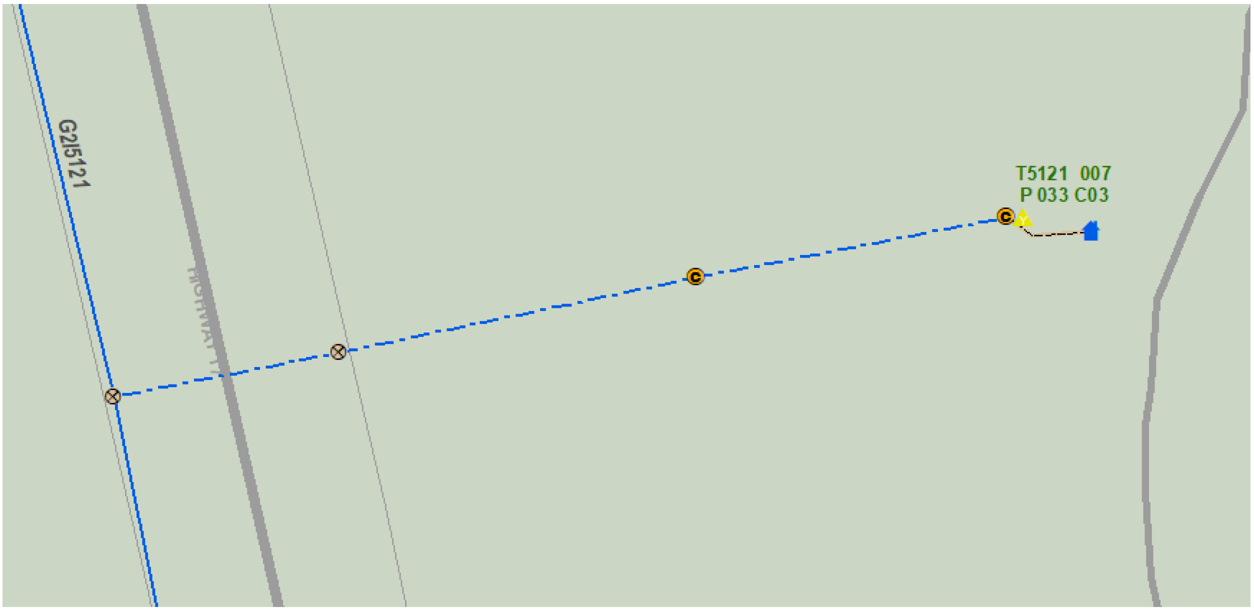
Also included in the Major Projects list for consideration is replacement of all 1968 or older poles, which is assumed to be all 86 poles.



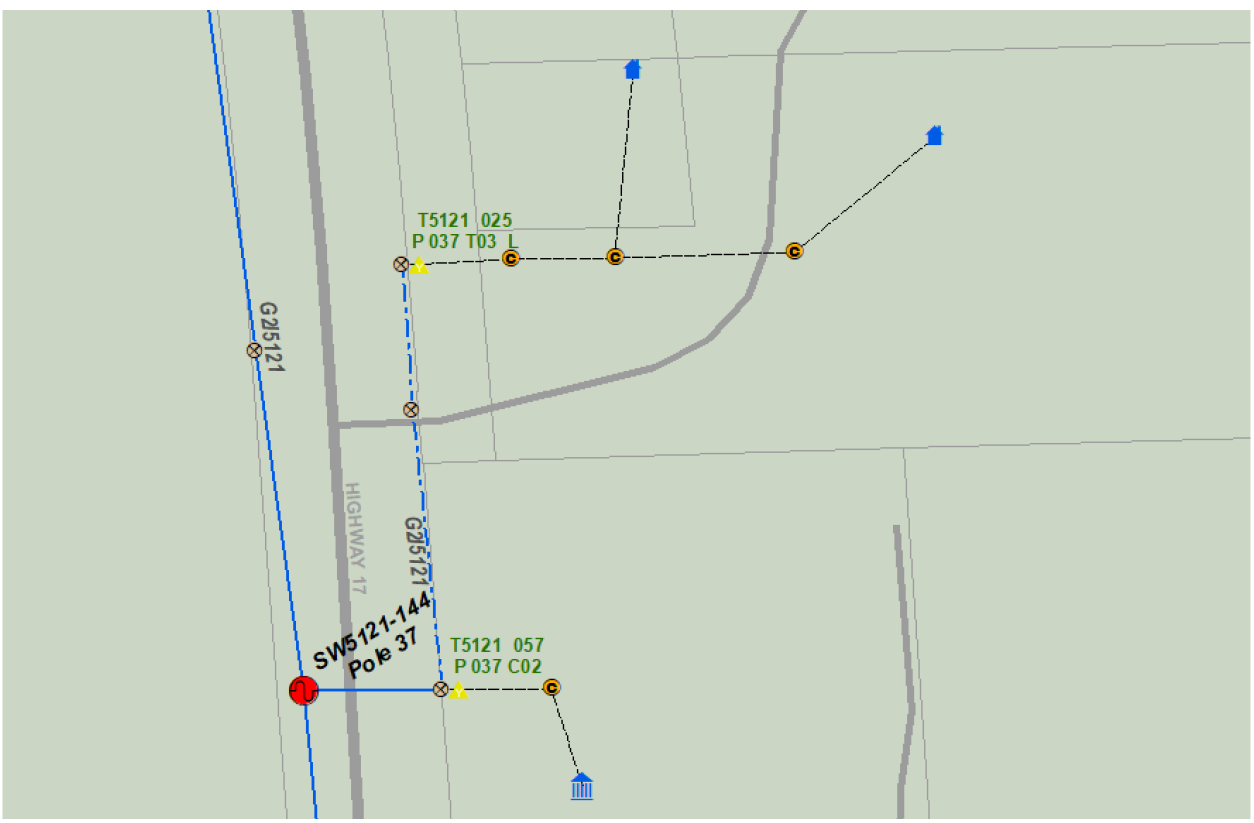
- 2771 Hwy 17 - Quick Convert customer owned single phase lateral to Superior Energy Solutions – 1 Customer owned pole and 1 dual voltage transformer.



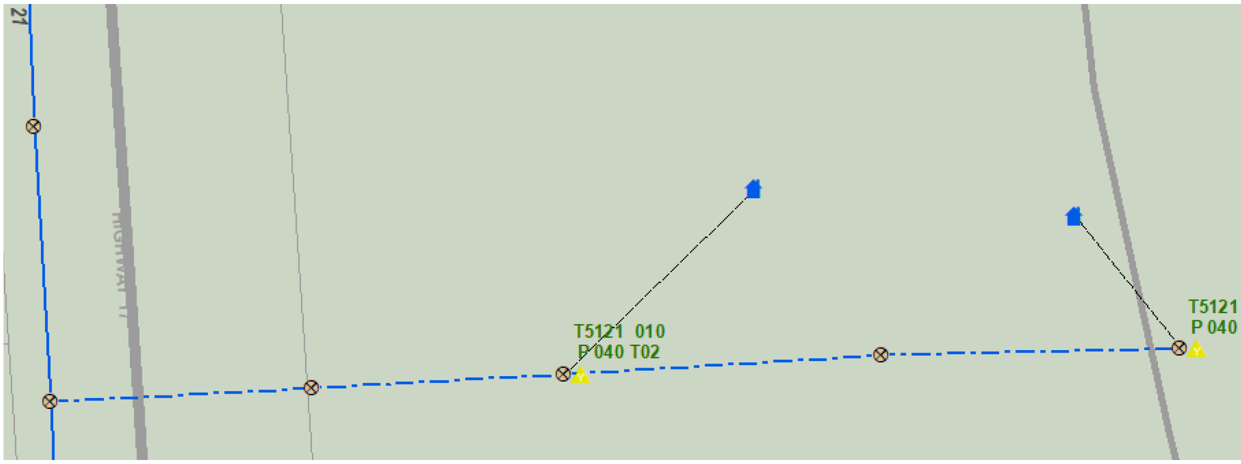
- 82 Lumber Lane - Quick Convert single phase lateral – 1 API owned pole and 2 Customer owned poles and 1 dual voltage transformer.



- 2632 Hwy 17 and 34 and 36 Elliott Lumber Road - Quick Convert single phase lateral – 3 API owned poles and 1 dual voltage transformer.

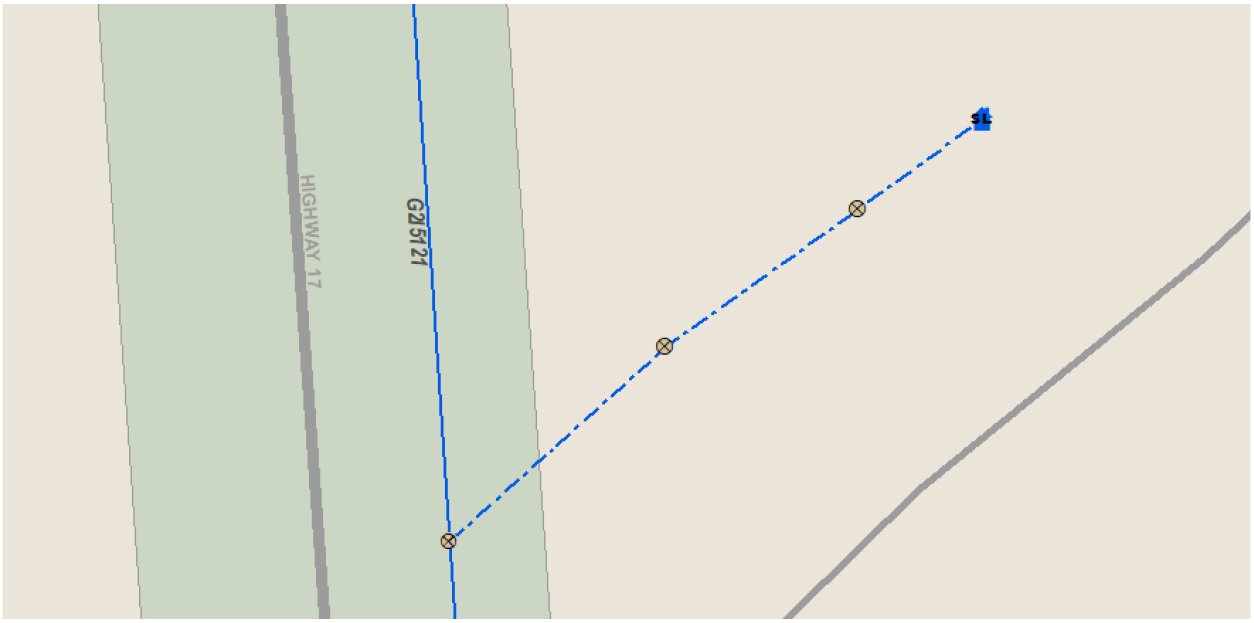


- 2528A Hwy 17 - Quick Convert single phase lateral – 4 API owned poles and 2 dual voltage transformers.

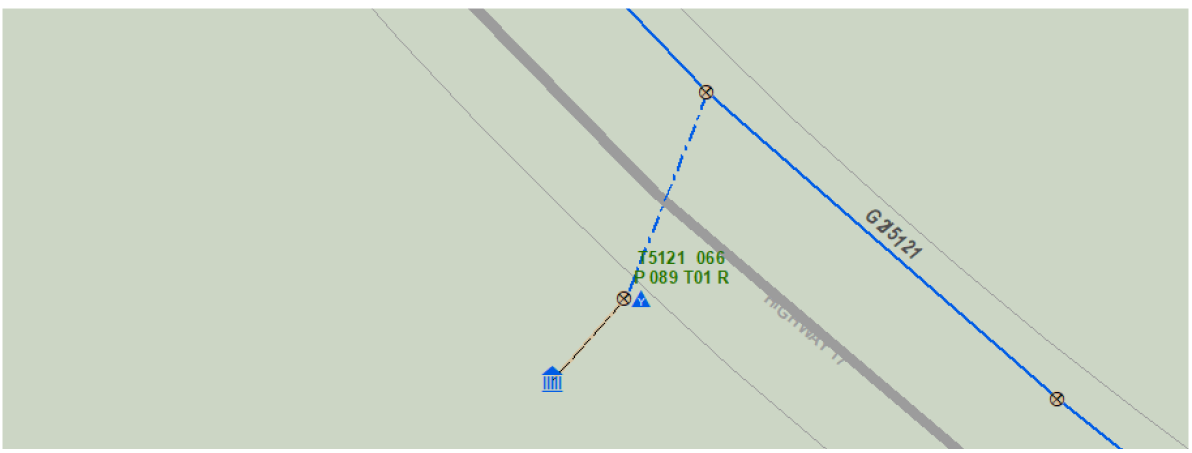


- 2528ABCD Hwy 17 – Blueberry Hill Campground - Quick Convert single phase lateral – 1 API owned pole and 4 Customer owned poles, an unknown number of customer owned transformers.

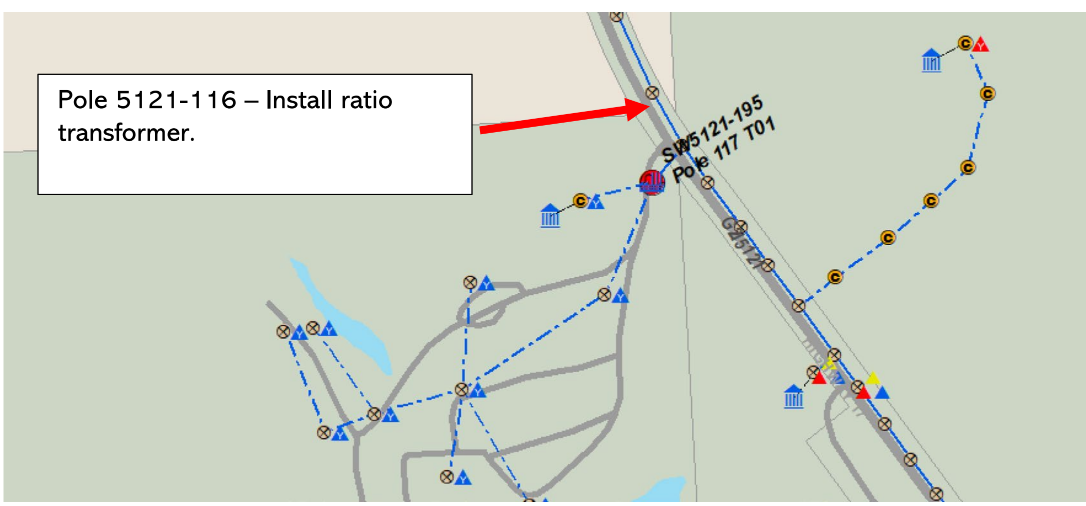
- Pole 5121-58 Hwy 17 – Algoma Central Railway unmetered load - Quick Convert single phase lateral – 3 API owned poles, and unknown dual voltage customer owned transformers,



- 1671 Hwy 17 – Quick Convert single phase lateral – 1 API owned pole and 1 dual voltage transformer.



- Pole 5121-116 Hwy 17 – Install 25kV to 12 kV ratio transformer.



5.2. Echo River 34.5kV Loop Reinforcement and Switching Automation

Section 4.7.4 analyzed the contingency backup between ER1 & ER2 and recommended to reconduct ~13km 3/0 34.5kV lines as 477 AAC (or ACSR) and install a capacitor bank along the 34.5kV Loop. Please refer to this section for details.

Other than the conductor size upgrade and reactive power compensation, considering the relatively large customer count and density in this area, this study performed an analysis on the feasibility of deploying a switching automation scheme.

In the current API protection and control scheme, protective devices are manually reset by dispatching field crew following any tripping event. This operation significantly extends the outage restoration time, especially for the customers that are supplied by unaffected segments of the feeder. The main two reasons that API falls behind of the utility trend to deploy distribution automation are 1) lack of SCADA/remote control of protective devices 2) majority of feeders are radial and the common FLISR (Fault Location, Isolation, and Service Restoration) scheme is not applicable.

API is currently in progress of establishing its SCADA network and plans to operate and remote control the available SCADA devices in the near future. This provides an opportunity to improve the reliability in the areas with looped feeders by deploying a full distribution automation (DA) scheme that can automatically implement the FLISR function or at least installing several automated switches that can be operated remotely and upgraded into a DA system if budget allows.

Echo River 34.5kV Feeder ER1 and ER2 are the only looped feeders with a significant count of 6202 customers downstream. Figure 21 below illustrates the service areas and the number of customers for each area. The division of the service area is based on its supply; each service area below can only be switched as a whole part and not feasible to be further sectionized:

- Debarats T1: normally supplied from ER1; ER2 is the available backup supply.
- Debarats T2: normally supplied from ER2; ER1 is the available backup supply.
- Bar River T1 (St. Joseph Island): normally supplied from ER2; ER1 is the available backup supply.
- Garden River: normally supplied from GR1 tapped-off ER2; No backup.
- Bruce Mines: normally supplied from DB1 tapped-off ER1; No backup.
- ER1 & ER2: ER1 and ER2 form a loop starting from the Echo River TS and ending at the Desbarats DS; there are two tie locations where API has the full control; one is at the Bar River DS and the other one is at the Desbarats DS. The feeder breakers at the Echo River TS are under the control of HOSSM.
- GR1: this 34.5kV section supplies Garden River DS and has no direct customer.
- DB1: this 34.5kV section not only supplies Bruce Mines DS, but also supplies a large industrial customer – Trap Rock.

After a close examination of the feeder configuration and feasible division of service areas, i.e., switchable chunk of line sections, this study proposes a Distribution Automation plan which can be phased-in based on priority and budget limit. The plan includes 11 participating protective devices which are located at three locations as illustrated by Figure 22:

- Point A (T-Intersection of Echo Lake Road): Install DA1, DA2, and DA11 at each of the lateral side of the T-Section.
- Bar River DS: Install DA3, DA4, and DA5 (see "Detail - Desbarats DA Devices")
- Desbarats DS: Install DA6, DA7, DA8, DA9, and DA10 (see Detail – Bar River DA Devices)

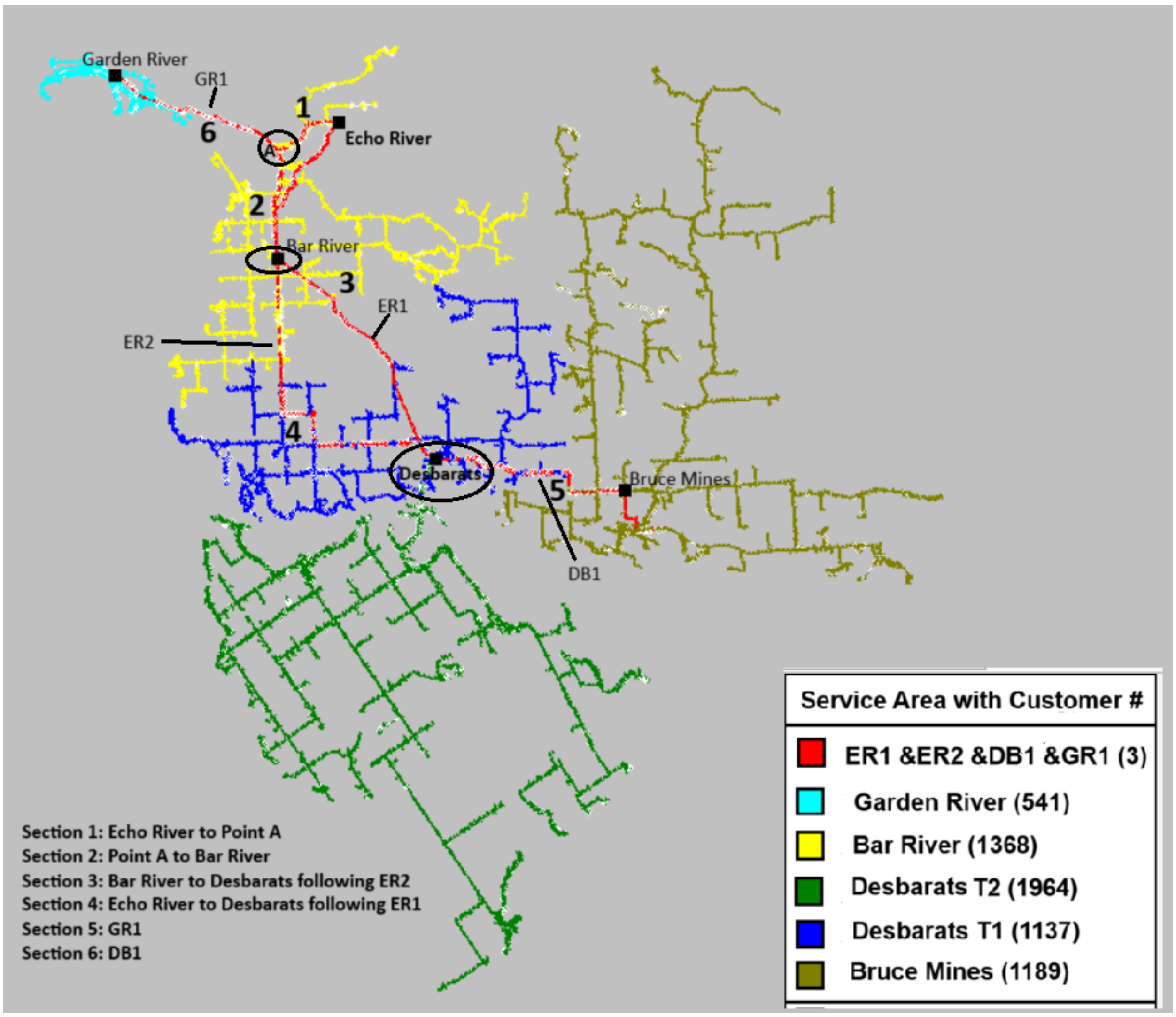


Figure 21: Echo River Service Area and Section Division

It is recommended all DA devices should offer over-current protection and equip with "loss of voltage" sensors (or proper alternatives) at both the line side and the load side; the capability for voltage measurement provides the highest level of flexibility for the distribution automation and the purpose of restoring power to as many loads as possible in the event of a fault or loss of a source.

Out of the above 11 locations for the proposed DA devices, if a protective device already exists, depending on the budget and phases, it can be either upgraded or retrofitted into a device with all required FLISR features, or left as is and becomes a participating device only, i.e., providing the status and analog readings, but not responding to the request from the automation system.

It is recommended to deploy the automation plan in phase following the sequence below:

- **Phase 1:** install DA3, DA4, DA5 at Bar River DS, and commission the SCADA control so they are all remotely operable.
- **Phase 2:** install DA6, DA7, DA8 at Desbarats DS; at the proposed locations for DA9 and DA10, there are existing protective devices SW052 and SW2005. These two devices are not in the 34.5kV loop and can be left as participating devices only. Commission all devices in SCADA to make them remotely operable.
- **Phase 3:** install DA1 and DA2 at the T-Section near the Echo Lake Road; at the proposed location for DA11, there is an existing protective device SW038. This device is not in the 34.5kV loop and can be left as a participating device only. Commission all devices in SCADA.
- **Phase 4:** purchase SCADA “FLISR” license and configure the distribution automation system upon all the 11 devices in above steps; in addition, HOSSM-owned ER1 & ER2 feeder relays should become participating devices as well. The total 13 devices will form a robust distribution automation network.

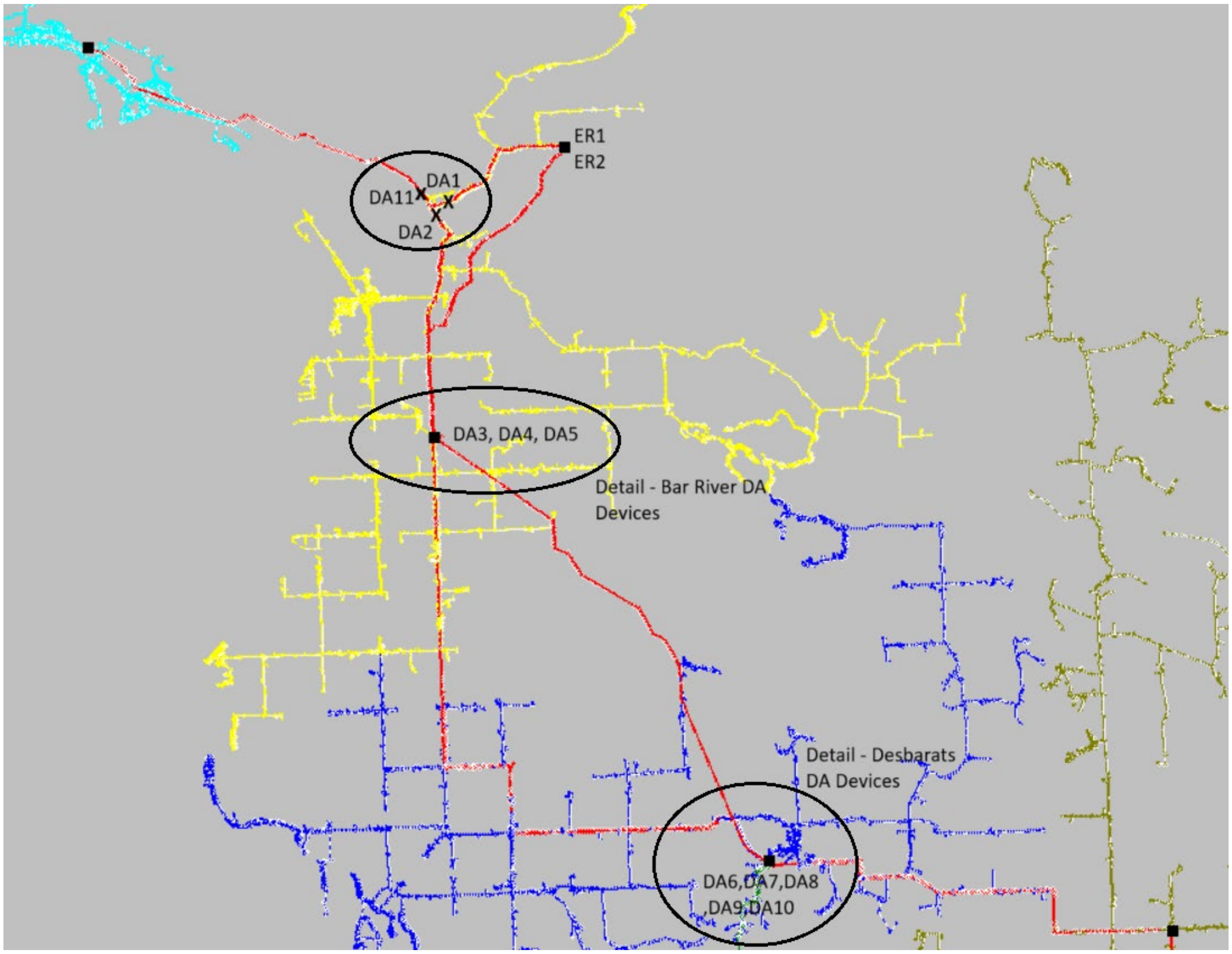
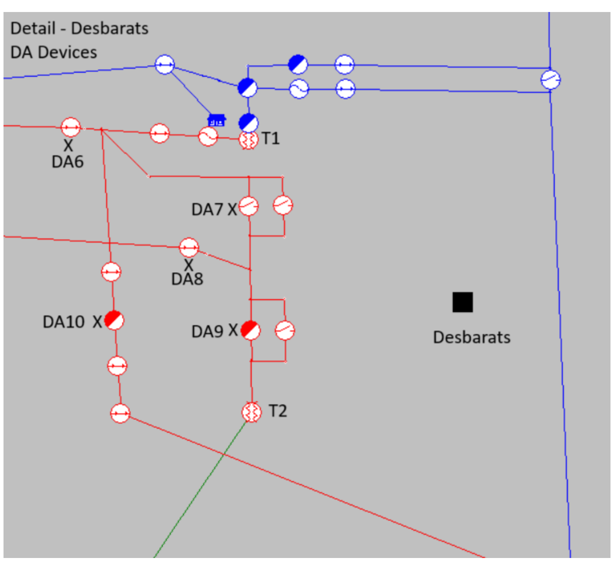
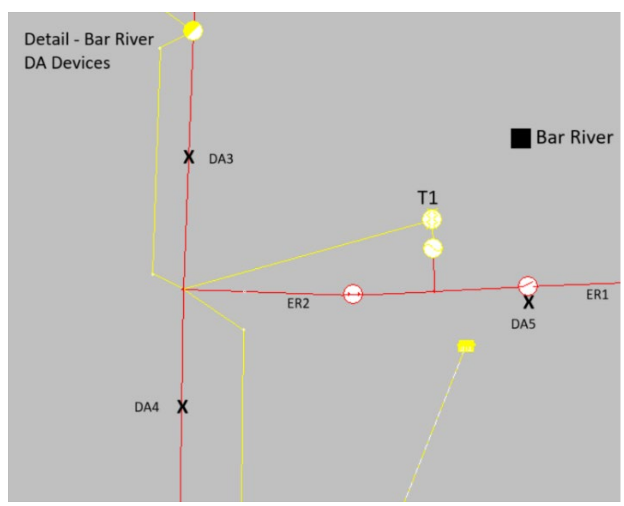


Figure 22: Recommended Locations for Distribution Automation Devices



Detail – Desbarats DA Devices



Detail – Bar River DA Devices

One advantage to implement the plan in phases is that the system will be benefiting from the new addition of a device immediately before a full automation system is in place. A protective device can interrupt a fault, improve the flexibility of switching, and reduce restoration time especially when the device can be remotely controlled. Phase 4, which is the truce implementation stage of a “Distribution Automation” system, should be left as the last step. If for some reason, for example, due to the limitation of operation procedures, the full automation system becomes a “no” option, Phase 4 can be cancelled without any investment loss or waste.

If all 4 phases above have been deployed, the system should achieve the following target (Refer to Figure 21 for Section #):

- When a fault happens in Section 1, causing ER2 trip, DA1 will open, and DA5 will close. None of the service areas loses power supply.
- When a fault happens in Section 2, causing DA2 trips, DA3 will open, and DA5 will close. None of the service areas loses power supply.
- When a fault happens in Section 3, causing ER1 trip, DA6 will open, and DA7 will close. None of the service areas loses power supply.
- When a fault happens in Section 4, causing DA4 trip, DA8 will open, and DA7 will close. None of the service areas loses power supply.
- When HOSSM ER1 loses of supply, DA1 will open, and DA5 will close. None of the service areas loses power supply.
- When HOSSM ER2 loses of supply, DA6 will open, and DA7 will close. None of the service areas loses power supply.
- When a fault happens in Section 5, causing DA19 trip, no FIISR action triggered and only DB1 and its downstream Bruce Mines lose power supply.
- When a fault happens in Section 6, causing DA11 trip, no FLISR action triggered and only Garden River loses power supply.

Assuming the FLISR is in full automation mode, all the switching will be performed automatically within 1 minute and the system reliability will be significantly improved.

Table 13: Loop Reinforcement - Cost Estimate*

Item	Description	Quantity	Unit Cost	Total Cost
1	Phase 1: automated switch installation (Engineering, material, and commissioning)	3	$60,000	$180,000
2	Phase 2: automated switch installation	3	$60,000	$180,000
3	Phase 2: existing device refurbishment and upgrade	2	$10,000	$20,000
4	Phase 3: automated switch installation	2	$60,000	$120,000
5	Phase 3: existing device refurbishment and upgrade	1	$10,000	$10,000
6	Phase 4: Survalent two-feeder FLISR License and Distribution Automation implementation	1	$130,000	$130,000
DA Subtotal				**$640,000**
7	34.5kV Loop Line reconductoring with necessary pole replacement (13km)	13	$100,000	$1,300,000
8	34.5kV Capacitor Bank Installation	1	$90,000	$90,000
Line Upgrade Subtotal				**$1,390,000**
Total Estimated Cost				**$2,030,000**

**Cost Estimate includes all phases. API will determine the pace to implement this project, as a result, the project may not be completed within this cycle of Cost-of-Service Application.*

5.3. East of Sault Ste. Marie 7.2/12.47kV Voltage & Phase Balance Improvement

As outlined in Section 4.4 and 4.5, some 7.2/12.47kV feeders in Echo River area tend to have a long run on a specific phase, causing the voltage drop issue near the feeder ends and phase imbalance at the feeder levels. Given the limitation of radial feed and remoteness, it is not economical to introduce the concept of multi-phase loop and invest on the line rebuild to fix the issues. In the past, capacitors and regulators had been installed as a measure to boost the voltage. However, if the load keeps increasing and the length of the single-phase radial feeder keeps extending, there will be a technical constraint for the maximum numbers of voltage regulators and capacitors that can be installed on a feeder without causing reactive power and voltage control complexity. At that time, extending two-phase or three-phase line and adjusting the lateral phases become necessary.

Alternative A:

Installing regulators is always a quick fix of voltage issue until reaching certain limits. It has been a widely adopted practice in API service territory, particularly in Batchawana-Goulais area. Depending on the load levels, line lengths, and conductor size, the effectiveness to boost the voltage may vary form location to location. As a best practice, it usually doesn't install more than three regulators in series, including any regulation available in the distribution source (i.e., substation).

If API opts to install regulators to correct the area's voltage issues associated with phase imbalance, the load and feeder end voltage should be monitored frequently so a correction measure can be deployed in time if necessary.

Alternative B:

Since the voltage issue is mainly caused by over-stretch of one particular phase and small conductor size such as #4 or 1/0, eventually, it will be necessary to rebuild the lines and introduce another phase(s) to balance the phase load.

The study below utilizes Load Scenario 2 (Section 4.6.2) to identify the 7.2/12.47kV feeders that are stressed-out by phase imbalance and single-phase voltage drop issues. Some issues may not be manifest today but become more evident during the stress test. Figures 23 illustrates the feeders that display this issue in an extensive scale; Figure Set 24-35 further provide a comparison of "Voltage Drop" vs "Color by Phase" for each identified feeder (or area). It clearly suggests the correlation between voltage drop and single-phase over-stretching.

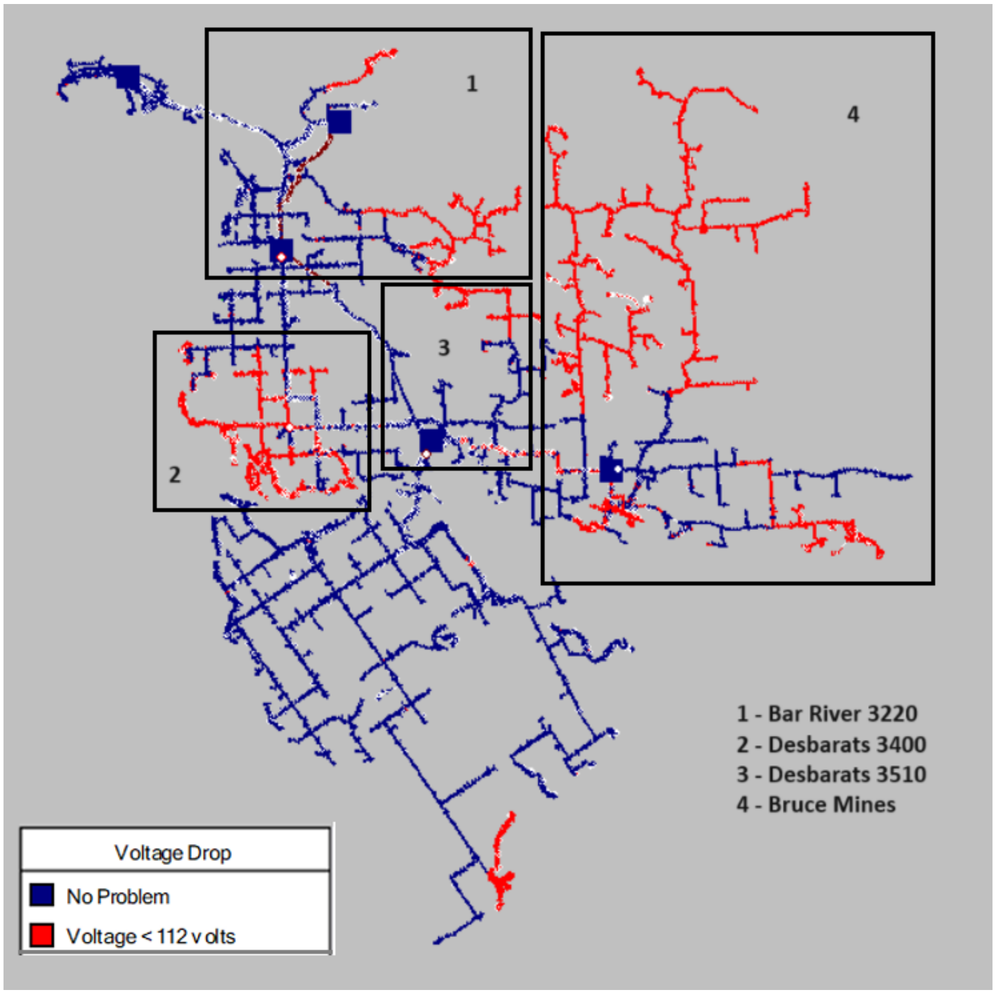


Figure 23: Echo River Area 7.2/12.47kV Feeders with Most Extensive Voltage Drop Issues

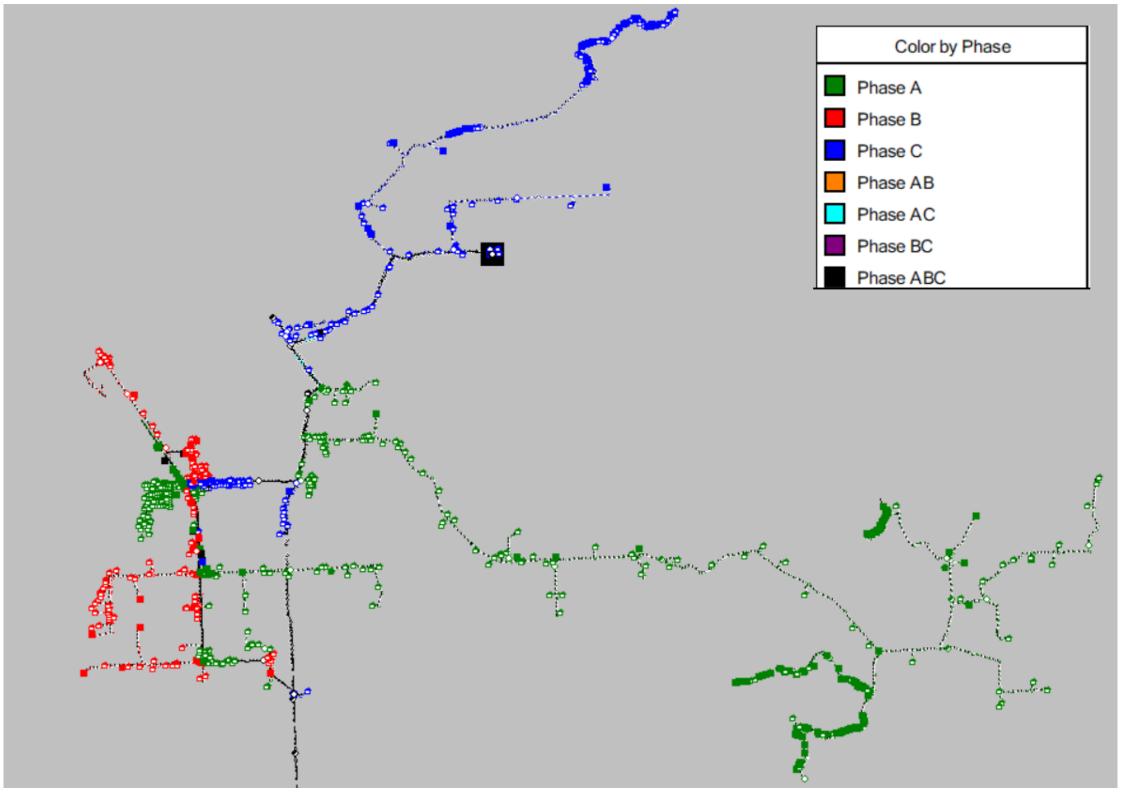


Figure 24: Bar River – Feeder 3220 – Color by Phase

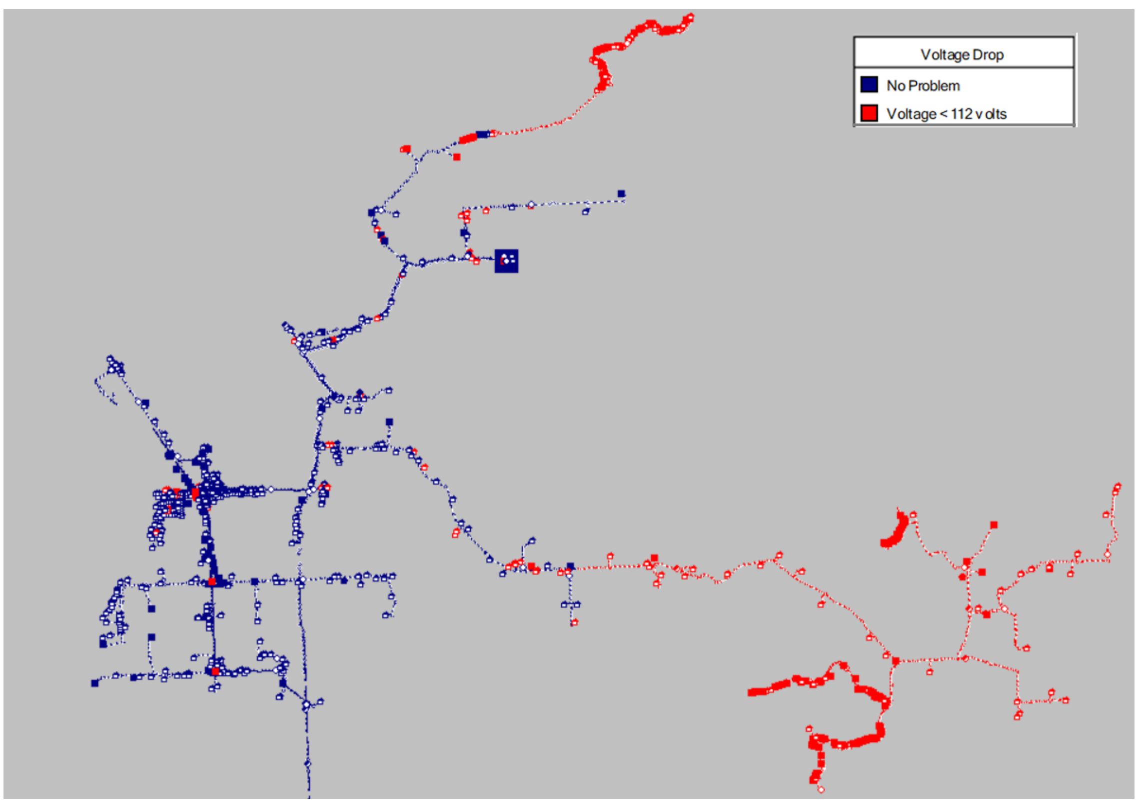


Figure 25: Bar River DS – Feeder 3210 – Voltage Drop (Bar River T1 tap at 100%)

Under the Load Scenario 2 assumption, Bar River DS - Feeder 3220 Phase B carries a relatively small load (**87 Amps**) within a relatively shorter distance away from Bar River DS (the Source). In comparison, Phase A carries a much larger load (**190 Amps**) and the distance from the farthest end to the Source is over **27 kilometers**. Phase C, on the other hand, carries about the same level of load (**84 Amps**) as Phase B, but the distance between the farthest end to the Source is about **22.4 kilometers**, which is more than twice that of Phase B (**9.2 kilometers**). As a result, Phase A and Phase C exhibit non-standard primary voltage issues approaching the feeder ends. In order to correct the issue without major line rebuilds, it is recommended to perform the following steps:

- In the adjacent area where the three phases just exit from the Bar River DS (as illustrated in the circled area in Figure 26 below), adjust Phase A and Phase C laterals to tap off from Phase B instead. This will reduce the load levels to be carried and distributed over a long distance.
- For Phase A, it will require to install a regulator to further boost the voltage (as indicated by the arrow in below Figure 26).
- For Phase C, allocating loads to other phases would solve the problem temporarily. If the load keeps growing, installing a regulator or re-conductoring the 1/0 as 3/0 or larger could be an option for future consideration.

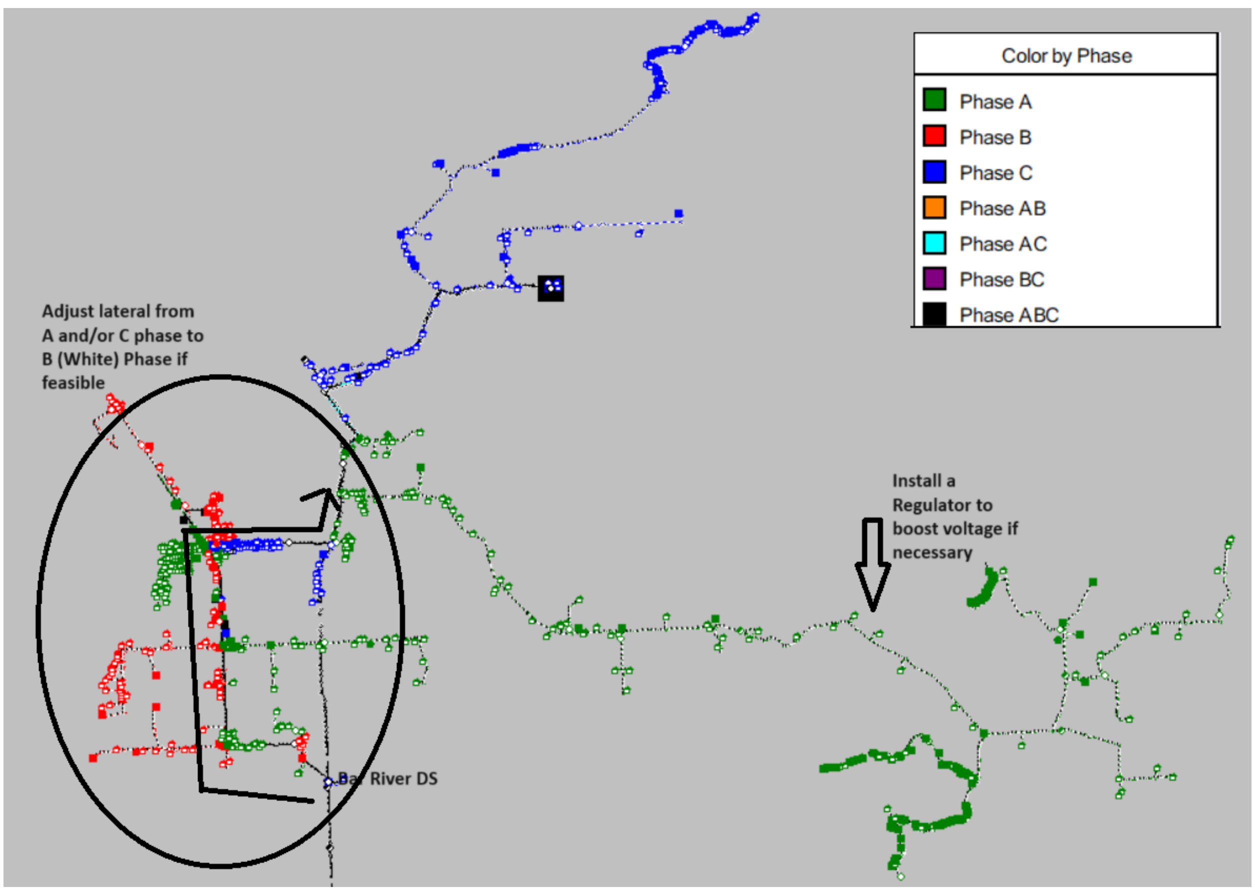


Figure 26: Bar River DS – Feeder 3220 – Voltage Issue Correction Plan

Under the Load Scenario 2 assumption, Bruce Mine carries a moderate load about4.1MW; at substation level, the phase imbalance is not prominent (**229, 219, 159 Amps**). However, towards the east side, one particular line carries a relatively small phase B load (**70 Amps**) and the distance from the farthest end to the Source (I.e., Bruce Mines substation) is over **34 kilometers**, not to mention the size of the conductor is either #4, #2, or 1/0ACSR. Similarly, towards the west side, one line, with small conductor size, carries a relatively small phase A load (**112 Amps**) and the distance from the farthest end to the Source is over **26 kilometers**. As a result, both lines exhibit non-standard primary voltage issues in an enormous territory.

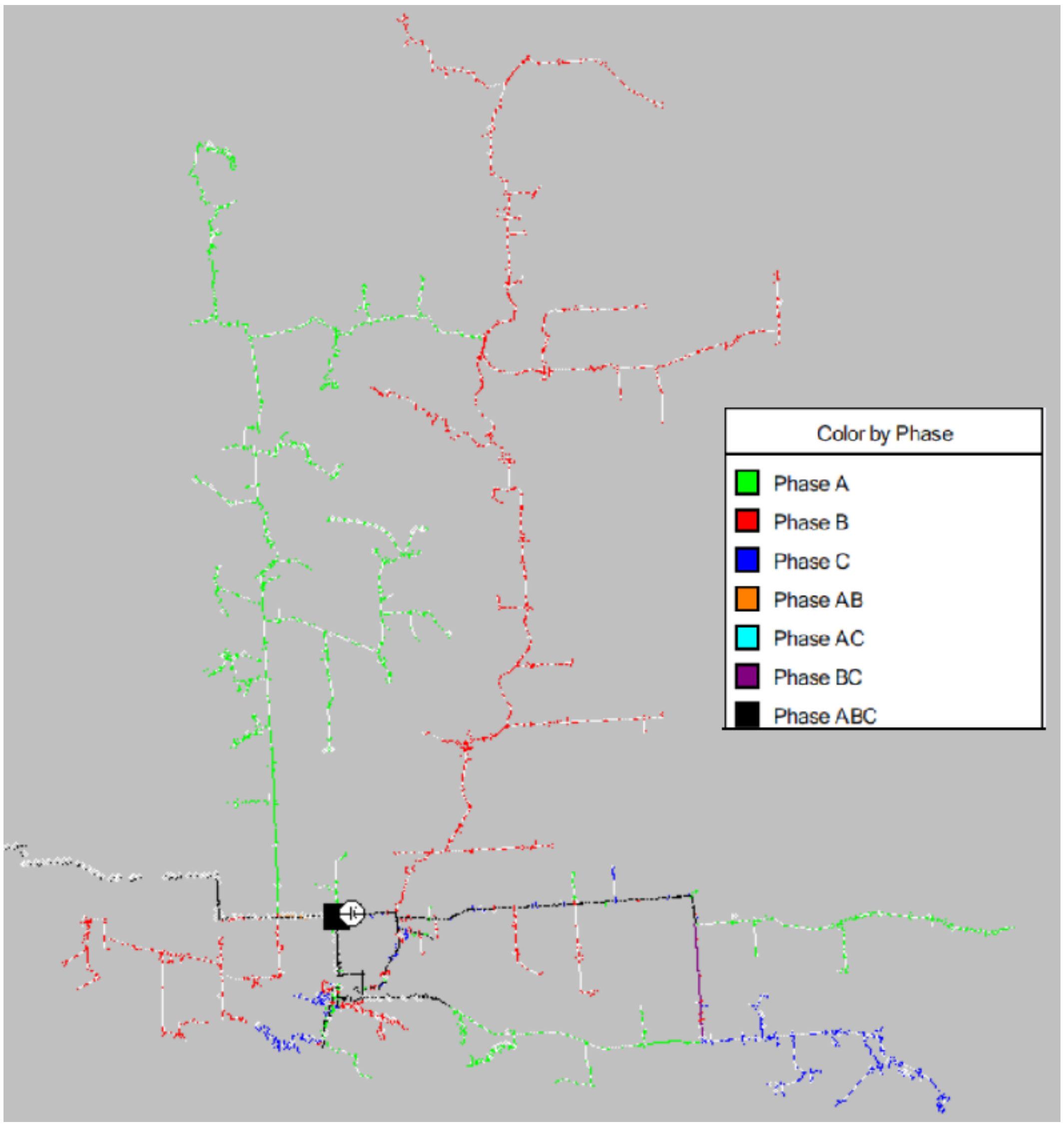


Figure 27: Bruce Mines – Color by Phase

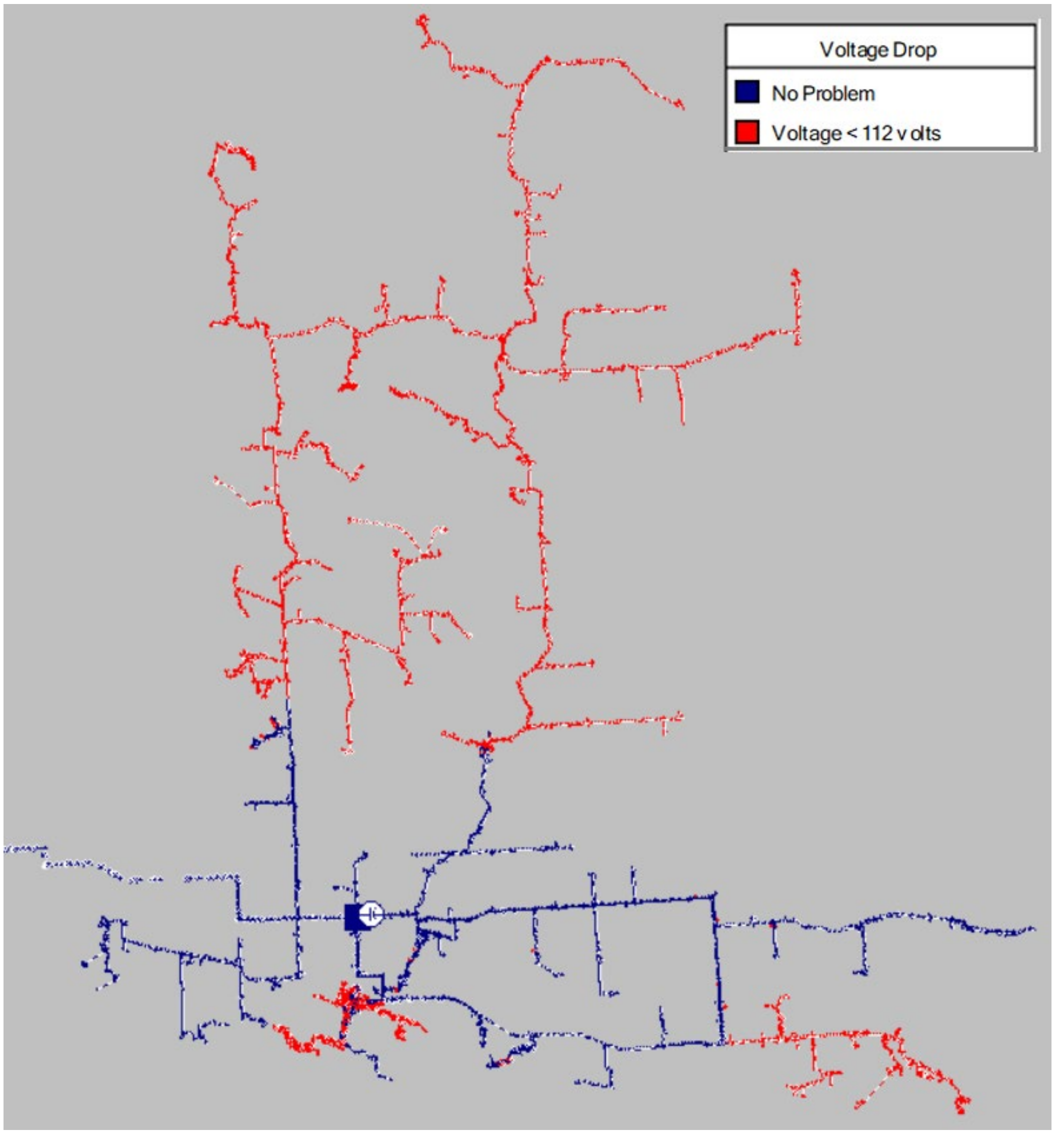


Figure 28: Bruce Mines – Voltage Drop

(Bruce Mines – Power Transformer tap at 95%)

In order to correct the issue it is recommended to perform the following steps (as illustrated in Figure 29):

- Complete the three-phase loop to correct the non-standard voltage issue exhibited at the south-east corner of Bruce Mines territory. This will improve the operational flexibility and phase availability along the loop. Depending on the conditions of existing poles, this work could be a mix of line rebuild (with pole replacement) or reconductoring only.
- Extend another phase to both lines mentioned above; push the rebuild as far as the budget allows. If the rebuild is constrained, it may require installing a regulator to further boost the voltage at the feeder end.

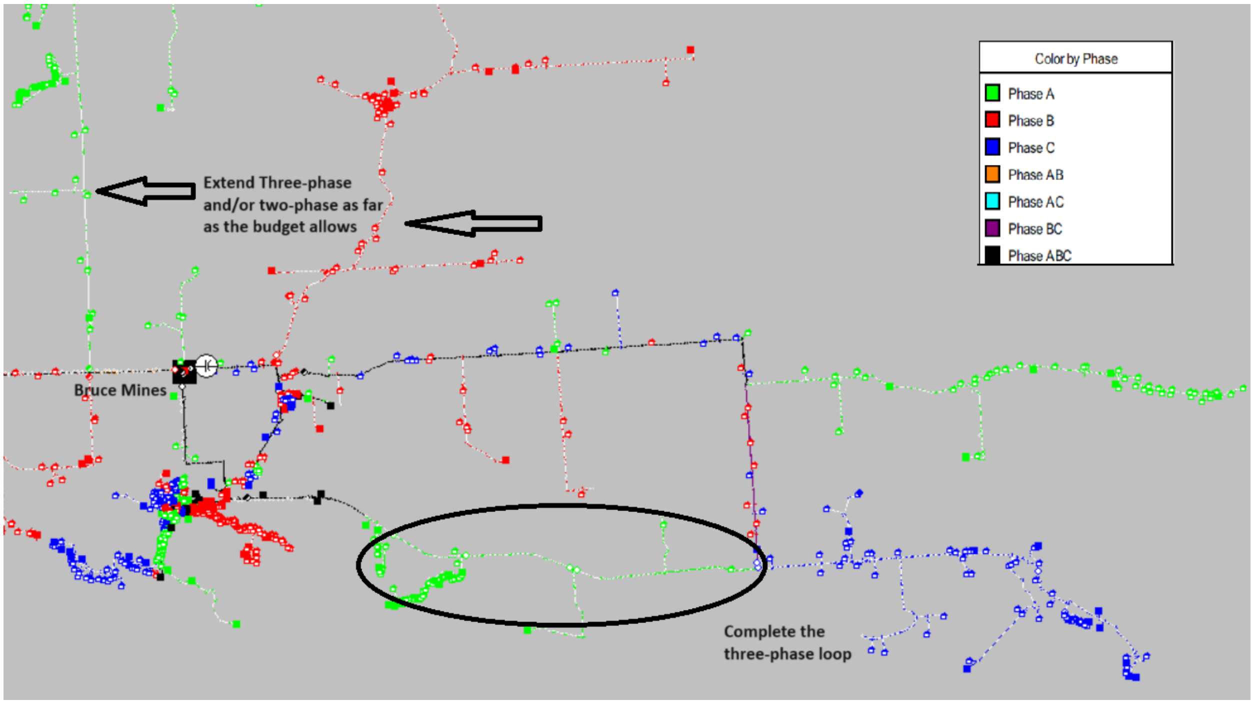


Figure 29: Bruce Mines - Voltage Issue Correction Plan

Under the Load Scenario 2 assumption, Desbarats DS - Feeder 3510 carries Phase B load (**138 Amps**) and the distance between the farthest end to the Source is over **19 kilometers**. As a result, Phase B exhibits non-standard primary voltage issues approaching the feeder ends. In order to correct the issue without major line rebuilds, it is recommended to perform the following steps (as illustrated in Figure 32):

- Extend three-phase, or at least two-phase, to the four-way split point close to SW3510B-128 (intersection of Government Rd and Gordon Lake Rd).
- Install a regulator to further boost the voltage if necessary.

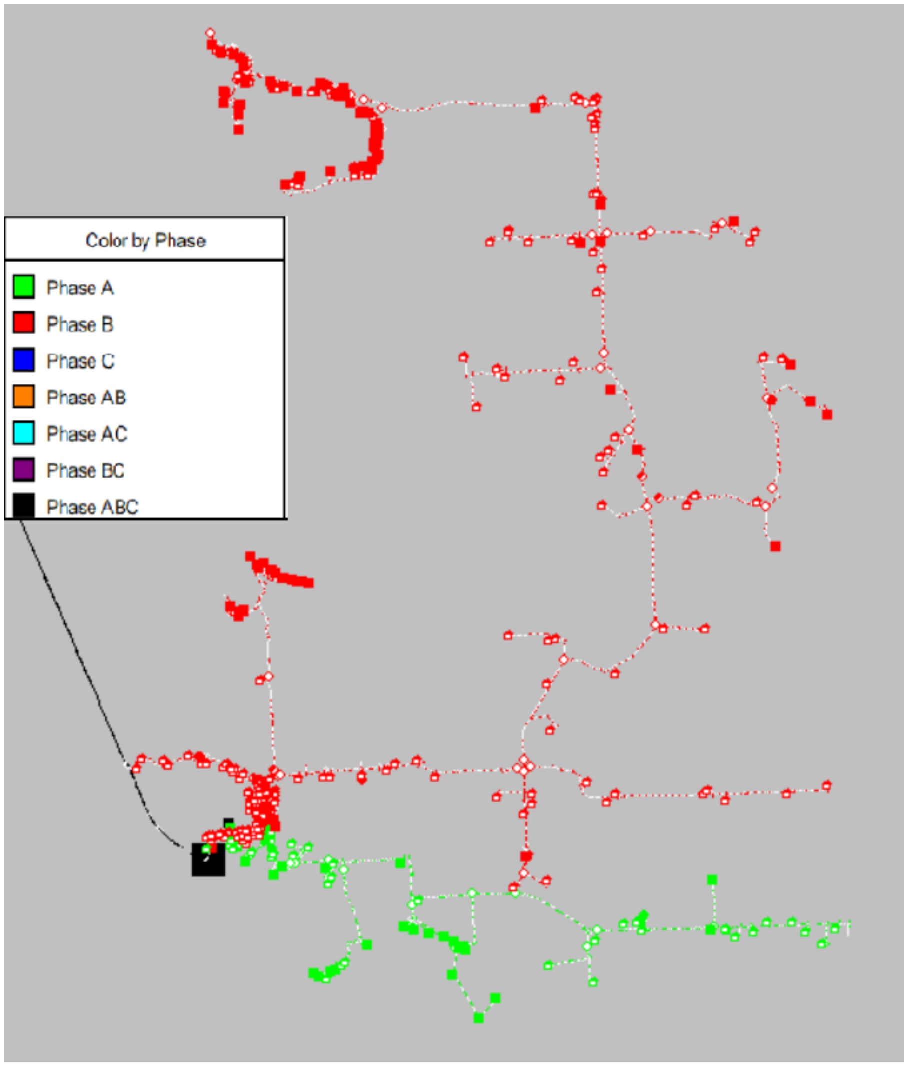


Figure 30: Desbarats – Feeder 3510 - Color by Phase

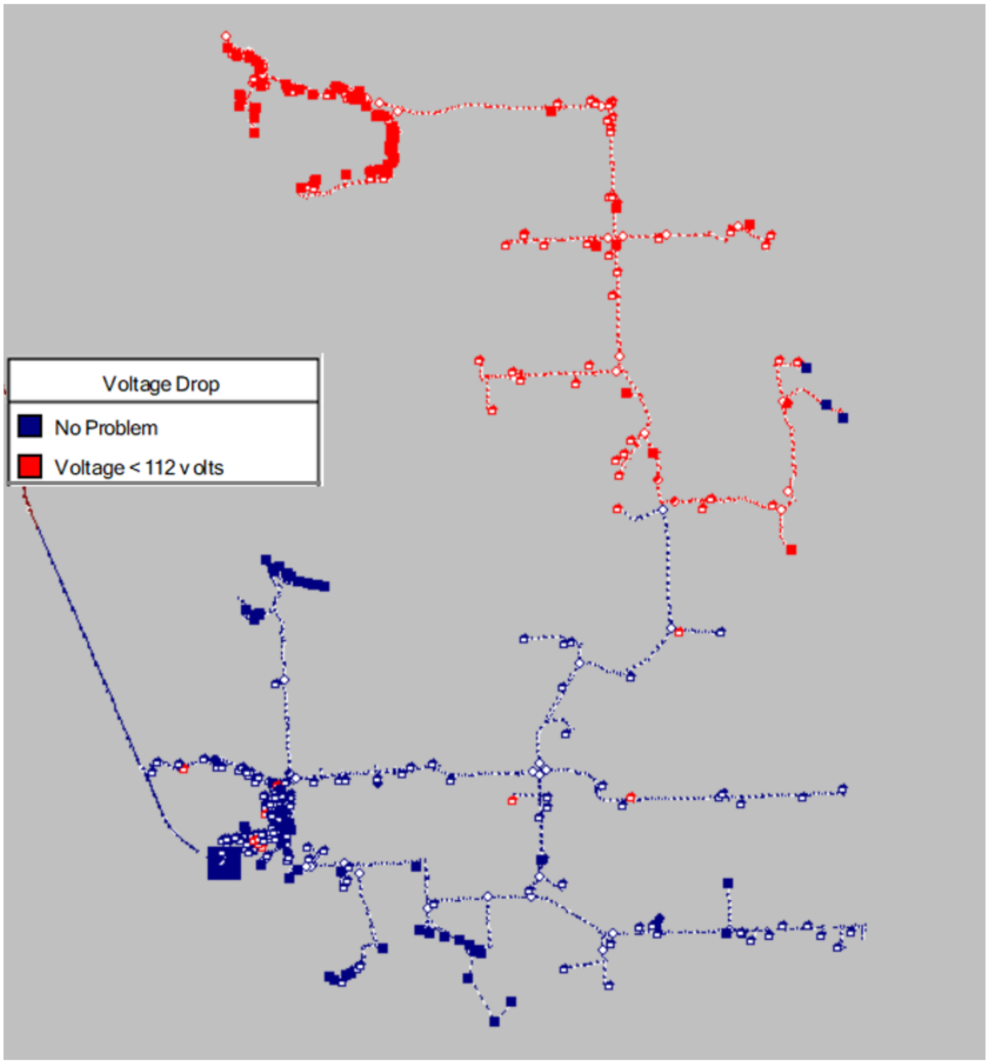


Figure 31: Desbarats – Feeder 3510 – Voltage Drop

(Desbarats T1 at 95%)

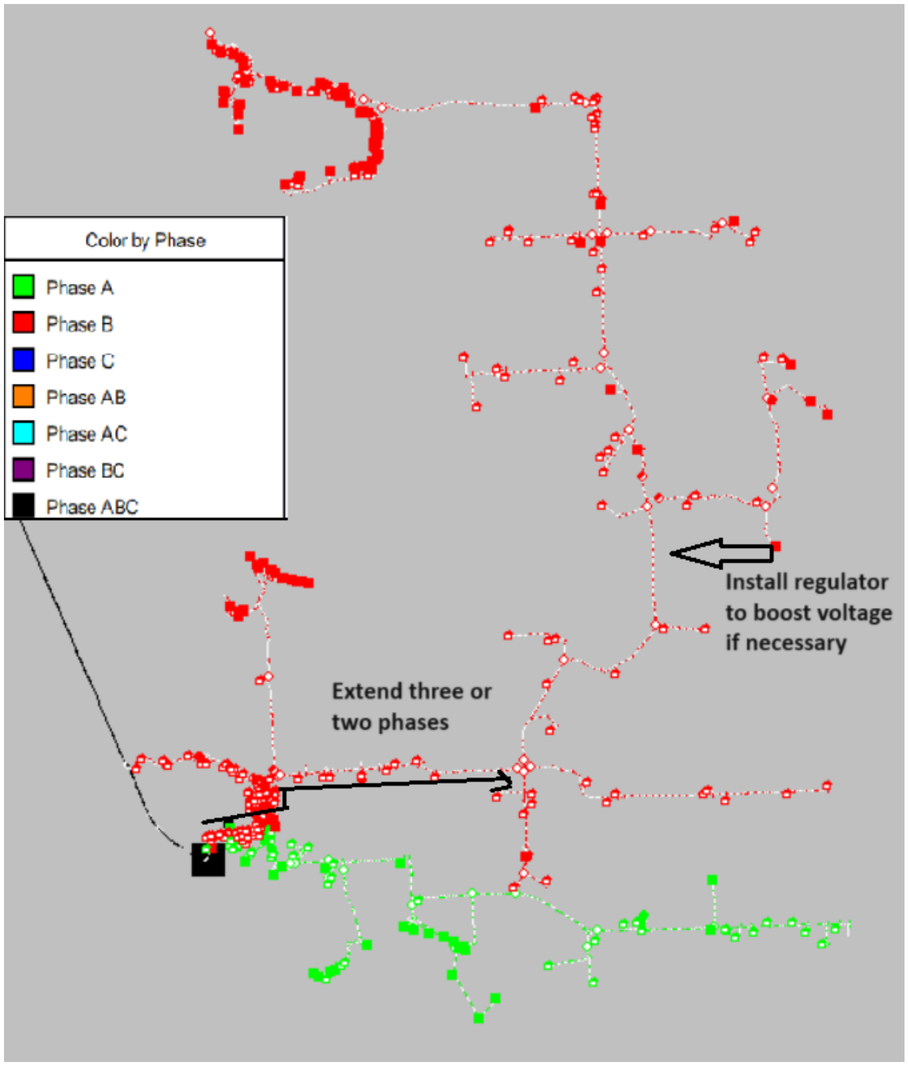


Figure 32: Desbarats – Feeder 3510 – Voltage Correction Plan

Under the Load Scenario 2 assumption, Desbarats DS - Feeder 3400 voltage drop iteration did not converge, i.e., it displays a symptom of voltage collapse on Phase B. The feeder shows an extreme phase imbalance at the feeder level (**69, 387, and 17 Amps**). The heavy loading on Phase B is due to system configuration constraints.

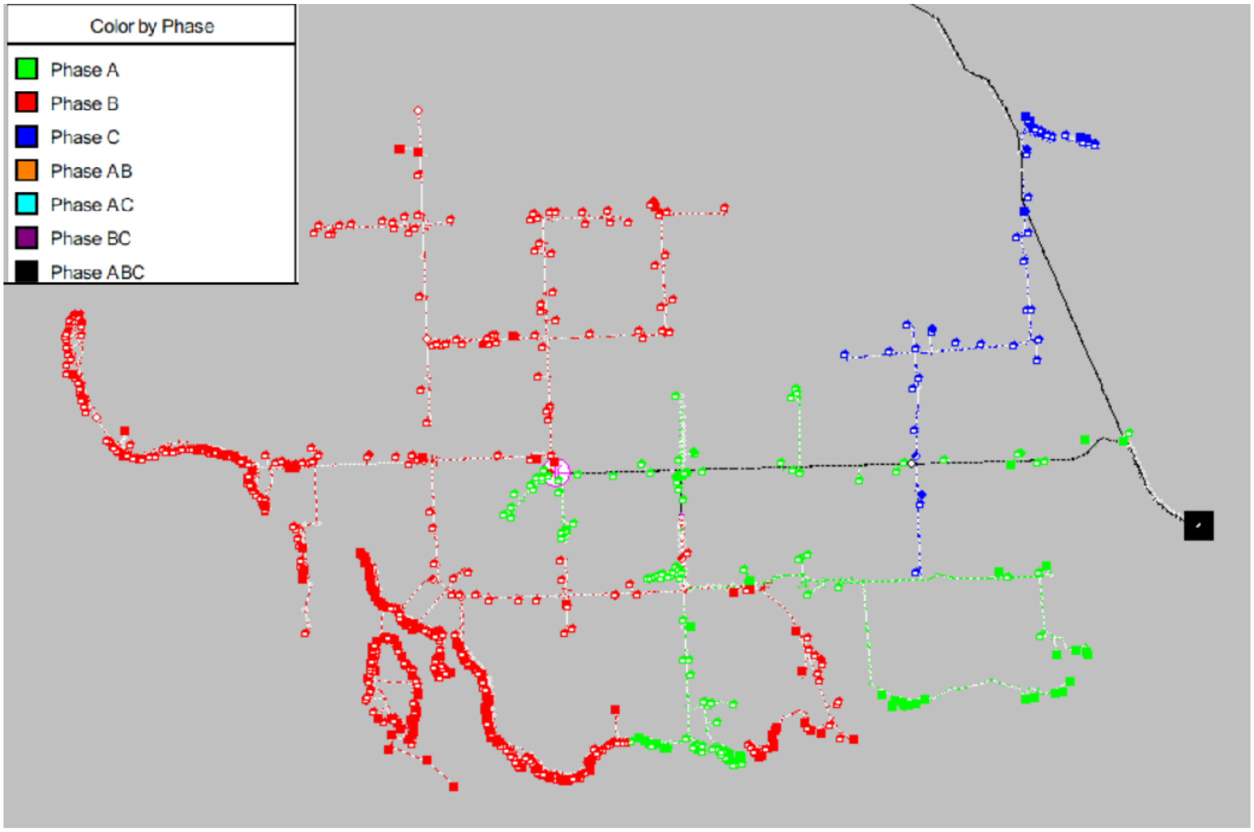


Figure 33: Desbarats – Feeder 3400 – Color by Phase

In order to correct the issue, it is recommended to perform the following steps (as illustrated in Figure 35):

- Extend three-phase, or at least two-phase to the point just a few spans north of the tap point near SW3400-140. In this way, Phase B load can be split into two chunks and Phase C can pick up a significant portion of the load.
- Near the location where the existing 1000KVA 7.2kV to 4.8kV step-down transformers on Phase A and Phase B are located, install another 1000KVA Phase C step-down transformer. Extend the lines so some lateral loads can be picked up by the new ratio transformer.
- Extend three-phase, or at least two-phase from west of Barr Rd South to the intersection near Townline Rd and Pine Island Rd, where heavily loaded laterals split to different directions.

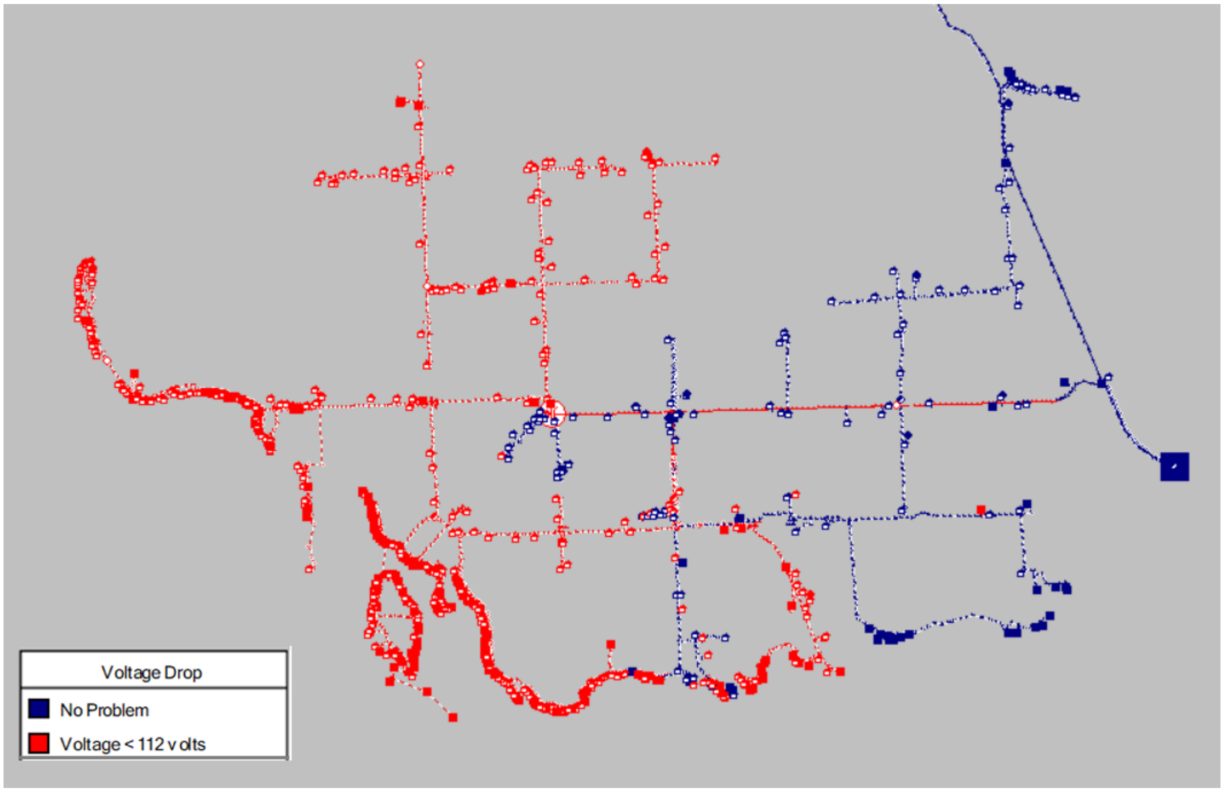


Figure 34: Desbarats – Feeder 3400 – Voltage Drop (Desbarats T1 tap at 95%)

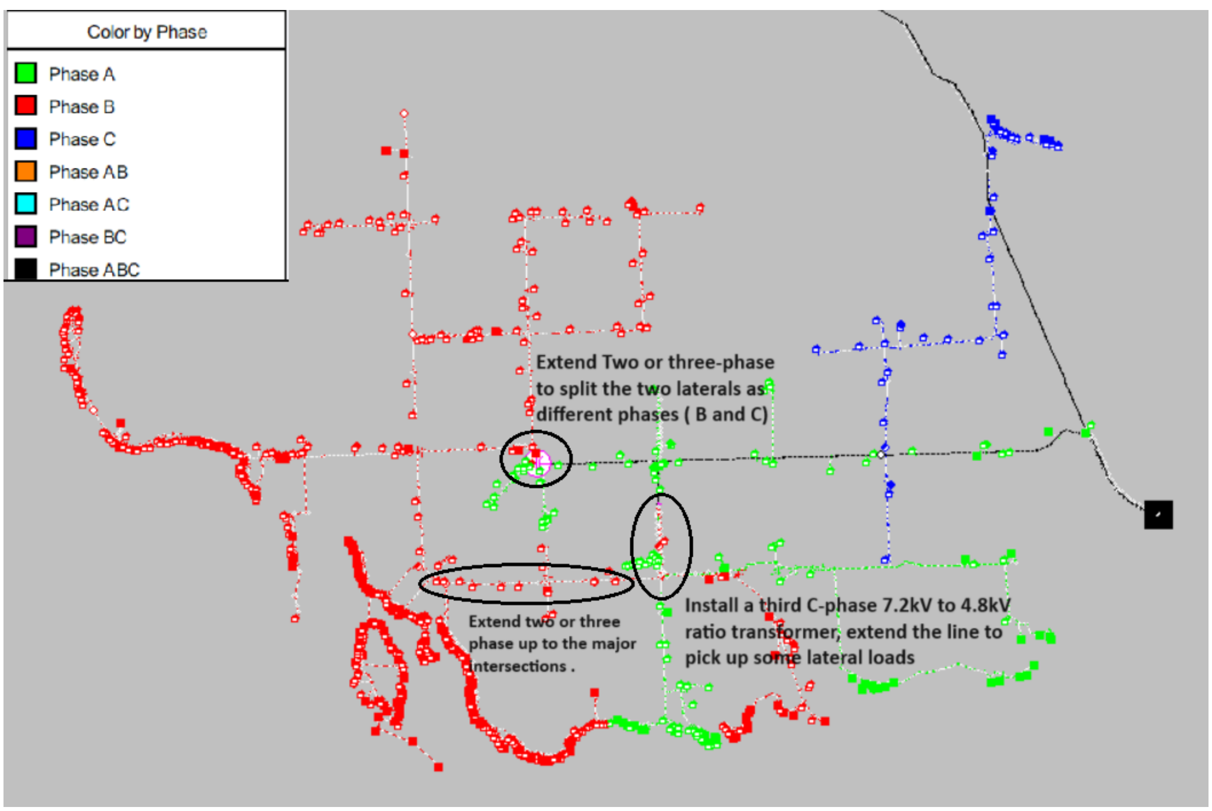


Figure 35: Desbarats – Feeder 3400 – Voltage Correction Plan

Table 14: **East of Sault Ste. Phase Balance Improvement - Cost Estimate**

Item	Description	Quantity	Unit Cost	Total Cost
1	Bar River Feeder 3220 phase adjustment and 1 regulator installation	1	$60,000	$60,000
2	Bruce Mines 3-phase line rebuild to complete the loop – with or without pole replacement (km)	7.3	$150,000	$1,095,000
3	Bruce Mines 2-phase extension line rebuild (6 + 7 = 13km)	13	$120,000	$1,560,000
4	Desbarats Feeder 3510 2-phase extension line rebuild (6km)	6	$120,000	$720,000
5	Desbarats Feeder 3400 2-phase extension line rebuild (1.2km)	1.2	$120,000	$144,000
6	Desbarats new 1000KVA single-phase ratio transformer installation	1	$120,000	$120,000
Total Estimated Cost				**$3,699,000**

5.4. Wawa Main Substation Upgrade

Algoma Power owns nine (9) Distribution Stations. A Distribution Station has two major components, the power transformer, which supplies the power required to service the customers within the station service area, and the station structure, which supports the switches and conductors that feed the customers. Although equipment within each substation is of various ages, it is reasonable to characterize API's Distribution Station population as having one (1) station over 50 years old, Wawa #2 DS.

The Town of Wawa load is served by two distribution stations, Wawa #1 DS and Wawa #2 DS. Each distribution station has a power transformer that operates at the 8.3kV level to supply the Town of Wawa load. Under normal operating conditions the town load is shared between the two stations. In the event of a catastrophic event at either station, the entire town load can be served by the remaining station. However, the lead time for replacement of a power transformer is currently 18 to 36 months, which risks leaving the Town of Wawa without back up for an extended period of time should the transformer at Wawa #2 DS fail.

The risk of transformer failure at Wawa #2 DS was heightened when routine transformer maintenance verified that the transformer is in poor condition due to the deterioration in the insulation of the transformer. This fact has been re-affirmed through a recent Asset Condition Assessment (ACA) report. The ACA also assessed that the yard and fence at this station needed to be upgraded/replaced.

Although not mentioned in the ACA, the lack of oil containment at Wawa #2 DS presents a real and ongoing environmental risk should the power transformer fail. It is not practical to add oil containment to the existing station. Further, the station structure design cannot be operated, nor worked on using live line procedures. The entire structure must be de-energized to perform routine switching operations or to replace failed or deteriorated components on the structure. A new structure will improve reliability, by reducing switching requirements in the event of a feeder outage and reducing the requirement for a total outage at Wawa #2 DS when structure components require maintenance. A new structure can reduce the risk of a total outage to the Town of Wawa when all load is transferred to Wawa #1 DS.

Current Federal statute targets zero-emission vehicle sales of 20% by 2026, 60% by 2030, and 100% by 2035. At present all zero emission light passenger vehicles are assumed to be electric vehicles. Therefore, it can be safely assumed that over the fifty plus (50+) year life of the proposed new station there is potential for significant load to be added in the Town of Wawa as all locally owned passenger vehicles are converted to electric vehicles. In addition, since Wawa is located on the Trans-Canada Highway, at some point in the future, both passenger and possibly commercial vehicles travelling through the area on this major transportation route will require electric charging facilities, especially during the busy tourist season. Therefore, as the station is rebuilt the option of increasing the station transformer capacity in anticipation of this possible new load should be kept firmly in mind.

It is recommended that the existing station transformer and structure be replaced with a new station on land available at the existing location. The main drivers for this recommendation are the age and condition of the station which point to the risk of transformer failure. The ensuing reliability impact on customers and possible environmental damage, combined with the operational restrictions and tight working clearances imposed by the existing outdated station structure are all factors that were taken into consideration.

The existing WAWA #2 DS station has a 5/6.67/8.33 MVA power transformer, which provides electrical service to the 9220 and 9210 8.32 kV feeders. Replacing the existing station with a new station of the same size is possible given that the 2022 peak loading (winter) of 1674 kVA at Wawa #2 DS was well below the nominal station maximum. Also, the 2022 maximum peak load (winter) for the Town of Wawa was 4621 kVA[6] which can be comfortably carried by a 5/6.67/8.33 MVA power transformer.

However, the 10-year load forecast (2033) predicts the following loads for Wawa.

- Wawa 2T1 – 4187 kVA
- Wawa 1T1 – 4931 kVA

Therefore in 2033, if the Town of Wawa load were split evenly between the two stations, each station would have a peak load of 4559 kVA; a load which exceeds the Fortis planning criteria of 50% of the nominal rating of the existing station transformer (8330/2 =4165 kVA). Given that the Typical Useful Life (TUL) for a power transformer was estimated[7] at 45 years (with a maximum life of 60 years and a minimum life of 30 years) it would be prudent to consider the load requirements beyond 2033 when recommending a power transformer capacity for the new station.

Alternative A: Replace the Existing Station Like-for-Like with the same Power Transformer Capacity

Fortis Ontario planning criteria (Section 2 – Area Planning Report) limit Substation Transformers to operate up to a maximum of 50% of their nominal capacity. The 10-year load forecast predicts the Town of Wawa peak load in 2033 to be an estimated 9118 kVA. Therefore, building a new Wawa #2 DS at a capacity of 8330 kVA is not recommended as 50% of the forecast Town peak load, exceeds 50% of the nominal rating of an 8330 kVA power transformer.

Estimated like-for-like replacement cost is $4,130,000.

	Like for Like Replacement Plan (5/6.67/8.33 MVA)
Project Management	$75,000
Owner's Engineer	$125,000
8.3kV Transformer (Option)	$350,000
12.5kV Transformer (5MVA)	$350,000
Major Switch Materials	$180,000
EPC-Engineering/Design	$240,000
EPC-Mob/Demob	$100,000
EPC-Civil/Electrical	$2,000,000
EPC-Commissioning	$150,000
EPC-Decommissioning	$50,000
EPC-Material Cost	$500,000
Station Energization	$10,000
SUBTOTAL	**$4,130,000**

Alternative B: Replace the Existing Station 50% Larger Power Transformer Capacity

Fortis Ontario planning criteria (Section 2 – Area Planning Report) limit Substation Transformers to operate up to a maximum of 50% of their nominal capacity. The 10-year load forecast predicts the Town of Wawa peak load in 2033 to be an estimated 9118 kVA. Building a new Wawa #2 DS with a power transformer

[6] This is the arithmetic sum of peak winter loads reported in Table 3. It is unclear if these peak loads are coincident.
[7] See OEB "Asset Depreciation Study for the Ontario Energy Board", Kinterics, July 8, 2010, Table F, Page 18.

rated at 12,500 kVA would allow such a station to operate below 50% of its nominal capacity if the estimated peak load calculated in the 10-year forecast becomes a reality.

Given the level of uncertainty that electrification and Electric Vehicle loads resulting from national decarbonization efforts introduce into the API load forecast it is recommended to build a new Wawa #2 DS at a capacity of 12,500 kVA.

Estimated cost to build Wawa #2 DS with a 12,500 kVA rated power transformer is $4,380,000.

	Increased Capacity (7.5/10/12.5 MVA)
Project Management	$75,000
Owner's Engineer	$125,000
8.3kV Transformer (Option)	$500,000
12.5kV Transformer (5MVA)	$350,000
Major Switch Materials	$180,000
EPC-Engineering/Design	$240,000
EPC-Mob/Demob	$100,000
EPC-Civil/Electrical	$2,100,000
EPC-Commissioning	$150,000
EPC-Decommissioning	$50,000
EPC-Material Cost	$500,000
Station Energization	$10,000
SUBTOTAL	**$4,380,000**

Alternative C: Replace the Existing Station 100% Larger Power Transformer Capacity

Fortis Ontario planning criteria (Section 2 – Area Planning Report) limit Substation Transformers to operate up to a maximum of 50% of their nominal capacity. The 10-year load forecast predicts the Town of Wawa peak load in 2033 to be an estimated 9118 kVA. Building a new Wawa #2 DS with a power transformer rated at 16,600 kVA would allow such a station to operate below 50% of its nominal capacity if the estimated peak load calculated in the 10-year forecast becomes a reality.

Given the level of uncertainty that electrification and Electric Vehicle loads resulting from national decarbonization efforts introduce into the API load forecast it is not recommended to build a new Wawa #2 DS at a capacity of 16, 600 kVA, pending annual review of actual load growth in Wawa.

Estimated cost to build Wawa #2 DS with a 16, 600 kVA rated power transformer is $4,635,000.

	Increased Capacity (10/13.3/16.6 MVA)
Project Management	$75,000
Owner's Engineer	$125,000
8.3kV Transformer (Option)	$650,000
12.5kV Transformer (5MVA)	$350,000
Major Switch Materials	$180,000
EPC-Engineering/Design	$240,000
EPC-Mob/Demob	$100,000
EPC-Civil/Electrical	$2,205,000
EPC-Commissioning	$150,000
EPC-Decommissioning	$50,000
EPC-Material Cost	$500,000
Station Energization	$10,000
SUBTOTAL	**$4,635,000**

Recommendation: Alternative B is recommended as the 12, 500 kVA rating of the power transformer suitably strikes a balance between the uncertainty of the load forecast (which includes the uncertainty with respect to the load impacts - size and timing) of electric vehicles and electrification in the API service territory and the Typical Useful life of the asset.

6. Asset Condition Driven Projects

6.1 Pole Replacement

Algoma Power operates a distribution system within one of the largest and most sparsely populated service territories in the Province of Ontario. API services approximate 12, 200 customers on a distribution system consisting of approximately 1,810 km of distribution line that are supported by about 28,931 poles. As a result, API has one of the highest poles to customer ratio's (2.37 poles per customer) within the Ontario Local Distribution Company community.

Each year, Algoma Power identifies and prioritizes pole lines for rebuilding based on their condition, age, and the consequences of their potential failure. Unplanned "catastrophic" pole failures in the field can result in very time consuming and costly reactive replacements. Catastrophic pole failure can also involve downed energized wires, which can present a safety and fire hazard to property and the public. With API's rural and remote service territory, this aspect is higher-risk, as immediate action to address the safety and fire hazard may be delayed as crews need time to reach the area. In addition, poor pole condition can delay needed maintenance and repairs and result in increased cost; for example, if crews arrive and the pole is in such poor condition that they cannot climb it to complete the repairs necessitating a subsequent trip.

API's Line Rebuild program is based on a targeted pole replacement rate of 500 poles per year. The level of 500 poles has been recommended because it is sustainable, and it is aligned with an expected average useful life of 50 years for each pole in the population. The program is intended to replace the majority of poles prior to in-service failure or remaining strength that is below relevant CSA specifications. This also ensures that the associated components (insulators, hardware, crossarms, grounding, guying, etc.) remain intact without major issues for the lifecycle of each pole.

Interestingly the 2019 Asset Condition Assessment (ACA) calculated that 6.9% of the wood pole population was in Fair condition and 2.4% were in poor or very poor condition. The 2023 ACA shows that 3.34% of the poles in API's distribution system are in poor or very poor condition. This is a 139% increase these two categories between the two ACAs. The same 2023 ACA calculated that 18.83% of the wood pole population was in the Fair category, a 273% increase in this category. An increase in the annual Pole Replacement rate may be in order if this trend continues into the future.

6.2 Metering Infrastructure Replacement (for compliance purpose)

On or about the year 2009 API, like all Ontario LDCs, was required to install Smart Meters on all residential customers. The meters available for the Smart Meter program were electronic meters and these new meters replaced existing electro-mechanical induction type meters that had registered residential consumption for decades. As a result of the Smart Meter program, the residential meters at API went from a chronologically diverse population that were spread out over a 25-to-40-year lifespan to a population with a single effective manufacture and seal date of 2009.

The immediate effect was the cancellation of all meter reverification OM&A activities and expenses covered by rate base. The longer-term effect was more subtle but has now come into full focus at all Ontario LDCs.

Industry Canada Bulletin E-26 defines the required reverification periods for electricity meters and metering installations. Of interest is Table 2, Electronic-type, Column II and Column III found on page eight of the Bulletin. For meters with lengthened initial reverification periods, such as the meters at API, the net effect is that meters are subject to reverification statistical sampling on or before their 18th in-service year; 2027 for meters installed in 2009. API anticipates that ten thousand (10000) of the population of twelve thousand (12000) meter will require resealing in 2027 and potentially replacement in the coming years.

As the entire population was installed in a single year, a “do-nothing” approach risks a high failure rate in the statistical sampling of the reverification population (which could be 7000 meters in 2027) and therefore the requirement to replace the reverified population with new meters in one budget year…a significant capital expenditure if required. Therefore, a number of Utilities are creating sample batches sized to represent a smaller portion of the meter population, usually 10% or so, and beginning the reverification process a few years ahead of the 2027 deadline. This allows the utilities to purchase meters annually, levelling the annual cost of replacement meters, and allowing for reverification of older meters so that they can be reintroduced into service, albeit at a reduced seal expiry date, again to allow time to levelize the purchase of replacement meters with longer seal expiry dates. The end goal being to create a manageable number of meter sample batches that can be reverified annually and replaced in a manner that allows for a more levelized capital expenditure year over year.

Andrew Trainor of API has developed a proactive Meter Replacement Plan that begins the process of meter reverification in 2025. The Trainor program provides for the purchase and installation of one thousand (1000) new meters per year, starting in 2025 and ending in 2029 (1000 per year, 5000 in total). The newly purchased meters will include eight hundred (800) direct replacements per year and, pending testing and approval, two hundred (200) Remote Disconnect Meters per year. Sensus’s Remote Disconnect Meters will need to be tested and approved for use in Ontario as the previous version of this meter was withdrawn from the Ontario market on or about 2013/4 after the Electrical Safety Authority associated a number of fires with these meters and banned their use in Ontario.

The Plan deploys a batch of 1000 new meters per year, gathers the used meters and puts them in inventory until required, at which point they could be resealed and put back into service with a reseal length of six (6) years. The objective is to gradually create 1000-meter annual reverification batches until a sustainable annual reverification program with a chronologically diverse batch size of about 1000 meters is re-established at API.

Of note is Industry Canada document S-S-06 which defines the requirements for sampling plans of isolated lots of meters in service. In addition, the document spells out the maximum seal period extension; which for the Sensus meters purchased in 2009 appears to be six (6) years as per Annex E. Extending the Trainor plan beyond 2029 would allow API to establish 1000 meter batch sizes within the period 2030 to 2035.

The proposed Plan

- Reduces the Supply Chain risks that have been experienced in recent years as API would be making annual requests for smaller quantities of meters at a time when all Ontario meters are beginning to come due for replacement.
- Increases the probability that the life of the existing meter stock can be extended based on the reverification testing process.
- Reduces annual capital costs if a batch fails (which is likely to happen more often as the meter population ages) by reducing the size of the failed batch to 1000; up to 2027 when the seals on every meter originally installed in 2009 (approximately 7000 meters at that time) expire and that population must be sampled and either reverified or replaced. Of note is the fact that API could retest all the 7000 meters in batches of 1000. Assuming that in 2027 the 7000 meters whose seals expire undergo reverification and the meters are acceptable, the meters can be resealed for a period of six (6) years; as defined in Annex D and Annex E of Industry Canada document S-S-06.
- Manages the need for qualified staff to complete this work by limiting the batch size and therefore both the need to remove existing meters from the field for sample testing and, if a batch failure occurs, the need to replace all the meters in the batch.

Table 15: Metering Infrastructure Replacement - Estimated annual cost

Meter Replacement Program	2025	2026	2027	2028	2029
Annual Estimated Cost (Material and Labour)	$ 364,402.16	$ 369,400.00	$ 375,791.00	$ 381,172.87	$ 386,545.46

6.3 Communication infrastructure reinforcement for Smart Meters

On or about the year 2009 API, like all Ontario LDCs, was required to install Smart Meters on all residential customers. The system chosen by API was the Sensus Flexnet Advanced Metering Infrastructure (AMI).

The Sensus Flexnet system was unique among AMI systems that were evaluated in the 2008-2009 London RFP process. Most AMI systems used a MESH network, so called point to multipoint technology, where a meter broadcast its meter reads which were picked up and relayed by every adjacent meter until it reached a Collector Meter or Collector Device where the reads were "collected" and passed on to the central computer for processing. A single meter read report could be picked up by multiple other meshed meters and passed back to the Collector multiple times, necessitating either the Collector to sort out a single report from the multiple reports and pass that along to the central computer or pass along everything and let the central computer sort it out. Typically, the mesh communications medium was 900 MHz unlicensed spread spectrum, also used for portable telephones, garage door openers and other consumer devices. The communication mesh was therefore prone to interference; either other devices interfering with the meter reads or meter reads interfering with the operation of other devices.

Sensus uses licensed 900 MHz and multipoint to point communications. Each meter broadcasts its meter reads, which is picked up by a single communication hub called a Tower Based Gateway (TGB). The TGB then passes on the meter read to the central computer (Regional Network Interface – RNI); thus, multiple meters talk to one central hub. The typical range for the TGB is about 3 km at 900 MHz; thus, a TGB covers about 10 square miles. However, depending upon the topology of the area where meters are deployed a TBG can cover a much larger, or somewhat smaller, territory. A propagation study will determine the probable range of a TGB for a given location and broadcast frequency.

In addition to the TGB receiving meter reads directly from meters and passing those reads along to the RNI, the Sensus Flexnet system can transmit meter reads to the TGB or RNI via a repeater network. Two types of repeaters were available when API deployed the Flexnet system: the Flexnet Remote Portal (FRP) and the Flexnet Network Portal (FNP). The Flexnet Remote Portal (FRP) uses the licensed 900 MHz spectrum employed by Sensus to gather the meter reads and transmit them to a TGB or another RFP. The Flexnet Network Portal (FNP) gathers the meter reads using the Sensus licensed 900 MHz spectrum and forwards the data directly to the RNI bypassing the TGB using a Public Network such as public carrier RF or phone modem.

Algoma Power Inc's service territory is very large and sparsely populated with customers (i.e. meters). Therefore, the number of TGBs that might be required to read all meters directly could be expected to be large and the network expensive. However, using the Sensus developed "repeaters" that could effectively pass meter reads to the TGB or directly to the RNI using a variety of communication media, API was able to achieve the required meter read success rate without deploying a significant number of TGBs.

API, in concert with Sensus, performed a prorogation study and developed a plan to deploy the most efficient and effective combination of TGB's and "repeaters". The final Flexnet system employed six (6) TGBs, ten (10) Flexnet Remote Portals (FRPs) and fourteen (14) Flexnet Network Portals (FNPs).

The FRPs have proven to be unreliable. When subject to a power outage the FRP often fails to reinitialize automatically upon restoration of service. Instead, API must dispatch a staff member to drive to the FRP and turn it off and on to manually reinitialize the unit. Due to the large distances typically involved, this creates an inefficient and ineffective use of trained staff and disrupts planned daily activities. Also, the FRPs are no longer available from Sensus and are being replaced with Flexnet R100NA Collectors. To date API has replaced three (3) FRPs with R100NA Collectors and uses the recovered FRPs as spares for the remaining population.

API has a Plan to continue to replace FRPs with R100NA collectors over a period from 2025 to 2029. It is recommended that API continue the replacement of the obsolete FRPs with the newer R100NA Collector technology.

Table 16: Communication Infrastructure Reinforcement - Estimated annual cost

Meter Replacement Program	2025	2026	2027	2028	2029
Annual Estimated Cost (Material and Labour)	$ 40,000.00	$ 40,600.00	$ 41,209.00	$ 41,827.14	$ 42,454.54

6.4 Transformer Replacement (“run to failure” strategy)

Over the next five years, Algoma Power is proposing a similar approach to what has been done in the past. That is, run the transformers until they fail and replace them with similar sized or “larger” transformers as required to accommodate increased electricity usage.

Depending on external conditions, a typical transformer operates for several decades. When a transformer does fail, it typically takes between 2 and 4 hours to replace it and get the power back on for the customers that it serves.

However, as more customers start getting electric vehicles (EVs), solar panels, or just generally continue to use more electricity as an alternative to gas and other fuel sources, Algoma Power is projecting that more and more transformers will need to be upgraded to accommodate these changes. If demand increases quicker than Algoma Power can upgrade transformers, this could lead to more transformers failing more frequently.

Current Federal statute targets zero-emission vehicle sales of 20% by 2026, 60% by 2030, and 100% by 2035. At present all zero emission light passenger vehicles are assumed to be electric vehicles (EV). Published studies to date find that the typical EV owner wants to charge the vehicle at home. Commercially available home charging systems are designated by Level.

“*The Society of Automotive Engineers outlines three levels of EV charging: Level 1, Level 2, and Level 3. The level chosen for in home installation will depend on a few factors, such as the home's electrical system and the makeup of available public chargers in a given locality.*[8]

Level 1

Automakers often include Level 1 charging equipment with new electric cars. This device plugs into a typical household 120V outlet. The ubiquity of these ordinary household outlets makes Level 1 charging incredibly convenient, even if this type of charging replenishes the car's battery pack at a very slow rate. Plan on seeing the EV add around three to six kilometers of range per hour, depending on the efficiency of the specific battery-powered car, truck, or SUV. This type of charging is much slower, far less efficient, and will cost the homeowner more than Level 2.

Level 1 alone won't be enough to keep up with the charging needs of most EV owners. That said, if the EV owner only drive 35 kilometers or so each day, perhaps the homeowner could get by with Level 1 only.

Level 2

Level 2 charging operates at 240 volts and typically at three to four times the amperage of a lesser Level 1 unit. As such, the majority of Level 2 units add electricity to the EV's battery pack at a rate that's roughly six to eight times faster than Level 1 setups, equating to 20 to 50 kilometers of driving range for each hour of charging.

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[8] Copied from https://www.caranddriver.com/research/a41803552/ev-charging-levels/ , modified for Canadian consumption (kilometers versus miles) and changed from second person (you/your) to generic (the).

But the charging rate of Level 2 can vary quite dramatically. A typical 240-volt, 24-amp unit can put out about 6.0 kW of continuous power. But the fastest possible Level 2 charging is at 80 amps, or 19.2 kW, which is more than three times faster. The hardware on the car dictates the maximum Level 2 charge rate, and most cars aren't capable of charging at 19.2 kW, so the homeowner will want to match the charging equipment to what the EV can handle to avoid paying for capability that cannot be used.

Experts recommend that any EV owner install Level 2 charging at home. If the EV's supplied or optionally available charging cord is incompatible with a 240-volt outlet, the homeowner will need to purchase dedicated Level 2 charging equipment for the home. The homeowner may also need to add electrical capacity to the home. They will need to consult an electrician to ensure the home's electric panel is up to the task.

Level 3 or DC Fast-Charging

Level 3 chargers are the quickest of the bunch. Alternatively known as DC fast-chargers, Level 3 chargers are especially useful during long trips that necessitate charges between destinations, as this sort of charging can add around 150 to 400 kilometers of range in 30–45 minutes. Unlike Level 1 and Level 2 charging, Level 3 setups connect to the vehicle by way of a socket with additional pins for handling the higher voltage (typically 400 or 800 volts).

Tesla's Supercharger network offers Level 3 charging, though the American automaker uses a proprietary plug that only works with its vehicles. However, traditional automakers, such as Ford and GM, are actively negotiating agreements to provide access to the Tesla Supercharger system to their EVs. Alternatively, drivers of other EVs can find Level 3 chargers at a number of stations from providers such as EVgo and Electrify America.

Level 3 charge rates currently range from as little as 50 kW to as high as 350 kW, depending on the charger. But charge rate is a two-way relationship. If the EV can only handle a maximum of 50 kW on a Level 3 charger, then it will not charge any faster than this, even if it's plugged into a charger capable of topping out at 350 kW. Additionally, the charge rate of an EV on a Level 3 charger changes dramatically depending on the battery's state of charge, slowing considerably when the battery pack nears 80 percent capacity in order to prevent overheating or overcharging. For example, it may take just as much time to charge from 80 to 100 percent as it does from 10 to 80 percent. That's why, on long drives with EVs, the quickest way to get back on the road is typically to charge no higher than 80 percent.[1] *"*

Based on the recommendation of the experts, it is highly probable that most EV owners will install a Level 2 charger in their homes. Therefore, it can be safely assumed that over the thirty-five plus (35+) year life of a distribution transformer there is potential for significant load to be added as all passenger vehicles within the API service territory are converted to electric vehicles.

However, the timing and location(s) of the added EV electrical load are unknown. At present, EVs are not a preferred purchase in Northern Ontario. Specifically, the large distances residents are required to travel to acquire goods and services, combined with the limited range of existing battery systems, the reduced operating range of battery systems at extremely low temperatures (winters of -30 degrees Celsius) and the perceived lengthy recharge times are deterrents to widespread acceptance in the North. Nonetheless, sometime after 2035 Northern Ontario residents will only be able to purchase EVs and their uptake will begin to impact local distribution transformers.

The conclusion that we are drawn to is that the impact of residential EV Level 2 chargers will be limited within the planning horizon of this Area Planning Study, 2025 to 2029 and therefore, API need take no proactive action with respect to the replacement of operational distribution transformers. API should continue to replace transformers on an as required basis, as opposed to a proactive basis.

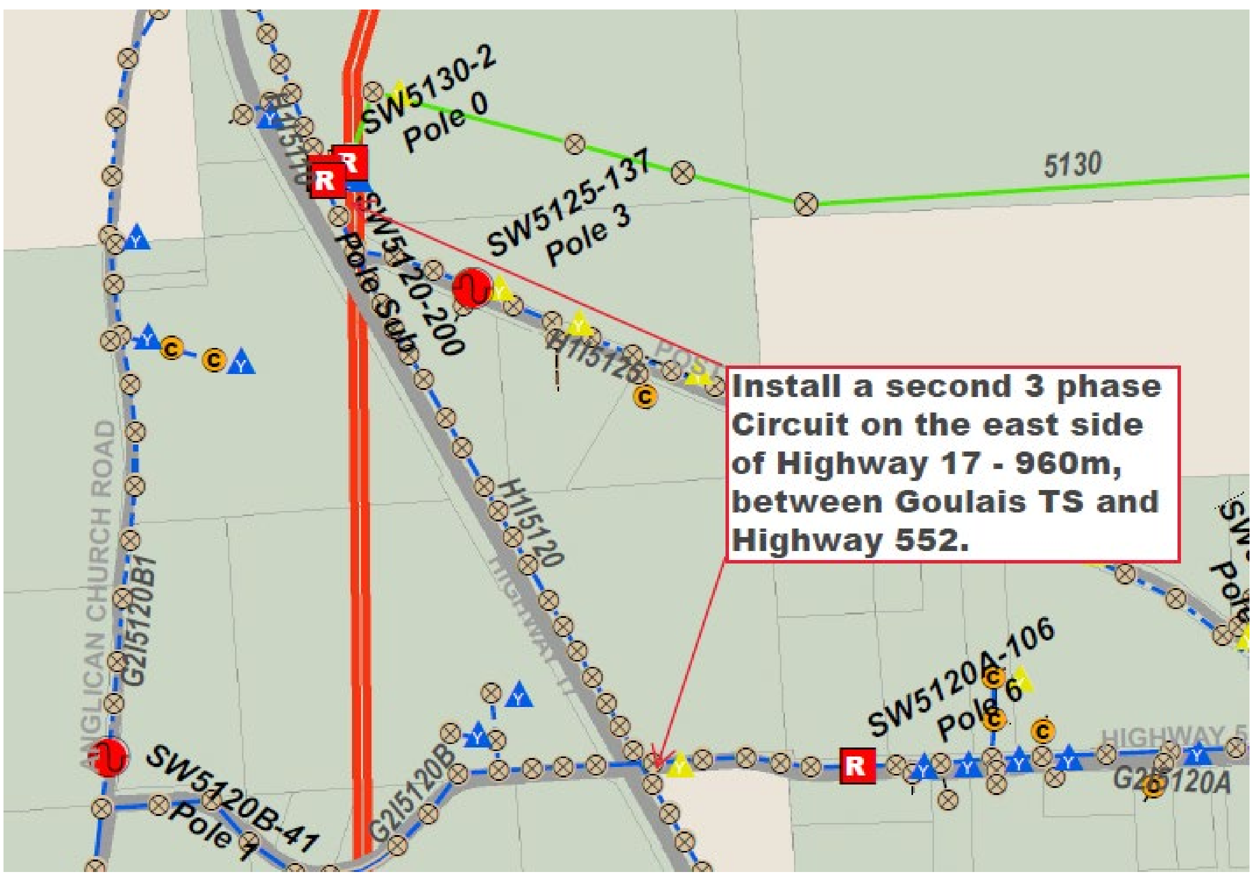
Nonetheless it is recommended that API actively monitor transformer loading and adjust distribution transformer replacement practices as dictated by events unfolding in real time. API should use their existing Meter Data Management Repository (MDMR), Metersense, in combination with the ESRI GIS system and the Customer Information System to closely monitor distribution transformer loading and predict probable overloading situations. If the number of overloaded transformers increases over time, due primarily to EV Level 2 chargers, API may have to adjust distribution transformer replacement practices to meet events in real time.

7. Reliability Driven Projects

7.1 Recommended Solution to improve the reliability of the Goulais 5120 Feeder

Over the seven-year period 2015 to 2022, the Goulais 5120 feeder was identified as the second worst performing feeder in the Algoma Power service territory in terms of Customer-Hours of duration. Customers served by the 12.5 kV 5120 feeder suffered a cumulative 154,469 customer-hours of outages over the seven-year period (Table 14 – Algoma Power Inc Reliability Study). The number one reason for customer outages (42.2% or 65,186 customer-hours) was Planned Interruptions (Table 15 – Algoma Power Inc Reliability Study), specifically planned interruptions along a 960m stretch of single circuit three-phase line connecting the substation with a junction at the corner of Highway 17 and Highway 552. The three-phase line splits into three directions at this junction heading east, south and west to serve a large number of customers. Any maintenance or capital work along this section of line that cannot be safely performed using live-line techniques requires an outage to the entire feeder as no back up connection exists.

Over the past seven years there have been numerous planned interruptions on this 960m section of line. Building a second three-phase circuit on the east side of Highway 17 960 meters from Goulais TS to the corner of Highway 552 and providing intertie switches will prevent total feeder outages in the future and improve reliability to the 5120 customers.



Item	Description	Quantity	Unit Cost	Total Cost
Install 22 poles on the east side of Highway 17 from Goulais Ts to just past the intersection of Highway 552.	In 2027, build a three-phase line connect to the 5120 breaker and intertied to existing east, south and west three-phase limes at the intersection of highway 552 and 17.	22	$9200	$202,400

7.2 Recommended Solution to improve the Reliability of the Desbarats 3600 Feeder

Over the seven-year period 2015 to 2022, the Desbarats 3600 feeder was identified as the third worst performing feeder in the Algoma Power service territory in terms of Customer-Hours of duration. Customers served by the 25 kV 3600 feeder suffered a cumulative 65,950 customer-hours of outages over the seven-year period (Table 14 – Algoma Power Inc Reliability Study).

The leading causes of outages were Tree Contacts (41.8%), Equipment Failures (16.7%) and Scheduled Outages (14.7%).

It is recommended to increase vegetation management efforts on the island to reduce the frequency and severity of tree contact outages. Nonetheless it is probable that Tree Contacts will continue to cause outages over the planning period 2025 to 2029, regardless of increased mitigation efforts because the island is fed from a single 25 kV source with no back up capability. If the source of the outage occurs on the mainland or in a line section between that point where the submarine cable rises on Dours Camp Rd to SW3611-10 at the intersection of 10th Side Road and F and G Line Road then the entire or most of the island is out of power.

It may be possible to improve reliability on St. Josephs Island by installing a suitably size Battery Energy Storage System (BESS) at or near the intersection of 10th Side Rd and F and G Line Rd. A study that includes the kW and kwh capacity required to carry the maximum island load over a defined number of hours for a worst-case scenario, such as the loss of the submarine cable during the winter, would need to be performed. To do so would require gathering significant amount of load and consumption data that may not be available at this time.

7.3 SCADA, Grid Modernization, and Distribution Automation

Algoma Power Incorporated (API) is owned by Fortis Ontario Limited, which is headquartered at Canadian Niagara Power (CNP) in Fort Erie Ontario. API is utilizing a SCADA master installed at CNP in Fort Erie to connect to Intelligent Electronic Devices (IEDs) installed in APIs service territory. API will create a Human Machine Interface (HMI) with each connected IED so that specific personnel at API can access this HMI and view real time system information, thus API begins to have real time monitoring capability of its distribution system. Initially remote-control capability will be disabled. Recommended implementation of remote-control capability will be discussed in this section.

The implementation of SCADA at API is important and necessary for a few reasons.

- The ability to integrate significant amounts of Distributed Energy Resources (DER) into the API distribution system requires that API "…***engage in more active monitoring and management of their systems…***"[9]
- The size and expanse of APIs service territory requires the real time visibility and remote-control capability of SCADA to achieve reliability improvements.

Distributed Energy Resource Integration

The Ontario Energy Board (OEB) in its January 2023 report entitled "Framework for Energy Innovation: Setting a Path Forward for DER Integration", says "The OEB expects distributors to modify their … operations to prepare for DER impacts on their systems…"[10]

The report goes on to say "Historically, the distribution system has been designed to "passively" serve the needs of load customers by sizing network infrastructure to meet peak demand. Given the role DERs are expected to play in the energy transition, DER adoption is likely to become more widespread. Eventually, a significant proportion of customers may engage with the electricity system via some form of DER, whether through a demand response program, a net-metering arrangement, or a battery participating in an aggregation to provide services to a distributor or the IESO. These DERs will impact the distribution system directly, by injecting supply into a system that was not originally designed for a two-way flow of power, or indirectly, by significantly changing load patterns the system has been built to serve. ***Managing these impacts without building oversized, underutilized network assets will require distributors to engage in more active monitoring and management of their systems and approach planning differently.***"[1]

It is impossible to foresee a Distribution System that enables significant penetrations of DER without the LDC having "active monitoring and management of their systems". An LDC can neither monitor nor control its distribution system without SCADA.

The Plan to implement SCADA that API has developed (thus far) provides API with the ability to "engage in more active monitoring…of their systems" and ultimately will provide the data to "approach planning differently." A discussion of and recommendation for the next phase of Grid Modernization at API will describe how the LDC can "engage in more active monitoring **and management** of their systems…" will be included at the end of this section.

Reliability

[9] Section 4.4 – The OEB's Conclusions - - "Framework for Energy Innovation: Setting a Path Forward for DER Integration", January 2023 report. Emphasis added
[10] Section 1 – Executive Summary - "Framework for Energy Innovation: Setting a Path Forward for DER Integration", January 2023 report.

In the past, an outage would occur, customers would call to report being out of power, someone would correlate the addresses of the customers reportedly out of power to a map and dispatch a line crew to the approximate location to investigate. The crew would patrol the line to visually inspect the condition of both the line and the switches that may or may not have operated creating the outage. The patrol might include driving, walking, and returning to the service center to get off road equipment such as snowmobiles, All Terrain Vehicles (ATVs) or boats to patrol inaccessible sections of line. The patrol could take many hours depending upon weather and terrain. Eventually the open switch(es) and the cause of outage, which would likely be at different locations on the line(s) would be found, repaired and power restored. The entire scenario would take between 2 and 24 hours to restore power.

In 2020, Algoma Power implemented an outage Management System (OMS), which has reduced outage time by automating some of the outage restoration steps. Specifically, the OMS uses an up-to-date topology (connectivity) of the API distribution system, combined with customer information linked to the customers connection point on the distribution system to quickly and accurately identify the location of customers out of power and identify the likely protective element (switch, sectionalizer or recloser) that has opened as a result of the fault on the distribution system. Thus, line crews can be dispatched to a more targeted line patrol area with a high probability that the fault is downstream of the protective device that OMS has predicted to be open.

Phase 1 of the API Plan for SCADA utilizes strategically located IEDs that can communicate with a SCADA master station to provide real time information that can reduce the length of some outages. The IED measures the fault current during the fault event. This information coupled with the system impedance can add to the available OMS information and help System Operators pinpoint the location of the fault. The line crews can then be dispatched directly to the likely repair location hopefully without the need for the line patrol that takes so much time. The ability to locate the fault using the real time monitoring capabilities of the IEDs reduces outage times, increases system reliability and improves the customer experience.

The active monitoring ability of API is significantly improved by Phase 1 of the Plan.

<u>The Plan</u>

Grid modernization is a stepwise process that involves adding software, equipment, communications and staff capabilities to improve reliability to the customer and enable DER integration.

Phase 1

Software - API has decided to use the existing Survalent SCADA master station, located at Canadian Niagara Power to provide real time monitoring within the API service territory. By leveraging the existing CNP SCADA license API can "acquire" and operate the necessary software at a reduced cost.

Equipment and Communications – API will acquire, install and connect various Intelligent Electronic Devices (IEDs) located throughput the API service territory beginning in 2023. Communications media, appropriate to the location of each device, will be acquired, installed, tested and operated to allow real-time monitoring of the API distribution system. Each IED will be programmed to be remote control ready when API is prepared to establish remote control capability. The initial annual deployment plan is described in detail below tabulated by location.

2023

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
6	SW038	Recloser	Cooper Form 6	Echo Bay	Sault	2023
8	SW3210-91	Recloser	SEL-651R	Bar River DS	Sault	2023
9	SW3220-88	Recloser	SEL-651R	Bar River DS	Sault	2023
12	SW2020	Recloser	SEL-651R	Bar River DS	Sault	2023
26	SW2012	Recloser	Cooper Form 6	Bruce Mines DS	Desbarats	2023
32	SW5200-1	Recloser	SEL-651R	Batchewana	Sault	2023
34	SW5221-63	Regulator	Cooper CL7	Batchewana (North)	Sault	2023
41	SW5121B-149	Regulator	Cooper CL7	Mission Rd	Sault	2023
45	Hawk Junction DS	DS	SEL RTAC	Hawk Junction DS	Wawa	2023
53	SW2036	Recloser	SEL-651R	Ratio Bank	Wawa	2023
59	Dubreuilville 86 DS	DS	SEL RTAC	Dubreuilville 86 DS	Wawa	2023

2024

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
5	Echo River TS	TS	Schneider ION8650	Echo Bay	Sault	2024
10	REG-ER1	Regulator	Cooper CL6B	Bar River DS	Sault	2024
19	SW2005	Recloser	SEL-651R	Desbarats DS	Desbarats	2024
20	SW2010	Recloser	SEL-651R	Desbarats DS	Desbarats	2024
23	SW2007	Switch	ABB Elastimold	Desbarats DS	Desbarats	2024
25	Bruce Mines DS	DS	SEL RTAC	Bruce Mines DS	Desbarats	2024
27	SW3820-2	Recloser	SEL-651R	Bruce Mines DS	Desbarats	2024
31	Batchewanna TS	TS	Schneider ION8650	Batchewana	Sault	2024
42	SW5120B-174	Recloser	SEL-651R	Goulais Junction	Sault	2024
43	SW5120A-106	Recloser	SEL-651R	Goulais Junction	Sault	2024
44	SW5121-71	Recloser	SEL-651R	Goulais Junction	Sault	2024
52	SW9400-84	Recloser	SEL-651R	Ratio Bank	Wawa	2024

2025

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
1	Northern Avenue TS	TS	Schneider ION8650	Sackville Road	Sault	2025
3	SW3120-10	Recloser	SEL-651R	Garden River DS	Sault	2025
4	SW3110-7	Recloser	SEL-651R	Garden River DS	Sault	2025
7	Bar River DS	DS	Transformer Assets	Bar River DS	Sault	2025
16	REG3600-163	Regulator	Cooper CL6B	SJI	Desbarats	2025
17	SW3610D-92	Recloser	SEL-651R	SJI	Desbarats	2025
48	Wawa No 1 DS	DS	Transformer Assets	Wawa #1 DS	Wawa	2025
49	SW9110-24	Recloser	Cooper Form 6	Wawa #1 DS	Wawa	2025
50	SW9120-25	Recloser	Cooper Form 6	Wawa #1 DS	Wawa	2025
58	Hollingsworth TS/GS	TS	Schneider ION8650	East of Wawa	Wawa	2025

2026

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
2	Garden River DS	DS	Transformer Assets	Garden River DS	Sault	2026
11	CAP3210-118	Capacitor	ABB CQ900	Bar River DS	Sault	2026
13	Desbarats DS	DS	Transformer Assets	Desbarats DS	Desbarats	2026
14	CAP3400-140	Capacitor	ABB CQ900	Bar Road	Desbarats	2026
18	REC052	Recloser	SEL-651R	Desbarats DS	Desbarats	2026
21	SW3400-136	Recloser	SEL-651R	Desbarats DS	Desbarats	2026
22	SW3400-9	Recloser	VXE-19	Desbarats DS	Desbarats	2026
24	CAP2022	Capacitor	ABB CQ900	CASS	Desbarats	2026
28	CAP3820-188	Capacitor	ABB CQ900	Bruce Mines DS	Desbarats	2026
33	SW5221-64	Regulator	Cooper CL7	Batchewana (North)	Sault	2026
46	Da Watson TS	TS	Schneider ION8650	Wawa	Wawa	2026
66	SW20XX	Recloser	SEL-651R	Desbarats DS	Desbarats	2026

2027

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
15	SW3410-75	Recloser	SEL-651R	Maclennan Road	Desbarats	2027
35	SW5220-62	Regulator	Cooper CL5E	Batchewana (North)	Sault	2027
36	SW5210-72	Regulator	Cooper CL7	Batchewana (South)	Sault	2027
51	Wawa No 2 DS	DS	SEL RTAC	Wawa #2 DS	Wawa	2027
54	SW9200-1	Recloser	Cooper Form 6	Wawa #2 DS	Wawa	2027
55	SW9200-2	Recloser	Cooper Form 6	Wawa #2 DS	Wawa	2027
56	SW1119	Recloser	SEL-651R	Wawa #2 DS	Wawa	2027
57	SW1120	Recloser	SEL-651R	Wawa #2 DS	Wawa	2027
61	SW8100-1	Recloser	SEL-651R	Hawk Junction DS	Wawa	2027

2028

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
29	Andrews TS	TS	Schneider ION8650	Montreal River	Wawa	2028
30	Mackay TS	TS	Schneider ION8650	Montreal River	Wawa	2028
47	SW9410E-31	Recloser	Cooper Form 6	Wawa	Wawa	2028
60	Dubreuilville 87 DS	DS	Transformer Assets	Dubreuilville 87 DS	Wawa	2028
62	SW2061	Recloser	SEL-651R	Goudreau	Wawa	2028
63	SW2062	Recloser	SEL-651R	Goudreau	Wawa	2028
64	SW2078	Recloser	SEL-651R	Bar River DS	Sault	2028
65	SW20XX	Recloser	SEL-651R	Desbarats DS	Desbarats	2028

2029

NO.	ASSET (DEVICES ID)	ASSET TYPE	CONTROLLER TYPE	LOCATION	AREA	TARGET YEAR
37	Goulais TS	TS	Transformer Assets	Goulais	Sault	??
38	SW5130-2	Recloser	SEL-651R	Goulais TS	Sault	??
39	SW5110-198	Recloser	SEL-651R	Goulais TS	Sault	??
40	SW5120-200	Recloser	SEL-651R	Goulais TS	Sault	??

Staff – API will create a Human Machine Interface (HMI) with each connected IED. Specific API staff will be trained in the use of SCADA so that they API can access this HMI and view real time system information. In addition, they will be trained in the functionality of the SCADA in order to develop the skills required to define data gathering needs that will develop as DER begins to penetrate the API distribution system. Thus, API begins to have real time monitoring capability of its distribution system.

Phase 2

API has a large, mostly rural service territory, with very few tie lines that allow one feeder to back up another. One location where back up capability exists is on the Echo River ER1 and ER2 sub-transmission system. This 34.5 kV system is a loop feed for Garden River DS, Bar River DS, Desbarats DS and Bruce Mines DS as well as one large directly fed sub-transmission customer.

API has developed a plan to install remotely controllable IEDs on the ER1 and ER2 sub-transmission systems such that a faulted line section can be easily identified, isolated and power restored using the line sections that remain in-service. The project plan also calls for the purchase and installation of Fault Locating, Isolation and Service Restoration (FLISR) software in the SCADA master at CNP to facilitate automatic power restoration if a fault occurs on either ER1 or ER2. Section 5.2 of this report contains the proposed locations, installation timing and costs for this Distribution Automation Project. The 6000+

customers served by the ER1 and ER2 sub-transmission systems will accrue immediate reliability benefits upon completion of Phase 2.

Upon completion of Phase 1 and, in particular, Phase 2, API will have the ability to "engage in more active monitoring **and management** of their systems…". Within the planning horizon of this Area Planning Study, 2025 to 2029, API does not anticipate enabling the ability to remotely control IED's. This capability is expected to be reviewed over the course of the years and implemented at some point in the future by utilizing the Control Room at CNP or possibly a Control Room at API or both.

Installation of a Control Room at API, and possibly utilizing it as a 8 to 5, Monday to Friday operating facility could have benefits as a back up to a main Control Room in Fort Erie. In the event of a catastrophic weather-related failure at the Fort Erie Control Room, the geographically diverse location of an API back up Control Room could prove beneficial.

It is recommended that API complete Phase 1 and Phase 2 of the proposed Grid Modernization and Distribution Automation be completed as resources and budget allow.

8. Innovation and Integration for DERs and EVs

Algoma Power Incorporated (API) is not a large Ontario Local Distribution Company (LDC) by any measure, except the size of its service territory and therefore API cannot afford to waste time, money and energy experimenting with unproven processes and methodologies that purport to enable the integration of DERs and EVs into the legacy distribution system that API has so carefully and thoughtfully developed over the past eighty plus years. However, API cannot sit on the sidelines and do nothing as the requirement to integrate DER grows; there is a need for API to develop an understanding of the state of the available technology and what can and cannot work for this unique LDC. The five-year planning horizon within this Area Planning Study provides the opportunity for API to learn and grow into an LDC that can provide *reasonable* access for DER and EV into a distribution system that, because of the size of the service territory and its location in Northern Ontario, has:

- a low customer density, and
- long heavily loaded single-phase feeders, and
- weak, "not stiff" feeders that have lower than average available fault currents, and
- a customer base that will likely adopt DER and EV at a much slower pace than the rest of the province.

The Ontario Energy Board (OEB) in its January 2023 report entitled "Framework for Energy Innovation: Setting a Path Forward for DER Integration", says "The OEB expects distributors to modify their … operations to prepare for DER impacts on their systems…"[11]

The report goes on to say "Historically, the distribution system has been designed to "passively" serve the needs of load customers by sizing network infrastructure to meet peak demand. Given the role DERs are expected to play in the energy transition, DER adoption is likely to become more widespread. Eventually, a significant proportion of customers may engage with the electricity system via some form of DER, whether through a demand response program, a net-metering arrangement, or a battery participating in an aggregation to provide services to a distributor or the IESO. These DERs will impact the distribution system directly, by injecting supply into a system that was not originally designed for a two-way flow of power, or indirectly, by significantly changing load patterns the system has been built to serve. ***Managing these impacts without building oversized, underutilized network assets will require distributors to engage in more active monitoring and management of their systems and approach planning differently.***"[1]

The proposed breadth and timing of the projects described in Section 7.3 – SCADA, Grid Modernization and Distribution Automation provide API with a reasonable and workable base from which API can build to meet the OEB's expectations.

8.1 The "Smart Grid Pyramid"

In the early 2000's BC Hydro developed a "Smart Grid Pyramid" to describe how a functional Smart Grid might be built. Each technology on a layer higher than the last is dependent upon data, information,

[11] Section 1 – Executive Summary - "Framework for Energy Innovation: Setting a Path Forward for DER Integration", January 2023 report.

calculations or system visibility that is provided by technology within the lower layer(s). The technology on each layer cannot fully function nor operate efficiently and effectively without the data, information, calculations or system visibility that is provided by technology within the lower layer(s). In addition to the layers of technology, the LDC must develop layers of understanding of the needs of each level and develop the skills to enable the lower level(s) to provide the required information to the subsequent level(s). It is a classic example of how "An LDC must crawl before it walks before it runs". It must be said that BC Hydro's Smart Grid Framework is not the only way to build a Smart Grid, but its logic provides a guidance that is compelling.

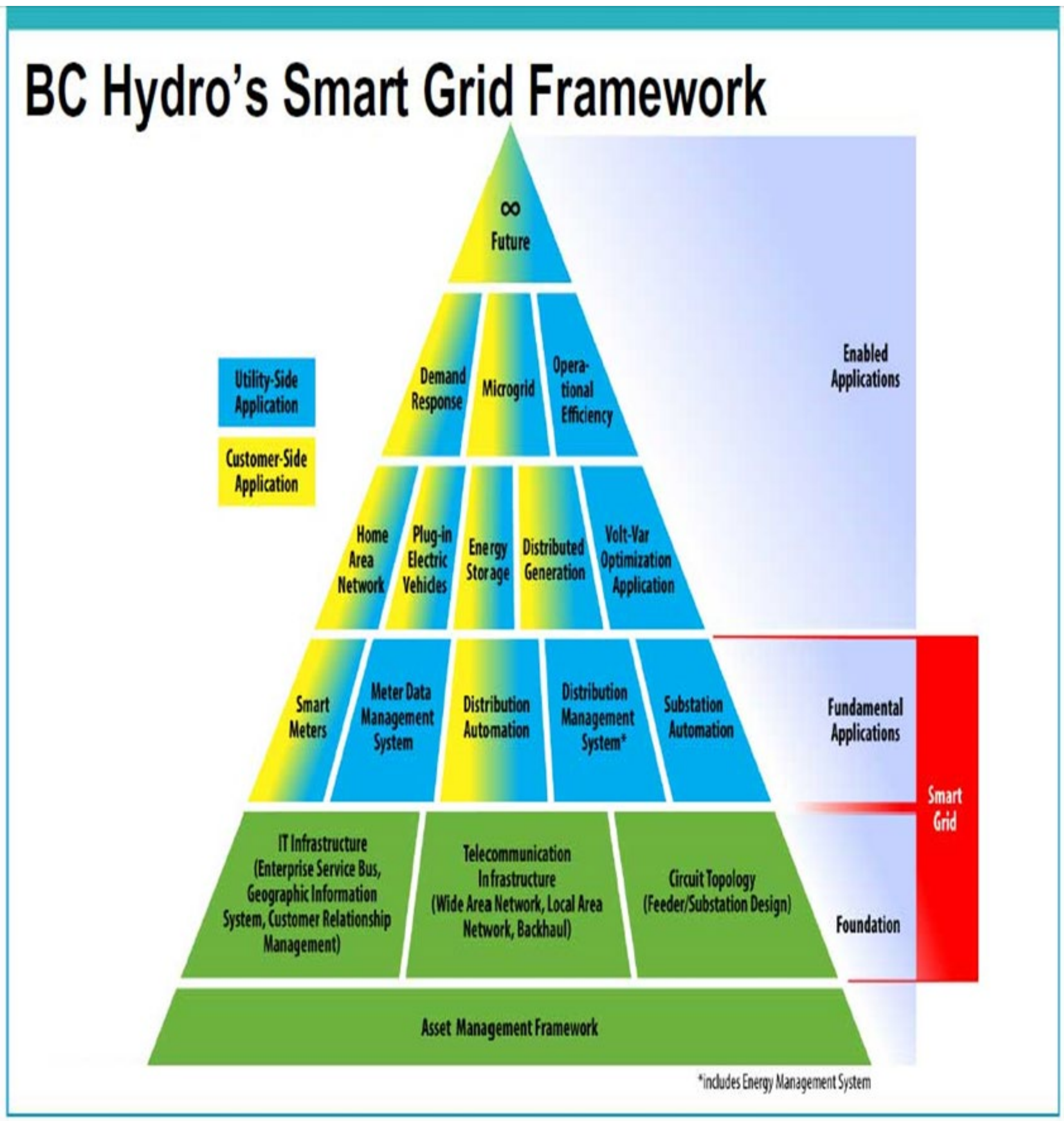


Figure 36: Smart Grid Pyramid

Foundational Layers - It is important to note how much API, and Fortis Ontario, have achieved with respect to the Framework. Most, if not all of the technology within the green foundational layers is up and running at API or is contemplated within this Area Planning Study.

- Asset Management is well established as a practice and managerial process at API. Its use in the creation of this Area Planning Study and the subsequent Distribution System Plan is required by the Ontario Energy Board and the processes required to make Asset Management operational are engrained within the normal work at API.
- IT Infrastructure is widely available within API, and it is kept current to meet the cybersecurity requirements of the OEB and operational needs of the LDC.
- Telecommunication Infrastructure – is mature within the API head office. The telecommunication infrastructure required to communicate with, and control Intelligent Electronic Devices (IEDs) geospatially scattered in the large API service territory is being developed within the projects defined in Section 6.3.
    - ONGOING NEED - It is important that API staff become knowledgeable and educated on the communication needs of each technology in the higher layers to ensure that communication systems with sufficient throughput, latency and bandwidth to meet the needs of the technologies in the higher layers are implemented within the foundational communication systems or upgrades are provided for in a timely manner. It is important for the Engineering staff at API and/or Fortis Ontario to develop and continually upgrade their knowledge of communication systems and Smart Grid needs for those systems.

Fundamental Applications Layer – The Fundamental Applications layer describes a number of technologies that are in place or planned for at API.

- **Smart Meters** – All LDCs in Ontario were required to install Smart Meters on or about 2009, therefore API has a functional Smart Meter system.

  Unfortunately, the OEB did not look ahead to the communication needs of the technologies on higher layers, technologies the OEB would ultimately mandate LDCs to incorporate into their operations, when creating the communication specification for Smart Meters[1].

  The OEB required that LDCs consider only the metering and meter reading requirement of Smart Meters when specifying and paying for the communication infrastructure underpinning the Smart Meter system deployed. Two-way communications and the ability of the Smart Meter system to gather distribution data and provide LDC distribution system visibility were discounted and in fact discouraged when purchasing the initial system. This has led to LDCs owning Smart Meter systems that cannot provide two-way communication or where the system installed has two-way communication capability the LDC cannot realize operational efficiencies with the system as originally installed.

  API is fortunate to have chosen the Sensus Flexnet System. The Sensus Flexnet system utilizes licensed frequency, two-way communications that can provide;

    - a secure communication path to every customer, and their “Home Area Netweork” via Zigbee (SEP II) and their meter, and
    - real time or near real time operational load flow data from each meter point, and
    - last gasp outage data to the Outage Management System, and
    - possible real time or near real time communication with IEDs.

The “base” model iConA (Gen 4) Sensus single–phase meter that API is purchasing today have the following capabilities:

- Load/generation data can be gathered using configurable interval (5 minute to more than an hour), and
- Voltage measurements - gathers six-hour average 240 voltage at the meter point, and
- Voltage alarms that are configurable, and
- Configurable measurement reporting interval, i.e. the maximum tine interval between measurement reading reporting to the TGB, typically 1-1/2 to 3 hours currently, and
- Tamper detection, and
- High temperature detection, and
- Power outage and restoration notification, and
- Remote Zigbee (SEP II), radio firmware download.

The iconA Sensus meter also has the following optional capabilities that can be ordered into specific meters at an additional cost.

- Power quality events and alarms, and
- Remote disconnect/ reconnect, and
- Load limiting, and
- Advanced event logging, and
- Home Area Network options.

<u>Preparation for DER and EV Deployment</u>

As API implements project “6.3 – Communication Infrastructure Reinforcement for Smart Meters” over the 2025 to 2029 period, it needs to consider the data gathering and two-way communication capabilities of the Sensus Flexnet system with respect to the Smart Grid needs of technologies found on the levels four and five of the BC Smart Grid Framework.

Specifically, technologies such as

- Home Area Network, and
- Electric Vehicles, and
- Distribution Energy Resource Management Systems (DERMS) which allow the LDC to manage fourth- and fifth-layer technologies such as Energy Storage (DER), Distributed Generation (DER), Volt-Var Optimization Application, Demand Response, Microgrid and Operational Efficiency…

…all need some of the data and two-way communication capabilities that a strategic expansion of the Sensus Flexnet system might be able to economically provide.

However, the practical implementation of this possibility requires study and objective cost-benefit analysis. The number of Tower Based Gateways (TBGs) within the API service territory would need to be increased, additional licensed 900 MHz frequencies would need to be secured, backhaul communication infrastructure would need to be leased or installed to ensure that both the metering requirements and operational Smart Grid needs could be provided economically by the Sensus system. Alternatives, such as broadband internet are or will soon be available at all Ontario meter locations and may well be a cheaper alternative or one with throughput, latency and bandwidth advantages that meet or exceed the needs of upper layer technologies described in the Smart Grid Framework.

RECOMMENDATION 8.1 – That in 2024 API establish a project to

1. Explore and document the data and control needs of DERMS, a Home Area Network interface and Electric Vehicle recharging, and
2. Map the data and control needs of these fourth and fifth layer technologies with the capabilities of the Sensus Flexnet system, and
3. Where the Sensus Flexnet system could provide the necessary two-way communication, control and/or data gathering capability perform a cost benefit analysis to establish which, if any service(s) are economically supplied by the Sensus system, and
4. Where appropriate, implement metering and communication upgrades to the Sensus Flexnet system, possibly as part of Project 6.3, to enable the integration of DER and EV into the API distribution system.

8.2 Meter Data Management System (MDMS)

MDMS is also known as a Meter data Management Repository (MDMR) in Ontario. API owns and operates a Harris Metersense MDMR.

The Harris Metersense MDMR stores a wealth of data that is made available from the "base" Smart Meter system that LDCs were forced to specify in the 2009 OEB mandated roll out. This includes, but is not limited to:

- For Single-Phase Meters
    - Hourly load or generation data, and
    - Six-hour average, instantaneous maximum and minimum voltage (@ 240 V level) at each meter, and
    - Outage blink count, and
    - Last gasp outage data, and
- For three-Phase meters
    - Elster A3 meters can be purchased with full power quality monitoring capabilities, such as
        - Harmonics
        - Voltage swell and sag recording,
        - Oscillography data for fault events which includes several cycles of pre-event data.
        - …and much more.

RECOMMENDATION 8.2 – That in 2024 API establish a project to

1. Document the operational and metering data currently being gathered and stored in the Metersense MDMR, and

2. Map the data and control needs of third, fourth and fifth layer technologies, as established by Recommendation 8.1, with the data currently being captured by the Sensus Flexnet system and stored in Metersense, and
3. Where the data stored in Metersense could provide useful inputs to imminent or implemented projects such as the API OMS, Project 7.3 - Distribution Automation Project, 6.4 – Transformer Replacement or others create the necessary software ties and develop information outputs that are strategically important to the integration of DER and EV at API. An example might be predictive transformer loading reports that identify potential EV installations, encroachment on transformer loading capabilities and possible pilot locations for LDC EV charging control systems such as DERMS.

8.3 Innovations for DERs and EV integration

- **Distribution Automation** – Project 7.3 – SCADA, Grid Modernization and Distribution Automation (DA) provides the foundation that will allow API to understand and gain experience with DA. DA is a foundational application in the BC Smart Grid Framework. It is foundational because the visibility and control capabilities that are gained when implementing a DA functionality are necessary enablers for layer four and five Smart Grid technologies. Without DA, API cannot enable DER and EV integration at scale. Only limited amounts of DER and EV can be integrated without DA in place.

  With API possibly rolling out Fault Locating Isolation and Service Restoration (FLISR) as part of the DA plan, API joins a number of Ontario LDCs who are piloting DA using FLISR as their first DA functionality deployed.

- **Substation Automation** – A subset of Project 7.3 – SCADA, Grid Modernization and Distribution Automation (DA) substation automation enables real time monitoring and remote control at the substation. The proposed DA Project 7.3 will create data points at every API substation to allow real time monitoring at critical power quality parameters such as voltage, current, power factor, regulator tap position, capacitor on/off status, power transformer thermal status and others. At some future point in time API will be able control many of these parameters using traditional distribution voltage and current management tools such as regulators and capacitors as well as Advanced Inverter Functionalities (AFI) found in CSA C22.3 No.9 compliant inverters used on Battery Energy Storage Systems (BESS), rooftop Solar Photovoltaic Systems (PV) and Electric Vehicle Power Exporting (EVPE) equipment. Visibility and control at the substation are key requirements to enabling DER and EV integration with the API distribution system.

- **Distribution Management Systems includes Energy Management Systems** – Advanced Distribution Management Systems (ADMS) and Distribution Energy Management Systems (DERMS) have similar capabilities and operational functionalities, but are distinct and different systems. In the future Distribution Systems are likely to be owned, maintained and operated differently than today. Whereas these three functions are inherent at each and every LDC in Ontario, and the LDC performs all three functions, it is possible that in the future a separate Distribution System Operator (DSO), which may not be a part of the LDC could take on the operating functions of the distribution system. Therefore, it is unclear if every LDC will require either an ADMS or a DERMS or both. Nonetheless, until the final decision is made it is incumbent upon each LDC, including API, to research the need for and capabilities of ADMS and DERMS and begin preparations to install and operate such system(s) within the LDC.

- **Non-Wires Alternatives (NWA)** – API is not now in a position to implement control of DER and EV that would allow deferral of poles and wires solutions to power quality (eg. voltage), reliability (eg Microgrid(s)) and thermal (eg. overloaded transformers or conductors) problems on the distribution system, when caused by DER or EV integration. However, there are at least two NWA solutions that API could deploy to alleviate low voltage problems that are common in a geospatially large, sparsely populated service territory such as APIs. Problems which may prevent DER or EV integration.

  - The Gridbridge ERMCO Energy Router – Is a device that offers real time visibility and autonomous voltage control at the 120/240-volt secondary buss level. The device offers the following functionality.
    - Real time secondary system information, and
    - Autonomous independent voltage control on each leg, buck or boost, of the split phase 120/240-volt secondary buss, and
    - VAR compensation at the secondary buss of up to +/- 5 kVAR in continuously variable amounts, and
    - Remote Network connection via the wireless radio (cell) network 2G or greater, and
    - Standard pole mounting, similar to pole mounted transformers.

  - The Gridbridge ERMCO Energy Router enables, but does not assure, seamless integration of renewables and energy storage (DER) by managing the secondary buss voltage. However, there is a significant caution that must be into account when deploying the router. The router is an electronic device that uses power electronics' and as such cannot endure significant overloads. When Gridbridge says the unit is rated at 50 kVA they mean 50 kVA instantaneous at the cycle level….not kVA as measured by LDCs using electro-mechanical meters that average the kVA over a period of approximately forty-five (45) minutes. Pre-deployment studies, using devices that can measure the size and duration of cycle level kVA loading that exceeds 50 kVA are necessary to ensure the kVA loading at a proposed transformer does not exceed the kVA capabilities of the Gridbridge unit.

    The Gridbridge unit can maintain secondary buss voltage at nominal even if input voltage (either on the grid or load side of the unit) falls or rises to a maximum of +/-10% of nominal. Below or above 10% the voltage on the secondary buss will follow the input voltage …so

-11% input voltage is -1% on the secondary buss, and -12% input voltage is -2% on the secondary buss, etc.

- Grid Edge Control using an ENCO Varentec Device – The Varentec unit is a pole mounted device that connects to the secondary buss of a transformer, measures both 120 volt legs and injects capacitive kVAR up to 10 kVAR when the measured line-to-ground voltage (120V) on either leg falls below a user defines voltage setpoint. The device offers the following functionality.
  - Real time secondary system information, and
  - Autonomous independent voltage support on each leg, boost only, using reactive power injection as voltage falls below a user defined setpoint, and
  - VAR compensation at the secondary buss of up to – 10 kVAR in 1 kVAR increments on a sub-cycle basis, and
  - Over the air setpoint and firmware upgrades, and
  - Standard pole mounting, below the pole mounted transformer.

- Grid Edge Control using an ENCO Varentec Device enables, but does not assure, seamless integration of renewables and energy storage (DER) by
  - Better accommodation of high penetrations of EV charging and industrial loads on feeders by ensuring that 114 volt minimums are met, and
  - Improving feeder energy savings by creating increased margin above 114V to enable Conservation Voltage Reduction (CVR) schemes, and
  - Increased solar hosting capacity without overvoltage issues by allowing station taps to be lowered thereby creating more local upper margin below 126V.

  Grid Edge Control using an ENCO Varentec Device enables, seamless integration of renewables and energy storage (DER) by ***supporting not controlling*** secondary buss voltage using capacitive reactance. That means the voltage can be supported or increased by injecting reactive power into the secondary buss when the voltage falls below a user defined setpoint BUT the device cannot and does not manage high voltage.

RECOMMENDATION 8.3 – That API commit Engineering resources to participate in technical organizations, committees, working groups and standards development and review activities to allow API to understand and prepare for the transition from passive system operator to active Distribution System Operator (DSO). As stated by the OEB, this transition… ***"will require distributors to engage in more active monitoring and management of their systems and approach planning differently.***"[1] API cannot be in a position to strategically understand the "best" direction that it can pursue to meet the expectations of the OEB without understanding the needs and requirements of the technologies on Layers four and five of the BC Smart Grid Framework.

9. Improve System Resilience for Climate Change

The effects of climate change, including the intensity and frequency of extreme weather and changing weather patterns, continues to cause damage to the power system. These climate risks are projected to increase into the future and compounding the situation when the reliability and resiliency of the grid is more critical than ever to society due to electrification of transportation.

In the past few years, API has participated in a few studies conducted by its parent company Fortis Inc. These studies provide an overview of how climate change risks and impact of extreme weather events are affecting the power system in general as well as mitigation strategies that have been implemented across the utilities to adapt to these extreme weather events. In a recent study performed by a consulting company Ernst & Young (EY), as one of the distribution participants, API submitted the asset data (poles, transformers, lines, cables, and substations) within grids representing 15% of its service territory with highest customer density. EY overlaid the asset data with the location-based climate risk exposure data derived from a prediction model they developed for this study. The study is still in progress. The goal of the study is to identify the asset-specific vulnerability ratings to a set of climate hazards due to inherent attributes of asset in question. The climate hazards considered in this study includes heat stress/waves, extreme cold events, higher or lower ambient temperatures, wildfire, flooding, strong winds, snow/ice storms, and water stress. For each climate hazard category, the prediction model forecasts its change to a specific location under both RCP 2.6 (low emissions) and RCP 8.5 (high emissions) scenarios.

Although previous studies, specifically, the EY's study, provide a framework to estimate and visualize the potential impact associated with specific climate hazards, they are insufficient to support API's strategic decision-making on enabling proactive risk management and optimizing future investment strategies in the context of a changing climate landscape. For example, in EY's study, the location-based climate exposure data usually has a spatial resolution of 33km x 33km. The coarse resolution cannot differentiate the subtle differences from location to location in terms of the vulnerability to a specific climate hazard, resulting in the study results may end up with being meaningful as a reference only.

In order to be proactive to combat climate change and improve the resiliency of API's system, it is recommended to conduct a detailed "**Climate Vulnerability Assessment**" that comprises the geospatial and statistical analysis on API-owned critical in-service structures and facilities. This study should be targeting at identifying critical assets located within high demand zone which has higher possibility to be hit by extreme weather events. The study should include GIS overlay and recommended design change and cost implication. In addition, the prediction around climate change used in this study shall focus on the impacts at a more localized level, i.e., local weather events, local anecdotal information, and local operational knowledge. As climate science is evolving and climate data progresses, it will become better at predicting local climate impacts.

Industry Associations such as CSA and CEA recognize that the impacts of extreme weather events highlight the susceptibility of utility's critical infrastructure to climate change. CSA has or is updating various standards including the overhead systems standard and underground systems standard to give direction guidance on increasing weather-related parameters.

With a detailed assessment that can increase the visibility of API's asset climate-risk vulnerability, and design standards/guidelines developed by key groups such as CSA, API will become more informed of the grid resiliency measures to be taken and transform from the reactive mode to a proactive mode in combating climate change.

Due to the knowledge limitation at this time, a list of best practices on what can be considered and/or implemented for dealing with the impacts of climate-related events may represent the best adaptation plan API can have at this moment. Historically, API's system is susceptible to a few climate hazards, including wildfire, strong winds, and snow/ice storms. Figure 37 shows the average wind speed and wildfire disturbances within API's service territory. With the predicted increased ambient temperature and heatwaves, API may be subject to an aggressive demand increase given of the low necessities to start with.

The best practices include:

1) Apply "overbuild" design standards in targeting areas associated with known climate-risks based on experience, i.e., within weather-sensitive areas that manifest relationships with certain inclement weather conditions. "Overbuild" includes but is not limited to:
- Upgrade the design standard with a stronger pole class
- Reinforce the overhead line design standard with shorter ruling span
- Apply high-profile overhead design standard to increase clearance and separation for increased sag
- Apply underground design & build (e.g., pad-mounted transforms, underground feeder exits, and etc.) if deemed necessary
- Increase size of conductors and cables to accommodate derated capacity due to future ambient temperature changes

2) Increase the frequency and coverage of inspection program to monitor asset conditions and report abnormal or premature-wear situations that may or may not be related to climate change.

3) Review "vegetation management" standards and increase tree-trimming frequency and intensity in targeting areas to mitigate the risks related to wildfire specifically.

The above "best practices" have a cost implication. Since it decision-making must be justified with field investigation and detailed engineering study, no specific capital projects for this matter have been outlined in this study. However, the incremental costs may be embedded in the unit cost estimate of projects that falls in these targeting areas and/or asset categories.

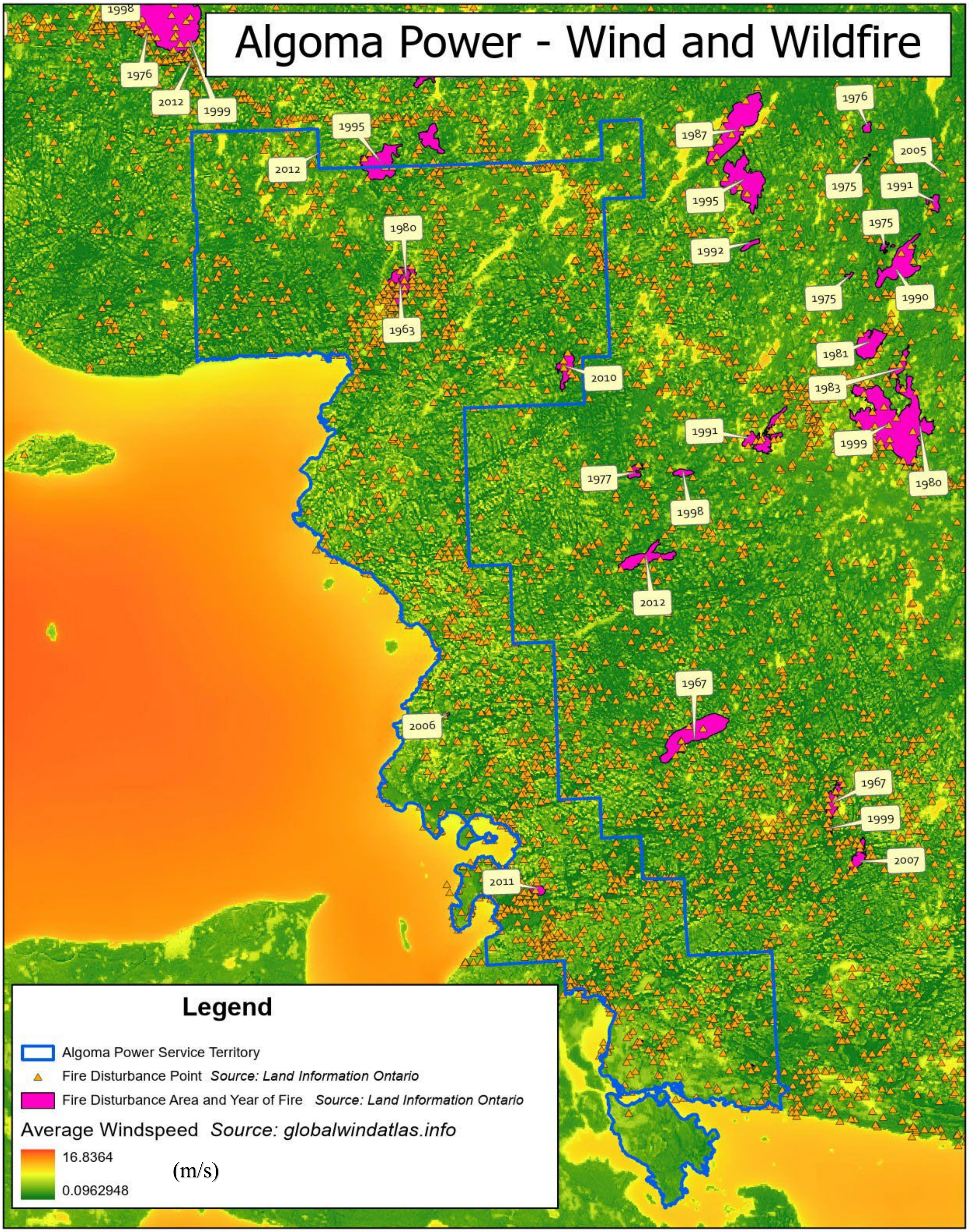


Figure 37: API Historical Average Wind Speed and Wildfire Disturbance