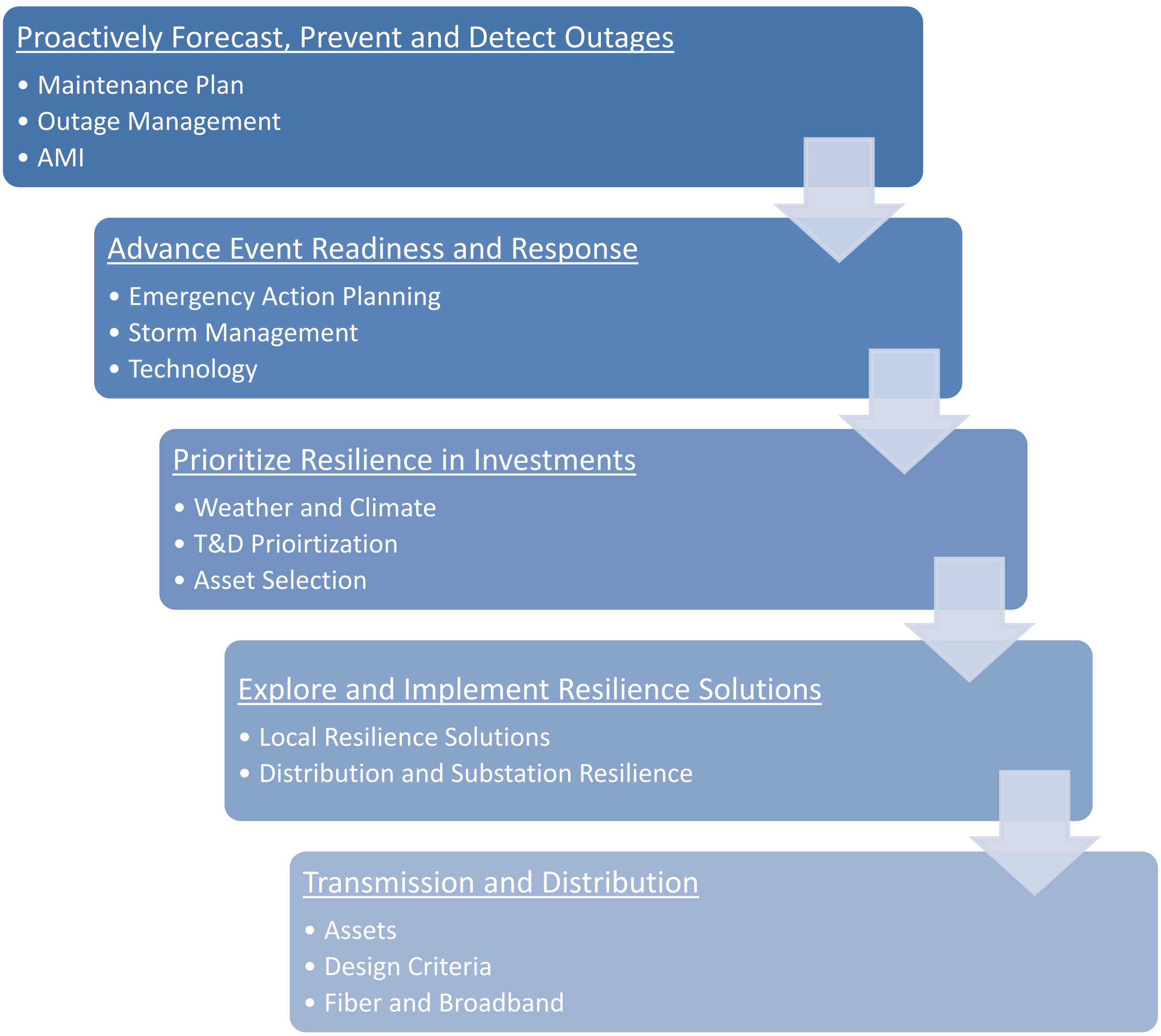
5 Pursue Operations Reliability

5.1 Introduction and Outage Statistics

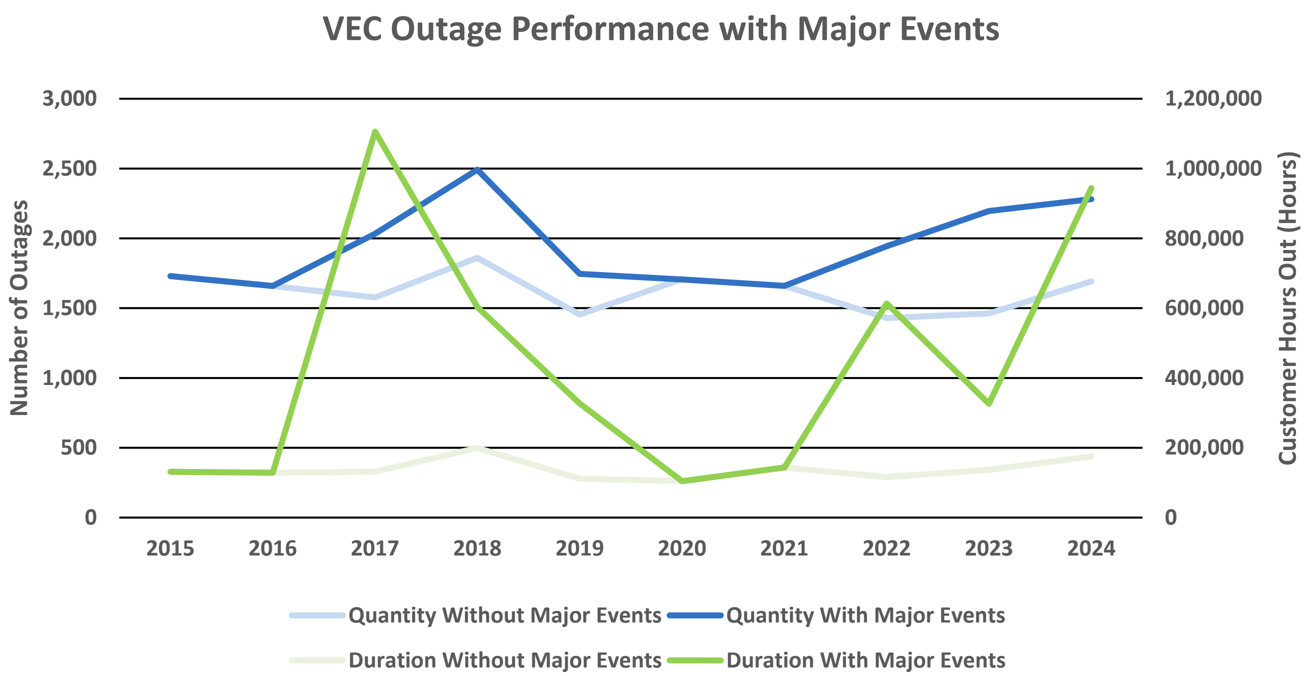
This section provides an overview of VEC's outage performance and strategies to prevent outages. With rising consumer expectations, climate change impacts, increased electricity use for heating and transportation, and limited investment resources, it is becoming ever more important to provide the highest level of reliability. This plan addresses these challenges and corresponding opportunities.

5.1.1 General Overview



5.1.2 Overall Outage Performance

While VEC continues to meet its PUC-defined reliability targets which remove major events, our members are seeing an increase in outages due to major and minor events such as wind and ice storms.



5.1.3 Outage Statistics

Per the IRP Appendix B guidance, the following section contains a detailed assessment of VEC's 2020-2024 outage performance without major events. This assessment follows PUC 4.900 definitions and as such, the outage information only includes outages greater than five minutes. Major event outages, such as wind and ice storms, are excluded from the data but are described further in the Major Events section below. VEC files a 4.900 outage report annually and these reports are available for review on VEC's website.

VEC has two reliability-related Service Quality and Reliability Plan (SQRP) goals for System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).

	SQRP Goals
SAIFI	**2.5**
CAIDI	**2.6**

Table 5.1.3.A VEC SAIFI and CAIDI SQRP Goals

VEC's SAIFI and CAIDI five-year averages, excluding all major storms, were 1.70 and 1.95, respectively.

	SQRP Goal	2020	2021	2022	2023	2024
VEC Members		39,539	39,953	40,253	40,245	40,741
# of Members Out		64,548	76,284	62,966	55,369	82,939

Customers Hours Out (CHO)		104,405	143,386	115,825	137,055	175,020
CAIDI	2.60	1.62	1.88	1.84	2.48	1.95
SAIFI	2.50	1.63	1.91	1.56	1.38	2.06

Table 5.1.3.B Total Members, # of Members Out, Member Hours Out, CAIDI, and SAIFI by Year

The chart below details VEC's outage durations and quantity from 2020-2024

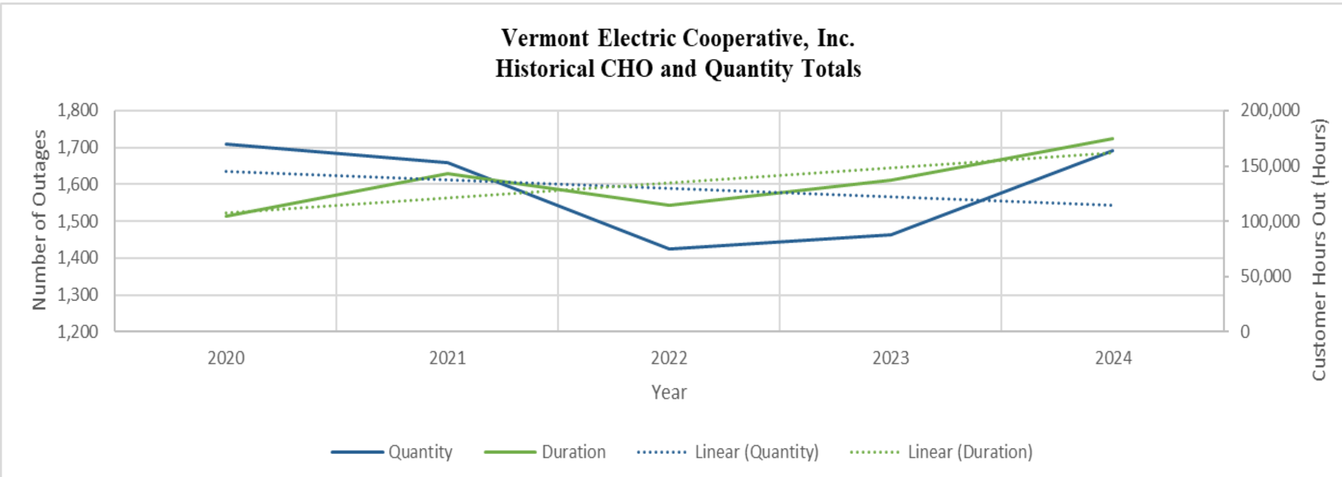


Figure 5.1.3.C VEC Historical Outage Duration and Quantity Totals

Overall, VEC has seen a slight increasing trend in outage duration and a flat trend in outage quantity.

Outage Quantity by Outage Cause

VEC experienced 1,692 outages in 2024 and averaged 1,621 over the five-year period between 2020 and 2024. The chart below identifies outage quantity by cause for 2020-2024. As shown in the data below, Company Initiated and tree-related outages continue to be the primary drivers for VEC's outages. Approximately 15 percent (50 of 324 outages) of the Company Initiated outages were due to outages required for capital projects generally associated with reliability improvements and other initiatives such as installing animal guards. Regarding the tree-related outages, VEC saw a slight increase in tree related outages in 2024 and was slightly above its five-year average for tree related outages.

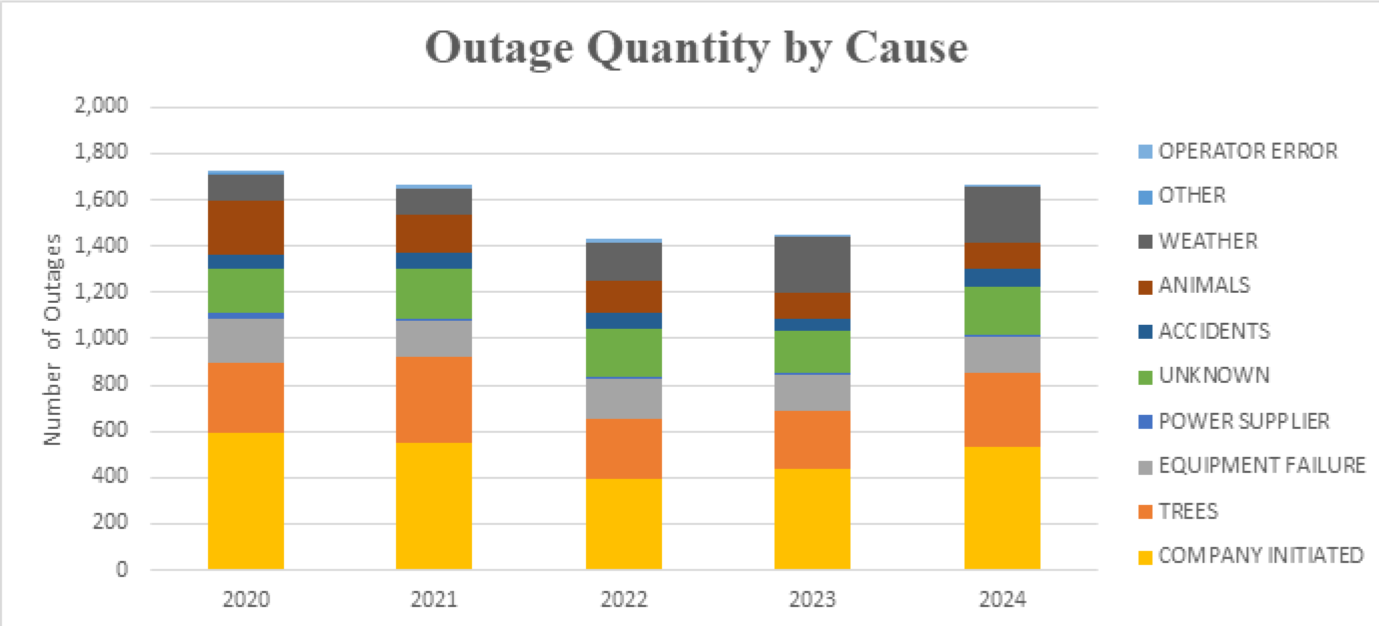


Figure 5.1.3.D   2020-2024 Quantity of Outages by Outage Cause

The chart below details the quantity of total outages by outage cause for 2024 and the five-year average.

RANK	CAUSE	2024 (Quantity)	Average (Quantity)
1	COMPANY INITIATED	528	491
2	TREES	324	326
3	WEATHER	240	135
4	UNKNOWN	209	204
5	EQUIPMENT FAILURE	156	182
6	ANIMALS	114	193
7	ACCIDENTS	77	65
8	OTHER	22	3
9	POWER SUPPLIER	16	9
10	OPERATOR ERROR	6	10

Table 5.1.3.E   2024 and Five-Year Average Quantity of Outages by Outage Cause

Outage Duration by Outage Cause

VEC experienced 175,020 Customer Hours Out in 2024 and averaged 134,549 over the five-year period between 2020 and 2024. The chart below identifies outage duration by cause for 2020-2024. As shown in the data below, tree-related outages, listed as “Trees” below, are the primary driver for Customer Hours Out. Equipment Failure and animal outages, “Animals”, saw a significant decline in Customer Hours Out while Company Initiated outages saw a large increase in Customer Hours Out.

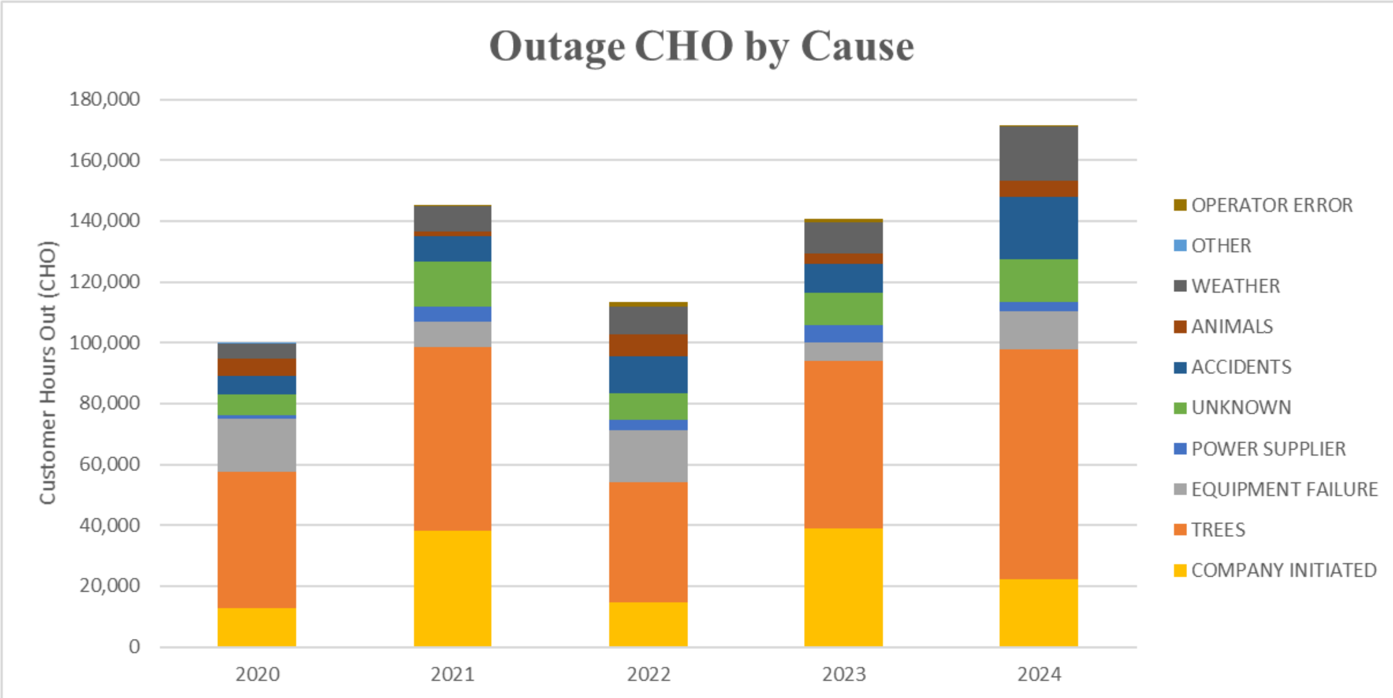


Figure 5.1.3.F 2020-2024 Duration of Outages by Outage Cause

The chart below details the duration in hours out by outage cause for 2024 as well as the five-year average from 2020-2024.

RANK	CAUSE	2024 (Hours)	Average (Hours)
1	TREES	75,682	57,919
2	COMPANY INITIATED	22,218	19,250
3	ACCIDENTS	20,243	12,485
4	WEATHER	17,967	7,802
5	UNKNOWN	14,139	10,548
6	EQUIPMENT FAILURE	12,474	14,726
7	ANIMALS	5,340	6,041
8	POWER SUPPLIER	5,146	5,096
9	OTHER	1,430	40
10	OPERATOR ERROR	376	643
11	NON-POWER SUPPLIER	0	-
	TOTAL	**175,020**	**134,549**

Table 5.1.3.G 2024 and Five-Year Average Duration of Outages by Outage Cause

Worst Performing Circuits

VEC breaks down its reliability data into worst performing feeders. VEC rates its top ten worst performers by prioritizing the number of outage events first and then customer hours out. Engineering reviews these worst performers based on type and location of the outages. VEC provided a list of worst performers based on a five-year average (2020-2024) but utilizes the 2024 data to develop projects and mitigate these outages.

Worst Performers Average (2020-2024)

The chart below displays the average worst performing circuits from 2020-2024

Rank	Circuit Name	OUTAGES	HOURS
1	Hinesburg 3A	**59**	5,367
2	Williston 3A	**53**	2,593
3	Cambridge 1A	**57**	2,316
4	Hinesburg 1A	**35.2**	3,193
5	South Alburg 1A	**45.8**	2,293
6	Island Pond 4A	**58.4**	1,714
7	West Charleston 1A	**42.8**	2,169
8	Irasburg 3A	**50.2**	1,535
9	West Charleston 2A	**34**	1,938
10	Burton Hill 3A	**62.2**	1,030

Table 5.1.3.H 2020-2024 Average Worst Performing Circuits

Worst Performers in 2024

The chart below displays the worst performing circuits in 2024.

Rank	Circuit Name	OUTAGES	HOURS
1	Burton Hill 3A	89	7866
2	East Berkshire 1A	40	7154
3	Island Pond 4A	69	4537
4	Lowell 3A	31	4682
5	Irasburg 3A	60	15437
6	Richmond 1A	31	7464
7	Cambridge 1A	37	3374
8	Williston 3A	38	5618
9	Pleasant Valley 3A	27	5088
10	South Hero 1A	51	3905

Table 5.1.3.I 2024 Worst Performing Circuits

In 2024, VEC invested in capital improvements on its 2023 worst performing circuits. These capital improvements included the installation of new animal and arrestor guards, new fused cutouts on side taps, and several line relocations. VEC invested approximately $5.35 million in routine vegetation maintenance and hazard tree removal over approximately 348 miles of line. VEC prioritizes reliability improvement projects, which generally include reconductoring with tree wire, adding mid-span poles, additional feeder protection, and line relocations, for the circuits identified on the worst performing list.

5.1.4 Major Events

Since 2022, VEC has had seven "Major Storm" events as per the VEC Service Quality & Reliability Plan (SQRP). As shown in the introduction to this chapter this is an increase over our prior IRP. While these events are excluded from VEC's outage reporting, they have impact on our members and VEC's ability to keep the lights on. SQRP defines a major storm as a severe weather event meeting all three criteria:

- Extensive mechanical damage to the utility infrastructure has occurred;
- More than 10 percent of the customers in a service territory are out of service due to the storm or the storm's effects; and
- At least 1 percent of the customers in the service territory are out of service for at least 24 hours.

The major storm events are:

  - Winter Storm Elliott (2022) – This December storm started on December 23rd, 2022, at 02:00 and ended on December 28th, 2022. At peak, the storm caused over 13,790 VEC meters to be without power, and 293 outage events during the storm.
  - Winter Storm Gerald (2023) - The November Snow Event started on November 27th at 02:00 and ended on November 28th at hour 20:00. At peak, the storm caused over 17,910VEC meters to be without power, and 229 outage events occurred during the storm.
  - Winter Storm Jake (2023) – Winter Storm Jake started on December 3 at hour 23:00 and ended on December 5 at hour 16:00. At peak, the storm caused over 8,405 VEC meters to be without power, and 178 outage events occurred during the storm.
  - Winter Storm Kendall (2023) – Winter Storm Kendall started on December 11 at hour 02:00 and ended on December 13 at hour 12:00. At peak, the storm caused over 37,052 VEC meters to be without power, and 402 separate outages.
  - Winter Storm Finn (2024) - January Snow Event started on January 9th at hour 19:00 and ended on January 15th at hour 15:00. At peak, the storm caused over 9,451 VEC meters to be without power, and 219 outage events occurred during the storm.
  - Winter Storm Gerri (2024) – Winter Storm Gerri started on January 13th at hour 00:00 and ended on January 15th at hour 12:00. At peak, the storm caused over 5,833 VEC meters to be without power, and 155 outage events occurred during the storm.
  - Winter Storm Debby (2024) – Winter Storm Debby started on August 9th at hour 19:00 and ended on August 12th at hour 22:00. At peak, the storm caused over 45,219 VEC meters to be without power, and 296 separate outages.

5.2 Proactively Forecast, Detect and Prevent Outages

Maintaining our assets and facilities is critical to keeping the lights on. The following section describes VEC's maintenance and practices that help reduce outages on the system.

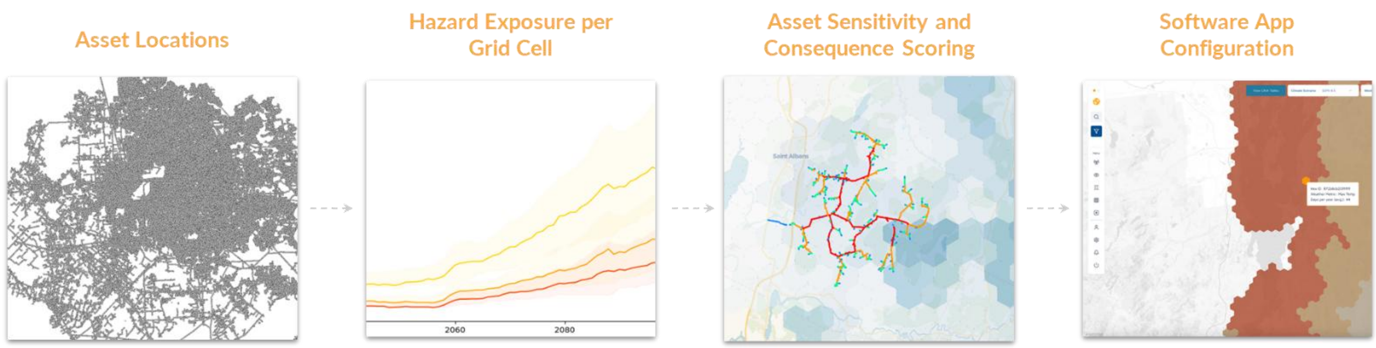
5.2.1 Forecast Weather and Climate

Weather reflects short-term conditions of the atmosphere while climate is the average daily weather for an extended period at a certain location. Weather (what you get) and climate (what you expect) both have significant impacts to VEC's event response, outage management, and asset planning. As members' expectations of reliability increase, it is important that we expand our monitoring and planning capabilities. VEC has been actively involved in several weather/climate monitoring/modeling, weather/climate research, and partnership with external companies to understand the challenges and potential solutions associated with weather and climate and to enhance our operational response.

Rhizome Climate Modeling and Infrastructure Impacts

In 2025, VEC began a partnership with Rhizome to perform a digital climate and asset vulnerability assessment. The growing risk of extreme weather-related power outages has increased. Rhizome allows VEC to access asset exposure, sensitivity, and consequence of various climate hazards within a 5 km square level. To provide VEC with this information Rhizome :

1. Pulled VEC's public GIS infrastructure data to identify the location and type of VEC asset
2. Then pulled from a variety of longer range climate models to identify the hazard at each 5km square of VEC's service territory
3. Then worked with VEC to identify which assets where of higher consequence and more sensitive to different hazard types



This is an example of what VEC was provided for snow and ice sensitivity in its territory (red is more sensitive and blue is less sensitive)

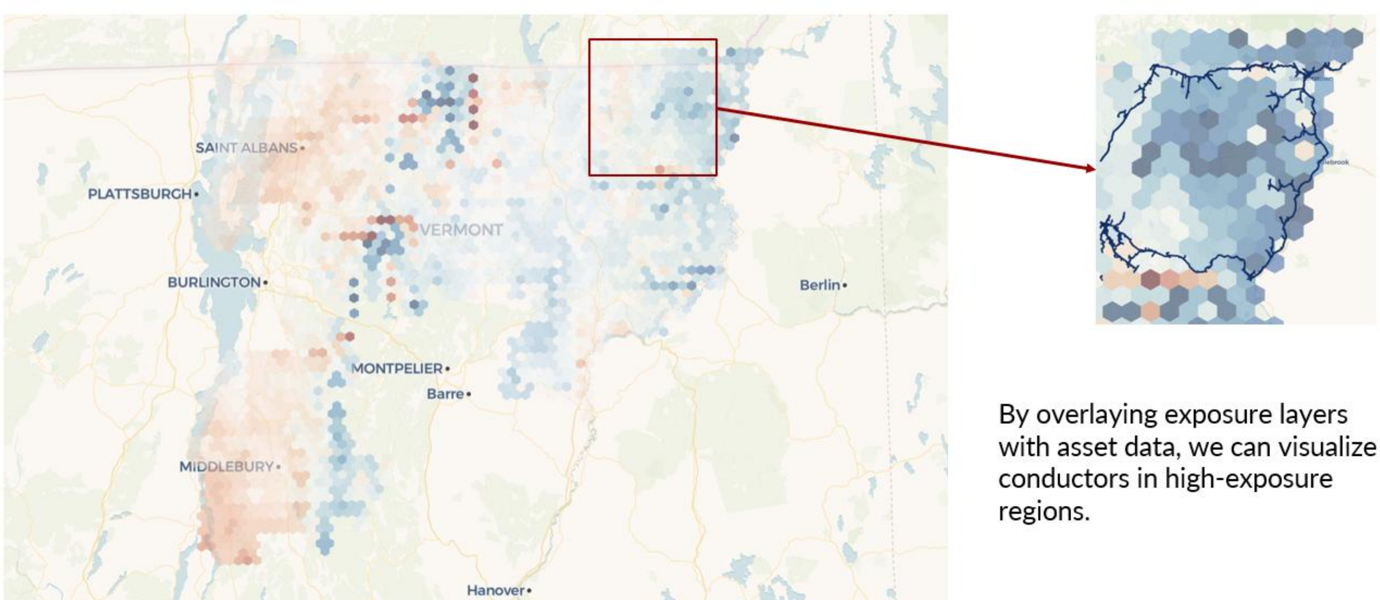
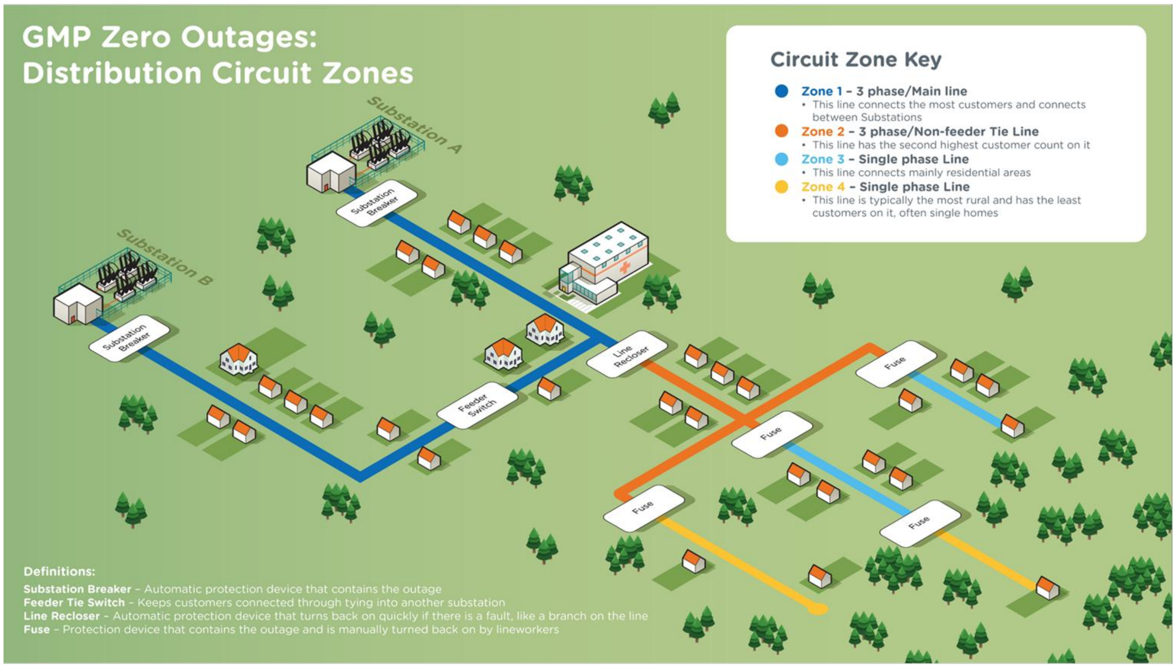


Figure 5.2.1.A Snow and Ice Sensitivty

VEC then utilized GMP's distribution circuit zone framework to develop consequence zones for each of VEC's substations.



The consequence zones are assigned using based on conductor phase (3 phase is more consequential than single phase) and then weighted based on the amount of downstream line segments. This then provides us with an asset vulnerability based on both the consequence of the asset as well as the weather hazard.

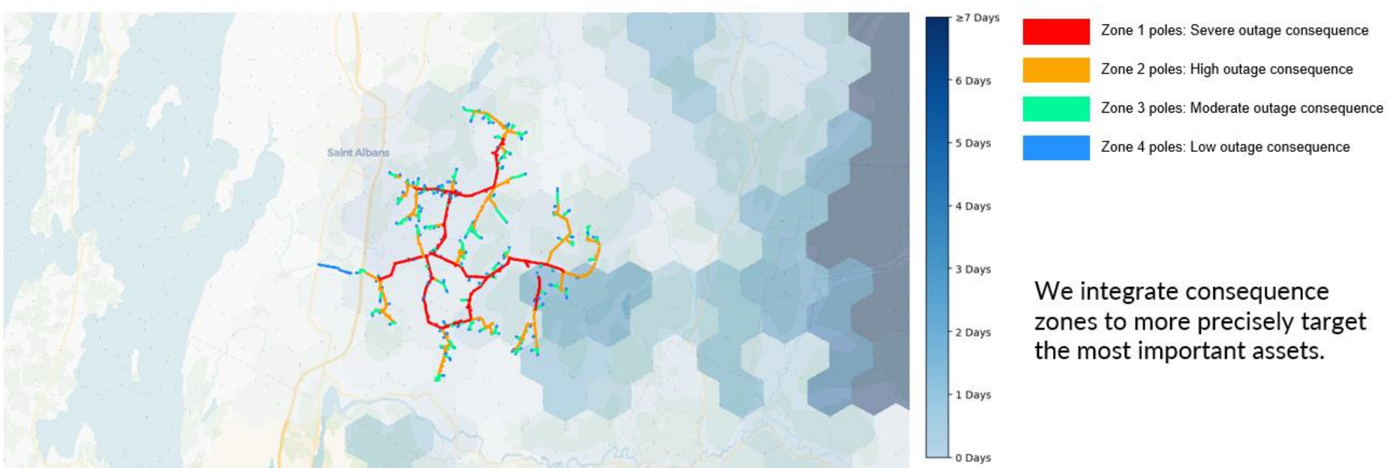


Figure 5.2.1.B Snow/Ice Asset Vulnerability (St. Rocks 06 Circuit)

VEC is still working to incorporate this information into our reliability and infrastructure replacement plans in the coming years. The tool will help advance VEC's existing capital prioritization process to not only look at past outage performance but prioritize areas that are modeled to be more vulnerable in the future.

DisasterTech Weather Pole Wind Data

In February 2025, Disaster Tech conducted a study to assess the ability of poles to withstand wind gusts. Authored by Dr. Jay Shafer from Northview Weather, the study indicates that high winds are responsible for most power outages experienced by utilities, particularly in Vermont. Power outages can occur at relatively low wind gust speeds of 40 to 50 mph, especially when trees are fully leafed out near rights-of-way and there is high soil moisture. Contact between trees and conductors (wires) can lead to outages by either breaking the conductor or causing stresses on poles that result in their failure. With the majority of VEC's lines above ground, this study is useful in identifying parts of the system that may be vulnerable to outages at certain wind speeds.

Several variables are considered when determining the likelihood of pole failure, including age, location, height, conductor size, other installed equipment such as transformers, class (e.g., thickness/girth), and material. These variables are combined with the American Society of Civil Engineers (ASCE) standards for wind stress or loading used by engineers when designing the electric grid. The graph below summarizes the results related to the probability of pole failure.

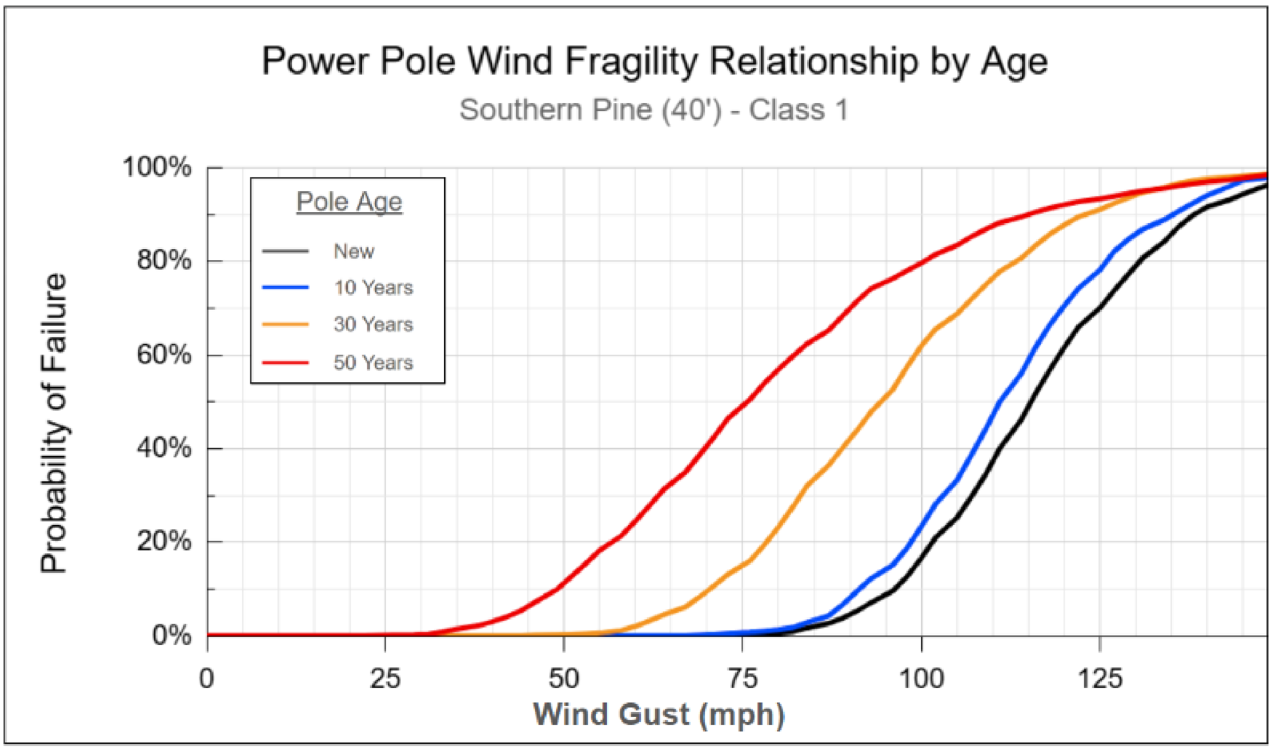


Figure 2. Fragility function showing relationship between wind gust and probability of pole failure by age of pole. Data source provided by Nirandjan et al. 2024 - Physical Vulnerability Database for Critical Infrastructure Multi-Hazard Risk Assessments – A systematic review and data collection.

Figure 5.2.1.C Power Pole Wind Fragility Relationship by Age

Dr. Shafer's study examined the January 10, 2024 Winter Storm "Finn" wind gusts in relation to all poles across the VEC system, as well as those poles which failed. The findings indicate that the median wind gusts across VEC's territory were 54 mph, while the median wind gusts for the approximately 40 broken poles were 75 mph. VEC will analyze other wind events over the past 10 years to better understand the overall median wind gusts that cause pole failure, including those caused by tree failures, and use that information to develop resilience investment strategies in areas most impacted by these occurrences.

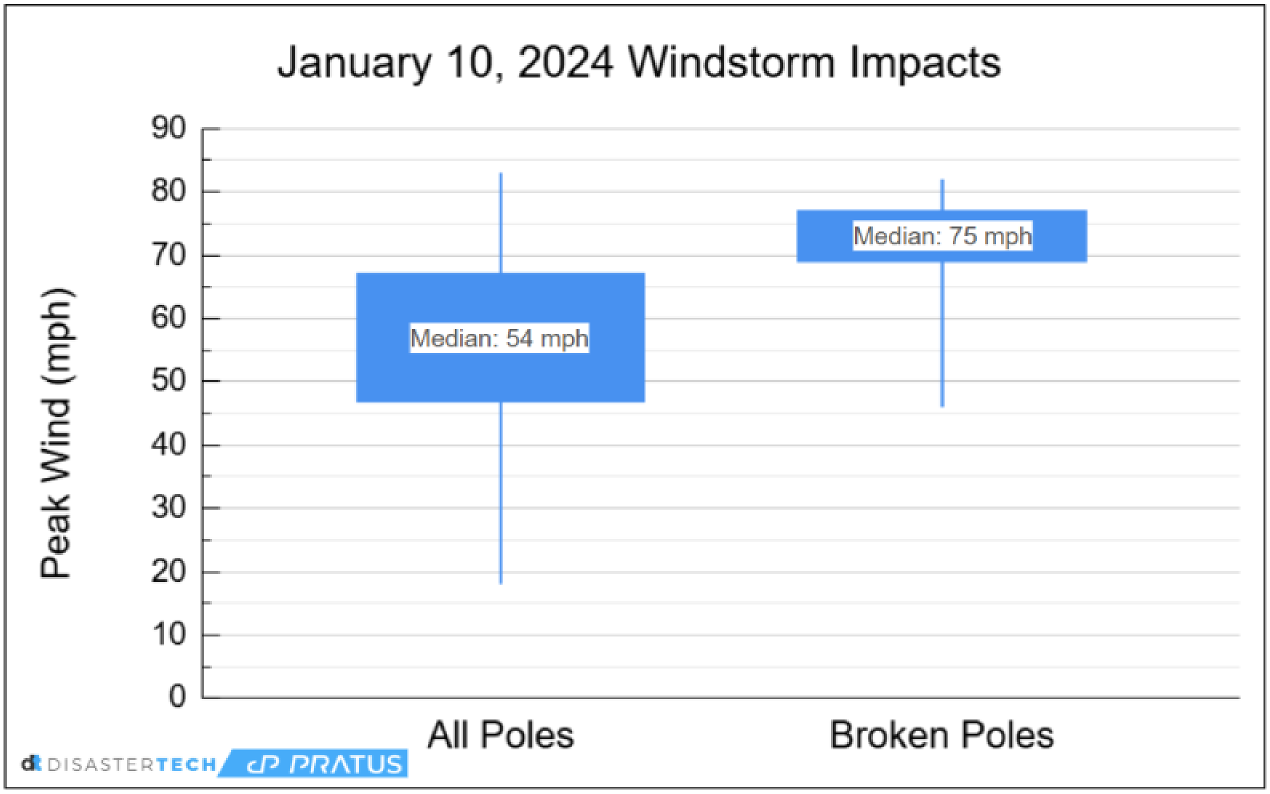


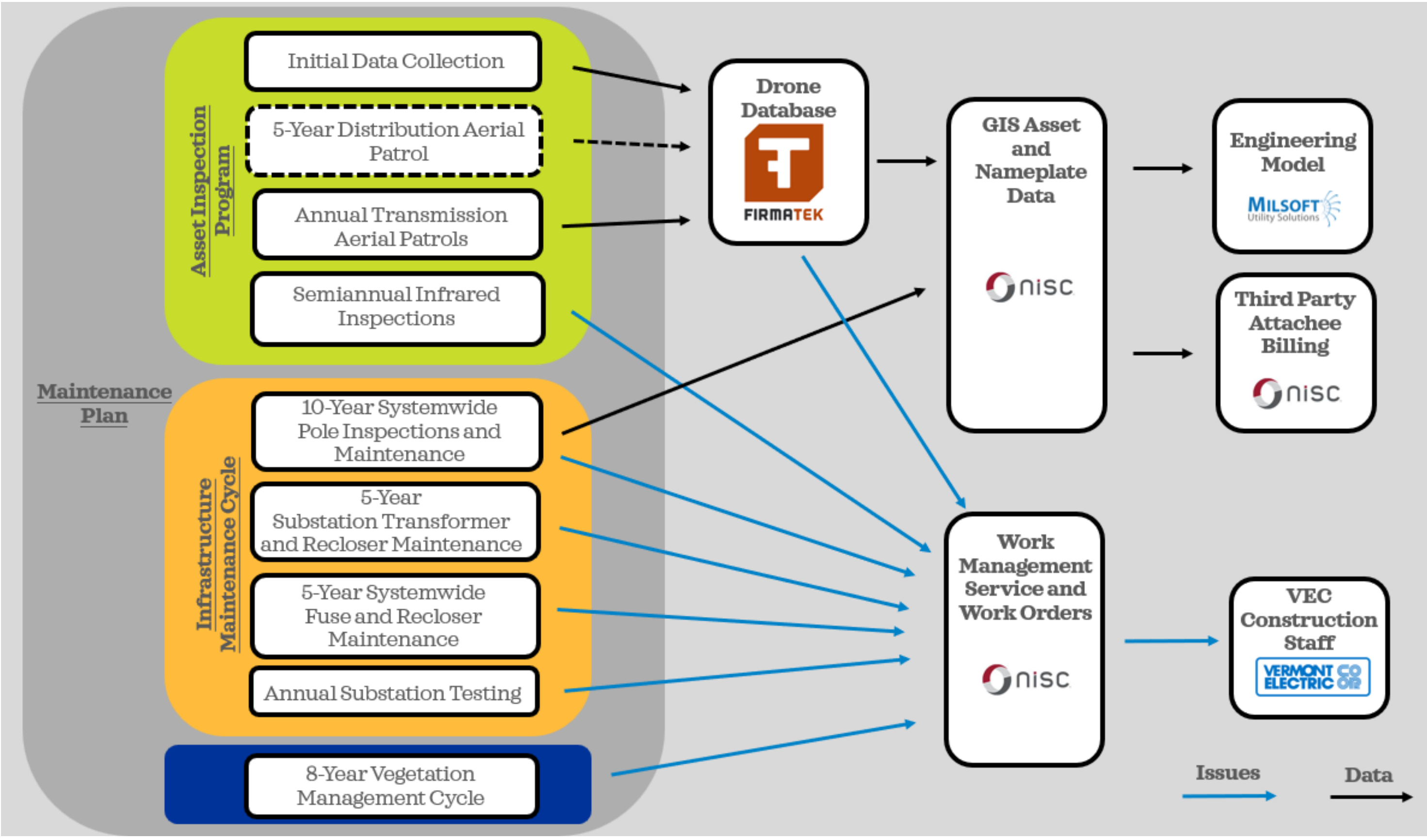
Figure 3. Distribution of peak wind gust for all poles and broken poles for January 10, 2024 winter storm "Finn" across Vermont Electric Cooperative's service area. Box shows inner 50th percentile and whiskers are max/min values.

Figure 5.2.1.D Windstorm Impacts

5.2.2 Prevent Outages with VEC Maintenance Plan

VEC initiated its comprehensive system wide Maintenance Plan (MP) in 2019 to enhance reliability, proactively reduce preventable outages, and ensure compliance with safety codes for VEC's members. The MP is broken up into two major components:

1. An "Asset Inspection Program" with the goal of gathering of accurate asset data such as conductor and transformer sizes, manufacturers, serial numbers, proper phasing, attachments, etc. The data is populated in VEC's GIS system via NISC's AppSuite Inspections software utilizing both internal VEC personnel and contractors. **VEC is currently 60 percent complete with the Asset Inspection program and expects to complete the initial data collection in 2026.**
2. An "Infrastructure Maintenance Cycle "where VEC performs proactive maintenance on the entire system over the course of an eight-year period. **VEC is currently 60 percent complete with this maintenance effort and expects to complete the first cycle in 2026.**
3. A "Vegetation Management Cycle" to maintain VEC rights-of-way to prevent tree related outages. **VEC has completed its first distribution cycle and is expected to complete the second distribution cycle in 2030.**



Asset Inspection Program

Initial Data Collection

VEC has used both contractors and internal staff to assess and gather data on the following:

- Pole hardware and third-party attachments (e.g. company owner and quantity)
- Conductors (e.g. size and type)
- Overhead Transformers (e.g. size and nameplate data)
- Streetlights

This data is saved in VEC's GIS system and then pushed to other platforms such as VEC's engineering model and NISC Financials for billing third party attachees. VEC has currently inspected an estimated 60% percent of the system, as of year-end 2024. VEC expects to complete the Initial Data Collection phase of the Asset Inspection Program at the end of 2026.

Annual Aerial Patrols

VEC's Vegetation and ROW Management Program Manager and Grand Isle Operations Supervisor will coordinate annual drone inspections of all VEC transmission lines, including thermal imaging. These patrols aim to identify equipment issues, danger trees, vegetation concerns, and safety hazards near transmission structures or facilities.

The collected imagery and data will be reviewed by VEC's Vegetation Management Department and Operations Supervisors. Necessary corrective actions will be scheduled within 90 days. Critical conditions posing imminent danger or likely to cause an outage within 30 days will be prioritized for immediate repair. The drone patrol company handles all required permits and notifications.

Semiannual Infrared Inspections

VEC engages an independent contractor to conduct biannual inspections, utilizing infrared cameras, of all substations, tie switches, and SCADA operable switches during January and July. The historical practice of performing infrared inspections on transmission lines using helicopters has been deemed unviable due to emerging safety concerns identified through risk assessments. VEC is currently exploring the potential of conducting these inspections using drones.

Infrared thermography is employed in these inspections to detect variations in ambient temperature with highly sensitive, non-contact, non-destructive electronic equipment that converts infrared energy into a video image. Since infrared energy is directly proportional to temperature, the resulting video image depicts various shades of gray or color to indicate temperature differences. In color mode, lighter shades correspond to higher temperatures. In black and white mode, darker shades of gray indicate lower temperatures, while lighter shades of gray or white indicate higher temperatures, commonly referred to as "hot spots."

The thermal images highlight the temperature differences between areas of concern/deficiency and corresponding normal reference areas. However, temperature variances alone do not necessarily indicate the severity of the issue. Each potential issue's significance is evaluated within the context of the entire system. The resulting report aids in accurately identifying areas requiring potential maintenance or replacement. VEC adheres to the infrared criteria outlined in MIL-STD-105 (Military Specification for Electrical Inspection Criteria).

Severity Code	Temperature Rise degrees C Over Ambient	Repair Priority	Severity/Recommendation
1	Less than 74 degrees Fahrenheit (0-24 degrees Celsius)	Desirable	Component failure is improbable, but corrective action is required at the next maintenance period or as scheduling permits
2	75-103 degrees F (25-39 degrees Celsius)	Important	Component failure is probable unless corrective action is taken
3	104-157 degrees F (40-69 degrees C)	Mandatory	Component failure almost certain unless corrective action is taken
4	Over 158 degrees F (Over 70 degrees C)	Immediate	Component failure imminent, repair Immediately

Table 5.2.2.A Infrared Criteria from MIL-STD-105

The external contractor provides a report for analysis by VEC's Manager of Engineering and Manager of Service Operations. They plan for and implement corrective action based on the Repair Priority and system outage impact. VEC also conducts annual infrared inspections on the Kingdom Community Wind (KCW) transmission line at peak times of generation.

5-Year Distribution Aerial Patrol

Once Initial Data Collection is complete at the end of 2026, VEC plans to fly the distribution system with drones on a 5-year cycle to capture issues. Contractors and internal staff use severity ratings to determine the response time. VEC uses the rating system on all assets and varies by asset. When VEC identifies an issue, the appropriate VEC personnel receive the information and fix the issue within an appropriate timeframe. In some cases, a capital project is designed, processed through VEC's prioritization scheme, budgeted, and constructed.

Maintenance Cycle

While the Asset Inspection Program is underway VEC personnel will perform assessment on special equipment such as reclosers, voltage regulators, and substation equipment. Each year one eighth of the system is assessed and equipment replaced as needed.

The plan is discussed in more detail in Appendix-F and includes discussions on aerial patrols, substation testing programs, and more details on distribution inspections.

Pole Inspections

VEC conducts a pole inspection and treatment program on all distribution poles within a 10-year cycle, in accordance with RUS Bulletin 1730B-121 guidelines. This program includes ground line inspection, treatment both 18 inches below ground level and internally with Mitci-Fume, a widely used fumigant, visual inspection of above-ground conditions, and other maintenance activities such as replacing missing guy guards and pole numbers.

As per VEC's joint ownership agreement with Consolidated Communications, pole installation ("set") and maintenance responsibilities are defined by respective maintenance areas. VEC inspects all its solely owned distribution poles across the system, as well as jointly owned poles within VEC's maintenance area. Consolidated Communications is responsible for inspecting jointly owned poles within its designated maintenance area.

Inspection data is stored within VEC's GIS system, and weekly reports generated from pole inspectors are reviewed by VEC's engineering team. Subsequently, work orders are initiated for pole replacements, and projects are designed and prepared for construction.

VEC replaces any rejected poles within twelve months following the inspection. During the current 10-year distribution pole inspection cycle (2015-2024), VEC has identified an average rejection rate of 2.54 percent among inspected poles, with a rejection rate of 1.98 percent recorded for 2024. Alamon was contracted to complete the pole inspections in 2024, identifying 61 rejected poles, with the average age of these poles being 61 years, manufactured in 1963.

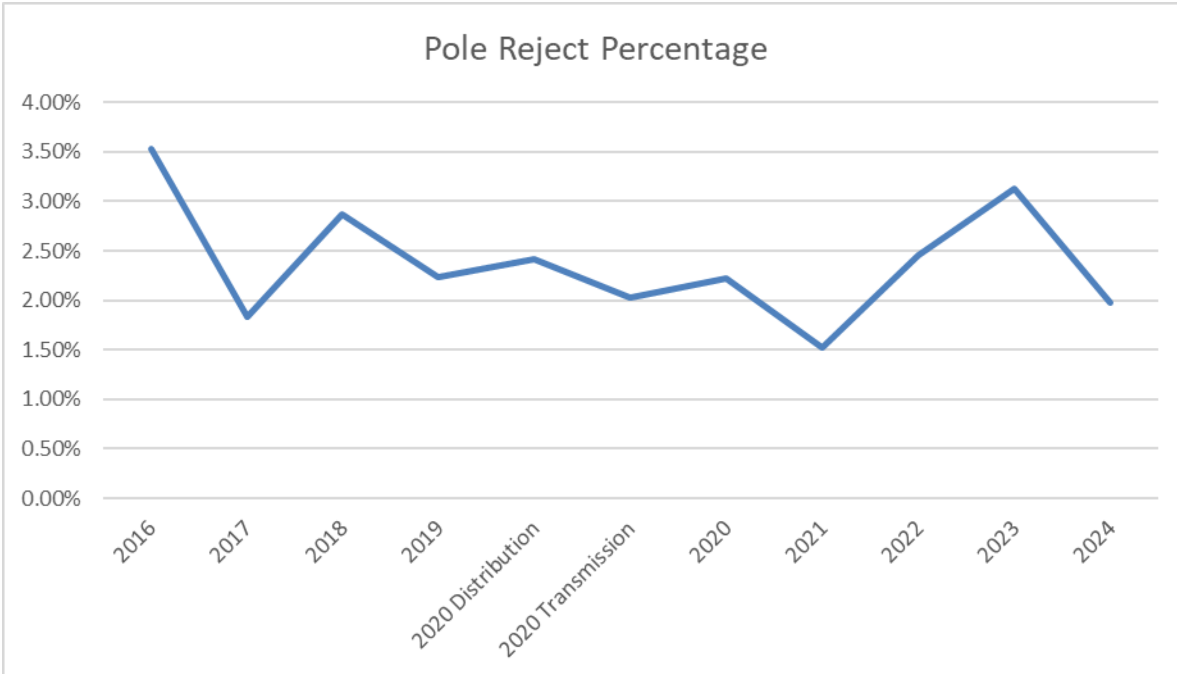


Figure 5.2.2.B Distribution Pole Reject Percentage

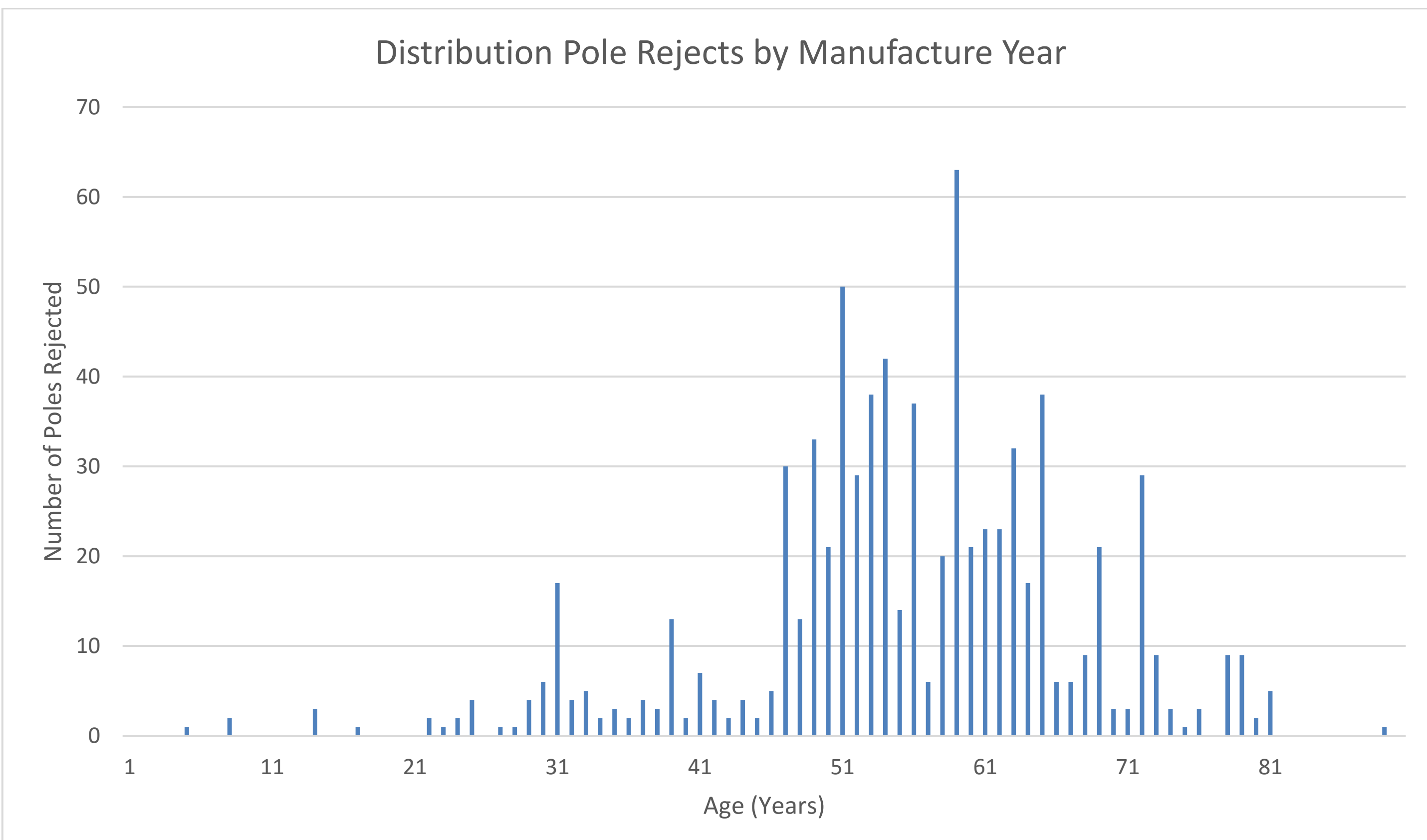


Figure 5.2.2.C Distribution pole rejects by manufacture year

The chart above shows that poles younger than the average rejection age of 58 years are less likely to be rejected. Poles at or older than this age are more likely to be rejected, as they typically have not been maintained since their installation. VEC completed its first pole inspection and treatment cycle in 2021.

While most pole rejections identified during the inspection program are due to issues at the ground line, VEC has also encountered problems at the top of poles caused by decay from water ingress and subsequent loosening of pole top hardware. In response, VEC has updated its pole installation standard to include an Osmose "Pole Topper" or cap on all new installations. This topper functions similarly to a roof on a house, protecting the pole top from moisture ingress and thus preventing future degradation.

5-Year Substation Transformer and Recloser Maintenance

The VEC Service Operations group performs the following testing on power transformers, bushings, and LTCs, as appropriate:

- Resistance measurements, insulation power factor ("Meggar" test) per IEEE C57.12.90
- Ratio test (turns ratio) – +/- 0.05% from calculated nameplate value
- Polarity/phase relation
- Applied potential test per IEEE C57.12.90
- Impulse/High frequency ("sweep frequency")
- Induced potential test per IEEE C57.12.90

Test results are located in the substation fileserver directory on the Doble DTA web.

In addition to the tests conducted above, the VEC Service Operations group will inspect oil levels in the transformer and add oil as necessary. The Service Operations group will also replace nitrogen once it refills.

The VEC Service Operations group tests Substation Transformers every 5 years the tests include: Power Factor Test (DOBLE), Insulation Resistance Test (Megger test), SFRA Sweep Frequency Reponses Analysis test (Doble), Transformer Turns Ratio Test (TTR) and visual Inspection.

- **Oil Containment-** Check for oil in containment, condition of containment
- **Power Transformers-** Winding temperature, max winding temp, indicated oil temperature, maximum oil temp, nitrogen pressure, oil levels, spare power fuses, resetting of drag hands

5-Year Systemwide Fuse and Recloser Maintenance

The Service Operations group records Recloser schemes and test following recloser control elements:

- Minimum Trip test
- Metering Test
- (3) Phase trip test points (ground trips disabled)
- 200%, 300%, and 400% of the minimum trip set-point
- (3) Ground trip test points (phase trips disabled)
- 200%, 300%, and 400% of the minimum trip set-point
- Cold Load Pickup
- VEC will replace Batteries will be for all relay controls on a 5-year rotating basis whether in substations on the line during DSI or DLI schedules, respectively.

Vegetation Management

VEC maintains vegetation to ensure the safety and reliability of its overhead electric facilities. VEC's distribution lines, largely built in the early to mid-1900s, are particularly susceptible to severe weather, due to their remote, cross-country locations. While our Green Mountain State takes pride in its trees, electricity and trees do not mix well, so VEC must balance system reliability with maintaining a safe electric grid, while also preserving the state's natural beauty.

VEC has maintained a target vegetation maintenance cycle of five years on transmission rights-of-way and eight-years on distribution rights-of-way. Following a comprehensive review and assessment of its Vegetation Management Program by a third party in 2018, VEC developed an alternative distribution treatment schedule to attain a more aggressive (shorter) overall cycle. The goal of a shorter cycle was in response to data collected during the assessment which identified maintenance workload by classifying five different types of work that include:

- Brush: 0-4 inches DBH or Diameter at Breast Height, approximately four feet above the ground. This is the most cost-effective removal type, not difficult to mitigate, and less chance of an emotional attachment for the member.
- Side Trim: Vegetation reaching towards the line from the side.
- Overhang: Vegetation reaching across the top of the line, above it up to 15 feet away vertically. This is the most expensive kind of trim and often an outage source).
- Crown Reduction: Vegetation directly under the line but not suitable to remove.
- Tree Removal**:** Vegetation/trees in ranges of four inches to 32+ inches DBH and are often expensive and the source of outages,depending on size, condition and/or positioning. R1 and R2 classes are generally most cost effective.
  - R1 = 4”- 8” DBH
  - R2 = 8” - 12” DBH
  - R3=12” - 16” DBH
  - R4=16” - 20” DBH

The different workloads are demonstrated in Figure 1 below:

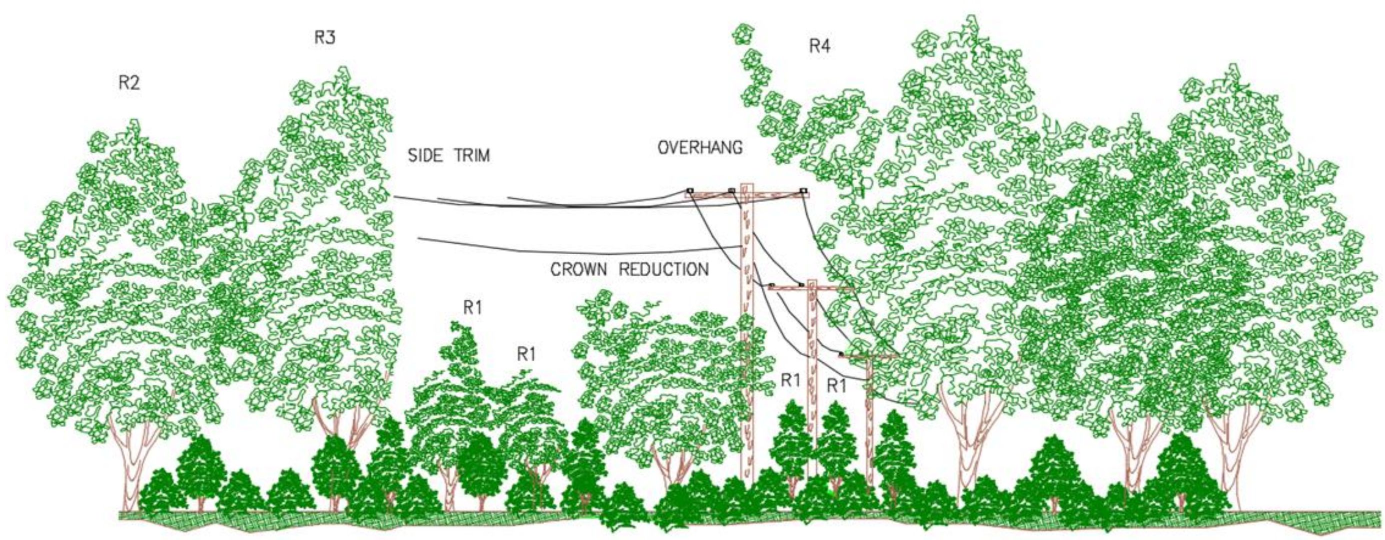


Figure 5.2.2.D Vegetation Management Workloads

At the time of the assessment, VEC's workload composition had a very high loading of overhang (24.4 percent) and significant loading of tree removal (19.9 percent). Excessive amounts in both areas tend to occur when the maintenance cycle is longer than optimum.

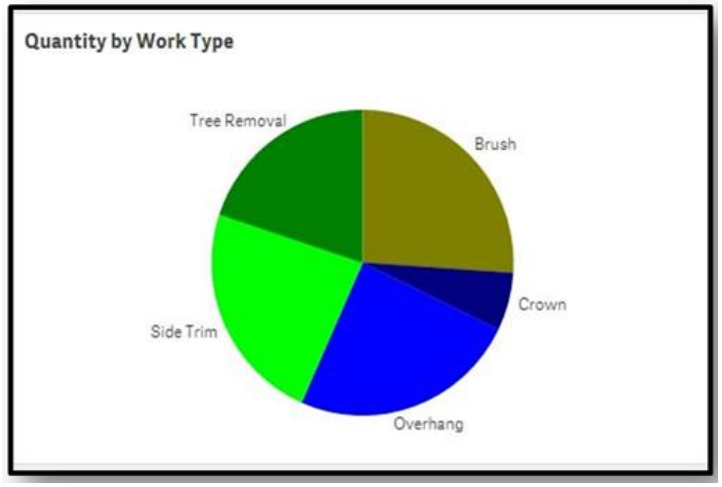


Figure 5.2.2.E Workload Breakdown

Workload Type	Current System	Best Practice	Evaluation
Crown Reduction	6.1%	Less than 7%	**Best Practice**
Overhang	24.4%	Less than 2%	**Critical Area ****
Tree Removals	19.9%	Less than 15%	**Critical Area****

Table 5.2.2.F   Workload Breakdown

As trees grow, they jump through the classes such as brush to R1, R2 to crown reduction or side trim to overhang. Class jumping drives costs. For example, overhang that was once a side trim will more than double the cost to mitigate. Growth within minimum approach distance or in contact with electric lines is exponentially more expensive and hazardous to remove. By understanding and strategically addressing workload types to mitigate class jumping, VEC can optimize vegetation management activities and maintain reliability standards within existing budget constraints.

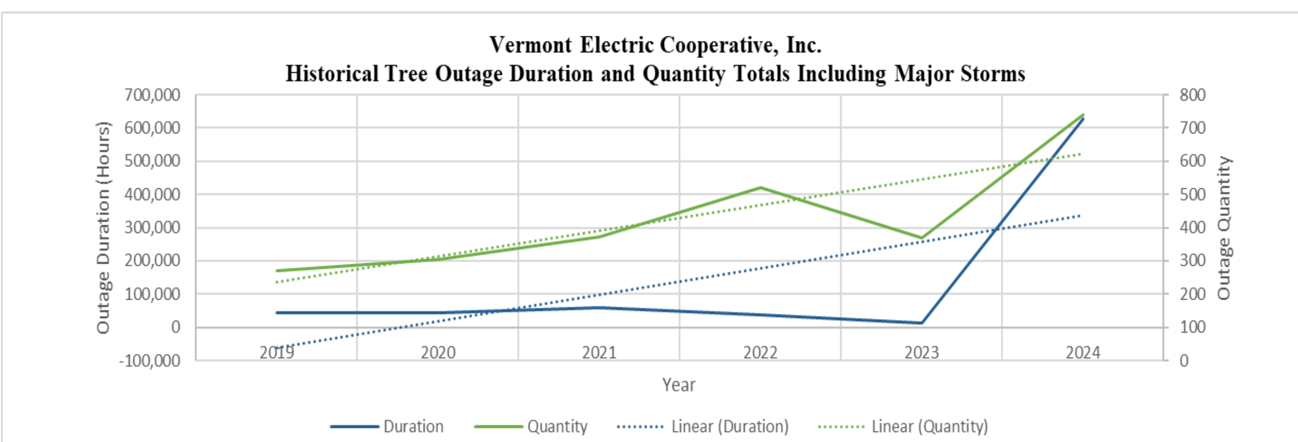


Figure 5.2.2.G Historical tree outage duration and quantity totals with Major Storms

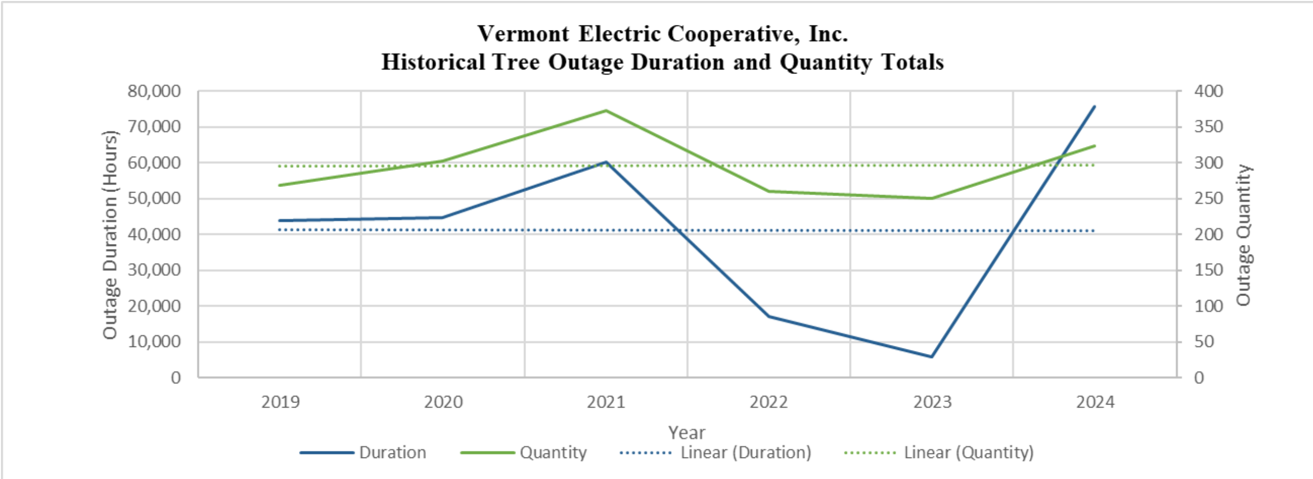


Figure 5.2.2.H   Historical tree outage duration and quantity totals

Due to budgetary constraints and potential rate impacts, VEC has decided to maintain an 8-10 year target for distribution rights-of-way. While a shorter cycle could improve reliability and cost-effectiveness in the long term, VEC prioritizes rate stability for its members.

This decision considers several factors. A more aggressive cycle would result in significant upfront costs and rate impacts, posing financial challenges for VEC members. Additionally, VEC has met reliability standards since implementing its current plan, demonstrating its effectiveness. The 8-10 year cycle allows for gradual improvements in reliability metrics while maintaining greater financial stability, balancing system reliability and cost management.

Although the distribution maintenance cycle remains unchanged, VEC seeks opportunities to improve efficiency through comprehensive program reviews, assessments, and data-driven decisions about scheduling maintenance. Our focus is on worst-performing circuits, considering construction type and past performance. We have shifted to scheduling maintenance on entire feeders within a cycle, rather than spreading work on individual circuits over multiple years, making better use of resources and achieving consistent results.

Vegetation Management strategies will be adjusted as long-range plans are implemented to attain and maintain target cycles on transmission and distribution systems, balancing rate impacts with reliability objectives.

Emerald Ash Borer (EAB)

A significant impact to VEC's Vegetation Management program is the Emerald Ash Borer (EAB). Vermont has confirmed the EAB is within its borders and throughout much of VEC's service territory. The EAB is a beetle that has devastated ash trees in states across the U.S., costing communities millions of dollars. Infested trees rapidly decline and die within 3-5 years. VEC faces a severe risk from a sudden wave of hazard trees along electric utility lines. Ash trees account for approximately five percent of all trees in Vermont or approximately 150 million ash trees across the state. VEC estimates there are approximately 750,000 ash trees within potential striking distance of VEC's overhead transmission and distribution electrical power lines. In 2024, it cost VEC an average of approximately $309 per EAB tree removal which is ~$50 above the current average cost of a routine tree removal. Other utilities that have already experienced the impacts of EAB infested ash trees report it potentially costing more than two times the normal cost to remove dead and dying infested ash trees as infestations progress through time. VEC has applied for outside funding for EAB response, but has not been successful in obtaining such funding, to date.

Figure 5.2.2.I   Emerald Ash Borer

EAB is known to be present in 37 states in the U.S., and utilities and communities through the U.S. are implementing response/mitigation plans to address the negative economic, social, and environmental impacts. EAB has continued to spread throughout Vermont and VEC's service territory over the past several years. While there have been some efforts to introduce species of wasps, known to be natural predators of EAB larvae, to slow the spread, there is no known cure. A single EAB can travel a half mile per year, with the potential to expand the range of an infestation up to several miles per year during the adult beetles' June to August flight period. Moreover, human transport has led to the spread of EAB over much greater distances.

In addition to the threat to Vermont's electric grid, due to the increase of potential hazard trees within striking distance to power lines, EAB and the death of Vermont's ash trees will have a variety of adverse impacts. The presence of so many dead and dying ash trees will be aesthetically damaging to a state known for the beauty of its forests and wooded hillsides. The dead trees tend to rapidly deteriorate and pose a safety threat to Vermont residents and tourists, most especially, those who work in and/or around trees. EAB will affect every type of utility and public infrastructure to some degree and the simultaneous death of multiple trees will compound the safety and cost of preemptive measures.

VEC's EAB Response Plan and Mitigation Program includes outreach/education to VEC's members and the communities they live in. In addition, VEC participates on a Vermont Utilities' Emerald Ash Borer coordination team, consisting of representatives from VELCO, distribution utilities, and Vermont state organizations who are responding to this issue.

Approximately $241,099 was spent removing 780 ash trees ($309 per tree) in 2024. VEC will continue to budget at least $250,000 annually for EAB mitigation and will continue to pursue additional funding for EAB response.

<u>Clearion Vegetation Management Software</u>

Vegetation management activities are scheduled and tracked utilizing a full featured, map-based data collection software program. In 2024, VEC's Vegetation Management Program transitioned to the Clearion Utility Vegetation Management (UVM) solution which includes:

<u>Clearion Web</u>

A browser-based, map and tabular application where work can be planned, organized, executed and tracked.

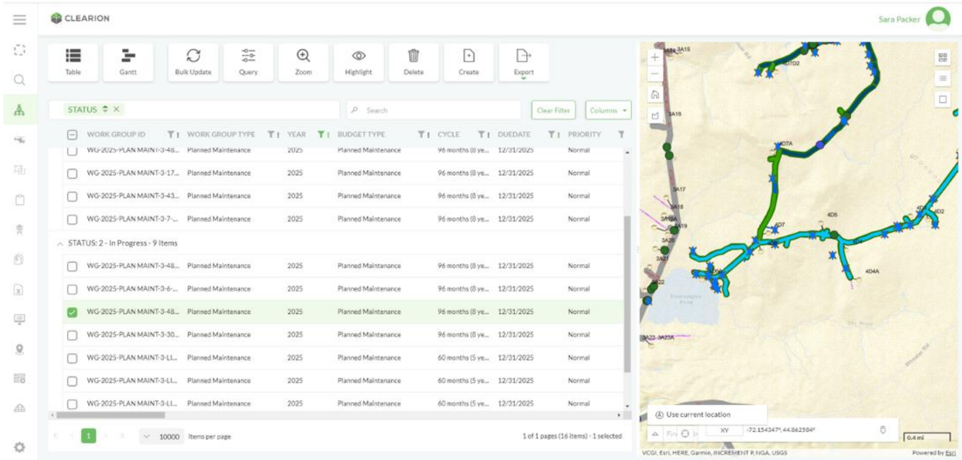


Figure 5.2.2.J   Clearion Web Sofware

<u>Clearion X</u>

A streamlined map-based application designed to allow field crews to receive work assignments, navigate, and identify completed work.

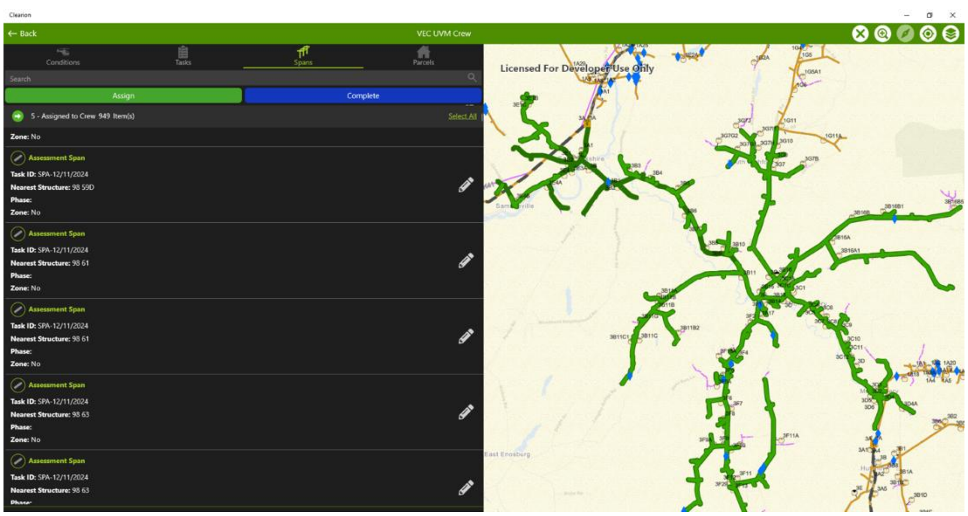
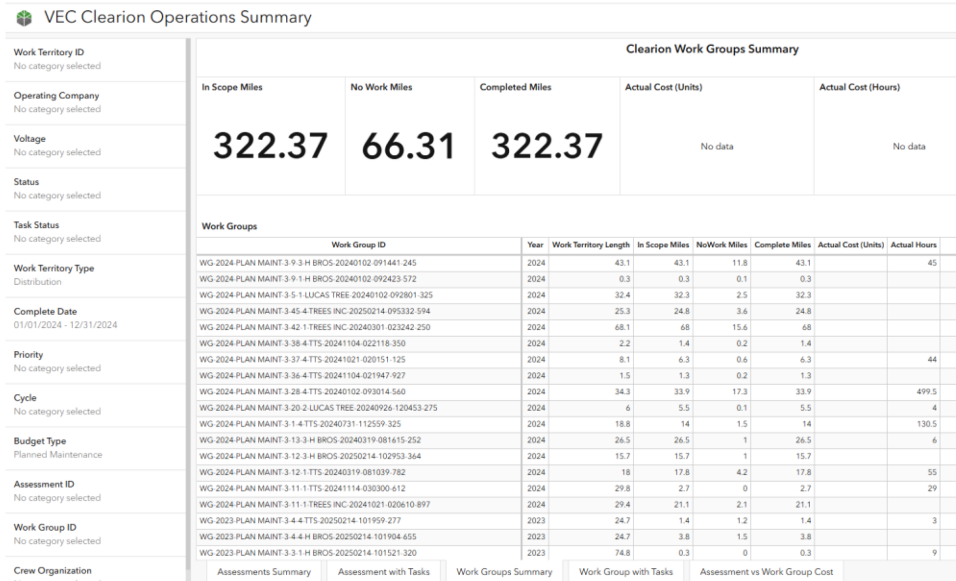


Figure 5.2.2.K   Clearion X Sofware

<u>Clearion Operations Summary</u>

A collection of reports and dashboards that track work production and progress.


VEC Clearion Operations Summary

Work Territory ID
No category selected
Operating Company
No category selected
Voltage
No category selected
Status
No category selected
Task Status
No category selected
Work Territory Type
Distribution
Complete Date
01/01/2024 - 12/31/2024
Priority
No category selected
Cycle
No category selected
Budget Type
Planned Maintenance
Assessment ID
No category selected
Work Group ID
No category selected
Crew Organization

Clearion Work Groups Summary

In Scope Miles	No Work Miles	Completed Miles	Actual Cost (Units)	Actual Cost (Hours)
322.37	66.31	322.37	No data	No data

Work Groups

Work Group ID	Year	Work Territory Length	In Scope Miles	NoWork Miles	Complete Miles	Actual Cost (Units)	Actual Hours
WG-2024-PLAN MAINT-3-9-3-H BROS-20240102-091441-245	2024	43.1	43.1	11.8	43.1		45
WG-2024-PLAN MAINT-3-9-1-H BROS-20240102-092423-572	2024	0.3	0.3	0.1	0.3		
WG-2024-PLAN MAINT-3-5-1-LUCAS TREE-20240102-092801-325	2024	32.4	32.3	2.5	32.3		
WG-2024-PLAN MAINT-3-45-4-TREES INC-20250214-095332-594	2024	25.3	24.8	3.6	24.8		
WG-2024-PLAN MAINT-3-42-1-TREES INC-20240301-023242-250	2024	68.1	68	15.6	68		
WG-2024-PLAN MAINT-3-38-4-TTS-20241104-022118-350	2024	2.2	1.4	0.2	1.4		
WG-2024-PLAN MAINT-3-37-4-TTS-20241021-020151-125	2024	8.1	6.3	0.6	6.3		44
WG-2024-PLAN MAINT-3-36-4-TTS-20241104-021947-927	2024	1.5	1.3	0.2	1.3		
WG-2024-PLAN MAINT-3-28-4-TTS-20240102-093014-560	2024	34.3	33.9	17.3	33.9		499.5
WG-2024-PLAN MAINT-3-20-2-LUCAS TREE-20240926-120453-275	2024	6	5.5	0.1	5.5		4
WG-2024-PLAN MAINT-3-1-4-TTS-20240731-112559-325	2024	18.8	14	1.5	14		130.5
WG-2024-PLAN MAINT-3-13-3-H BROS-20240319-081615-252	2024	26.5	26.5	1	26.5		6
WG-2024-PLAN MAINT-3-12-3-H BROS-20250214-102953-364	2024	15.7	15.7	1	15.7		
WG-2024-PLAN MAINT-3-12-1-TTS-20240319-081039-782	2024	18	17.8	4.2	17.8		55
WG-2024-PLAN MAINT-3-11-1-TTS-20241114-030300-612	2024	29.8	2.7	0	2.7		29
WG-2024-PLAN MAINT-3-11-1-TREES INC-20241021-020610-897	2024	29.4	21.1	2.1	21.1		
WG-2023-PLAN MAINT-3-4-4-TTS-20250214-101959-277	2023	24.7	1.4	1.2	1.4		3
WG-2023-PLAN MAINT-3-4-4-H BROS-20250214-101904-655	2023	24.7	3.8	1.5	3.8		
WG-2023-PLAN MAINT-3-3-1-H BROS-20250214-101521-320	2023	74.8	0.3	0	0.3		9

Assessments Summary | Assessment with Tasks | Work Groups Summary | Work Group with Tasks | Assessment vs Work Group Cost

Figure 5.2.2.L Clearion Operations Summary Report

Satellite Imagery

VEC is currently participating in a satellite imagery pilot project to improve vegetation monitoring and risk assessment across its service territory. The integration of satellite imagery technology aligns with VEC's commitment to leveraging advanced tools for improved reliability and safety. As the utility continues to evaluate the benefits and cost-effectiveness of this approach, it plans to gradually incorporate satellite-based vegetation management into its existing inspection and monitoring standards, subject to available funding.

5.2.3 System Protection

VEC designs its power system protection to automatically detect faults that occur on the system and sectionalize or isolate the faulted lines from the rest of the electrical network. The aim is to improve worker and public safety, minimize damage, and improve the overall service reliability of the power system while preventing outages for a larger number of members. VEC uses the following system protection equipment designed to automatically coordinate with one another to sense system faults and sectionalize or isolate the system closest to the faulted parts:

- Reclosers – Located at all VEC's distribution substations and at various locations throughout the distribution system, these devices are the primary distribution circuit protection and quickly attempt to clear a fault or de-energize an entire circuit to protect the substation transformer and other distribution equipment from damage.
- Line fuses – Located on distribution lines or taps, fuses isolate faults and work in addition to, and in coordination with reclosers to help maximize sectionalizing.
- Transformer fuses – Located on all conventional transformers, these fuses limit the energy released during a short circuit and protect the associated equipment from failing.
- Arrestors – Located on aerial transformers, reclosers, switches, and capacitors. Arrestors protect those devices from over-voltage such those caused by lightning strikes.

The design settings of these equipment types aim to reduce the time of fault exposure to the shortest possible to improve worker and public safety, minimize asset damages, and maintain an acceptable level of overall system service reliability.

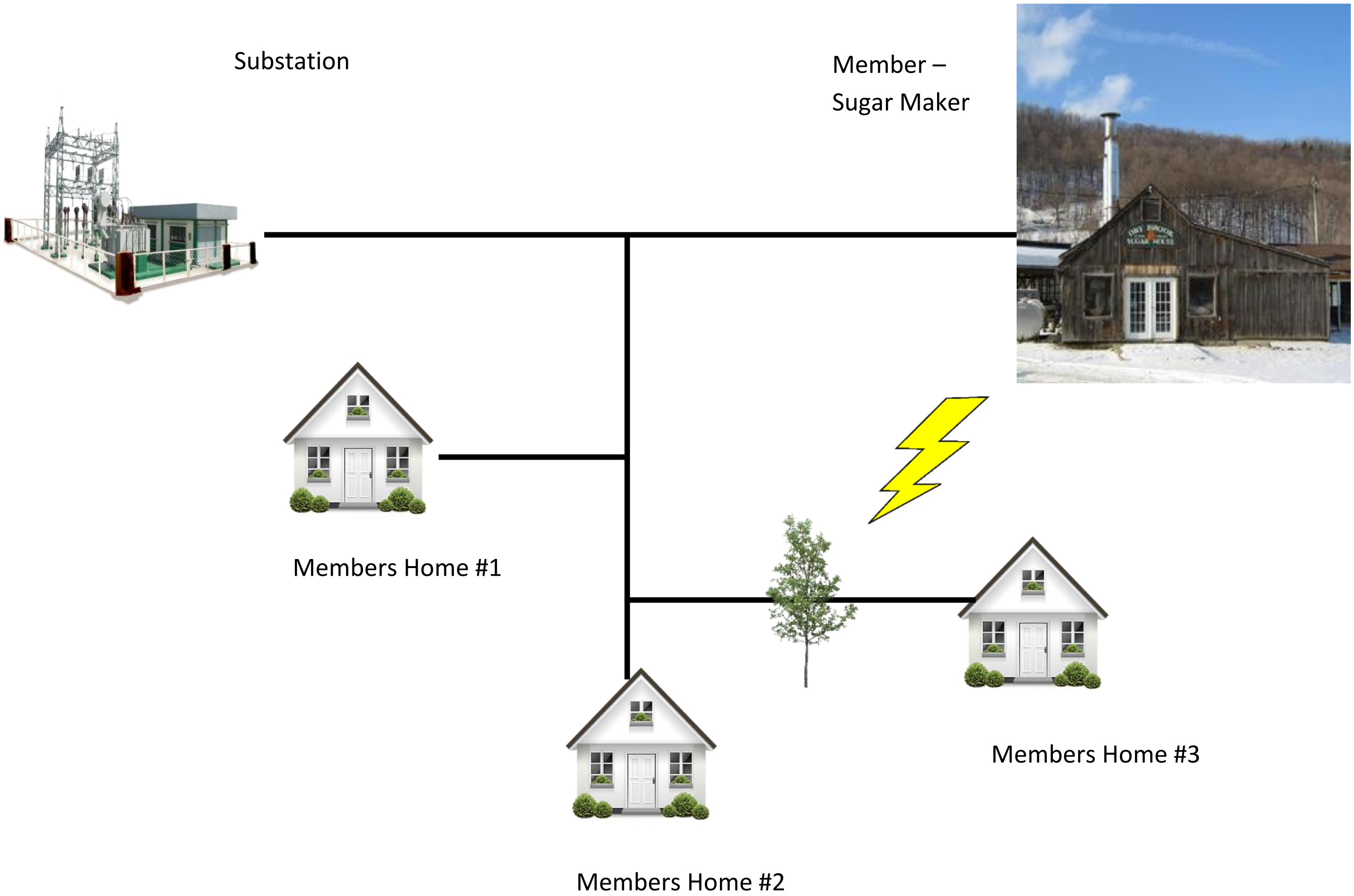


Figure 5.2.3.A Tree Falling on Line Near Member #3

With adequate sectionalizing via the installation of fuses 1, 2, and 3, the same fault would only affect member #3 instead of the entire circuit.

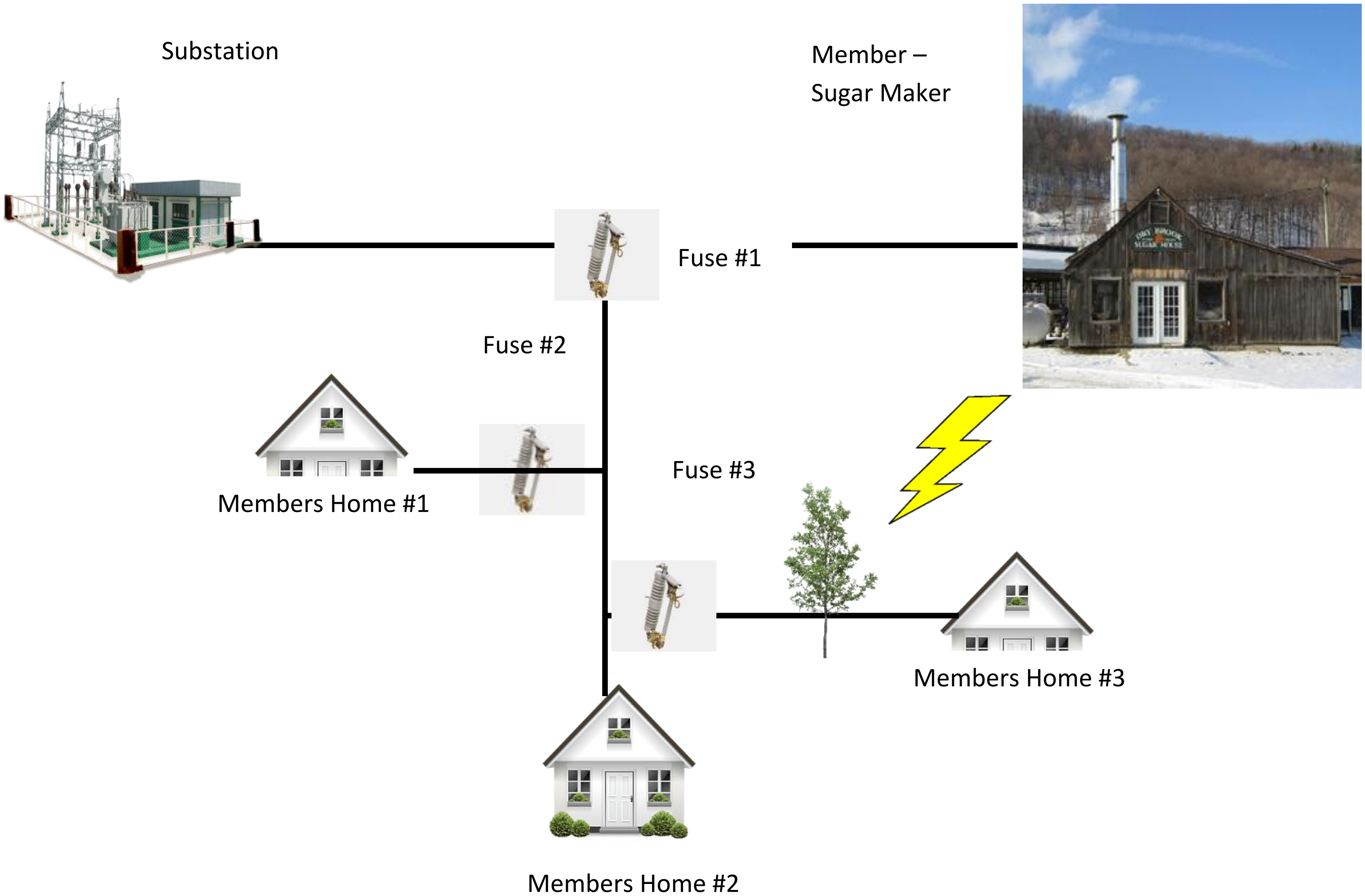


Figure 5.2.3.B   Adequately Sectionalized Circuit

Extensive studies of overhead distribution systems established approximately 80 to 95 percent of all system faults are temporary and last from only a few cycles to a few seconds. A single recloser operation opening and reclosing helps keep these temporary type faults from becoming a longer outage. An example of a temporary fault includes an animal or bird contacting an energized line, wind gusts blowing a tree limb into the line, lightning strikes, and snow unloading from tree limbs that are hanging below primary conductors making contact as they spring upwards. Most line faults occur only in a single phase.

While VEC still has some unfused taps from the main feeders, we have made significant progress in sectionalizing and routinely add fuses to these tap lines to better sectionalize outages and minimize the quantity of members affected by them.

<u>Substation</u>

VEC has standardized on using” triple-single” three-phase electronic reclosers at its substations and on three-phase distribution lines in general. These reclosers are programmable to trip only the phase that experiences a fault without interrupting power to the other two phases. Additional programming allows VEC to either lock open a single phase for permanent faults or lock open all three phases to prevent "single phasing" of sensitive three-phase loads. For many rural substation feeders that have few or no three-phase loads, it is desirable to lock open only the single phase affected by the fault. VEC recommends that member owned equipment be equipped with a protective device in addition to those required by the NEC to guard damage caused by the following events: loss of phase, under-voltage/over-voltage, or automatic restart following an interruption.

In addition, VEC utilizes overcurrent protection to maximize load current, allow for cold load pickup (significant load demands after an outage), feeder back up configurations, and maintain sensitivity required to keep the system protected from bolted ground faults.

The majority of VEC's substation transformers utilize a high side power fuse for protection. VEC sizes these fuses to carry the full, expected load of the transformer's capacity and protect the transformer from a high magnitude short circuit current between the fuses and the transformer, within the transformer itself and the substation's distribution bus before the feeder protection equipment. The distribution feeder protection equipment protects the transformer from faults on the distribution feeders.

VEC has standardized using S&C power fuses to protect its substation power transformers. These fuses are very reliable and not prone to preheating allowing for:

- **Superior transformer protection**. You can fuse close to the transformer full-load current — thus providing protection against a broad range of secondary-side faults.
- **Higher levels of service continuity**. "Sneakouts" (unnecessary fuse operations) are eliminated.
- **Close coordination with other protective devices**. No "safety zones" or "set-back allowances" are needed to the published TCCs to protect element against damage.
- **Operating economies**. No need to replace unblown companion fuses on suspicion of damage following a fuse operation.
- **Superior transformer protection**. You can fuse close to the transformer full-load current — thus providing protection against a broad range of secondary-side faults. Fusing closer to the transformer full-load current -- providing protection against a broad range of secondary-side faults.
    - Higher levels of service continuity – eliminates "sneak-outs" (unnecessary fuse operations).
    - Close coordination with other protective devices – no "safety zones" or "set-back allowances" needed to the published time-current curves to protect fuse elements against damage.
    - Operating economies -- no need to replace unblown companion fuses on suspicion of damage following a fuse operation.

VEC's substation feeder protections typically do not use "fuse-saving" trip operations, allowing the down-stream line reclosers and fuses to operate and clear faults without causing substation feeder protections to momentarily interrupt power to the entire feeder to save a feeder down-stream line fuse. Where VEC does utilize fuse saving trip operations, we limit the number of "fast" trips to a single operation per device to limit the momentary interruptions to the members served by the recloser.

Subtransmission

VEC communicates directly with VELCO and GMP regarding what we have planned for substation transformer fuses and transformer sizes interconnected to their transmission systems, including any tap transmission lines owned and operated by VEC that have independent protections installed. VEC does not possess a copy of the transmission or sub-transmission system model and cannot perform these studies on our own without the assistance of VELCO or GMP.

5.2.4 Wildlife Protection

Wildlife protection (also referred to as animal guards) deters squirrels and other animals from accessing electric power lines, substations, and transformers resulting in reduced outages.

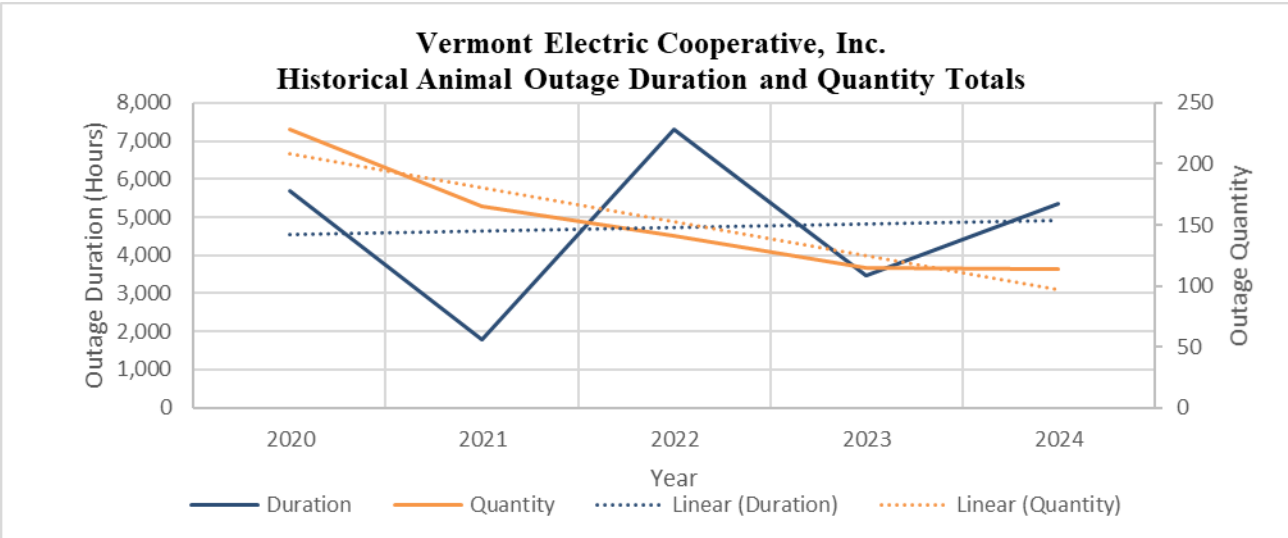


Figure 5.2.4.A VEC Animal Outages 2017-2024

On its distribution system, VEC adds wildlife protection to all new and replaced reclosers, regulators, transformers and substation equipment. VEC uses a RUS approved Reliaguard product that combines effectiveness and durability while considering the least cost solution. Reliaguard products follow IEEE 1656-2010 (IEEE Guide for Testing the Electrical, Mechanical, Durability Performance of Wildlife Protective Devices on Overhead Power Distribution Systems Rated up to 38 kV), and UL94 V-0 flammability.

While squirrels represent a large amount of animal outages, VEC has recently seen an increase in bird related outages due to an increase in osprey population around Lake Champlain. Unfortunately, three-phase, forty-five-foot poles with cross-arms make excellent nesting spots for osprey. Outages on these locations generally affect many members due to a high density of members in that area. VEC established an avian protection plan that involves patrolling three phase main lines and removing sticks before they turn into nests identified on these (late April through October). If the osprey comes back to same location, VEC sets a pole and platform away from our distribution line to allow the osprey to build their nest while not affecting the power system.

5.2.5 Detect Outages with AMI

Current AMI (Automated Metering Infrastructure) System

VEC has been evaluating, testing, and installing AMI technologies since 2000 with the aim of improving outage response and reducing costs. From 2001 to 2004, VEC tested various meter technologies and chose the Two-Way Automatic Communication System (TWACS) Power Line Carrier (PLC) AMI system. From 2004 to 2015, VEC installed an Aclara AMI system for 98% of VEC members at a cost of $5.2 million, with an $884,000 Department of Energy grant from the American Recovery and Reinvestment Act (ARRA). By the end of the 11-year rollout, VEC had achieved savings of $6.5 million through reduced truck rolls (27% of total savings) and meter staff reductions (from 14 to 6 employees).

In early 2022, VEC rolled out a cost-effective Radio Frequency AMI system for the remaining 2% of meters. Expanding the existing Aclara PLC AMI system was not financially feasible. Less than 0.1% of VEC members opted out of the AMI system. Since 2005, VEC has used the Aclara based AMI system for 99% of demand usage metering and outage monitoring for residential, small commercial, and industrial consumers. Integrated through Multipeak, VEC's AMI system stores meter data in NISC's "iVUE" Meter Data Management system.

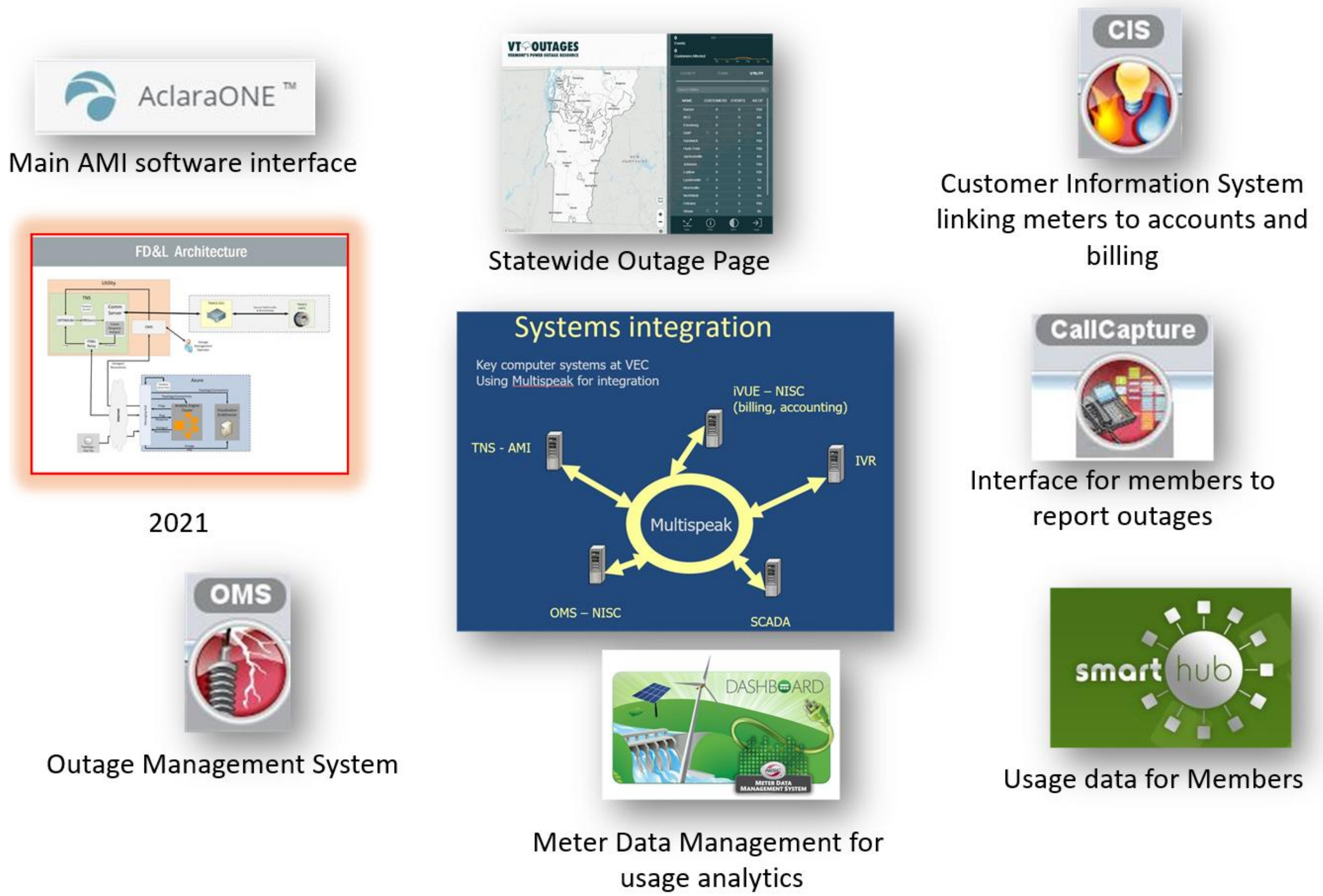


Figure 5.2.5.B AMI integration with other products.

Limitations of Existing System

While VEC’s AMI system has provided significant value since its initial installation in 2004 over the last 3-5 years, VEC has seen faults in its capabilities, especially when using the technology as a tool in energy transition.

<u>Outage Identification Requires Member Call or Time-Consuming Query</u>

VEC’s existing PLC system does not notify VEC of an outage. Instead, alternate notifications are required to initiate an Outage Management System (OMS) query. The OMS query will find the meters that are not connected and are likely in an outage state. This alternate notification typically comes from a member notifying VEC that they have an outage or from a SCADA controlled piece of equipment.

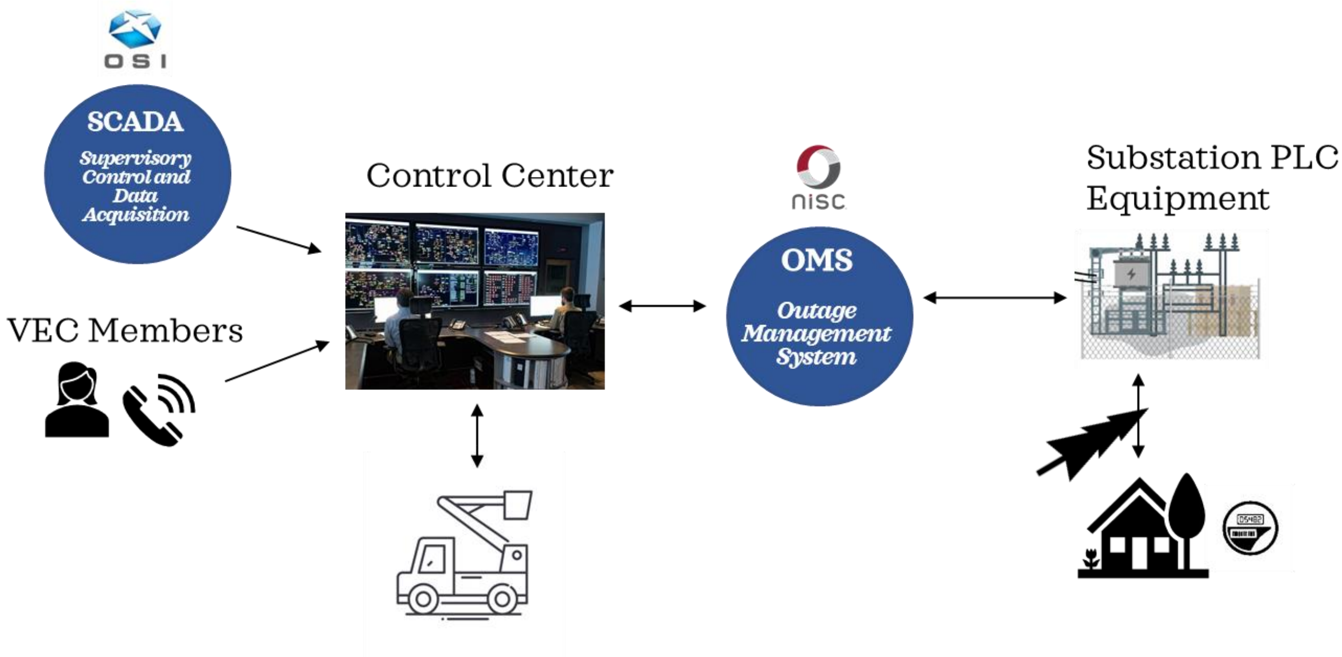


Figure 5.2.5.B System Monitoring Process

Depending on the size of the circuit, the OMS query can take anywhere from 1 to 10 minutes. In some cases, such as part-time residents who are away for long durations), VEC may not be notified of an outage.

Delayed Data for Operations

VEC's current AMI system sends hourly kWH data every 8 hours to the headend system. The data is then processed and made available in VEC's Camus system 20-30 hours after measurement. This is a limitation in the power line carrier technology and there is limited opportunity to increase the frequency at which data is sent without negatively impacting billing and or outage operations.

VEC has a direct connection to over 100 member-owned ChargePoint chargers which send data every 1 minute. The image below shows the disparity in the two data sets (AMI in brown and ChargePoint data in purple):

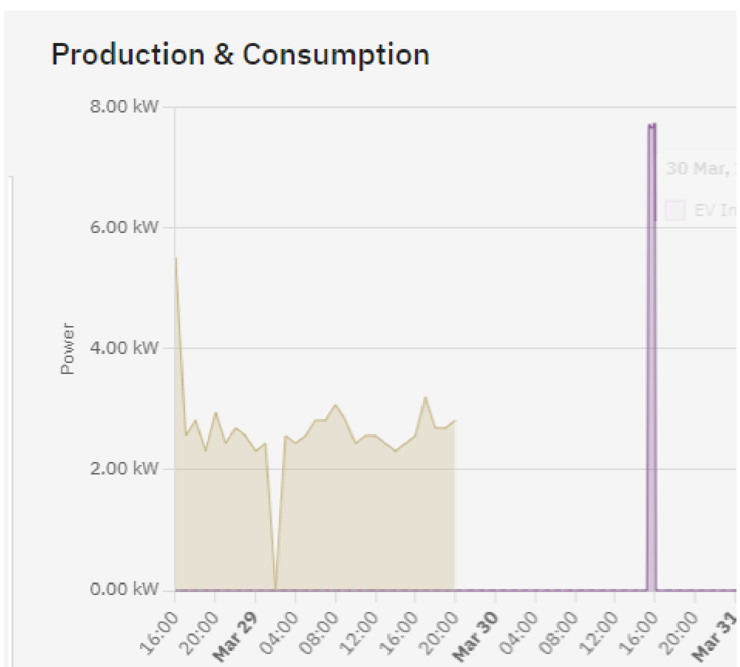


Figure 5.2.5.C   Energy Consumption AMI Versus ChargePoint

While the hourly data kWh data is sufficient for billing, it does not allow control center operators to use the AMI data for support during operations or resolving power quality issues.

Hourly Data Resolution

For billing VEC's existing volumetric and time of use rates, hourly kWH readings are more than adequate. However, the hourly data makes analytics, such as electric vehicle (EV) detection much more difficult. The image below provides an example of this:

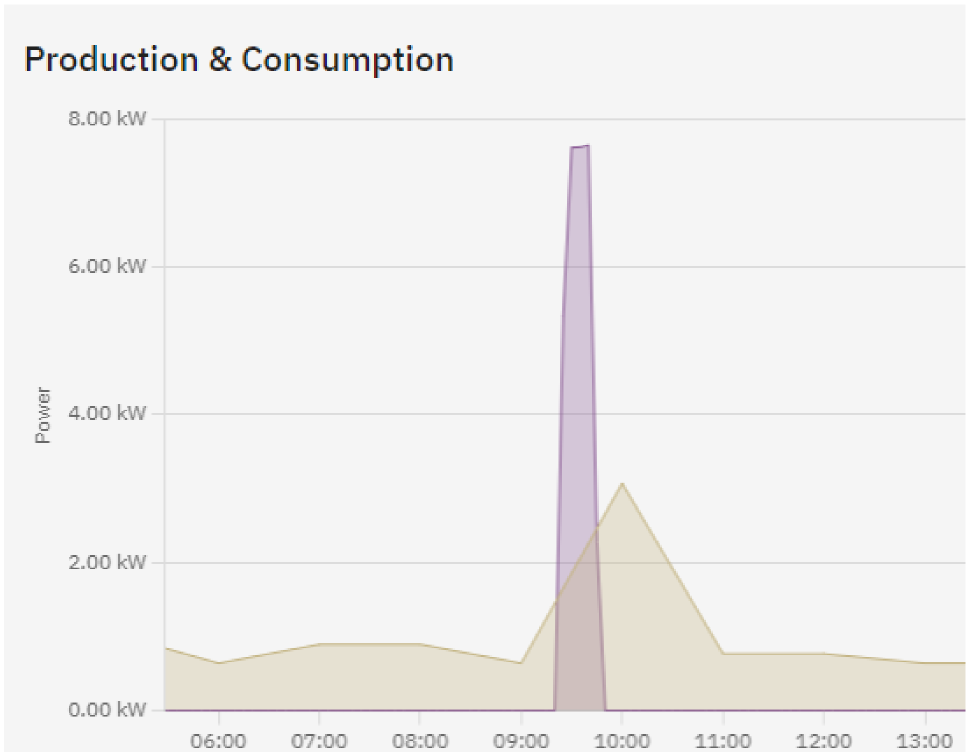


Figure 5.2.5.D   Energy Consumption AMI Versus ChargePoint Showing EV Detection

The hourly kWH data (brown) shows a peak of around 3 kW while the charger data (purple) shows a peak of almost 8 kW.

Existing AMI System does not Send Back Power Quality Data

As mentioned above, the existing AMI system is limited in the amount and speed of data it can send back without negatively impacting billing and or outage operations. Datapoints like voltage, real power, frequency or reactive power are critical to what control center operators and planners need to reliability operate the system. For many years this level of visibility was not required below the transmission and substation level and systems like SCADA were adequate. As the amount of distributed generation has increased so has the complexity of managing the system and as a result visibility into the distribution system has become much more important.

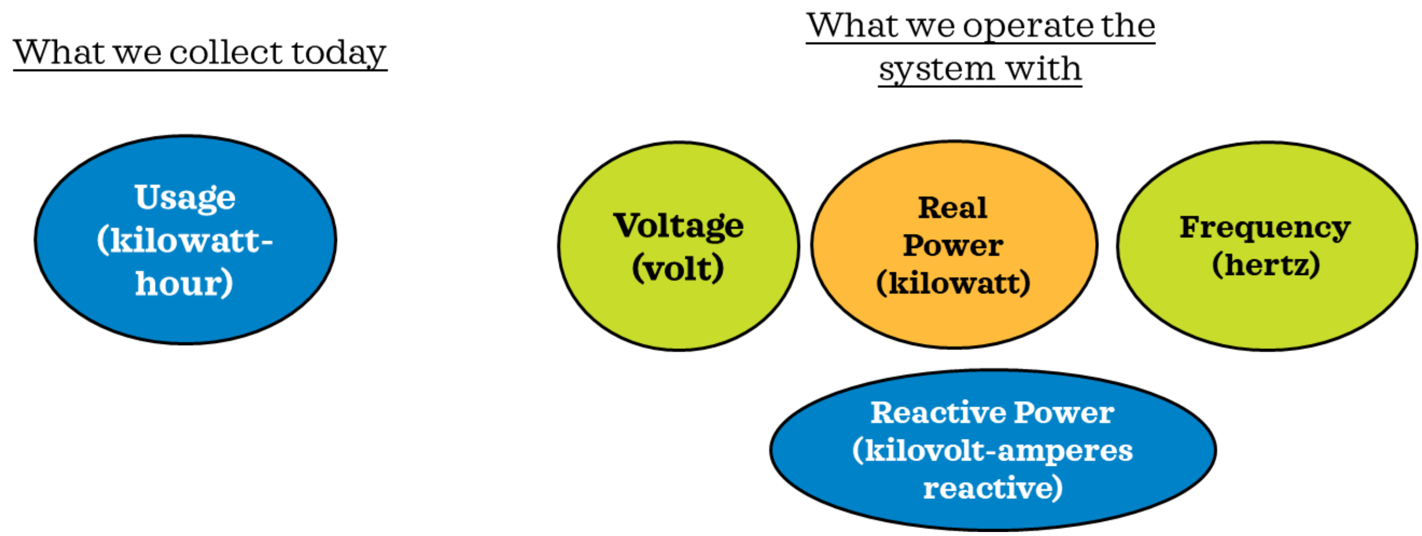


Figure 5.2.5.E Distibution System Visibility

Without power quality data, VEC uses an engineering model to identify potential low voltage issues. For urgent cases like blinking lights or solar inverters tripping offline, VEC sends linemen to record voltage or install a voltage recorder, which can take weeks to analyze. The upcoming AMI upgrades funded will address these problems.

Managing Distributed Energy Resources to Reduce Capital Investment

VEC estimates that over $100 million in distribution investment will be needed to fully electrify heating and transportation by 2040. This excludes the higher costs for VELCO or ISONE's transmission infrastructure. Despite recent increases in T&D capital expenditure for growth and technology, more flexibility is still required.

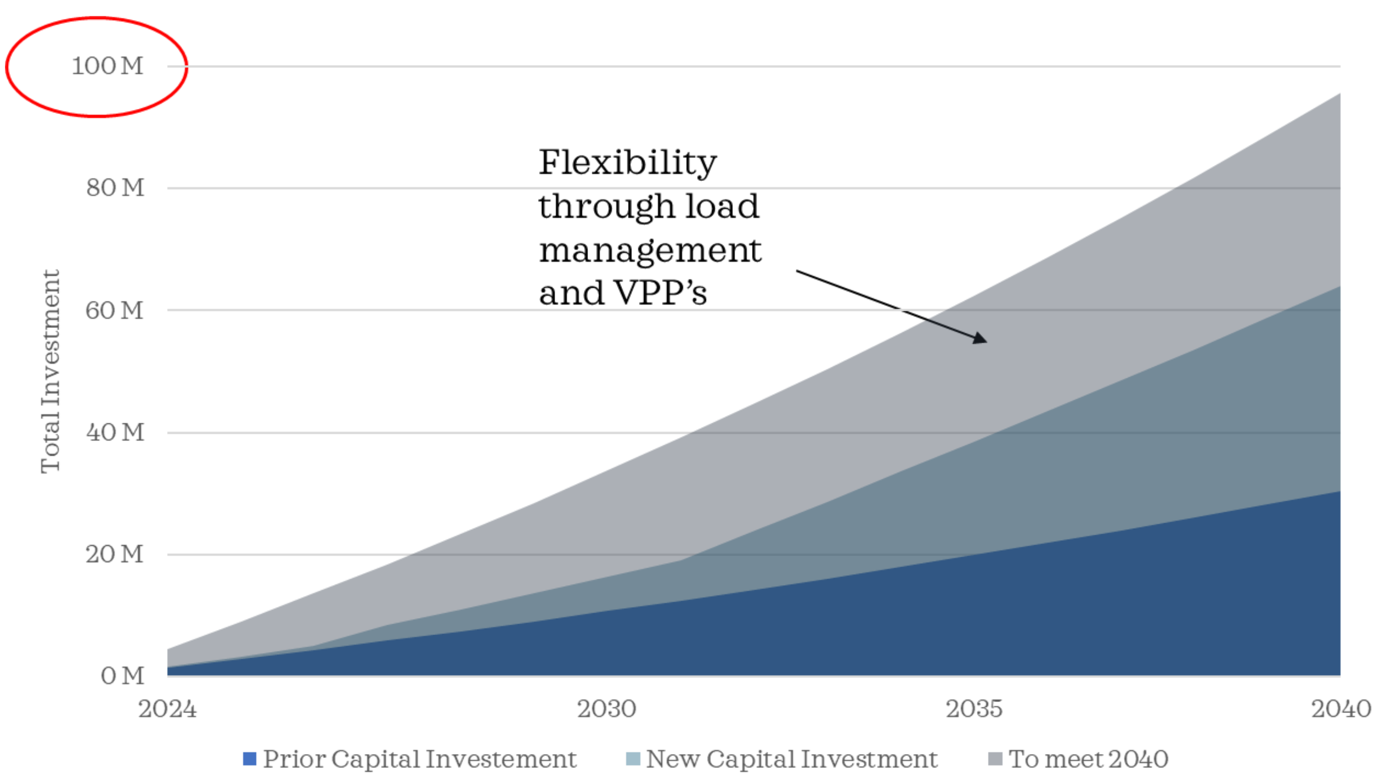


Figure 5.2.5.F   Flexibility Defers Capital Investment

VEC is proposing an innovation pilot to enhance EV management programs for peak management and deferral of transmission and distribution asset upgrades. This would allow more flexibility during upgrades and reduce cost burdens on VEC members. The AMI project is essential to this pilot, as the current AMI system lacks sufficient data to manage all distribution constraints.

Asset constraints typically show up in two categories– thermal (kW overloading) or transient (voltage). In the case of thermal overloading, such as a distribution transformer, VEC's existing AMI system provides enough data to visualize the overloading. While the data is 20-30 hours delayed, VEC has tools to forecast the AMI data. The goal of the upcoming pilot is to reduce the charging speed of an EV and not exceed the distribution transformer limit while also continuing to provide grid services such as peak shaving. An example of this is provided below:

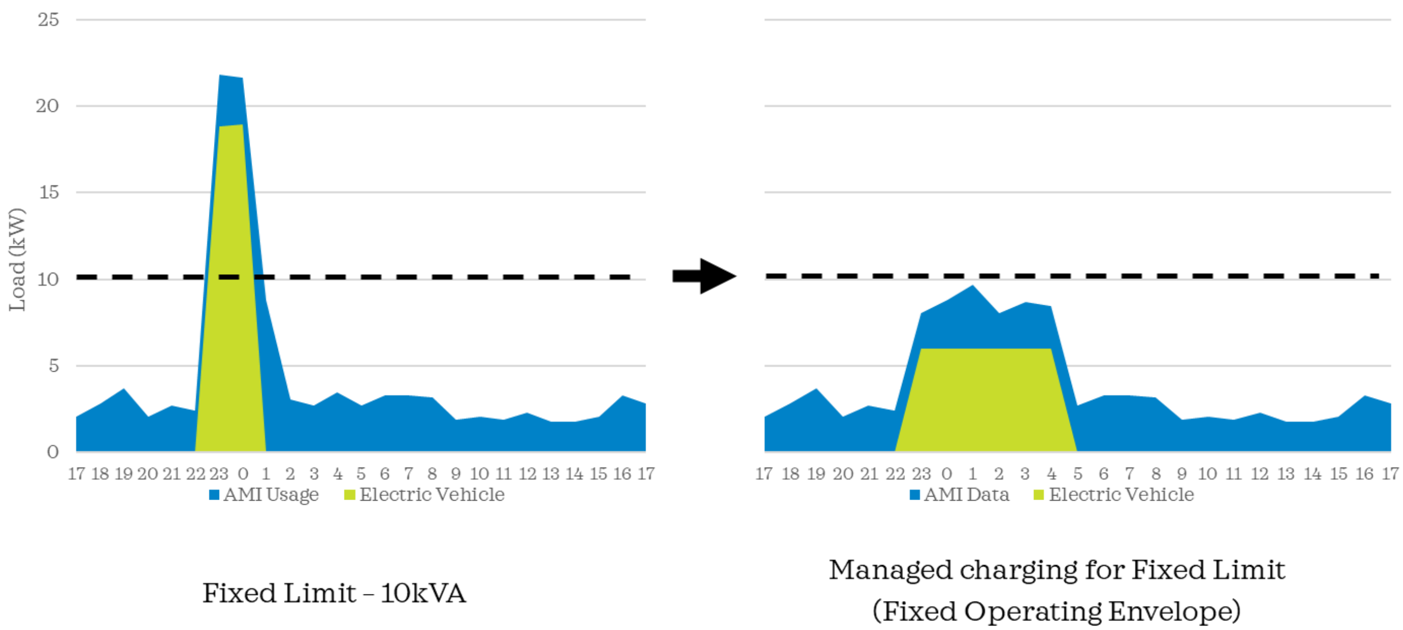


Figure 5.2.5.G   Peak Shaving with Managed Charging

This same principle applies to issues further upstream at the primary line, substation, and transmission levels. However, many of these issues, especially in the case of distribution primary lines, are transient voltage related issues. Since VEC does not currently receive voltage from the meters, it will be impossible to achieve the same goals without investment in more sensors data on the distribution system. VEC's proposed AMI investment would address these issues.

<u>Limited data for members to understand and manage usage</u>

With VEC's existing AMI system and NISC integration, members see hourly usage data as soon as the information is received by VEC's Meter Data Management system (MDM).

Figure 5.2.5.H   Member Meter Data Management Interface

VEC receives occasional high bill complaints and will work with the members to identify what might be the root cause of that issue. While the hourly data can provide an overall understanding of usage, it is not high enough resolution to identify issues that the member may have on their end.

Limitations to Implement Smart Rates

VEC offers a variety of rates. Most members participate in volumetric rates with fixed per kWH and demand charges. While VEC offers a Time of Use rate, only 45 members participate (8 commercial, 37 residential).

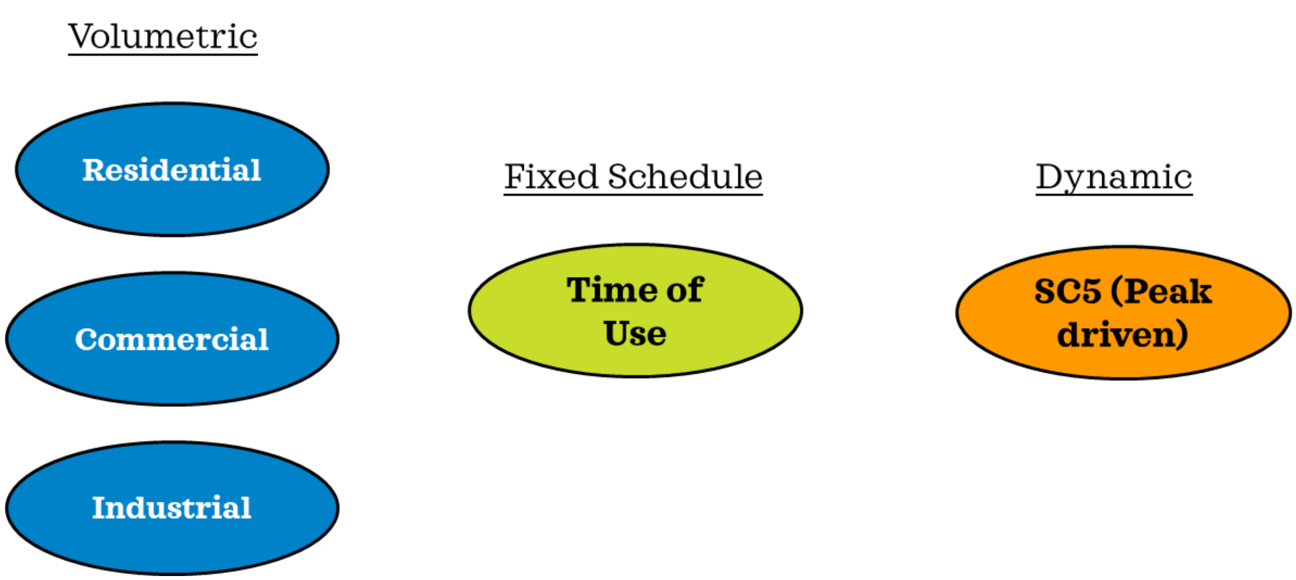


Figure 5.2.5.I   Rate Options

VEC has one dynamic rate offering whereby members pay a variable transmission charge. VEC currently uses email to notify members of potential Forward Capacity Market (FCM) and Regional Network Service (RNS) peaks but does not offer any near real time signals as the existing PLC system is too slow to enable this function.

As VEC looks to cover the cost to serve all members and incentivize participation in load management programs, dynamic rate structures provide a potential pathway. VECs' current metering system would not support dynamic rates, but VEC's proposed AMI upgrades would.

PLC End of Life

Almost half of the electric cooperatives who had installed PLC in the 2000s are actively moving or have completed a transition to an RF based metering platform. This includes our sister cooperative in Vermont, WEC. In many cases, vendors are no longer offering new PLC installations. While the PLC technology remains viable for billing, it is no longer suitable to meet the needs of a distributed grid.

Benefits of the New System

Proactive Outage Detection

VEC's new RF mesh system will incorporate "last gasp" technology, which enables a signal to be transmitted following a power interruption. This feature, not available with PLC systems, can identify an outage within minutes, potentially leading to faster outage response and restoration times.

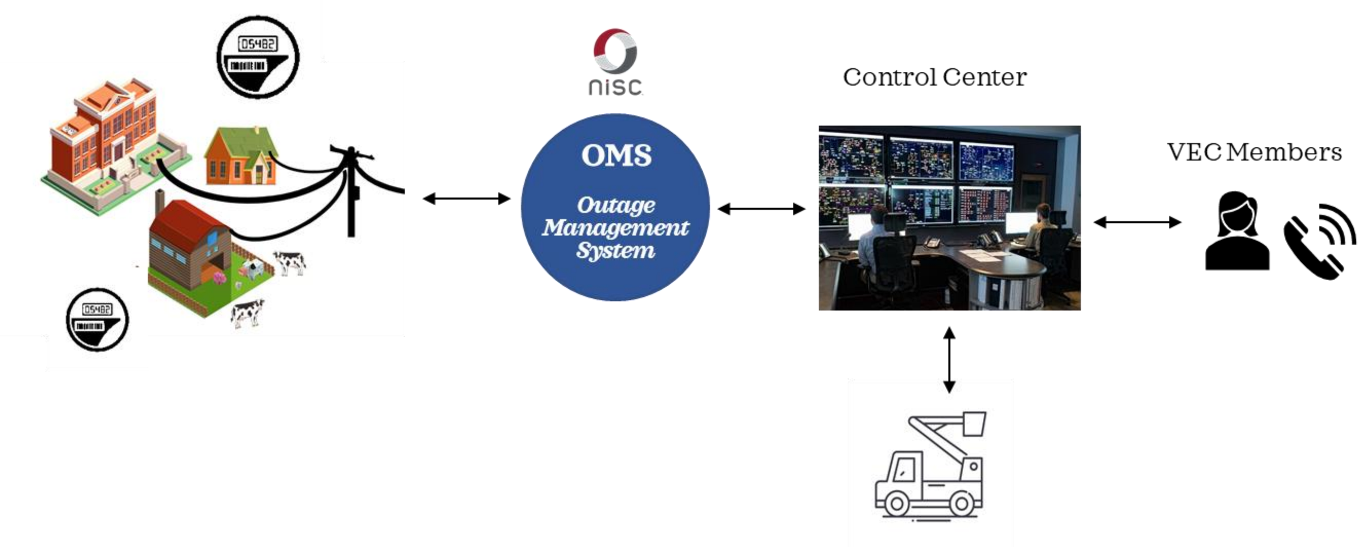


Figure 5.2.5.J   Meter Based Outage Detection

As described earlier, VEC rolled out a small RF based AMI pilot in 2022. The outages in this pilot are routinely identified before a member calls.

Visibility to Orchestrate Distributed Renewable Energy

VEC's upgraded AMI system will record and send power quality data back to the headend every 5-15 minutes. VEC will also be able to poll the meter at any time to see the real time measurements.

These functionalities will allow VEC to be more proactive when it comes to addressing power quality issues and planning the system for growth in distributed generation

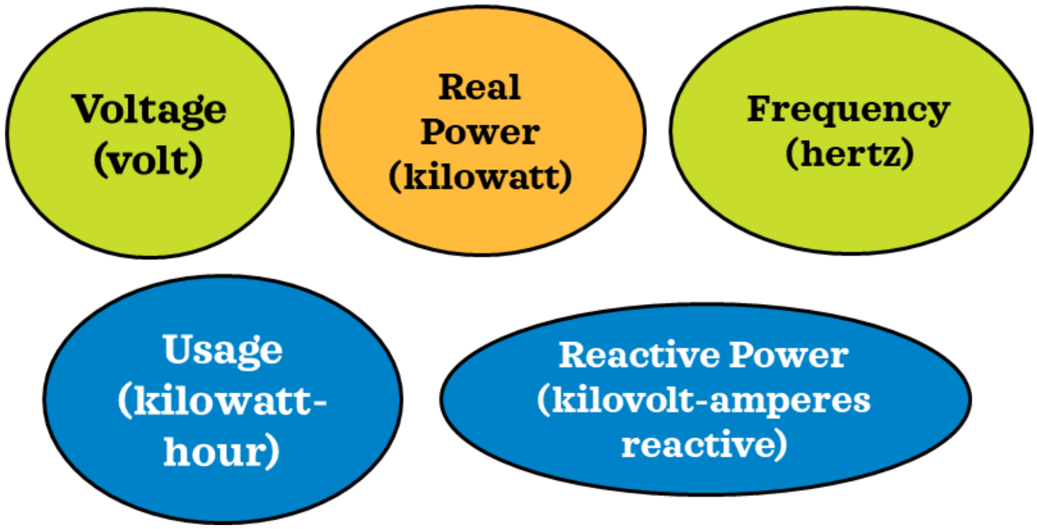


Figure 5.2.5.K AMI Meter Data Access

By collecting the data above, VEC will be able to calculate a variety of power data points such as power factor.

Flexibility to Maximize Infrastructure

As outlined in section 1.3.5, the current PLC AMI system lacks the necessary data types and frequency required to support VEC's objective of managing DERs to defer capital investments. The AMI upgrade, along with existing DER programs and providers such as Camus, will enable VEC to defer up to $40 million in capital investments by 2040.

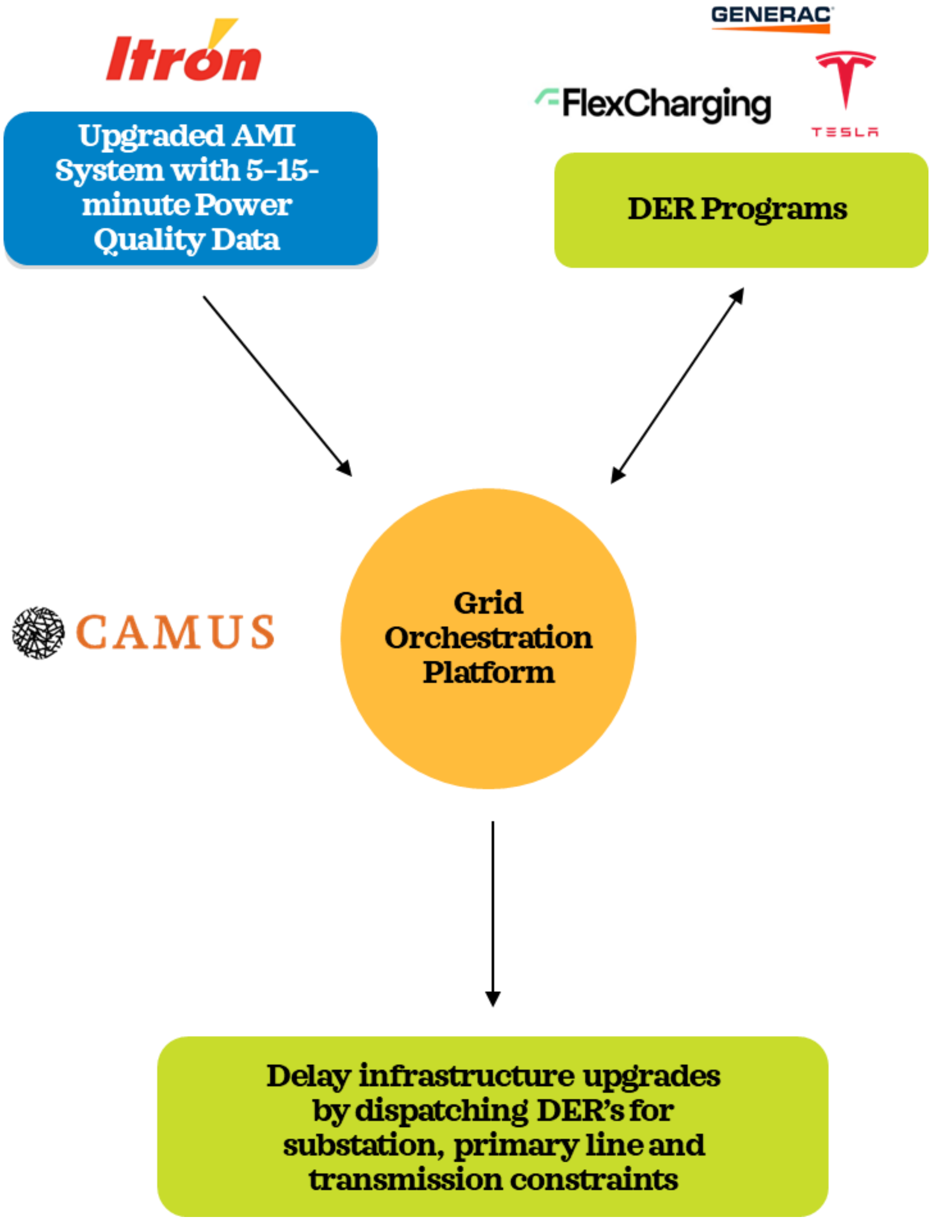


Figure 5.2.5.L Delay System Upgrades Using Technology

<u>Higher Resolution Data and Disaggregation to Proactively Identify Member Issues</u>

To address members' high bill complaints, such as pump failures or other electrical issues, VEC's new metering system will provide data in 5–15-minute intervals. This will allow the use of NISC disaggregation tools, offering members insights into their usage and alerts on potential billing impacts. VEC aims to assist members in reducing costs, particularly those with significant energy burdens. The information provided can help identify opportunities for reducing unnecessary usage and addressing affordability challenges.

Figure 5.2.5.M High Quality Meter Data

Data and Communication to Support Innovative Rates

VEC's metering system is foundational to supporting the use of innovative rates, such as peak pricing or dynamic fixed charges. The current system is too slow to support sending signals to members to enable these pricing structures and integrations with DER devices are limited. VEC's AMI upgrade will enable time-of-use and dynamic rates, demand response programs, grid-management improvements, and greater customer engagement

Figure 5.2.5.N Meter Upgrade Value Add

Alternatives Considered

VEC plans to switch from a PLC based system to a 902-928 MHz unlicensed spectrum mesh radio network for two-way meter-reading. In 2021, VEC identified challenges with the current system and researched AMI options (RF Mesh, PLC, RF point-to-point, Fiber to the home). RF Mesh was chosen as the most affordable and reliable option for their territory. Although RF point-to-point solutions can be cost-effective, they require tall communication towers for reliability. A 200-meter RF point-to-point pilot in 2019 showed unreliable coverage and technology. Fiber to the home offers high bandwidth but is too costly, covering less than half of VEC's territory.

Implementation Schedule

VEC began exploring AMI technology options in late 2021 and since then has been focused on selection and funding strategies to support the upgrade:

- Late 2021 – VEC spent the majority of 2021 identifying the challenges of the existing system and researching the various AMI technology options (RF Mesh, PLC, RF point to point and Fiber to the home).
- Mid 2022 – VEC filed its 2022 IRP and in Section 6.4.4 described its need and strategy for seeking a replacement to its PLC AMI system.
- Late 2022 – VEC sent out an AMI RFP to 5 vendors.
- May 2023 – VEC selected Itron for the AMI upgrade with NRTC providing installation support, project management, and integration services.
- July 2023 – VEC identified the project's total costs with the NRTC/Itron contract and internal labor and materials.
- May 2024 – The VEC finance team prepared a financial forecast for an upcoming bond that included the AMI project and its impact on rates and equity.
- June 2024 – The VEC board approved the AMI upgrade and approved CEO signing the NRTC/Itron contract.

VEC anticipates the following implementation schedule:

- 2025 – System Acceptance Testing (SAT) – complete system site survey to confirm the propagation studies to evaluate the RF network and finalize the communications-network design, complete preliminary meter configuration, installation of hardware and meters to support 2000-meter pilot
- 2026 – 1/5 of meter and network hardware installations
- 2027– 1/5 of meter and network hardware installations
- 2028 – 1/5 of meter and network hardware installations
- 2029 – 1/5 of meter and network hardware installations
- 2030 – final year meter and network hardware installations

Member Education and Outreach

VEC has developed a customer outreach plan to educate customers on the new AMI system, including meter-installation logistics. VEC plans to implement the following:

- Overall Project Info
  - A website FAQ that includes a project overview, explanations for why VEC is pursuing it, and how it will impact members;

    - A video on VEC's website that will include a visual version of the above information.
    - Information about the project in the Member Newsletters (Coop Life), VEC innovation webinars, VEC's C&I newsletter, and at VEC's Annual Meeting.
- Location Specific Updates
    - As VEC begins replacing meters, it will put posts in Front Porch Forum and provide email alerts to the local community.
- Opt Outs
    - VEC will continue to offer optouts. For members who choose to opt out, VEC will allow for manual meter reading monthly or allow the member to read the meter and email in the measurements.

Substation, C&I, Generation Metering

VEC utilizes EIG (Electro Industries GaugeTech) Nexus and Shark meters for generation, substations and tie-points. VEC has 72 of these meters installed currently, with roughly 12 on our largest accounts. All the Standard Offer projects are equipped with this style meter as are large generation/storage facilities like Kingdom Community Wind and our Hinesburg Utility Scale battery.

We use the EIG Meter Manager to allow our data to be archived and tied to our CIS system. The log data from the meters is pulled into our MDM database on a scheduled routine (every 4 hours). Another tool, CommunicatorPQA, allows us to access real-time data such as current, voltage, real power, reactive power, and apparent power, quality, vector diagrams, harmonics, etc.

We are experimenting with some additional control & monitoring features, such as alerts outside of preset levels and signals to relays. We are hopeful that with these monitoring features we could get notified if we lost a current transformer (CT) or loads shifted significantly.

5.2.6 Sensors and Fault Finders

Fault indicators provide a cost-effective visual indication of faults on the power system. They help to identify fault locations and to reduce outage duration and restoration costs. VEC utilizes Schweitzer Engineering Laboratories (SEL) AutoRanger fault indicators with approximately 300 devices installed on its system. In general, VEC installs fault indicators where power lines cross the road in areas that are difficult to access to help identify the sections of line impacted by a fault to reduce the time for restoration.

Fault indicators come in varying types but the majority last only three to five years depending on how frequently they operate. VEC checks these devices periodically to ensure proper operation as part of the maintenance plan. VEC enters each location into its GIS mapping system with the date installed.

VEC is also exploring the use of SCADA connected fault indicators to help further reduce the time it takes to find an outage both in the field and through its OMS system.

5.3 Advance Event Readiness and Response

5.3.1 Outage Management

VEC uses several tools to plan for and respond to outages as quickly and effectively as possible.

Outage Management System (OMS)

VEC has used an Outage Management System (OMS) supplied by the National Information Solutions Cooperative (NISC) since February 2008. The system relies on four inputs:

1. AMI meter information provided by Aclara.
2. Integrated Voice Response (IVR) automated phone system data.
3. Member service inputs from the VEC Member Service Department.
4. Inputs from VEC's external overflow call center (CRC - Cooperative Response Center).

The system is initiated by an outage call from a member or by the VEC Control Center. The OMS system then begins to "ping" surrounding AMI meters from that member until power is detected. The process for identifying the location of an outage normally takes between 30 seconds and two to three minutes depending on the size of the outage.

VEC publishes these outages to vtoutages.com and posts every outage on its website (https://www.vermontelectric.coop/outage) with an estimated time of restoration (ETR). VEC updates the outage information every five minutes, which balances the needs of members to be informed with the stress on the OMS system of more frequent updates.

In addition to the online member-facing information, VEC employees can view and update outages on their mobile devices through NISC's AppSuite.

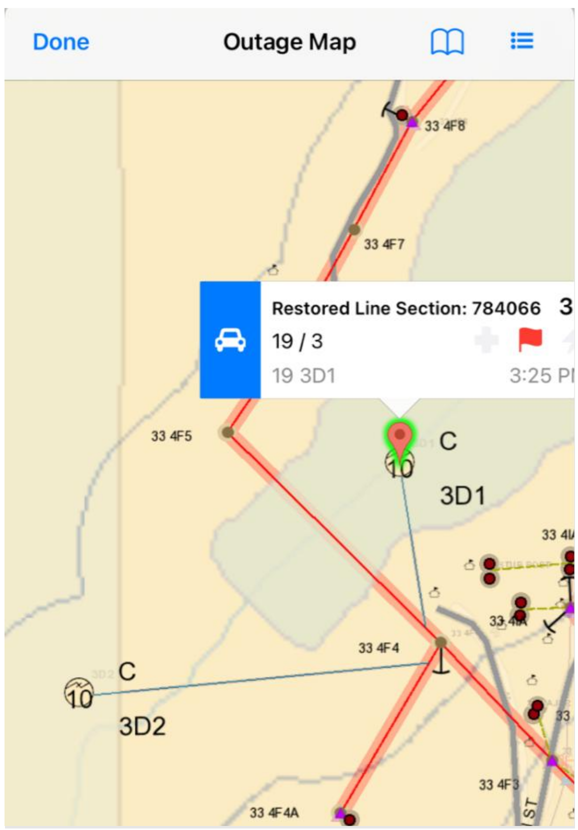


Figure 5.3.1.A   VEC AppSuite Outage Response

Storm Response

VEC employs numerous weather sources and historical event data to predict both outage magnitude and duration. Utilizing a weather predictive resource coordinated by VELCO, VEC closely monitors this data through System

Operations. Additionally, VEC engages in statewide utility emergency calls and internal communications before and during significant events. Based on its Event Planning Level (EPL) and Operating Procedure-57guidance, VEC formulates internal crew rosters for each event according to available personnel and the anticipated type and duration of damage. VEC also assesses the needs and availability of external crews and resources.

When external assistance is necessary, VEC contacts pre-defined contractors and requests aid from local cooperatives and utilities, NEPPA, or other external contractors. VEC provides Mutual Aid assistance to:

- Any utility in Vermont, New Hampshire, Maine, or New York.
- Cooperatives within a 500-mile radius of Johnson, VT.
- Municipals in any New England state.

External crews are supervised by VEC-qualified personnel and equipped with VEC-specified materials and electronic GIS mapping tools.

Effective communication and data sharing are crucial for managing events and incidents. VEC has integrated several software platforms including Microsoft Teams and SharePoint to manage staff availability and emergency response information. Other enterprise software from the National Information Solutions Cooperative (NISC) is used for managing Service and Work Orders, Outage Management and Mapping, and Customer Management (e.g., member inquiries). Following the significant storm restoration event in August 2024, VEC is transitioning all ICS documents and communications to Microsoft Teams to reduce confusion and duplication of efforts associated with using multiple platforms.

Since 2017, VEC has successfully managed various major and minor events utilizing these software packages but continually seeks to streamline processes and enhance effectiveness. VEC participated in the 2021 Electric Power Research Institute (EPRI) Incubatenergy program, which brings together electric utility experts, industry specialists, and EPRI employees to evaluate new technologies and innovative startups. From this program, DisasterTech was identified as a potential solution for VEC's need for an enterprise-level event management platform.

Although DisasterTech offers numerous capabilities, it did not fully meet VEC’s requirements as an enterprise event management platform; however, its weather forecasting functions are currently used as a predictive tool for event management. It is noteworthy that DisasterTech acquired Northview Weather, allowing VEC to leverage a combination of traditional meteorologist-based weather forecasting and open-source AI predictive analysis. Historically, Northview Weather, a collaboration between Northern Vermont University - Lyndon and Northview Weather, LLC, focused on enhancing weather forecasting approaches for utilities. This partnership aimed at providing reliable and actionable forecast information, particularly during wet snow, ice, and wind conditions, to minimize outage restoration costs. The integration of DisasterTech and Northview Weather is expected to facilitate high-speed, accurate severe weather forecasting and analysis, thereby improving storm response effectiveness.

Enterprise Level Event Management

Communication and data sharing are imperative to manage events and incidents effectively. VEC has leveraged several software platforms including multiple lists and pages on Microsoft Teams and SharePoint to manage staff availability and various emergency response information along with other enterprise software from National Information Solutions Cooperative (NISC) to manage Service and Work Orders, Outage Management and Mapping, and Customer Management (e.g., member inquiries). After the most recent significant storm related restoration event in August 2024, VEC transitioned all ICS documents and communications to Microsoft Teams to minimize confusion and duplication of efforts that can occur if using multiple platforms.

While VEC has successfully managed several major and minor events since 2017 utilizing these software packages, VEC is always looking to streamline the process, make improvements, and enhance effectiveness. VEC participated in the 2021 Electric Power Research Institute (EPRI) Incubatenergy program which combines electric utility experts, other industry experts, and EPRI employees to evaluate new technologies and innovative startups. From that EPRI program, DisasterTech was identified as a possible solution for the need for VEC to utilize an enterprise level event management platform.

Though DisasterTech has a number of capabilities, VEC identified that this software did not meet the needs of the organization as an enterprise level event management platform though the weather forecasting capabilities of DisasterTech are being used currently as a predictive tool for event management.

VEC is currently piloting an enterprise-level event management platform called Urbint Storm Manager (formerly WRM). . This tools are expected to streamline storm management in one platform, improving efficiency during storm restorations, logistics, and cost recovery while reducing overall costs. The software aims to secure and track resources, provide meals and lodging, and ensure timely compensation during storm recovery events.

By using an enterprise-level event management platform, VEC connects with the entire workforce (both internal and external personnel) in real-time during storm restoration. Field users can update crew rosters, track labor, submit expenses, and get directions via a mobile app. This efficient data and resource management leads to faster and cheaper restorations.

Emergency Action Plan OP-57 and Storm Response

VEC Operating Procedure 57 (OP-57) documents procedures for responding to threats to the reliability of the power system. While these threats tend to be primarily weather-related outage events, the plan includes responses to natural disasters, cybersecurity threats, and acts of sabotage. The plan identifies an organizational structure and processes for initiating preparedness actions based on the level of threat. The operating procedure is modeled after the FEMA-based Incident Command Structure (ICS).

VEC categorizes events into four Emergency Planning Levels (EPL): Green (No Concerns), Yellow (Medium Concern), Orange (Probable), and Red (Imminent). An Orange or Red EPL level initiates the ICS, lower level EPL levels are handled by an event manager. Once VEC publishes the status on the intranet, it communicates changes in status to VEC employees via a variety of communication methods (e.g., email, text, pager, etc.). As new weather forecasts or other threats develop that change the EPL, VEC updates status levels accordingly. Establishing and adjusting the EPL (and the corresponding response from Planning (Green/Yellow) to Response (Orange/Red)) is at the discretion of the Event Manager/Incident Commander with reference to the EPL Criteria and in consultation with Operation and Planning Section Chiefs. With the General and Command staff, there is at least one primary, and one backup individual well-trained to handle the requirements of those positions. In other areas, a backup may not yet be available. VEC continuously looks for improvements of the system and opportunities to enhance personnel training.

Outage Forecasting

VEC uses numerous weather sources as well as its experience from past events to predict both outage magnitude and duration. VEC uses a weather predictive resource coordinated by VELCO, which is monitored closely by System Operations. VEC also participates in statewide utility emergency calls and internal calls/communication before and during larger events. In addition, depending on the EPL and OP-57 guidance, VEC will create internal crew rosters for each event based on the available personnel and estimated type and duration of damage. VEC will also determine external crew and resource needs and availability.

It should also be noted that DisasterTech purchased Northview Weather so VEC is now using DisasterTech as a weather forecasting platform with weather forecasting capabilities using more traditional meteorologist-based weather forecasting and open source AI predictive weather analysis weather forecasting.

5.3.2 VEC System Operations

In addition to great technology, VEC is fortunate to have highly trained System Operators who manage and respond to the power system. System Operators monitor the power system via SCADA and OMS and provide support to field personnel as required. Qualified System Operators staff VEC's control room twenty-four hours a day, seven days a week, 365 days per year. In addition to utilizing SCADA and OMS, System Operators also utilize a security system which provides real time video footage of all VEC's service facilities (Grand Isle, Richford, Newport, and Johnson headquarters), and over ten substations within VEC's system.

Figure 5.3.2.B VEC Control Room

As of early 2021, VEC also has a fully redundant control room and computer server room in an undisclosed location close to VEC's telecommunications network and in an area that would not be affected by localized natural disasters (tornados, flooding, etc.) that could affect VEC's control room in Johnson. Both control rooms are used equally by operators who live closest to one or the other. 2022 marked the first time during a 12-hour shift on the weekend VEC's system was completely controlled from the redundant control room with no personnel in the Johnson facility.

Both control rooms/server rooms houses a fully redundant, hot standby SCADA system. Operators can access operating documents through the VEC Intranet system that is also backed up at this location. VEC also maintains paper copies of all operating documents at this location.

All other systems including OMS, mapping, radio and other company network services are available at the backup control room. There are phone restrictions due to infrastructure limitations so in the event VEC needs to operate from the backup control room, VEC would rely heavily on an external call-center support provider to handle at least a portion of member calls.

VEC Operating Procedure OP-30 – Evacuation of Control Room, which VEC tests annually, guides all company actions if evacuation is required.

5.3.3 Supervisory Control and Data Acquisition (SCADA)

Existing System

SCADA enables VEC to view real time data as to the status of equipment and other assets (open vs. closed states on reclosers for instance) and their analog values (e.g., power, voltage, current, etc.). It also allows us to remotely operate assets such as reclosers and switches.

In 2011, VEC received a $5.7 million dollar grant from the Department of Energy that facilitated the modernization and upgrade of almost all VEC substation reclosers and regulators and implementation of SCADA to over 65 locations including at all VEC substations and metering points (roughly 11,000 data points). VEC supplies much of this information to VELCO for operational and planning purposes via an Inter-Control Center Communications Protocol (ICCP) connection. These investments took place over four years and VEC was able to complete almost $11.4 million worth of projects with a 50 percent cost share with the Department of Energy.

Remote or supervisory operation allows VEC to save labor hours and reduce outage times by allowing remote switching and tagging, reducing or eliminating travel time to the field or between devices. Travel and labor hours can be reduced by eliminating trips to the field to place monitoring devices, to perform switching and tagging for maintenance and outage restoration activities and to perform operational mandates such as voltage reductions tests or events. The overall result is shorter outages and lower costs.

Real-time data monitoring (2-second intervals) provides visibility for system operations to monitor and react to events on the power system. In addition, as VEC sees more multi-direction electric flows throughout its system, the real time data provides engineering and planning with a view into the system that can be used to review system irregularities (such as voltage drops or outages) and planning analysis (identification of substation transformer upgrades or load balancing). While this data is a great asset, one of the challenges VEC faces is data validation and accuracy. The devices and relays that provide data to the Remote Terminal Units (RTUs) are not revenue grade and generally have an accuracy rate between three to five percent. This level of accuracy is adequate for high level planning, but VEC continues to rely on revenue grade Electro Industries Nexus meters at its substations or Power Quality (PQ) recorders to review system events.

Long Term Strategy

VEC has no plans to significantly expand its SCADA system. VEC will maintain its currents system and incorporate minor expansions as needed for additional DER (Distributed Energy Resources) and new field devices as part of a 5-year SCADA upgrade cycle. VEC no longer plans to integrate SCADA with OMS because the benefit of faster outage identification and restoration is expected to be achieved through the new AMI Upgrade.

OSIsoft PI Historian

VEC utilizes an OSIsoft PI Historian, which archives SCADA data for use in post-mortem review of system events and anomalies as well as for system planning. VEC has built dashboards to enable mobile access to SCADA data for use by field personnel, which provides near real time visuals of the system during SCADA commissioning and during equipment maintenance. The snapshot below shows the one line for VEC's Fairfax #1 Substation with reclosers in the closed position for each main circuit (red) and no faults or trips (green) along with other vital information.

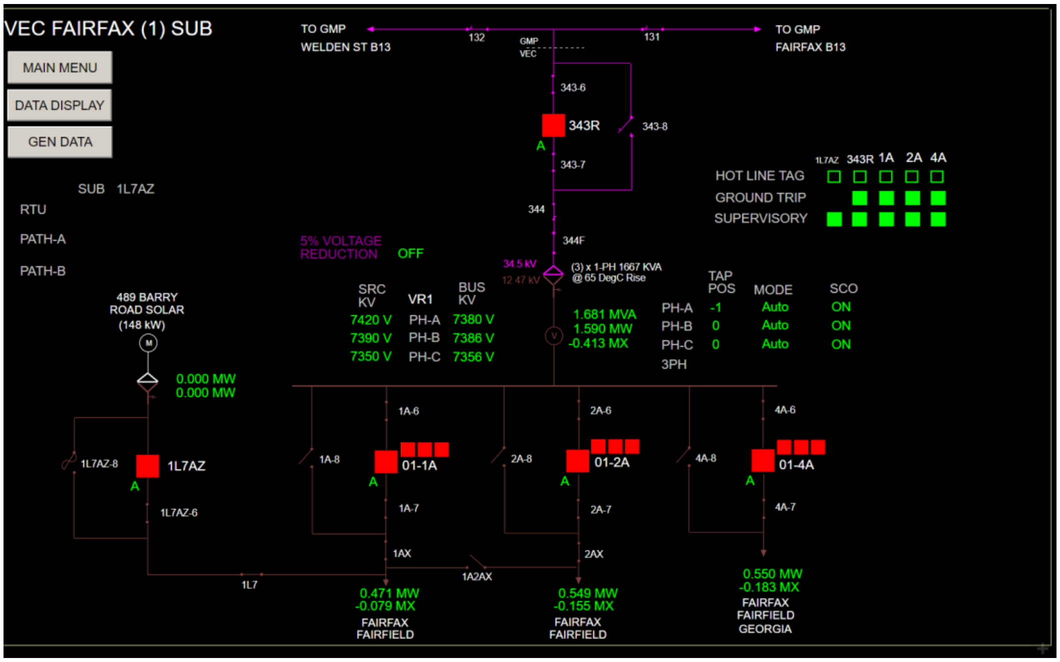


Figure 5.3.4.A   OSIsoft PI SCADA Display (Near Real Time Data)

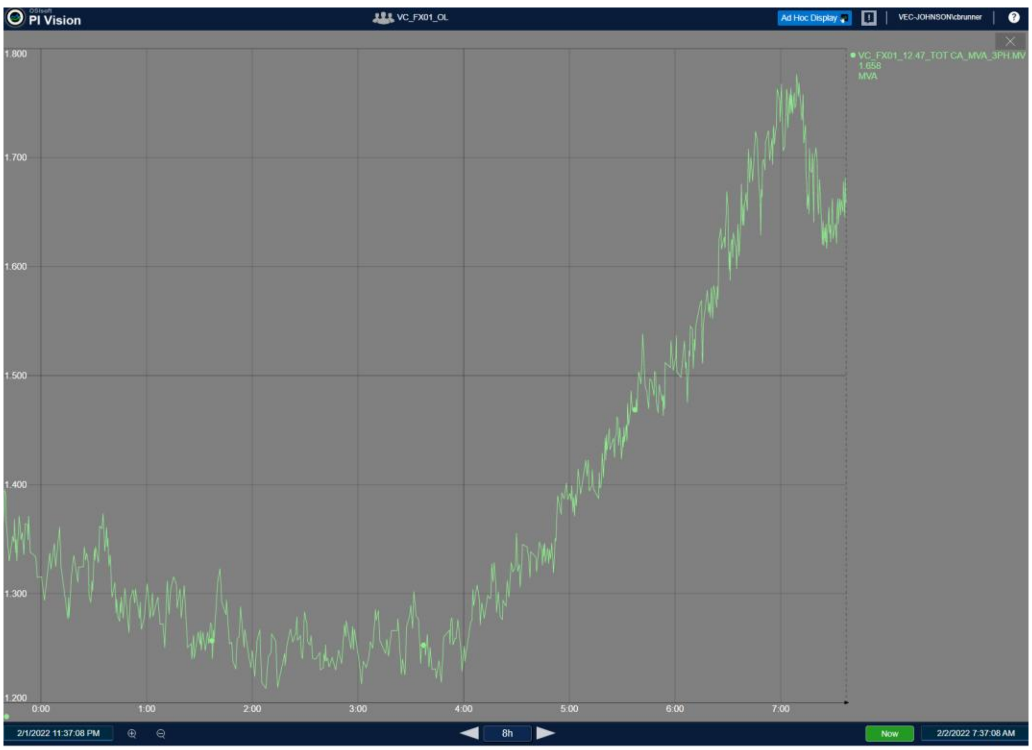


Figure 5.3.4.B   OSIsoft PI SCADA Historical Data

5.3.4 Geographic Information System (GIS)

VEC's Geographic Information System (GIS) is fundamental to VEC's analytics tools. GIS sits at the center of our Customer Information System (CIS/Service) and Accounting Business Solution (ABS/Financials) and is integrated with VEC's engineering model. The system runs on an ArcGIS server, which is an Environmental Systems Research Institute (ESRI) product.

GIS map editing allows new services, line relocations, and other changes to the VEC system to be added to the GIS as part of the normal workflow of VEC's engineering and design staff. In this way, all portions of the VEC electric system can be displayed in a series of mapping tools. The electric connectivity of the GIS is used to integrate with VEC's Outage Management System (OMS), also created by NISC. The GIS system is integrated with Clearion Vegetation Management software used to schedule and track the clearing of VEC rights-of-way.

NISC MapViewer

VEC's office staff rely on a web-based GIS tool (MapViewer) to view the system, protective devices, and many different background layers such as wetlands and parcels

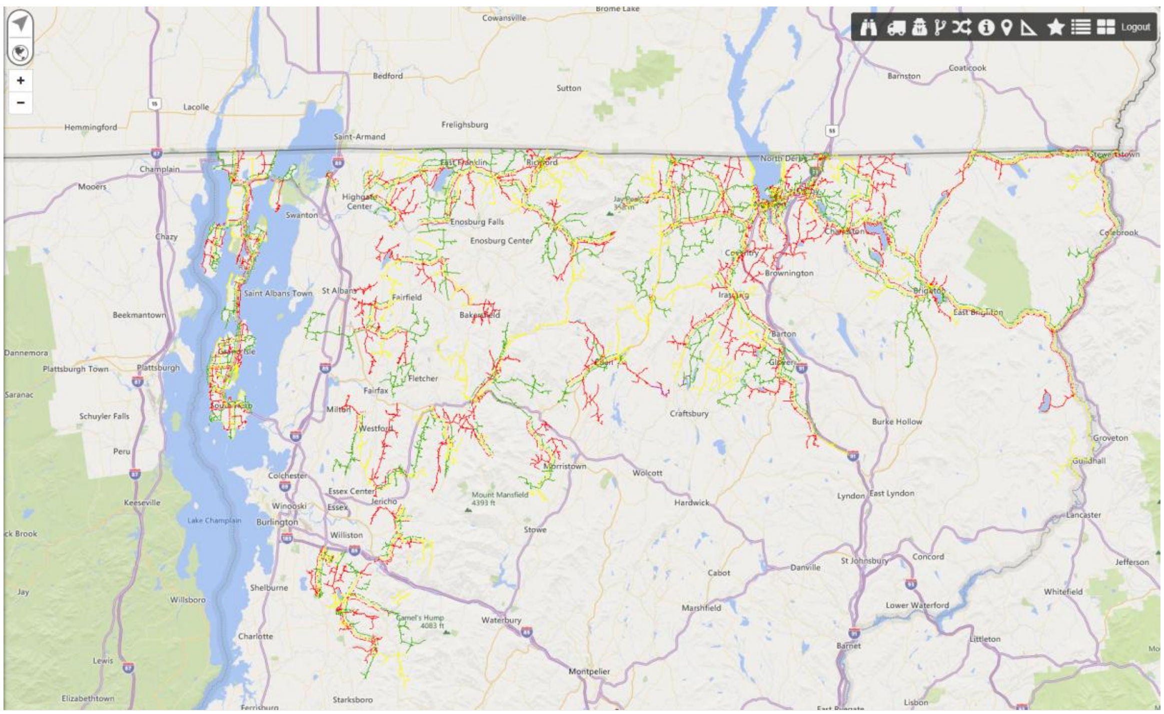


Figure 5.3.4.C NISC MapViewer

NISC AppSuite

Field staff can view the same information on their iPhones/iPads through a tool called AppSuite. They can also manage their task workflow, view outages, and perform paperless inspections.

Figure 5.3.4.D NISC AppSuite

Public GIS Access

VEC distributes shape files of the electric system to the Vermont Open Geodata Portal via VCGI (Vermont Center for Geographic Information). These shape files include pole locations, wire (overhead and underground), and number of phases. While this information is limited, VEC regularly distributes more detailed GIS data to several utilities, state entities, and supporting vendors for uses such as system planning, broadband deployment, or utility location services to support the DigSafe program. An online GIS portal that provides visibility of VEC's poles, three phase lines, generation locations is available here https://vermontelectric.coop/electric-system/grid-data-and-mapping

5.3.5 VEC Telecommunications for SCADA and Metering

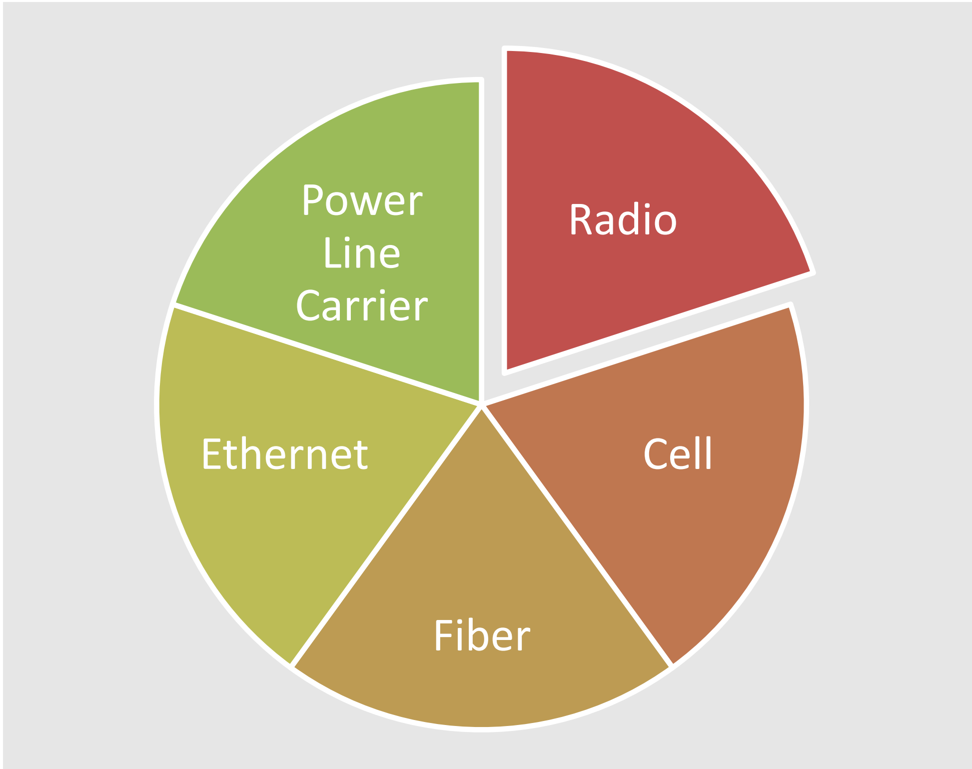


Figure 5.3.4.E VEC Telecommunication Options

Fiber

Vermont Electric Coop relies heavily on our private fiber network to enable fast and effective communication the Equipment at Substations, District Offices and other Field Devices. To ensure the infrastructure continues to meet our current needs and to enable new and innovative technology VEC will be upgrading our existing SONET network to a Multi-Protocol Label Switching - Transport Profile (MPLS-TP) network. Our existing network lacks stability and speed, both of which will be resolved with the new network.

The schedule and rollout of this upgrade will be driven by cost of equipment, priority of new services/applications and the experience of other utilities using this currently. The switch to MPLS-TP will enable enhanced physical security at substations, new metering technologies and the growth of distribution automation, plus position us to adapt better to the unknown.

Radio

We use Point to Point or Point to Multi-Point radio for our distribution SCADA devices. In general, these are reclosers out on the line or generation sites. As part of our Radio Frequency (RF) metering pilot and AMI upgrade we have also begun using radio to communicate with some of our meters.

Cell

We use both a public and private cell network to communicate with various devices. For sensitive controls and monitoring we use a private network to connect to some our SCADA enabled switches and reclosers as well as distributed generation. Our public cell network is used to communicate with our C&I meters and some larger generation meters. We also use cell to communicate to any metering that requires 3rd party access.

Ethernet

VEC utilizes a mix of carrier ethernet through Consolidated Communications and ethernet provided by VELCO. This is used for equipment at substations, field devices, and for AMI/Metering backhaul.

Industrial metering

VEC uses a variety of methods to communicate with large members or generation metering. These include Public/Private cell networks, Carrere Ethernet services and VEC's own fiber network. The communications method is informed by the reliable and security needs of the connection, available communications technologies and the access needs of partner organizations. Metering data is stored at VEC's data centers in its raw form and processed by our MDM for billing and engineering/planning applications.

5.3.6 Notification of Planned and Unplanned Outages

VEC knows that the availability of an electric service is of primary concern to our members. We look to minimize outages, but also to look to provide excellent communication when outages do occur and ensure that any company-initiated outages create the least possible inconvenience. VEC OP-59 identifies those interested in receiving outage information, defines outage notification criteria, and identifies the proper communication methods depending on the type of work.

In addition, VEC ensures public safety by adhering to the following criteria for company-initiated outages based on temperature ranges. These criteria are guidelines and will be considered on a case-by-case basis. Heat index and wind chill are also considerations.

Company Initiated Outages		Planning Criteria
>40 °F	**<80 °F**	No Restrictions
33-40°F		Limit to 4 Hours Max
20-32°F	**80-84 °F**	Limit to 2 Hours Max
0-20°F	**85-90 °F**	Limit to 1 Hour Max
<0 °F	**>90 °F**	Not Allowed

Table 5.3.6.A Planning Criteria for Company-Initiated Outages Based on Temperature

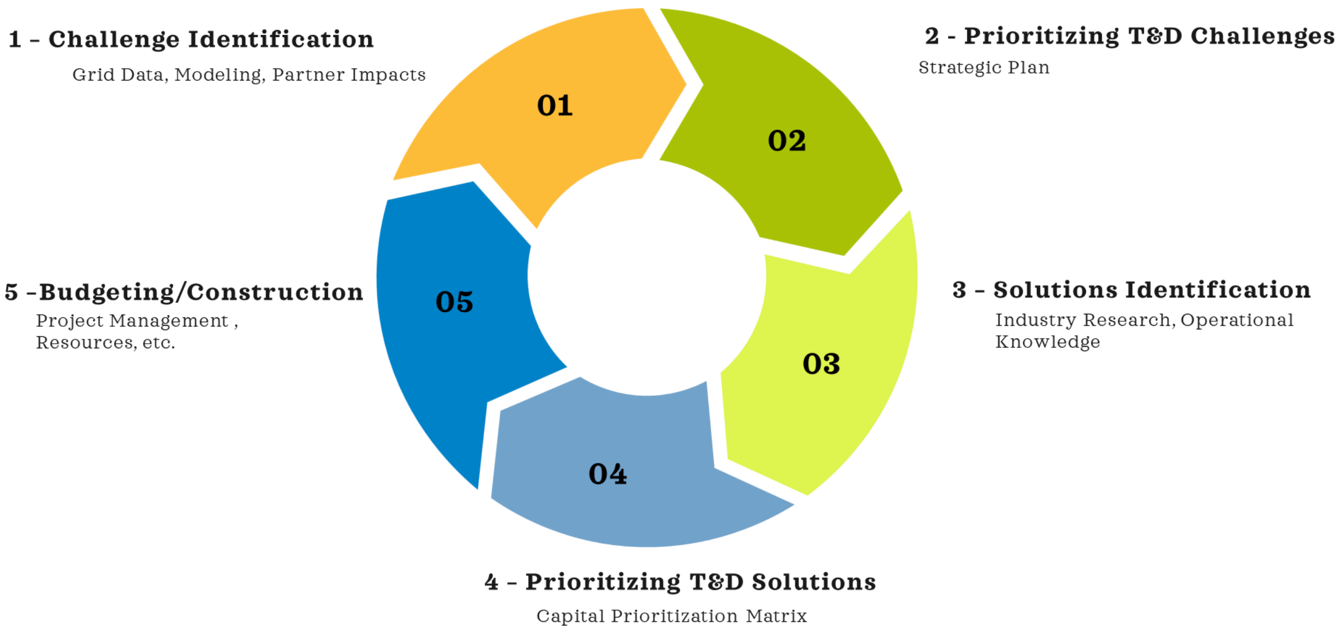
During a non-major, event-related, unplanned outage, the VEC Control Center notifies all medical priority members by searching the outage location on VEC's Customer Information System (CIS). The VEC Control Center will also attempt to contact priority members such as large businesses or other members that have requested to be on this list.

For more information, see OP-59 Appendix-D.

5.4 Prioritize Resiliency in Investments

5.4.1 T&D Capital Project Process

Any project over $20,000 is specifically identified in VEC's capital project process. VEC manages around 1,000 other projects such as line extensions, increase in capacities, and minor equipment replacements within annual buckets. These projects still follow the same work management process but are not identified individually during the budgeting process.



5.4.2 Challenge Identification

T&D capital projects are identified from studies performed by VEC engineers, maintenance procedures performed by VEC line and substation crews, and outside entities such VAOT or other electrical utilities. All T&D projects are tracked in a SharePoint database with identifying attributes.

5.4.3 Prioritizing T&D Challenges

Each challenge receives a prioritization number which VEC updates annually. The prioritization process takes into consideration components such as economic payback, impact to reliability, number of members, size of loads, efficiency, and safety considerations. The process is as follows for all projects:

- VEC enters each project into an internal VEC database and places it through the prioritization process.
- Reviews occur with the appropriate stakeholders involved in the project (Engineering and Operations) and an overall value is assigned to each project. These reviews include:
    - A discussion of impacted stakeholders (landowners, attaching entities etc.)
    - Alternatives to the project (overhead versus underground, relocations, retirements)
- A capital budget target is developed, and projects are chosen based on their ranking, resource planning, and time constraints. For instance, some projects may require permitting or easement acquisition. In other cases, there may not be adequate internal resources available to accomplish the work.

A chart of the ranking scheme is provided below along with an explanation of each metric and adder.

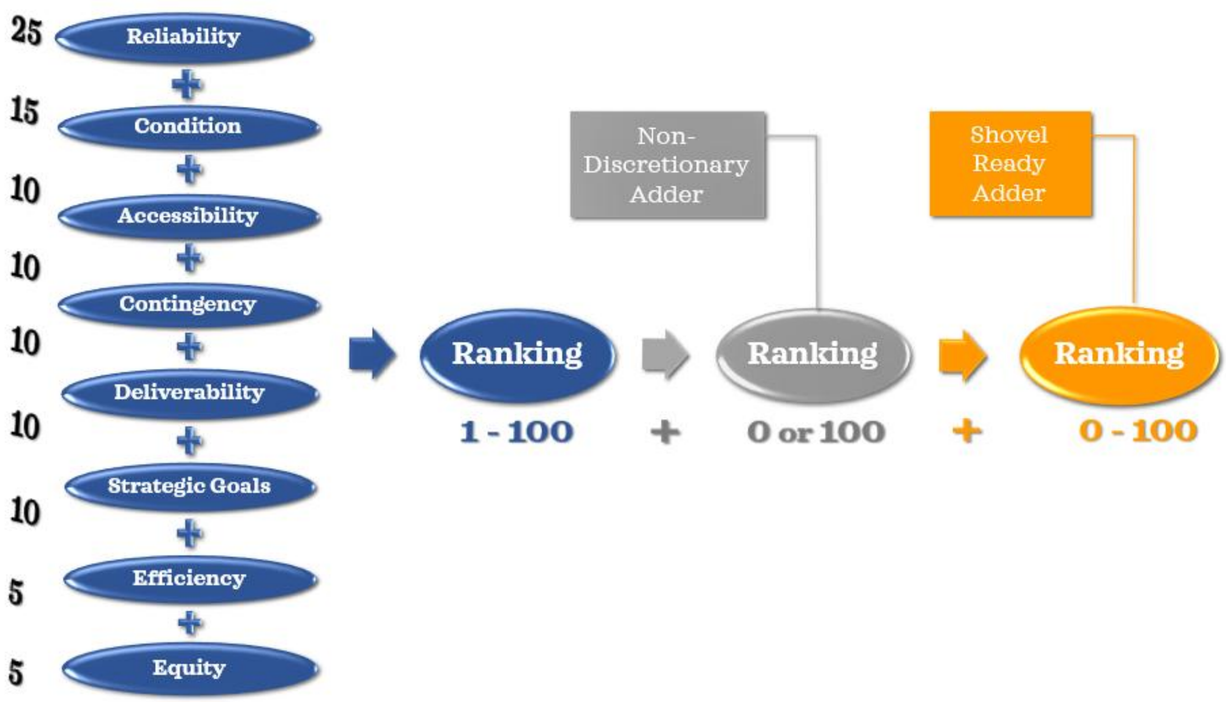


Figure 5.4.3.B VEC T&D Capital Project Ranking Scheme

Initial Metrics

VEC reviews each project for seven initial metrics, which make up an initial ranking:

Reliability

The maximum value for reliability is 25 points. The table below is used to calculate reliability:

Value	Impact on Reliability
0	Project not on worst performers (with storms)
0.5	Some impact to reducing worst performers (with storms)
1	Large impact to reducing worst performers (with storms)

VEC updates its worst performing circuits annually using a 5-year rolling SAIDI average including major storms. A project on a top 20 worst performing circuit would receive a 1 or an additional 25 points applied to the initial ranking. A project not on a top 20 worst performing circuit (average rolling 5 years, with storms) would receive a 0.5 or an additional 12.5 points applied to the initial ranking depending on rank to the top 10.

Deliverability

The maximum value for Deliverability is 10 points. The equation below is used to calculate Deliverability and will give a value between 0 and 1.

$$= \left(\frac{\#\ of\ Meters\ Impacted}{2 * Max\ Meters\ on\ VEC\ Max\ Dist.\ Feeder} + \frac{\#\ Annual\ MWh\ for\ Meters\ Impacted}{2 * Max\ MWh\ on\ VEC\ Max\ Dist.\ Feeder}\right)$$

As an example, a transformer upgrade at Fairfax 12 that will affect 535 members

$$= 10 * \left(\frac{535}{2 * 1{,}840\ members} + \frac{5065}{2 * 19{,}971\ MWh}\right)$$

$$= 10 * 0.27$$

$$= 2.70$$

<u>Condition</u>

The maximum value for Condition is 15 points. The table below is used to calculate the Condition value.

Value	Description	Verbiage
0	No Condition Concerns	Excellent
0.5	Low Severity (minimal members impacted) or can be mitigated by maintenance.	Good
1	High Severity (many members impacted)	Poor

A project to replace a regulator that has been tested and is no longer functioning would receive a 1 or an additional 15 points applied to the initial ranking. A project where there are a lot of failures (e.g., a line with same failing insulators) would receive a 1 or an additional 15 points applied to the initial ranking.

<u>Contingency</u>

The maximum value for Contingency is 10 points. This weighting measures the ability of a project to reduce restoration times or otherwise improve the operability of the system by reducing planned outages for maintenance and other switching operations. The table below is used to calculate the Contingency.

	To No Contingency	To Emergency	To Single	To Multiple
From No Contingency	0	0.4	0.8	1
From Emergency	0	0	0.6	0.8
From Single	0	0	0	0.4
From Multiple	0	0	0	0

A project to add three phase feeder backup to the Fairfax 01 substation from the Fairfax 12 substation would receive a 0.8.

<u>Accessibility</u>

VEC gives higher priority to projects that improve accessibility to locations with poor/no accessibility in normal and extreme weather. The maximum value for Accessibility is 10 points. The table below is used to calculate the Accessibility value.

Value	Description	Verbiage
0	Road Access	Excellent
0.5	Track Bucket/Vehicle Accessible	Good
1	Foot Accessible or Very Difficult to Access, Climbing Only	Poor

A project to bring a distribution line from the ROW to the road would receive a 1 or an additional 10 points applied to the initial ranking. A project to develop access to a ROW such as a road or bridge would receive a 0.5 or an additional 5 points applied to the initial ranking.

Efficiency

VEC gives higher priority to projects that reduce power system losses. The maximum value for the Efficiency metric is 5 points. The table below is used to calculate the Efficiency value.

Value	Description
0	Project does not impact losses or increases losses
1	Project decreases losses

Strategic Goals

Each year VEC puts together a annual performance plan, which lists certain goals/targets; VEC gives priority to T&D projects that help meet these goals/targets. The maximum value for the Strategic Goals metric is 10 points. The table below is used to calculate the Strategic Goals value.

Value	Description
0	Project does not assist in achieving VEC's strategic goals
1	Project assists in achieving VEC's strategic goals

Equity

The maximum value for the Equity metric is 5 points. The table below is used to calculate the Equity value.

Value	Description
0	Project impacts town(s) with energy burden up to 12%.

0.5	Project impacts town (s) with energy burden between 12.1% - 15%.
1	Project town(s) with energy burden over 15%.

Energy burden is determined by the most recent Energy Burden Report published by Efficiency Vermont.

Non-Discretionary Adder

The non-discretionary adder exists to prioritize certain projects above all others. The value for this adder will be either 0 or 100. If a project meets one of the following criteria, it is automatically rated ahead of any discretionary project:

- Regulatory (VAOT, FairPoint IOP, NERC, PUC, Tier 3 Projects, etc.).
- Code Violations (NESC, IEEE, ANSI, etc.).
- Load Growth.
- VELCO Projects.

Shovel Ready Adder

To account for projects that may have already been designed, for example multiyear projects, the following "adders" are available:

Value	Description
10	Project fully designed and/or staked
10	Project has been permitted (AOT, CPG, etc.) or easements attained
10	Material has been installed or ordered
10	Agreement in place (Joint Ownership or other)
10	Multi-Year Project
50	ROI of 6 years or less

Table 6.4.2.B Shovel Ready Adder Table

The prioritization process guides VEC's capital investment focus and once completed, we review the information with the appropriate stakeholders involved with the project to come up with potential solutions.

Each challenge receives a detailed scope which identifies construction types, line relocations, reliability impacts, and future costs impacts.

5.4.4 Solutions Prioritization

VEC prioritizes distribution project solutions through a structured process that includes evaluating each challenge with a detailed scope and considering factors such as construction types, line relocations, reliability, and future costs. Solutions are reviewed and discussed with stakeholders to identify the most effective and feasible options, often weighing long-term benefits against upfront investments. This approach ensures that capital investment is focused on projects that provide the greatest reliability improvements and cost efficiencies.

Overhead Versus Underground

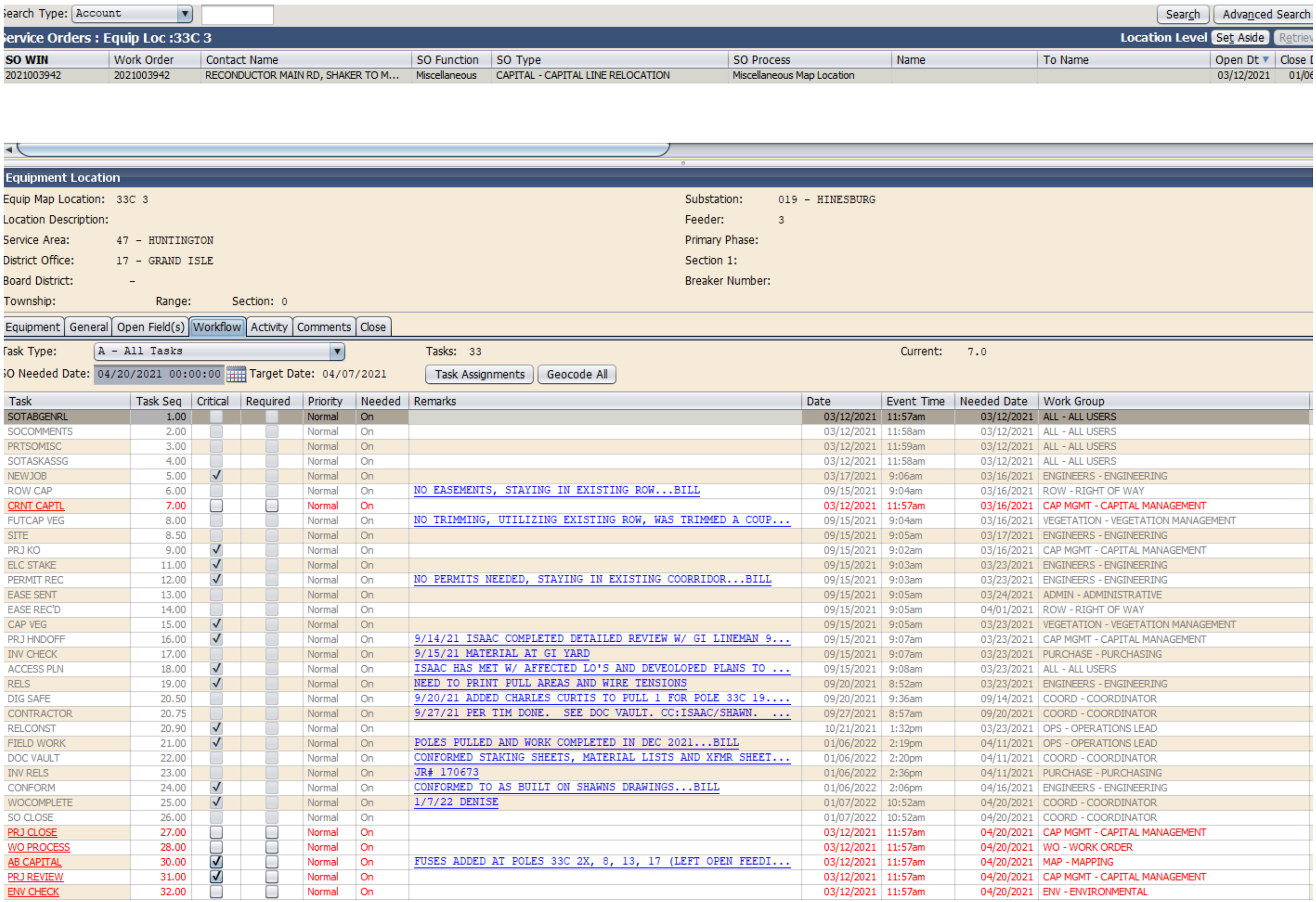
VEC prioritizes undergrounding or relocating lines from forested areas when practical. While obstacles like ledge rock make it challenging, this approach is considered during project design. Most of our system is above ground, but we evaluate the costs of burying lines in strategic locations versus overhead placement. Underground lines are cheaper in the long run but have higher upfront costs and repair times can be longer. Moving lines to roadside areas often reduces outage impact due to easier access. Vermont's reforested mountains now pose challenges for lines initially placed when the area was deforested.

This is discussed further in section 5.4.8

5.4.5 Budgeting and Construction

Project Management

Once a project is identified a Project Manager will be assigned. Typically, this is an Operation Supervisor for T&D projects or a System Engineer for Substation projects. In addition, VEC will plan out projects two to three years in advance of construction and uses its NISC CIS Work Management System to manage project status:



Task	Task Seq	Critical	Required	Priority	Needed	Remarks	Date	Event Time	Needed Date	Work Group
SOTABGENRL	1.00			Normal	On		03/12/2021	11:57am	03/12/2021	ALL - ALL USERS
SOCOMMENTS	2.00			Normal	On		03/12/2021	11:58am	03/12/2021	ALL - ALL USERS
PRTSOMISC	3.00			Normal	On		03/12/2021	11:59am	03/12/2021	ALL - ALL USERS
SOTASKASSG	4.00			Normal	On		03/12/2021	11:58am	03/12/2021	ALL - ALL USERS
NEWJOB	5.00	✓		Normal	On		03/17/2021	9:06am	03/16/2021	ENGINEERS - ENGINEERING
ROW CAP	6.00			Normal	On	NO EASEMENTS, STAYING IN EXISTING ROW...BILL	09/15/2021	9:04am	03/16/2021	ROW - RIGHT OF WAY
CRNT CAPTL	7.00			Normal	On		03/12/2021	11:57am	03/16/2021	CAP MGMT - CAPITAL MANAGEMENT
FUTCAP VEG	8.00			Normal	On	NO TRIMMING, UTILIZING EXISTING ROW, WAS TRIMMED A COUP...	09/15/2021	9:04am	03/16/2021	VEGETATION - VEGETATION MANAGEMENT
SITE	8.50			Normal	On		09/15/2021	9:05am	03/17/2021	ENGINEERS - ENGINEERING
PRJ KO	9.00	✓		Normal	On		09/15/2021	9:02am	03/16/2021	CAP MGMT - CAPITAL MANAGEMENT
ELC STAKE	11.00	✓		Normal	On		09/15/2021	9:03am	03/23/2021	ENGINEERS - ENGINEERING
PERMIT REC	12.00	✓		Normal	On	NO PERMITS NEEDED, STAYING IN EXISTING COORRIDOR...BILL	09/15/2021	9:03am	03/23/2021	ENGINEERS - ENGINEERING
EASE SENT	13.00			Normal	On		09/15/2021	9:05am	03/24/2021	ADMIN - ADMINISTRATIVE
EASE REC'D	14.00			Normal	On		09/15/2021	9:05am	04/01/2021	ROW - RIGHT OF WAY
CAP VEG	15.00	✓		Normal	On		09/15/2021	9:05am	03/23/2021	VEGETATION - VEGETATION MANAGEMENT
PRJ HNDOFF	16.00	✓		Normal	On	9/14/21 ISAAC COMPLETED DETAILED REVIEW W/ GI LINEMAN 9...	09/15/2021	9:07am	03/23/2021	CAP MGMT - CAPITAL MANAGEMENT
INV CHECK	17.00			Normal	On	9/15/21 MATERIAL AT GI YARD	09/15/2021	9:07am	03/23/2021	PURCHASE - PURCHASING
ACCESS PLN	18.00	✓		Normal	On	ISAAC HAS MET W/ AFFECTED LO'S AND DEVEOLOPED PLANS TO ...	09/15/2021	9:08am	03/23/2021	ALL - ALL USERS
RELS	19.00	✓		Normal	On	NEED TO PRINT PULL AREAS AND WIRE TENSIONS	09/20/2021	8:52am	03/23/2021	ENGINEERS - ENGINEERING
DIG SAFE	20.50			Normal	On	9/20/21 ADDED CHARLES CURTIS TO PULL 1 FOR POLE 33C 19....	09/20/2021	9:36am	09/14/2021	COORD - COORDINATOR
CONTRACTOR	20.75			Normal	On	9/27/21 PER TIM DONE. SEE DOC VAULT. CC:ISAAC/SHAWN. ...	09/27/2021	8:57am	09/20/2021	COORD - COORDINATOR
RELCONST	20.90	✓		Normal	On		10/21/2021	1:32pm	03/23/2021	OPS - OPERATIONS LEAD
FIELD WORK	21.00	✓		Normal	On	POLES PULLED AND WORK COMPLETED IN DEC 2021...BILL	01/06/2022	2:19pm	04/11/2021	OPS - OPERATIONS LEAD
DOC VAULT	22.00			Normal	On	CONFORMED STAKING SHEETS, MATERIAL LISTS AND XFMR SHEET...	01/06/2022	2:20pm	04/11/2021	COORD - COORDINATOR
INV RELS	23.00			Normal	On	JR# 170673	01/06/2022	2:36pm	04/11/2021	PURCHASE - PURCHASING
CONFORM	24.00	✓		Normal	On	CONFORMED TO AS BUILT ON SHAWNS DRAWINGS...BILL	01/06/2022	2:06pm	04/16/2021	ENGINEERS - ENGINEERING
WOCOMPLETE	25.00	✓		Normal	On	1/7/22 DENISE	01/07/2022	10:52am	04/20/2021	COORD - COORDINATOR
SO CLOSE	26.00			Normal	On		01/07/2022	10:52am	04/20/2021	COORD - COORDINATOR
PRJ CLOSE	27.00			Normal	On		03/12/2021	11:57am	04/20/2021	CAP MGMT - CAPITAL MANAGEMENT
WO PROCESS	28.00			Normal	On		03/12/2021	11:57am	04/20/2021	WO - WORK ORDER
AB CAPITAL	30.00	✓		Normal	On	FUSES ADDED AT POLES 33C 2X, 8, 13, 17 (LEFT OPEN FEEDI...	03/12/2021	11:57am	04/20/2021	MAP - MAPPING
PRJ REVIEW	31.00	✓		Normal	On		03/12/2021	11:57am	04/20/2021	CAP MGMT - CAPITAL MANAGEMENT
ENV CHECK	32.00			Normal	On		03/12/2021	11:57am	04/20/2021	ENV - ENVIRONMENTAL

Figure 6.4.2.A VEC Work Management System

This system allows all project managers and stakeholders to see the current project status, add tasks and receive notifications. In addition, project folders are utilized for project scoping documents, landowner identification, and other project documents.

Every year, VEC identifies a capital budget target and then chooses projects based on their ranking, resource planning, and time constraints. VEC fills out a Construction Estimate Worksheet (CEW) for every project, and these are used during the budget process.

Projects could span multiple fiscal years and are tracked accordingly.

Construction and Budgeting

Once a project has met all the necessary pre-construction criteria such as permits, vegetation management, and easement acquisition, it will be ready for construction. VEC reviews financial results monthly, and Project Managers receive real-time financial information through its NISC Mosaic ABS portal.

VEC has created a Capital Project tracking tool for upcoming and current projects. This tool monitors key tasks and timelines. Procedures were developed for each task. Tracking Permitting and Easements is crucial to prevent delays.

Johnson | Richford | Grand Isle | Newport | Substation
2025 | 2026 | 2027 | 2028 | All
Distribution | Substation | Transmission | Generation | All
ROW/ENV

Type	Project	WO Number	District	Year	Identify Project	Document Management	Contractor?	CEW	Staking/Design	Land Owner Meetings	Easements
Distribution	03-1D Reconductor/Relocation	2018015420	Johnson	2025	YES	YES	INTERNAL	YES	YES	YES	YES
Distribution	15-1F9 Stebbins Rd Reconductor	2023009984	Johnson	2025	YES	YES	INTERNAL	YES	YES	N/A	N/A
Distribution	SLVS - 06-2D1 Crowe Hill Rd	2024002922	Johnson	2025	YES	YES	INTERNAL	YES	YES	YES	YES
Distribution	30-2J3 Hammond Road Relocation	2023004903	Richford	2025	YES	YES	INTERNAL	YES	YES	YES	YES
Distribution	30-2F5 Reconductor West Berkshire to Scott Road	2022007127	Richford	2025	YES	YES	INTERNAL	YES	YES	N/A	N/A
Distribution	32-1G Barnum Rd Relocation	CP2501009	Richford	2025	YES	YES	INTERNAL	YES	YES	YES	YES
Distribution	30-3G11 Coy Road Reconductoring - FEMA	FEMA202202	Richford	2025	YES	YES	INTERNAL	YES	YES	YES	N/A
Distribution	05-1D7 Tetreault Rd Tie Line/Relocation	2025003248	Johnson	2026	YES	NO	INTERNAL	IN PROG	YES	YES	IN PROG
Distribution	03-1Q7 Smithville Rd Relocation	2023002232	Johnson	2026	YES	YES	INTERNAL	NO	YES	IN PROG	IN PROG
Distribution	06-4D7 McKenzie Rd Reconductor	2024010465	Johnson	2026	YES	YES	INTERNAL	YES	YES	N/A	N/A
Distribution	05-3E/3E2 VT Rte 100 VTRANS KCW Relocation	2022015888	Johnson	2026	YES	NO	INTERNAL	NO	YES	N/A	IN PROG
Distribution	31-1E2 Guilmette Road Reconductor/Relocation	2023018583	Richford	2026	NO	NO	UNDECIDED	NO	NO	NO	IN PROG

Figure 6.4.2.C VEC Capital Project Management Tool

1. **Distribution–** This includes our primary overhead and underground lines as well as any equipment associated with them. Our strategy focuses on strategic undergrounding, reconductoring and sensors.
2. **Substation and Transmission –** This includes our substations, subtransmission lines, and any bulk transmission assets. We focus on feeder backup and motor operated switches. In addition, our strategy here is to explore long duration transmission storage, adequate planning, and expand our capacity to connect to Hydro Quebec.

VEC has several key data sources and analytical tools critical to the day-to-day functions of the cooperative that helps us to understand the complex power system, VEC members' needs and usage, and enhancements to utility operations. Data and data analysis are increasingly important as the grid becomes more complex through the addition of distributed generation, battery storage and other load management devices.

These data and tools used by VEC are listed in further detail below.

5.4.6 Our Resiliency Investment Strategy

Regarding resiliency our strategy and priorities are as follows:

1. **Invest in strategic line relocations and undergrounding** – Over 60 percent of VEC's lines are "off-road" and difficult to access with appropriate large equipment for restoration activities, often extending outages. Additionally, VEC has over 200 miles of #6 Steel and 8D Amerductor wire many of which correspond to the same off-road line locations. This type of wire is extremely brittle and requires an outage to conduct any work on the wire, whether it is due to a broken wire. We plan to replace all our #6 Steel and 8D Amerductor and relocate as much line as possible.

2. **Utilize FEMA Hazard Mitigation Funding (HMF) to speed up investments** – FEMA HMF This assistance is unique to municipalities and non-for-profit cooperatives such as VEC. This funding allows VEC to benefit from additional capital investment to achieve its goals of improving resiliency across the priority areas described above. While the additional funding is valuable, it does require resources and time to build/monitor the grants and implement additional projects in a timely manner. But VEC finds this effort worthwhile. Since 2015, VEC has received approximately $5 million from FEMA for Hazard mitigation projects and the projects that have been completed have had dramatic decreases in outage events, in some cases eliminated altogether.

3. **Maintaining our capacity to connect to HQ during emergencies** – VEC has four interconnections with HQ that could be used during a capacity deficiency scenario, if one was declared, by ISONE England. Utilizing the substations connected through these interconnections has the potential for significant positive impacts to VEC and the entire state of Vermont during a capacity deficiency (e.g., reduce or eliminate the necessity for "rolling blackouts" to meet a load reduction declaration). HQ provides sustainable reliable, renewable, base load that is not part of the ISONE grid.

4. **Expand feeder backup and invest in motor operated switches** – Around 57% of the members mentioned above who are on radial sub transmission lines (around 28% percent of VEC's total membership) are also served from a substation that does not have full feeder backup. Feeder backup enhances reliability and reduces cost by adding greater flexibility to the system.

5.4.7 Local and Community Resiliency

Local and Community resiliency is focused on our members' homes, businesses and communities. Unfortunately, given the scale and scope of our needed investments and routine maintenance our members will continue to see outages. Even in the most reliable areas of the country, customers still see periodic outages, especially during large events. VEC's is actively identifying ways to reduce outages for our members through examples listed below.

Home Batteries

Energy Transformation incentives provided by VEC can significantly reduce the cost of installing a home battery system. These systems not only lower expenses but also offer resiliency benefits to members. For example, a typical Tesla Powerwall has approximately 5kW and 13kWh capacity. Additionally, VEC recently received an ESAP grant to supply around 75 residential batteries to low-income members who are at the end of a line with a high likelihood of outages and those dependent on power for health reasons.

Home Standby or Portable Generators

In 2022, VEC conducted a member survey in which more than 3,000 of VEC's members responded that they already have standby generators, in many cases eliminating outages altogether. In our most recent survey almost 50% of members had either a standby or portable generator.

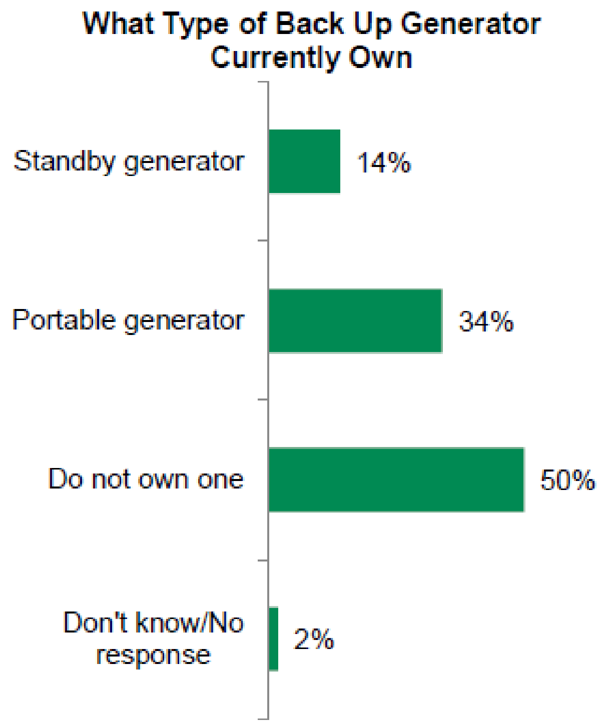


Figure 6.5.4.A 2022 Member Survey Data on Standby and Portable Generator Ownership

Secondary Underground on New Service

The recent trend shows that the majority of new services installed were underground. The percentages are even higher for new developments. In addition, the towns of Hinesburg, Williston and South Hero require that any new secondary installation must be underground. Underground, over the lifetime of the asset, is both more reliable and less costly than overhead in the case of a brand-new installation. This is discussed further in the Underground section.

5.4.8 Distribution Resiliency

Distribution Resiliency includes primary overhead and underground lines, along with any associated equipment. The focus is on relocating difficult-to-access lines, reconductoring infrastructure that is in poor condition, and undergrounding were cost-effective and applicable. While outages are expected to continue, the aim is to have facilities that are easy to access and less susceptible to weather-related events.

Strategic Line Relocations

Almost 60 percent of VEC's distribution lines traverse cross-country, not roadside locations. Much of VEC's system was constructed in the early to mid-1900's, when Vermont was mostly pastured, or open land and utility lines were constructed based on the shortest distance between two points to save on costs.

Bucket trucks cannot easily access cross-country lines, resulting in higher maintenance costs and longer outage restoration times compared to road right-of-way lines. Additionally, these poles are older and smaller, making them difficult to climb safely. VEC also uses off-road vehicles like ATVs and tracked bucket trucks.

Figure 6.5.3.A   VEC Line Crews Utilizing a Tracked Bucket Truck to Access an Off-Road Pole

While it is unrealistic to move all VEC's off-road lines to the road, there are many outage-prone, difficult to access, and high maintenance cost (vegetation maintenance) locations where the cost and time to relocate the line are justified. VEC gives higher priority to lines that are currently inaccessible or present environmental challenges (wetlands or washout). However, these projects are dependent on the acquisition of easements and permits required to move lines to the road. In many cases, there are significant delays for these projects due to difficulty obtaining easements from members for a variety of reasons (e.g., tree removal or pruning, aesthetics, access for outages and maintenance, etc.). In the event of easement issues, VEC may have to redesign the project or delay the project indefinitely.

When a project is identified for relocation, VEC performs the following coordination with stakeholders:

1. VEC will contact landowners affected by the relocation during the easement procurement process. This includes any locations where VEC will need to perform routine vegetation maintenance for poles and anchors.
2. If there are attachees on the existing line or the line targeted for relocation, VEC will contact the appropriate attachee a minimum of one year in advance of project construction.
3. VEC will contact State, Towns, and Municipalities when a relocation occurs within city, town, or state right-of-way to acquire permits.
4. VEC will contact Act 250 District Coordinators or the Vermont Agency of Natural Resources for required permits such as Act 250, or wetland permits.

If relocation is not feasible, VEC will attempt to improve the line's reliability through more robust construction such as the use of spacer cable, compact construction, and covered tree wire for conductors, an increase in right of way width, or more frequent right of way trimming.

Undergrounding

VEC has found that undergrounding can greatly expedite and enhance the right-of-way acquisition process.

In VEC's service territory, on average a 12.47 kV underground distribution line initial construction costs approximately two times the cost of an overhead line, mainly due to the increased labor, increased indirect costs (e.g., conduit, vaults, drainage systems, etc.), and specialized equipment used for cable pulling. However, VEC has seen costs of overhead construction increase over the last ten years reducing the cost difference making going underground a more viable and cost competitive alternative.

When looking at yearly and lifetime maintenance costs, overhead construction is often more than four times the lifetime cost of underground primarily due to vegetation management costs and a higher susceptibility to outages.

	Per Mile Yearly Maintenance Cost	Lifetime Cost (50 Years)
Single Phase Overhead	$ 7,621	$381,050
Single Phase Underground	$1,923	$96,150

Table 6.5.3.A Yearly and Lifetime Cost of Underground Conductor

VEC calculates the annual maintenance costs using the following:

- Property tax costs per mile for underground and overhead lines.
- An average of vegetation management costs per mile. This includes all internal and external contract crews required to maintain the Rights-of-Way (ROW) corridors for VEC.
- An average of overhead line maintenance costs per mile. This includes line worker time spent on outage restoration and routine inspection of overhead and underground lines.

Using the numbers above and assuming new construction (conduit, jacketed EPR cable, burial, and installation) if the initial cost is less than 2.1 times the cost of overhead construction, then underground would be best option from an overall cost standpoint. There are other factors to consider, especially when relocating lines from overhead to underground. These factors include presences of ledge, number of existing overhead services, environmental constraints such as streams or wetlands, and future load growth. All these factors will increase the cost of underground and in many cases to a point where it is no longer feasible to move a line underground.

Reliability of Underground Conductor

Undergrounded systems offer fewer outages than an exposed overhead line. However, when outages do occur (especially during frozen ground conditions) the outage is generally three to four times longer than a similar overhead outage. On average it took about three to four times as long to restore outages for underground lines (approximately seven hours) versus overhead lines (approximately two hours). Direct buried underground lines take particularly long to restore because new conductor cannot be pulled into existing conduit. As a result, since all new

VEC and member installed underground are required to have conduit, a new trench and conduit needs to be installed before the new line can be pulled and terminated.

VEC anticipates that it will continue to increase the number of underground line miles installed annually.

Covered conductor

The majority (84 percent) of VEC's distribution conductor is bare and the remaining 16 percent is covered conductor (often referred to as "tree wire"). VEC installs covered conductors in areas where line relocation is not feasible and in locations of likely exposure to tree-related outages. Contact with fallen or wind-driven trees and vegetation not only provides a path to earth (ground) and between conductors but can damage bare conductors resulting from arcing and sparking. VEC has seen that covered conductor can prevent these types of outages due to the benefit of insulation on the conductor.

VEC uses three types of overhead conductor on its system: bare conductor, covered conductor ("tree wire"), and spacer cable.

Figure 6.5.3.B Bare Conductor

Figure 6.5.3.C Covered Conductor ("Tree Wire")

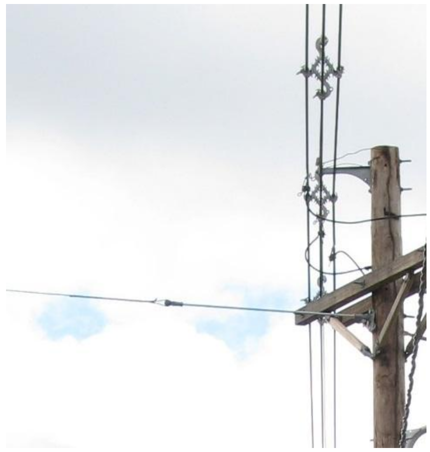


Figure 6.5.3.D Hendrix Spacer Cable

In general, covered conductor adds a significant amount to material costs (because it is more expensive and requires shorter span lengths – e.g., more poles due to increased weight) and the total project cost due to increase in labor due to the handling of more material. However, VEC finds that covered conductor and spacer cable can improve reliability and provide flexibility in space constrained areas. VEC expects to continue reconductoring areas with outage concerns with covered conductor.

Construction Practices and Solutions

One of the many challenges VEC faces on its distribution system is prior construction practices that are no longer adequate. Wet snow events can cause additional conductor sag and creep or stretching over time, which results in conductors contacting one another. The timing of these "snow unloading" events can lead to long duration outages for VEC members with limited or no system damage. There are several causes and corresponding solutions to these challenges.

Conductor Tension

As conductor ages and wears under tension, it begins to cause creep or stretching of the conductor. This normal creep or additional sag can increase with heavy wet snow events or hard tree contacts and if the conductor is not re-tensioned, there is an increased likelihood of an outage if the primary wire sags into the neutral wire. In some cases, particularly older conductors such as 6A, 6 Steel or 8D, it may not be possible to re-tension the conductor and VEC may need to replace it.

Long Conductor Spans

Some of these challenges are a result of long conductor spans (conductor distance between two poles). On average, VEC spans have a length of 234 feet; however, 7,419 spans out of 99,021 (7.5 percent) are greater than 350 feet. These longer spans are needed to cross rivers, wetlands, gullies, highways, etc. In some cases, the conductor in these long spans has stretched due to snow and ice loading over the years and becomes more prone to causing outages during weather events. Additional or mid-span poles could be installed where possible to mitigate these issues. This 598-foot span in Richmond is a good example of long conductor spans:

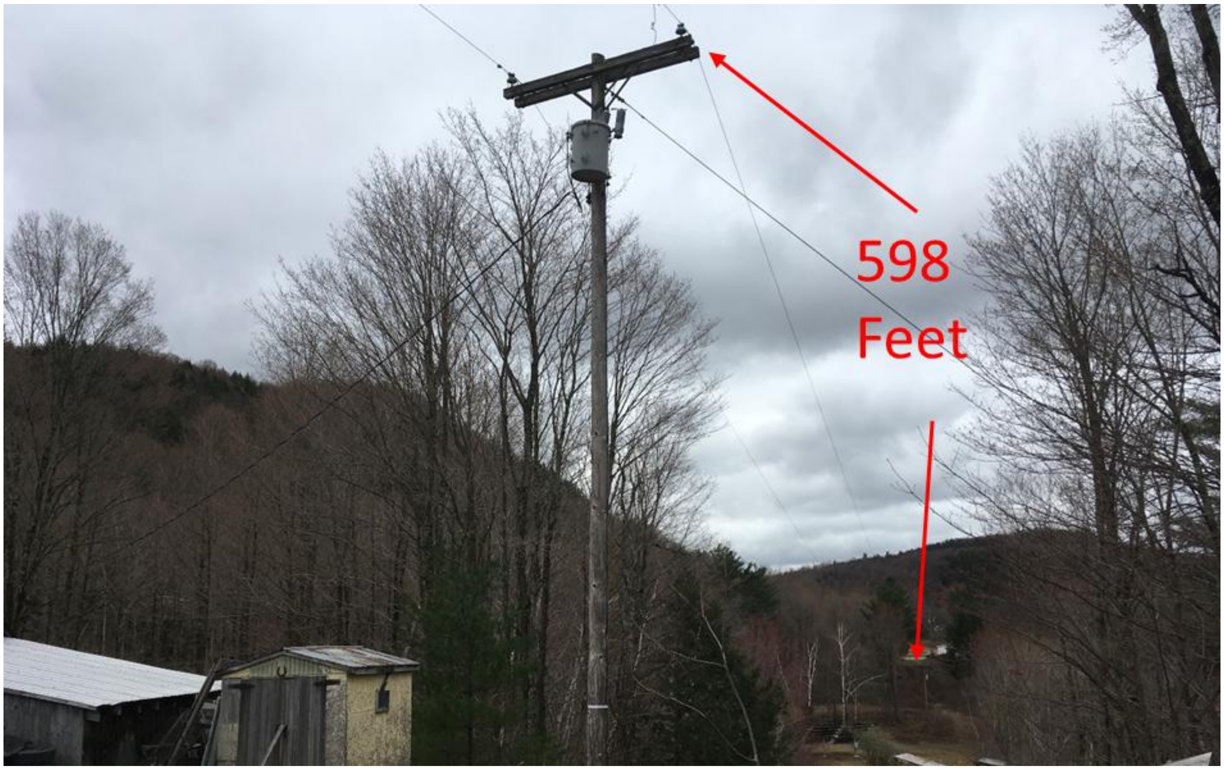


Figure 6.5.3.E 598-foot Span in Richmond

5.4.9 Substation and Transmission Resiliency

Substation resiliency encompasses our substations, subtransmission lines, and any bulk transmission assets connected to ISONE-based generation. The ISONE system is experiencing an increase in renewable energy penetration, resulting in a reduction of base load assets and an associated rise in reliability risks beyond VEC's control.

Approximately 20,000 VEC members are fed off a radial subtransmission line and are therefore more susceptible to subtransmission level outages. VEC can focus on feeder backup, motor operated switches, and potential VEC-owned utility scale storage projects to address these challenges.

Opportunities for Feeder-Backup

Around 57% of the members mentioned above who are on radial subtransmission lines are also served from a substation that does not have full feeder backup. Feeder backup enhances reliability and reduces cost by adding greater flexibility to the system. VEC gives projects that add new ties or enhance existing ties higher priority within the capital project prioritization process especially where member counts and loads are high, increased priority is given.

VEC's system includes two distinct systems: the legacy Citizens Utilities system and the legacy VEC system. The northern legacy Citizens Utilities system consists of a networked distribution system with previous investments made to connect substations or circuits. On the other hand, the legacy VEC system is radial, with limited prior investment in connecting substations or circuits.

<u>What is Feeder backup?</u>

Feeder backup allows a circuit or substation to be supported by another substation or feeder during outages or maintenance. In the example below, Substation #1 and Substation #2 are linked by a normally open tie switch.

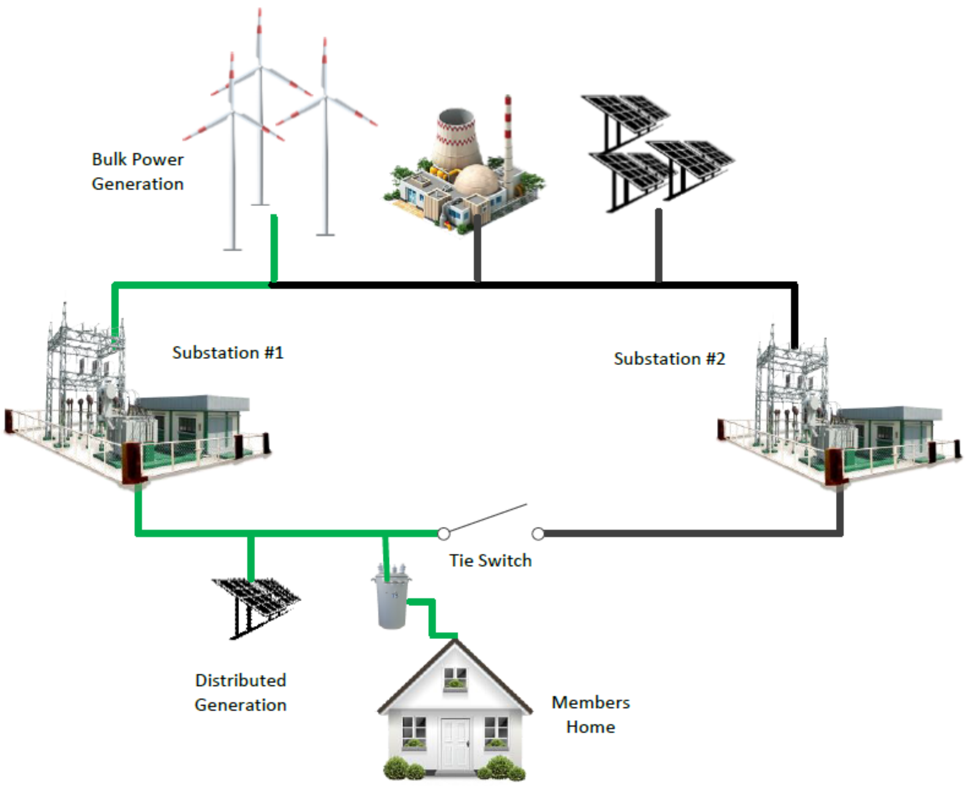


Figure 6.5.2.A Normal Configuration Without Feeder Backup Utilized

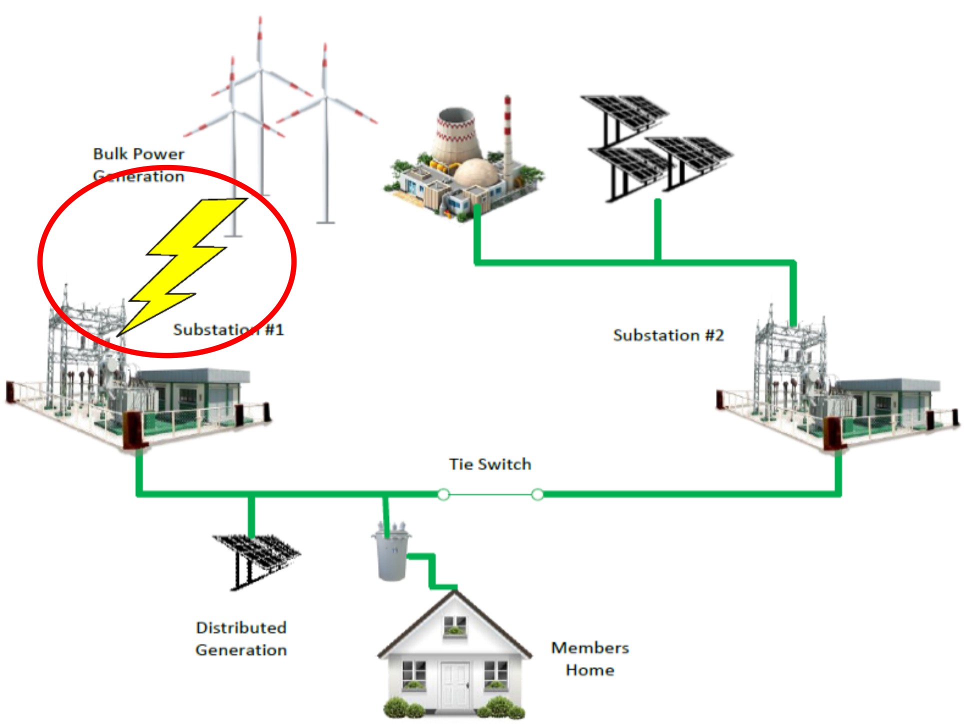


Figure 6.5.2.A Transmission Outage Member Restoration Using Feeder Backup

This allows the two substations to tie together, and the members located on Substation #1 to regain power. In making decisions in the future as to whether to build a feeder backup, VEC will consider the following needs:

- **Availability of a tie line** – Feeder backup is feasible only in networked sections of the system (where lines connecting two circuits or substations can be interconnected), primarily located in the northern part of VEC's service territory.
- **Substation transformer capacity** – The capacity of the substation transformer must be sufficient to accommodate the additional load.
- **Distribution system capacity** – The wire size must be adequate to handle the additional load.
- **Voltage of the members on the line** – The VEC system contains many long distribution feeders with sparse loading per mile, small conductors, and single-phase operation. In some instances, the voltage may fall outside acceptable limits if another substation assumes the load due to the increased distance of the line.
- **Distributed generation on the system** – If a feeder with a large generator is connected to and powered by a feeder more distant from the source, the voltage rise may exceed the upper limit of the acceptable voltage range.

Motor-Operated Tie Switches

To enable feeder backup, system upgrades such as reconductoring or new tie lines are typically required. VEC considers installing motor operated supervisory control and data acquisition (SCADA) controlled tie switches to these feeder backups when necessary to facilitate easier and faster switching.

In the event of a transmission outage, SCADA and Inter Company Communications Protocol (ICCP) notify VEC System Operations. Using transmission operating guides (TOGs), VEC system operators will verify if VEC can pick up the load from another source. If another source is available, system operators will remotely close a motor-operated tie switch that allows restoration to that circuit. VEC has 14 motor operated tie-switches that are equipped with SCADA where feeder backup is possible.

While SCADA is typically beneficial for transmission outages, if the fault occurs downstream of a distribution system protective device, VEC personnel would still need to patrol the line to confirm it is safe to re-energize, thereby reducing the time-saving benefits of SCADA. Consequently, VEC does not install SCADA on all electronic distribution line reclosers and switches and weighs the cost and benefits of SCADA installations on a case-by-case basis.

Subtransmission Improvements

VEC has several substations that are fed from GMP owned 34.5kV subtransmission lines. Many of these lines are long and travel through off road and wooded terrain and are prone to outages.

VEC recently completed a joint project with GMP at its Richmond substation. VEC worked with GMP to strategically place two transmission breakers. This greatly increases reliability to members off of Richmond and Hinesburg substations by sectionalizing transmission between GMP Essex and GMP Bolton. Previously, if a fault were to occur previously anywhere along the GMP 3334 line, the VEC Richmond and Hinesburg Substations, are left without power until utility crews can get the line fault sectionalized and assess and repair the damage to restore electric service.

Utility Scale Battery Storage

VEC has a utility scale battery at its Hinesburg 19 and the North Troy 41 substation and is planning to install batteries at other substations in its territory. These batteries are primarily focused on peak shaving but could be utilized in times of transmission level outages. However, there are two issues with doing so:

- Cost – Currently VEC pays to utilize the battery for decreasing our load during the Vermont monthly peaks and ISONE yearly peaks. To utilize the battery for outages we would need a new contract which would limit our developer's ability to utilize the battery in the frequency regulation market. Given the limited cost/benefit of the project we have not pursued further. Additionally, we would need additional system protection and equipment to allow the battery to feed back onto the feeder when grid power was not present.
- Reliability benefit – While using the battery during a transmission outage would keep the lights on at the substation, we would not be able to eliminate downstream outages which are much more common. VEC has very few transmission and subtransmission outages.

Expanding our Capacity to Connect to HQ During Emergencies

VEC has four interconnections with Hydro Quebec (HQ) that we can use during a capacity deficiency scenario, if one was declared, by ISONE England. This capacity deficiency scenario would most likely be the result of prolonged cold temperatures (a week or more) in Southern New England (December through February) where natural gas is diverted from electrical generation to home heating and the ability to maintain natural gas and diesel levels for electrical generation is strained or compromised.

VEC participates in the Winter Readiness Task Force, a sub-committee of the VELCO Operating Committee, comprised of several Distribution Utilities and VELCO to discuss options for meeting a voltage reduction order from ISONE England. While VEC and others are prepared to enact various Operating Procedures such as Actions During a Capacity Deficiency, Actions During an Emergency, and Voltage Reduction and Load Shed Capability (load shedding and Under Frequency Load Shedding – UFLS) that may include "rolling blackouts", VEC has the unique opportunity to transfer load from ISONE England to HQ which may prevent "rolling blackouts" in VEC's territory and perhaps for the entire state.

The interconnections between VEC and HQ are broken into two blocks:

Highgate Block

This interconnection is used by several DUs and is interconnected to the Vermont grid through VELCO. 250 MW is available from HQ but only 225 MW can be used due to permitting limitations of the incoming transmission line. VEC is working with VELCO on a Section 248 petition to increase the permitted capacity of the line by 25 MW. VEC loads connected at this source ranged from 10-24 MW in 2021. VEC has confirmed ISONE England will not prevent VELCO from splitting the ring bus at its Highgate substation even though it is a Blackstart Cranking Path for the McNeil generator. VELCO has also confirmed they have the capacity to put the system into this type of configuration. Prior to load transfers, VEC will need to confirm that HQ can provide capacity as they are sometime limited to 140 MW. Sometimes power deliveries are restricted to the Highgate Converter but there is uncertainty as to whether this is driven by reliability, economics, or both. A final decision/implementation is expected to occur in 2025. A diagram of the planned emergency configuration is below. Maximum load for the following substations that have a good possibility of being added to this block include:

- South Alburgh = 6.5 MW

- Sheldon = 2.6 MW
- Enosburg = 5.0 MW
- Berkshire = 3.6 MW
- Richford = 4.4 MW
- Westrock = 1.9 MW
- TOTAL = 24.2 MW

Newport Block

The Newport Block consists of four interconnection points directly with VEC. Currently this block ranges from 0 MW (e.g., being fed from VELCO) and 20 MW (e.g., fed from HW) on average with a maximum of 30 MW in one hour. 2021 load on these four interconnection points includes:

- Norton = 200-300 kW
- Canaan = 3-3.5 MW
- Derby Line = 1 MW
- Newport = 15 MW
- TOTAL = 19.8 MW

Without any investment, VEC has added the Irasburg 1A circuit (1.5 MW) to its distribution system to this block. VEC has analyzed adding all circuits from the Irasburg substation (3.5 MW) but there are capacity concerns that need to be addressed. Additionally, tying all of the Newport and Irasburg distribution circuits together on one feeder recloser increases reliability risks. The better option is to feed the entire Irasburg substation from the block via the 46 kV system. However, there are issues with Kingdom Community Wind's electrical flow and capacity issues on the 34.5 kV line owned by GMP. While GMP may have plans to upgrade this line, these would need to be addressed before we could proceed with this option.

Utilizing and expanding the Highgate and Newport Blocks has the potential for significant positive impacts to VEC and the entire state of Vermont during a capacity deficiency. VELCO's peak load in 2021 was approximately 950 MW which means VEC could reduce that load by eight percent. VEC's peak load in 2021 was 84 MW which means approximately 62 percent of its load could be shifted to HQ. These two large load reductions may mean VELCO and Distribution Utilities in Vermont would not need to shed load through "rolling blackouts" if ISONE England's call for load reduction (to VELCO passed down to the Distribution Utilities) was eight percent or lower. If ISONE England called for a greater load reduction, VEC members may not have to participate in any "rolling blackouts" as it can move approximately 62 percent of its system to be fed from HQ. This all hinges on if the ISONE England call for load reduction came when VEC was being fed from the United States.

5.5 Transmission & Distribution

5.5.1 Assets

VEC is a rural electric cooperative utility consisting of legacy Citizens and VEC assets. VEC's mission is to provide safe, affordable, and reliable power to all its members. However, its network of poles, wires, and assets poses unique challenges. Unlike many rural electric cooperatives in the country, VEC is not currently a RUS borrower. However, because it had been a RUS borrower prior to bankruptcy in 1995, parts of its distribution system were built to RUS standards. The legacy Citizens assets, on the other hand, did not follow RUS standards and as a result, it has been a continual challenge, since the acquisition in 2004, to merge and standardize the two electrical systems.

Services per Mile of Line	***~16 per Mile***
Meters	***40,741***
Peak Load	***87.55 MW (01/02/2014)***
Distribution Poles	***54,617***
Primary Distribution Overhead Line Miles	***~2,445 miles***
• Single Phase	***~1,994 miles (82%)***
• Two Phase	***~52 miles***
• Three Phase	***~459 miles***
Primary Distribution Underground Conductor	***~372 miles***
Equipment (Reclosers, Sectionalizers)	***~450***
Line Regulators and Capacitors	***121, 114***
Transformers	***~21,000 (Pole mount), ~3,500 (Padmount)***
Transmission Poles	***2,527***
Transmission Line Miles	***138 Miles***
Substations	***35 (Distribution), 2 (Transmission)***
Metering Points	***3 (All with GMP)***
VEC Owned Fiber Optic Cable	***~88 Miles***

Table 5.5.1.A VEC T&D Statistics as of 01/01/2025

VEC's assets consists of following categories:

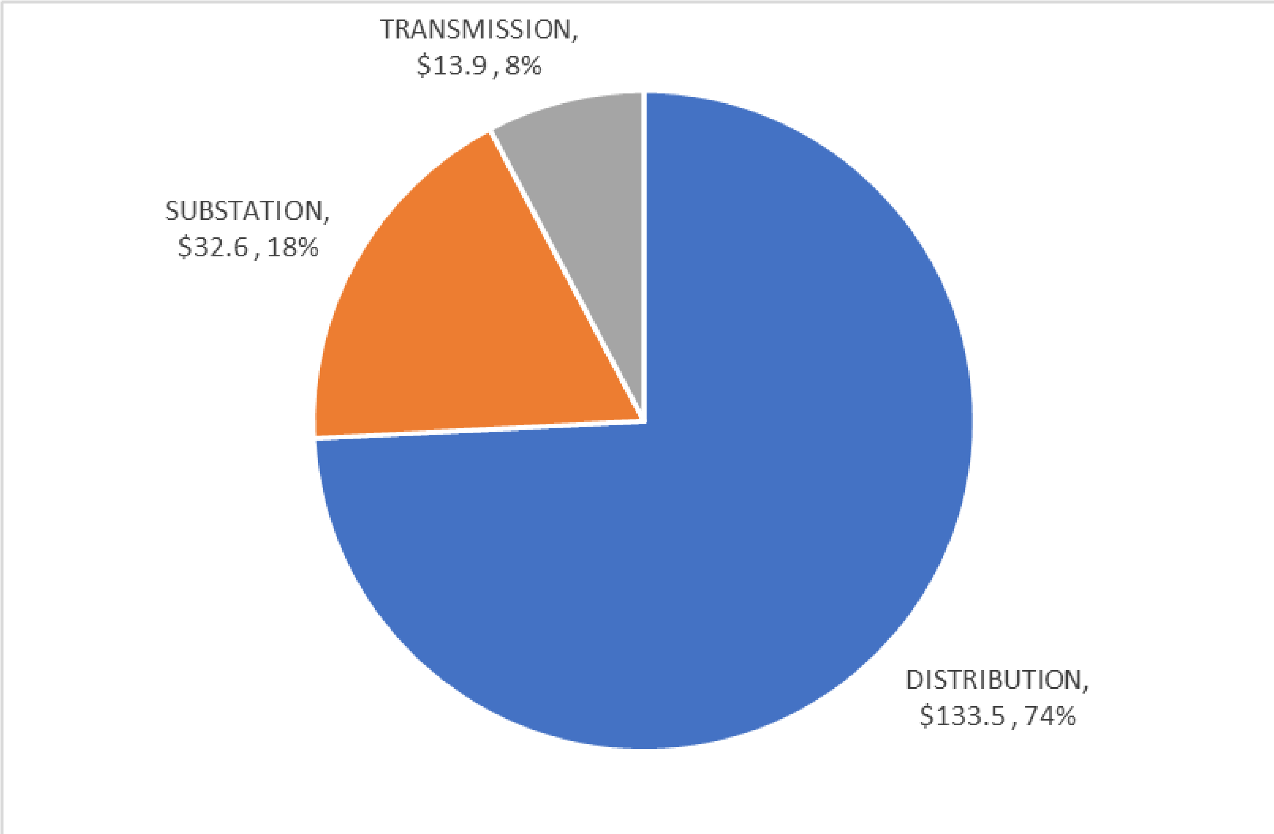


Figure 5.5.1.B VEC Assets (In Millions)

The largest category,VEC's distribution system assets, can be further broken into the following areas:

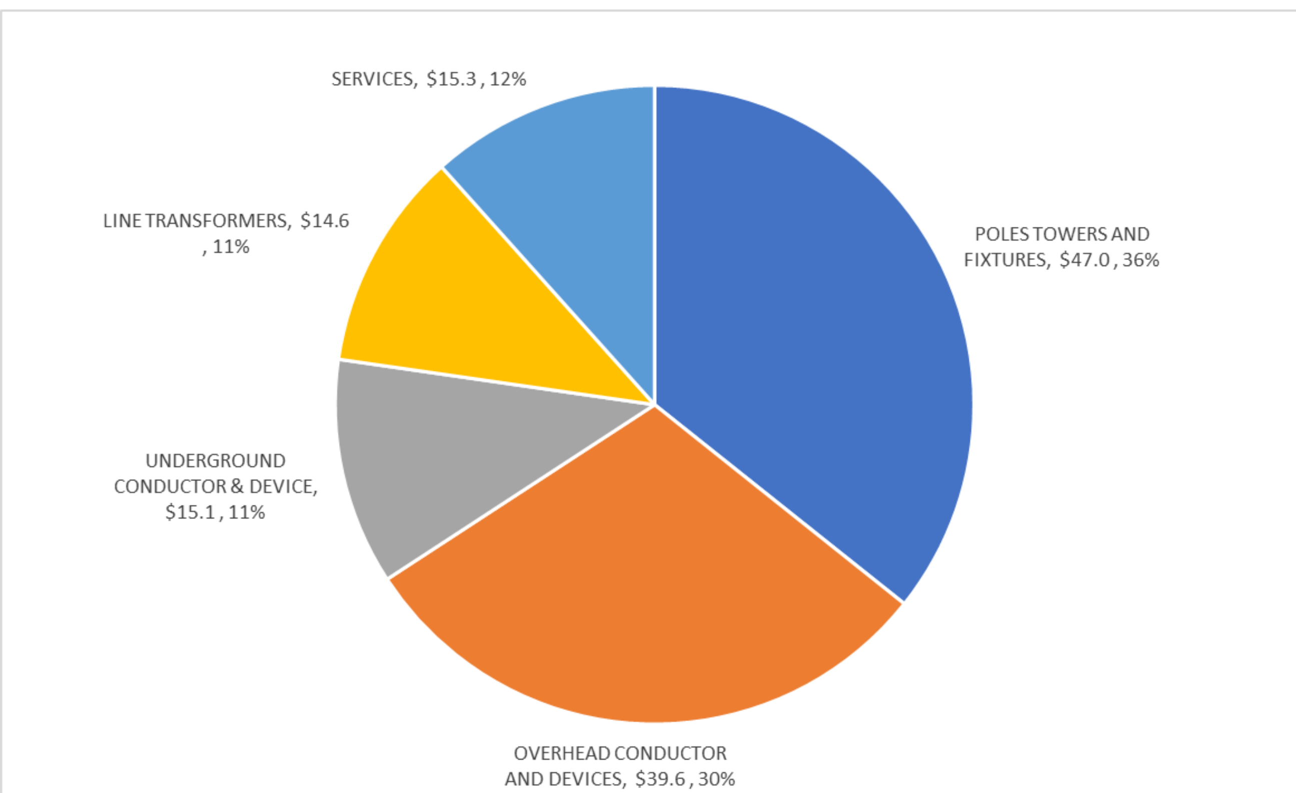


Figure 5.5.1.C Distribution Assets by Sub-Category (In Millions)

Feeding power to this distribution system, VEC owns and maintains a sub transmission network that stretches from Canaan to the Islands of Alburgh and South Hero. VEC's transmission network is long, predominantly rural, and represents roughly eight percent of total assets. The remaining 19 percent of assets are within VEC's 40 distribution substations, transmission substations, and primary metering points.

5.5.2 Design Criteria

VEC conducts distribution planning to ensure it can deliver power safely and reliably with a focus on voltage performance adhering to ANSI Standard C84.1. VEC developed criteria detailing these planning requirements. These criteria ensure both the adequate performance of the power system and the safety of those working on the system. More detailed information regarding VEC's distribution criteria is available in Appendix - A.

Distribution

VEC's standard distribution system voltage is 12.47 kV/7.2 kV grounded wye. In some areas, VEC also utilizes 34.5 kV/19.9 kV distribution voltage. VEC operates approximately 85 miles of 4.16 kV/2.4 kV grounded wye lines; however, we are steadily converting these voltages to the standard 12.47 kV/7.2 kV grounded wye.

Transmission

VEC's standard subtransmission voltages are 34.5 kV and 46 kV. VEC transmits power from VELCO, GMP, Eversource and Hydro Quebec on its subtransmission system to its distribution substations and large industrial members. VEC strives for "N-1" planning criteria for all looped transmission lines and radial transmission lines. The term N-1 refers to the ability to continue serving uninterrupted power even if we have an equipment or line failure. "N" is the total number of components that the system relies on to operate properly. The number subtracted from N is the number of components that can fail but power is still able to be served in a given scenario. Therefore, N-1 means that only one component has failed but the system is still functional. N-1-1 means that two components have failed, which is generally worse than having only one fail. To achieve N-1 on radial transmission lines, VEC looks for feeder backup opportunities.

More detailed information regarding VEC's transmission criteria is available in Appendix - A.

Voltage Regulation

All VEC's electric substations employ bus voltage regulation as opposed to feeder or individual line voltage regulation. This reduces capital costs and maintenance costs by minimizing the number of voltage regulators on the system. Generally, we set a base voltage set point, bandwidth, and time delay. These settings are to keep the Voltage within an acceptable range and to minimize regulator switching and mechanical degradation.

The VEC system has many relatively long single-phase distribution feeders with sparse loading per mile and small conductors. During peak times, we need to boost bus voltage to stay within acceptable range further out on the feeders.

Voltage rise due to distributed generation on VEC's circuits is becoming a widespread issue across VEC's system. In some cases, Voltage setpoints have had to be reduced to lower the system Voltage such that Distributed generation will not raise the Voltage above acceptable levels. Typically, the electric distribution system has run in one direction and now we are having to run it in reverse as well with the increase in DG located out on the line exceeding the load. The system was originally designed to operate in the forward direction with larger conductors and higher voltages at the source to compensate for voltage drop due to load current. We need to lower the system voltage to enable reverse power flow without overvoltage at the DG sources, while still keeping enough voltage for the loads when DG is unavailable.

VEC is beginning to try and mitigate this by utilizing the Voltage regulation features of the inverter based distributed generation. However, this requires participation from the majority of generators on the affected circuit to have a significant impact. Getting generator owners to change settings is proving to be a challenge. There could also be impacts to generation production since the regulation feature relies on either reducing watt output directly, or indirectly by altering the power factor of the generator. There may also be challenges with maintaining overall system power factor if this method is deployed across large areas of the circuit.

Another method of Voltage regulation to help prevent Voltage rise from DG that VEC is exploring is line drop compensation. Line Drop Compensation utilizes line impedance information to help calculate the voltage drop at the end of the distribution line based on the load current. The Regulator can determine if the load is forward or reverse from DG and compensate the voltage accordingly. It also allows us to utilize a lower Voltage setpoint which should mitigate the Voltage rise from DG. When load increases while DG is unavailable, the regulator calculates the Voltage drop and increases the system voltage even if the Voltage at the regulator is not out of band. The biggest challenge with this method is the diversity of our line impedances and lengths, and lack of infrastructure to implement it. Voltage regulators are relatively expensive and are not currently deployed across many areas of the VEC system. Additionally because VEC uses bus regulation and not feeder regulation, it may be difficult to implement line drop compensation at our substation voltage regulators for the reasons mentioned above.

Conservation Voltage Reduction (CVR)

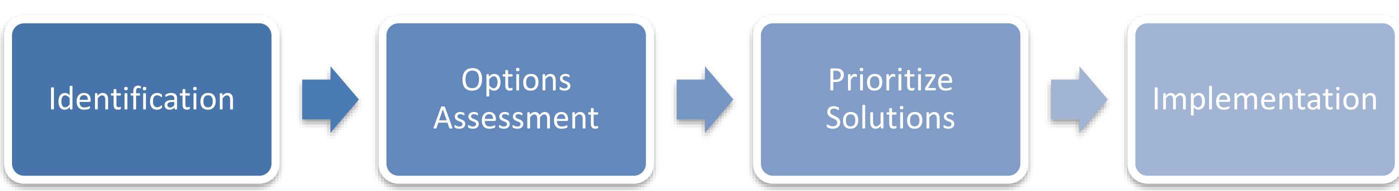
VEC has reviewed the potential costs and benefits of implementing a Conservation Voltage Reduction (CVR) program but has no immediate plans to install this on its system. CVR lowers the voltage during high resistive load times to conserve energy. By lowering the voltage to a resistive load such as an incandescent light bulb, the current would also be reduced proportionately, hence decreasing losses and costs.

Motors and pumps require constant power, so if the voltage is reduced, the motor draws more current to maintain the same amount of power output (Power = Voltage x Amperage). This can make regulating the line voltage more difficult: if we were to lower the bus voltage, the line current may increase leading to further voltage drops and causing the end of line voltages to be below an acceptable range.

5.5.3 Planning

To provide the least cost solution while monitoring efficiency, enhancing reliability, and allowing for growth, VEC approaches system planning as a balance between day-to-day analyses and longer-range holistic reviews of the system.

While the timing for day-to-day analysis and overall system reviews are different, VEC uses a similar process for both categories:



- **Identification** – Examination and definition of project/area versus design criteria, which will provide triggers for further review.
- **Options Assessment** – Detailed analysis via software tools and data to solve problems identified. Proposed solutions are developed using engineering calculations, cost/benefit analysis, or power load flow simulations, as required.
- **Prioritize Solutions** – Least cost, most feasible, and most reliable solutions are recommended. Projects are prioritized, timelines are established, and detailed cost estimates are developed and proposed for capital budget inclusion.
- **Implementation** -- Once approvals are secured, projects are scheduled, constructed, and closed out.

Distribution System Planning

VEC has 41 distribution substations and primary metering points that supply 77 distribution circuits. Distribution system planning is broken into four general categories:

- Forecasting (load and generation)
- Power Flow Analysis (peak capacity, contingency, ampacity)
- Power Quality Analysis (voltage analysis)
- Fault Analysis (protection and coordination)

VEC performs various studies to address these four categories that are described in further detail below:

System Load and Voltage Study (SLVS)

VEC completes the SLVS annually. The study reviews all VEC's 77 distribution circuits via equipment loading, voltage performance, and phase load balancing design criteria. VEC utilizes Supervisory Control and Data Acquisition (SCADA), Automated Metering Infrastructure (AMI) data, and Milsoft WindMil model to identify system constraints and appropriate solutions. VEC completes this system-wide study annually to identify constraints up to five years from the study completion. Given the substantial increase in distributed generation and increased load through beneficial electrification initiatives (e.g., electric vehicles and heat pumps), planning outside the five-year horizon is more uncertain than it ever has been. The report includes the following analysis tasks:

- Peak loads for each substation.
- Percent unbalance of the phase amps at the substation low side bus.
- Any substation or distribution equipment that is overloaded.
- Any single-phase circuits that are loaded greater than 288 kVA (40 amps at 7.2 kV)
- Any circuit elements experiencing voltage outside of 0.95-1.05 per unit.
- Any distribution circuits with greater than two percent voltage unbalance.
- Solutions to any criteria violations.

4.900 Reliability Report

Public Utility Commission (PUC) Rule 4.900 requires that VEC file a 4.900 Reliability Report annually. This report contains a detailed assessment of VEC's outage performance and a plan for how to improve reliability to its members. Target reliability metrics used in the report are defined via VEC's Service Quality and Reliability Plan (SQRP) approved by the PUC. Through this analysis, VEC identifies its top 10 worst performing circuits. VEC rates its top ten worst performers, prioritizing by the number of outage events first then customer hours out. VEC reviews these worst performers based on type and location of the outages to develop projects to mitigate these outages in the future.

Transmission and Sub-Transmission System Planning

VEC coordinates with other Vermont utilities to ensure reliable electric service to VEC's members, and the customers of other utilities fed from VEC's sub transmission facilities. These Vermont utilities include Green Mountain Power and the villages of Barton, Orleans, Swanton, and Enosburg.

In addition, VEC works very closely with VELCO, Vermont's transmission operator, to provide analysis and collaboration on system improvements. VELCO in turn works with New England's regional electric grid operator, ISONE England (ISONE).

In addition, VEC is a member of the Vermont System Planning Committee (VSPC) and brings forward all reliability issues at the substation and transmission level to determine whether a potential resolution exists to the issue considering energy efficiency, demand response and distributed generation, or a hybrid of transmission and non-transmission solutions.

If the project is eligible via either the Docket 7081 VSPC Non-Transmission Alternatives Screening or the Docket 6290 Screening tool, the VSPC and VEC will work together to identify solutions. All the electric utilities in Vermont complete this screening on an annual basis.

VEC anticipates that energy transformation will result in load growth but through load management we hope to defer or eliminate system upgrades altogether. As a result, most of the projects that are reviewed via Dockets 7081 and 6290 are categorized as either asset management or reliability improvement projects.

5.5.4 Milsoft WindMil Model

At the heart of system planning is VEC's Milsoft Engineering model which allows VEC system engineers to perform specific studies and identify voltage or loading constraints on new loads, new generation, and system upgrades. In addition, the tool is also used to coordinate protective devices such as fuses and reclosers.

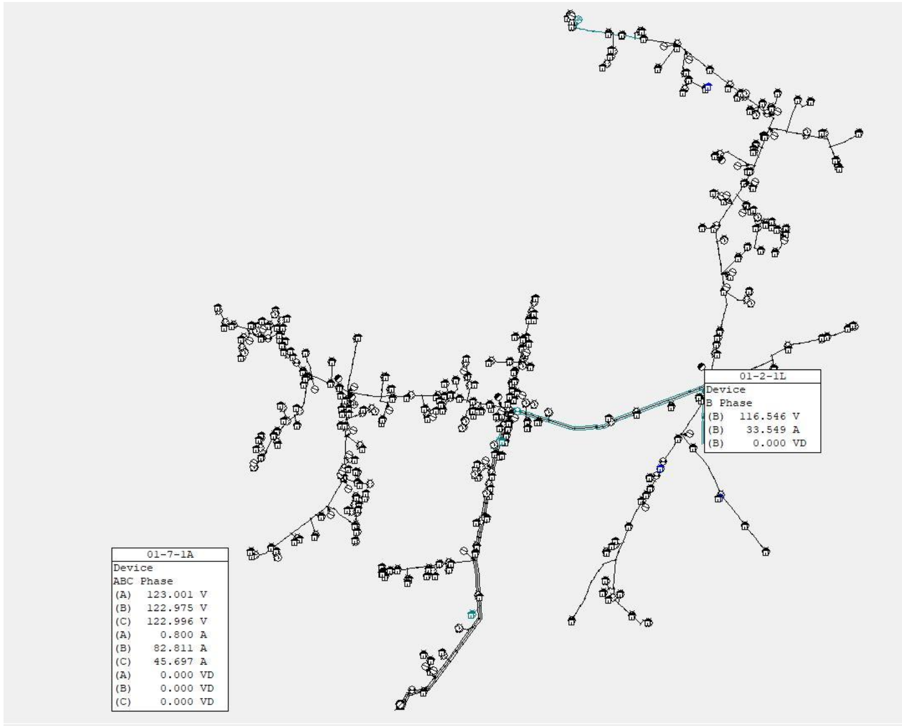


Figure 5.5.4.A VEC Fairfax 01-1A Circuit Engineering Model

5.5.5 Asset Selection and Replacement

The following section provides an overview of VEC's processes used to select all major equipment according to least-cost principles.

In general, on material purchases of $50,000 or greater, VEC's purchasing policy requires three competitive bids which are evaluated based on least overall cost, lead time, efficiency, and quality of product. VEC may opt to purchase a unit that is higher in initial cost if that unit has a substantially shorter lead-time (where time is important) or if the unit to be purchased needs to be identical to the existing unit. VEC attempts to take all aspects of a product or service into consideration when deciding which to purchase.

Transformers

Distribution Transformers

For new distribution transformer purchases, VEC utilizes a spreadsheet developed from a tool provided by the Vermont Department of Public Service (DPS). The tool uses current and future energy and capacity market projections along with transformer nameplate data to calculate an estimate of lifecycle losses and resulting total ownership cost. VEC has provided the most recent version of VEC's transformer purchase spreadsheet in Appendix-G, which includes VEC's transformer acquisition multipliers. The spreadsheet utilizes the following measures:

- Avoided energy and transmission costs.
- VEC's Weighted Average Cost of Capital (WACC) and discount rate.
- Transformer loss factors that utilize average load and no-load losses over standard transformer sizes.
    - Load losses are also referred to as copper or winding losses and vary with the square of the current through the transformer winding.

    - No-load losses are also referred to as iron or core losses and vary exponentially with the voltage applied.
- Avoided capacity costs which include fixed costs and capacity charges for power including on peak line losses.
- Expected load growth.
- Peak and average system losses.

The Department of Energy (DOE) CFR part 431 (Energy Conservation Program: Energy Conservation Standards for Distribution Transformers) outlines standards for distribution transformers. The DOE amended this document to increase the energy efficiency standards for distribution transformers beginning in January 1, 2016. VEC takes into consideration the total cost of ownership identified in the tool described above choosing the transformer with the lowest initial cost may not provide the lowest total ownership cost option for the VEC membership. This could occur if the increased cost of losses for the lower initial cost unit intersects with the higher initial cost, lower loss unit over the 30-year financial life period of the transformers.

The following table shows the initial ownership cost, no load losses, full load losses, and total ownership cost of a typical 15 kVA transformer.

Transformer	Sell Price	No Load Losses	Full Load Losses	30 Year Losses	Total Ownership Cost
15 kVA Polemount	***$1,233***	$593.94	$807.10	$1,401.04	$2,669.63

Table 5.5.5.A Total Cost of Ownership, No Load, Full Load, and 30-Year Losses by Transformer Manufacturer

The following graph presents the total ownership cost of a 10 kVA transformer by year and manufacturer:

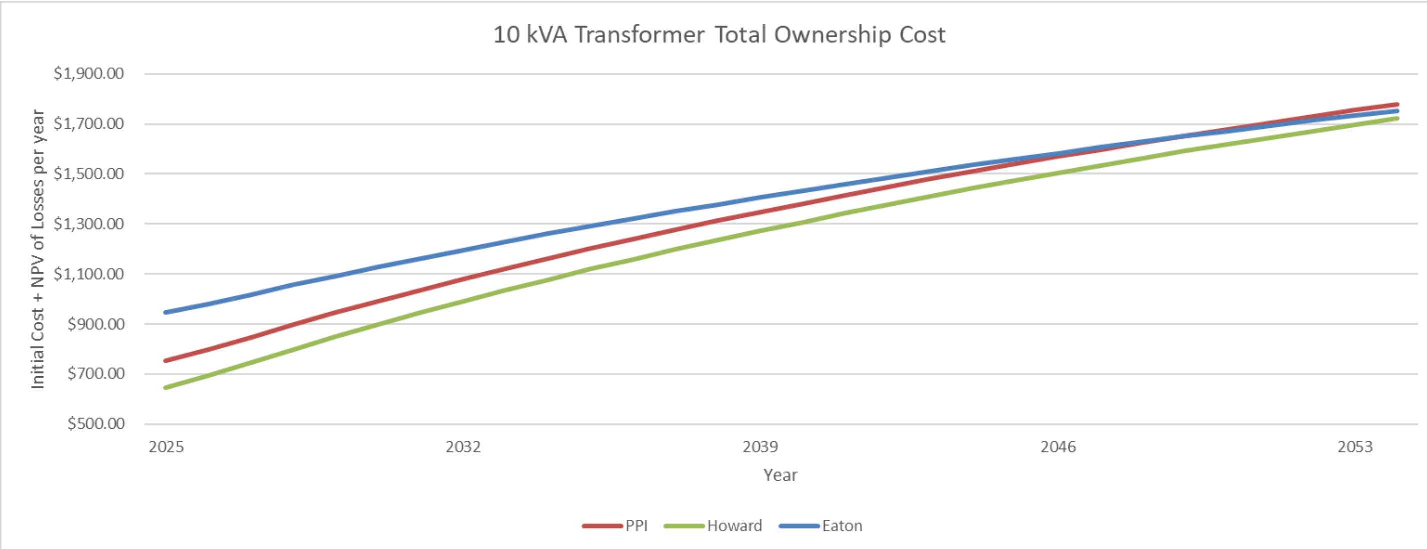


Figure 5.5.5.A Total Transformer Ownership Cost by Year and Manufacturer Over 30 Years

In the analysis depicted above, savings from fewer losses do not necessarily justify the increase in the initial cost of a more efficient transformer as seen when comparing the Howard 10kVA transformer to the PPI and Eaton models.

There are two common types of overhead transformers, conventional and CSP (Completely Self-Protected). VEC has recently standardized conventional transformers but still maintains some CSP inventory. VEC utilizes the following distribution transformer sizes:

- Pole Mounted – 1 kVA, 5 kVA, 15kVA, 25 kVA, 37.5 kVA, 50 kVA, 100 kVA, 167 kVA
- Pad Mounted– 15 kVA, 25 kVA, 50 kVA, 100 kVA, 167 kVA, 250 kVA, 333 kVA

VEC personnel identify the proper transformer size to ensure high-quality electric service and lowest life cycle cost for VEC membership. The smallest transformer size VEC utilizes on residential loads is a 15 kVA pole mounted transformer while 1 and 5 kVA transformers are used for station service and streetlights. VEC discusses a recent change to increase its standard transformer size from 10 kVA to 15 kVA in the Energy Transformation section of this IRP.

VEC has found that a typical residential member will draw around 3 kVA and, in some cases, up to 10 kVA if the member has multiple electric vehicles. A 15-kVA transformer is utilized for residential loads which would allow for an additional member to be added without changing the transformer.

For commercial loads, VEC utilizes a required member load sheet and comparable sized loads to determine the transformer size needed. VEC also regularly monitors loading on larger transformers typically associated with commercial or small industrial members to ensure efficient transformer sizing.

Utilizing the calculated losses of the transformer purchase tool VEC was able to model the approximate lifecycle losses based on transformer size.

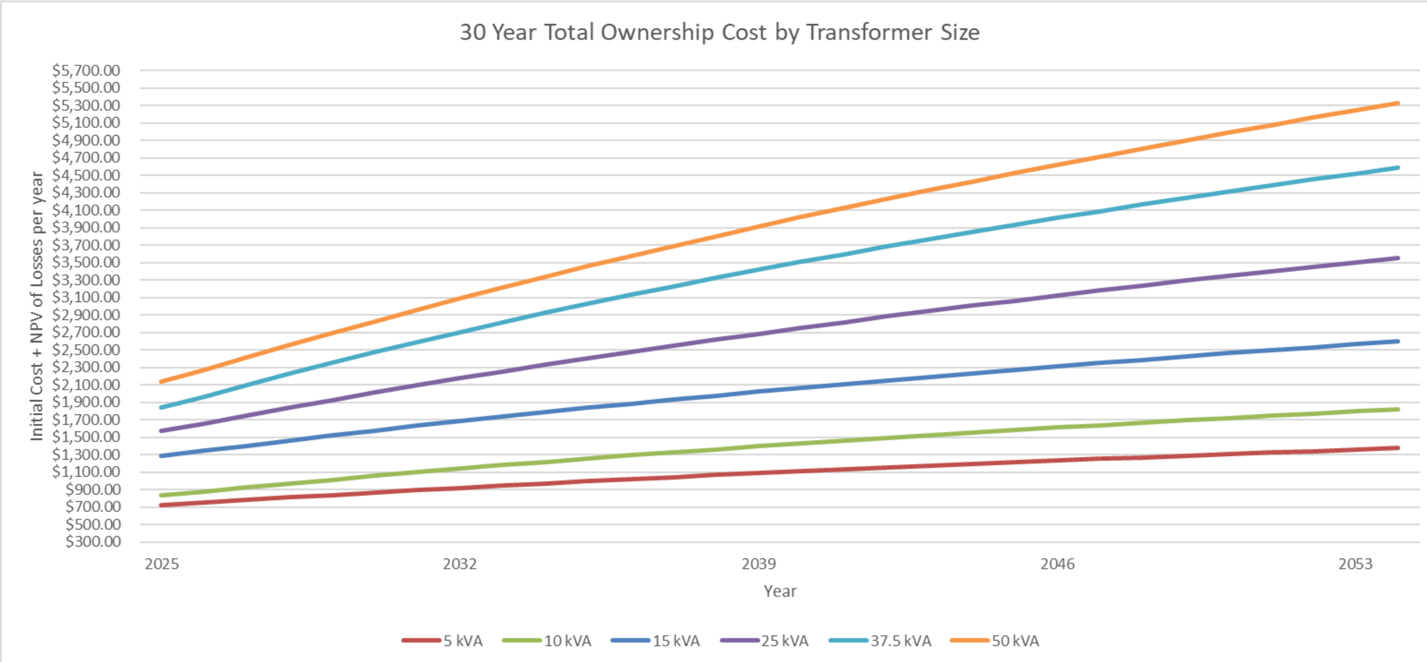


Figure 5.5.5.B Total Transformer Ownership Cost by Year and Transformer Size Over 30 Years

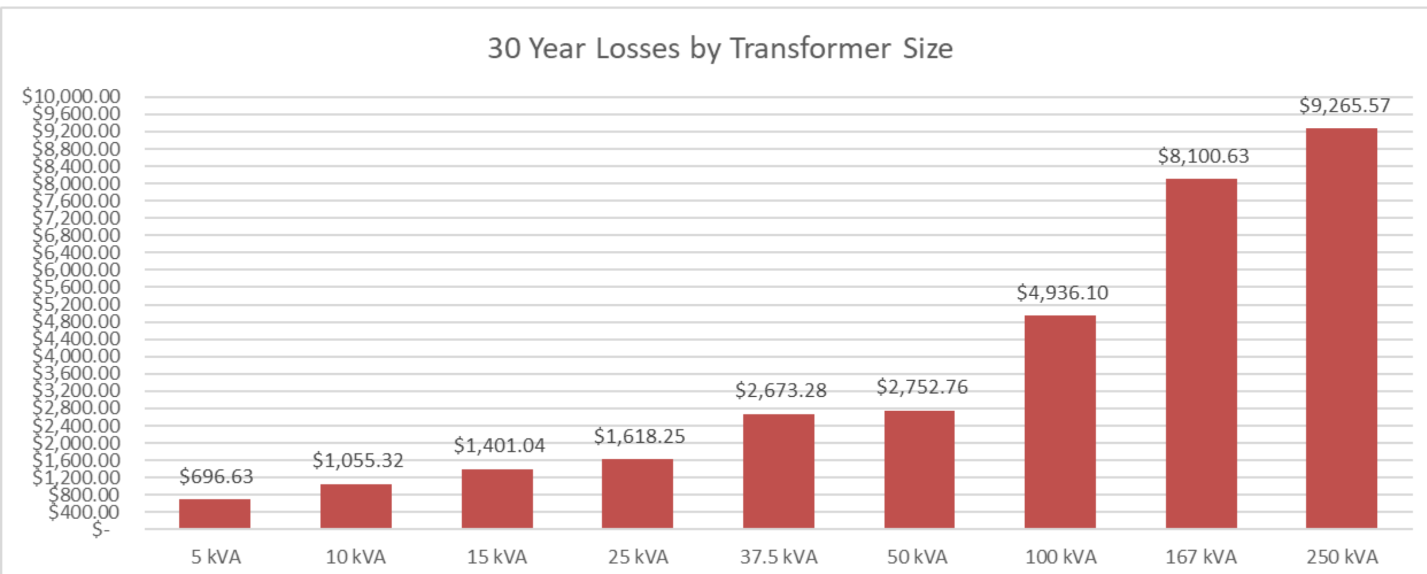


Figure 5.5.5.B Total Transformer Losses Over 30 Years by Transformer Size

VEC replaces undersized transformers as soon as concerns are identified; however, we will replace oversized transformers on a case-by-case basis when cost-justified.

VEC has seen an increase in overhead and transformer replacement because of voltage conversions and underground reconductoring projects. VEC typically replaces transformers due to condition, load growth, or capital projects. The charts below details VEC's transformer replacements associated with load growth, condition (generally like for like), or capital projects for both overhead and underground transformers.

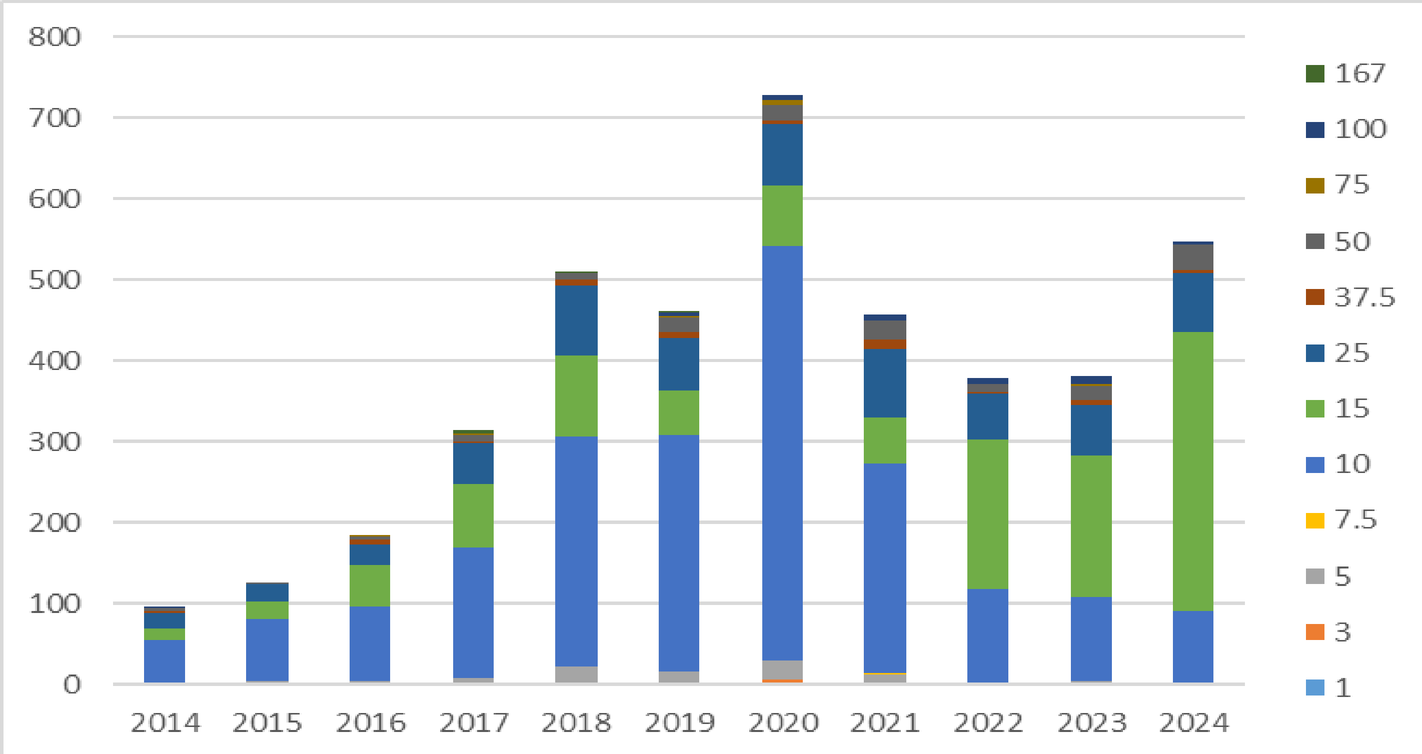


Figure 5.5.5.C Number of Overhead Transformers Replaced by Size (kVA) 2014-2024

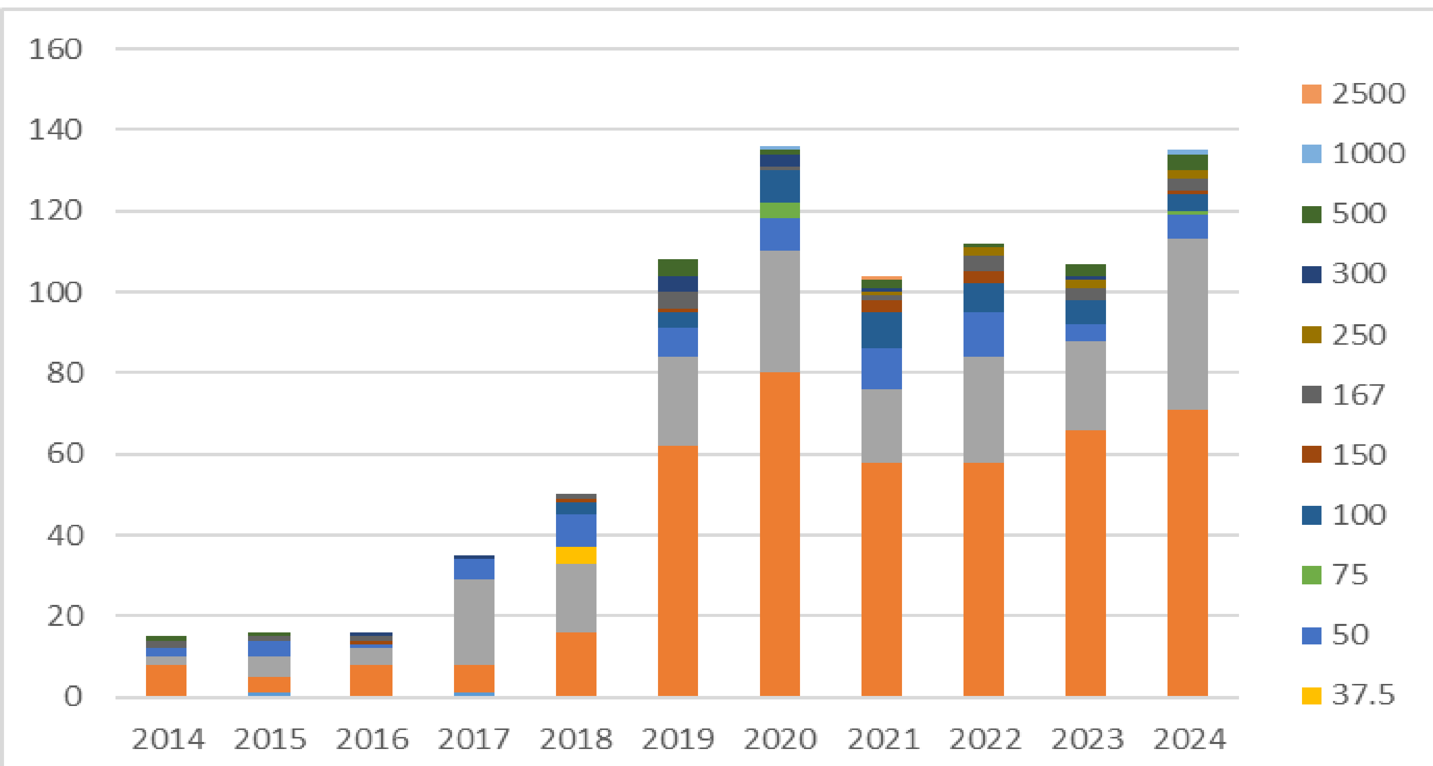


Figure 5.5.5.D Number of Padmounted Transformers Replaced by Size (kVA) 2014-2024

Substation Transformers

VEC evaluates substation transformers using the same analytical tool described in the distribution section. The following table shows the initial ownership cost, no load and full load losses, and total ownership cost of six 10/14 MVA transformers using proposals officially received in January 2025.

Transformer	Sell Price	No Load Losses	Full Load Losses	Total Losses	Total Ownership Cost
Pioneer Electrogroup Canada 10/14 MVA	***$491,805***	$151,556	$149,486	$301,042	$807,042
Virginia Transformer 10/14 MVA	***$595,600***	$153,604	$125,619	$279,223	$892,013
Niagara Transformer 10/14 MVA	***$647,346***	$131,075	$159,850	$290,925	$956,955
Hitachi 10/14 MVA	***$723,255***	$174,903	$156,050	$330,953	$1,075,083
WEG 10/14 MVA	***$728,439***	$130,870	$336,031	$446,901	$1,216,365
JST 10/14 MVA	***$728,851***	$286,727	$213,552	$500,279	$1,250,167

Table 5.5.5.B Total Cost of Ownership, No Load, Full Load, and 30-Year Losses by Transformer Manufacturer

The following graph shows the same information in a different format.

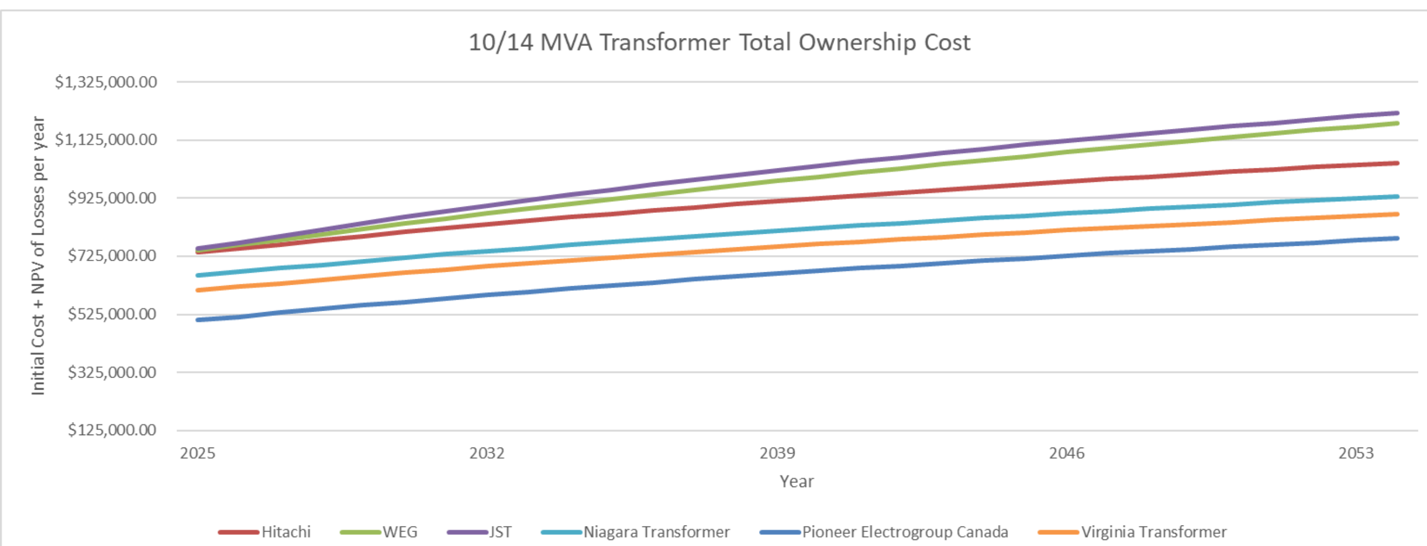


Figure 5.5.5.E 10/14 MVA Substation Transformer Total Ownership Cost

Substation transformers will be reviewed for replacement once the load exceeds 80 percent of the nameplate rating. VEC's substation criteria are detailed in further detail in Appendix A.

Overhead Conductor

Conductor Selection

Replacement of conductor (wire) generally occurs either because of poor condition or as needed for load growth or reliability. Loss savings alone generally do not justify a reconductoring project. VEC has recently standardized on the following conductor sizes:

- 1/0 AAAC (Azusa)
- 336 ACSR (Linnet)
- 556 ACSR (Dove)

VEC takes into consideration the total ownership costs of conductor upgrades. VEC uses a six-year net present value (NPV) payback period for major investment decisions. VEC calculates losses by multiplying the resistance by the square of the current. VEC models the initial cost of our three conductor standards along with the NPV of six years of losses per mile per conductor given a specific amperage. The analysis utilizes the approximate spot market savings in $/kWh to determine the value of losses. The chart below shows this comparison:

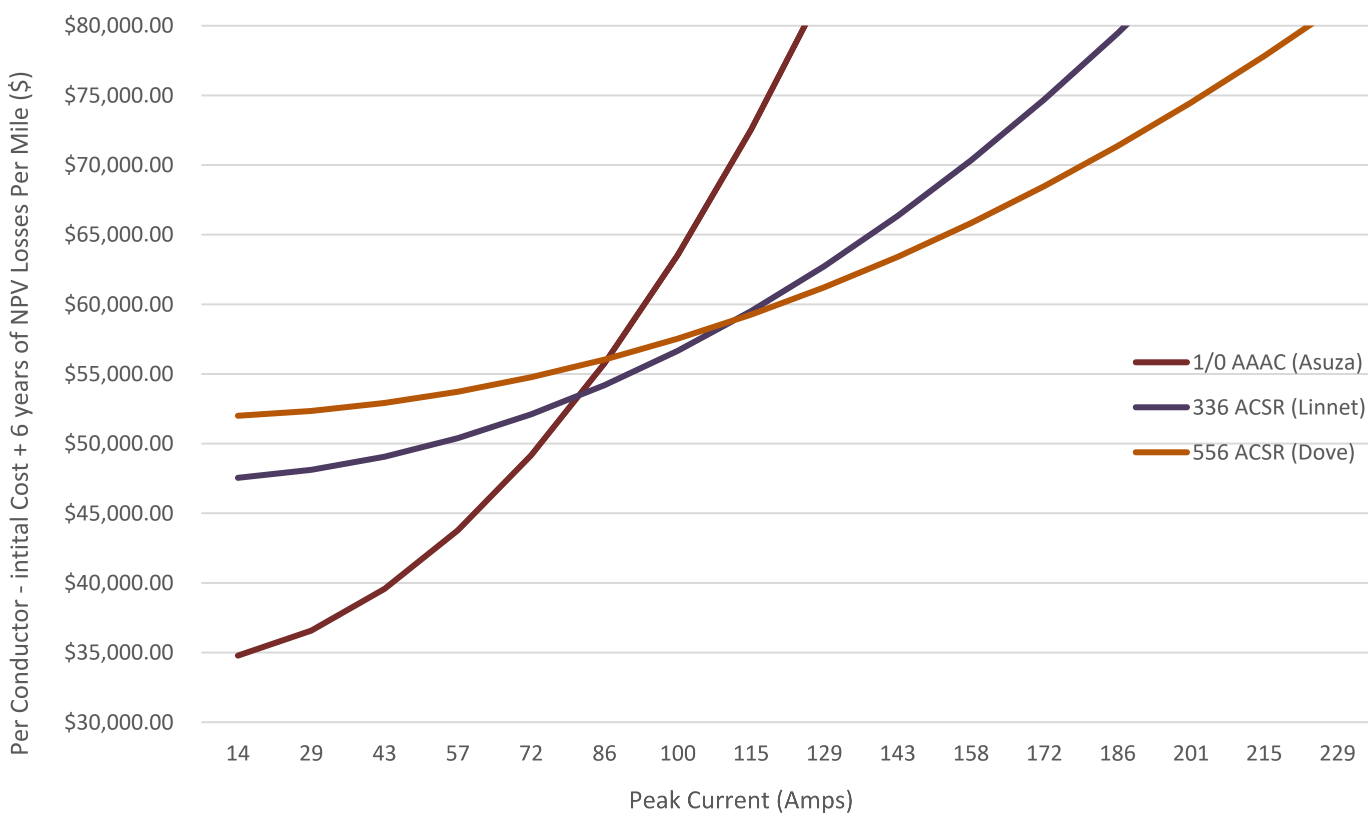


Figure 5.5.5.F Per Conductor Initial Cost + 6-Year Losses Versus Current (Amps)

From this analysis, VEC developed a wire chart, which is provided in the provided in Appendix-H.

Underground Conductor

An overhead line is considered the best utility practice from an overall power system installation and operating cost perspective. Overhead lines allow for flexibility such as the ability to add phases, upgrade conductors due to overload, identification of faults or damage, to convert to higher voltages, add secondary services, provide VAR support by adding capacitors, and voltage support with voltage regulators; all of which help manage the overall design and operation of the power system.

However, approximately 82 percent of VEC's new line extensions are underground primarily due to aesthetic preferences on behalf of VEC members. While aesthetic and reliability benefits exist for underground systems, underground cable has a greater impedance and voltage drop than overhead due to trapped conductor heat and magnetic coupling. Underground cables have more power losses due to heating and the lack of cooling within the conduit itself (unlike that of an overhead conductor that is cooled by the temperature and movement of the surrounding ambient air). For this reason, larger conductors are needed for underground cables versus overhead conductors to serve the same load levels.

Construction Practices

Proper installation of underground requires the following:

- Conduit (for protection).
- Jacketed EPR (ethylene propylene rubber-insulated) Cable
- Proper burial, installation, and termination.

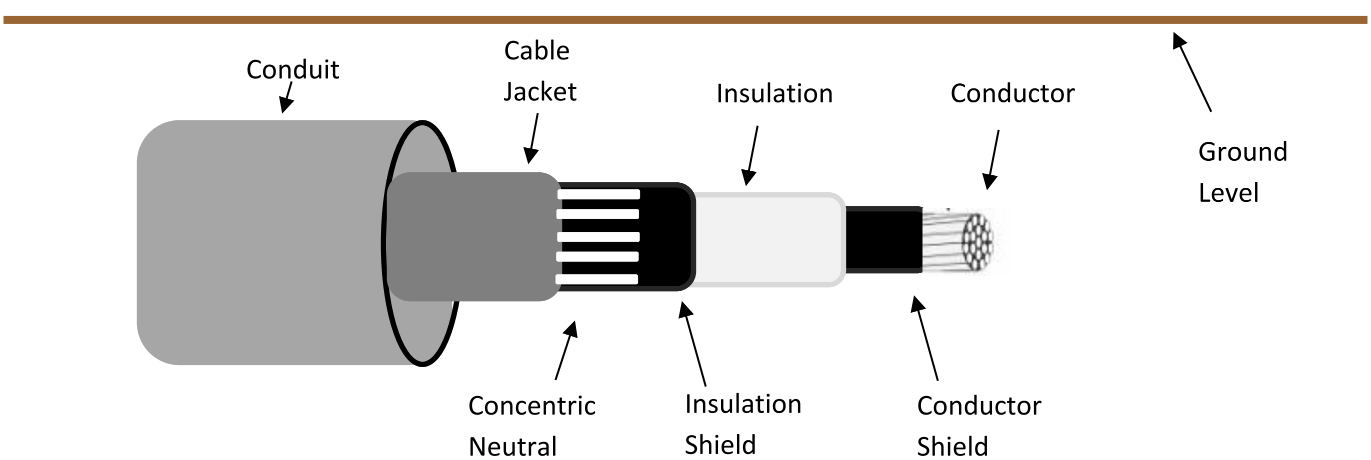


Figure 5.5.5.G   VEC Standard Installation of Underground Conduit and Conductor

Direct Buried Underground

While the above installation is VEC's standard today, direct buried underground cable was common practice in the 1970s and earlier.

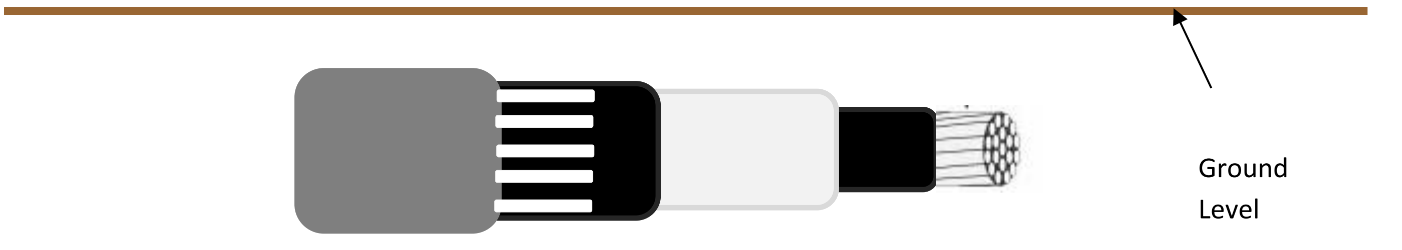


Figure 5.5.5.H Direct Buried Underground Installation

Direct buried cable is not in conduit and can be more susceptible to failure.

Unjacketed Cable

In addition to direct buried cable, VEC also has several locations where unjacketed cable was used and the concentric neutral had become separated from the cable. This makes locating a fault extremely time consuming as fault finding equipment depends on this neutral.

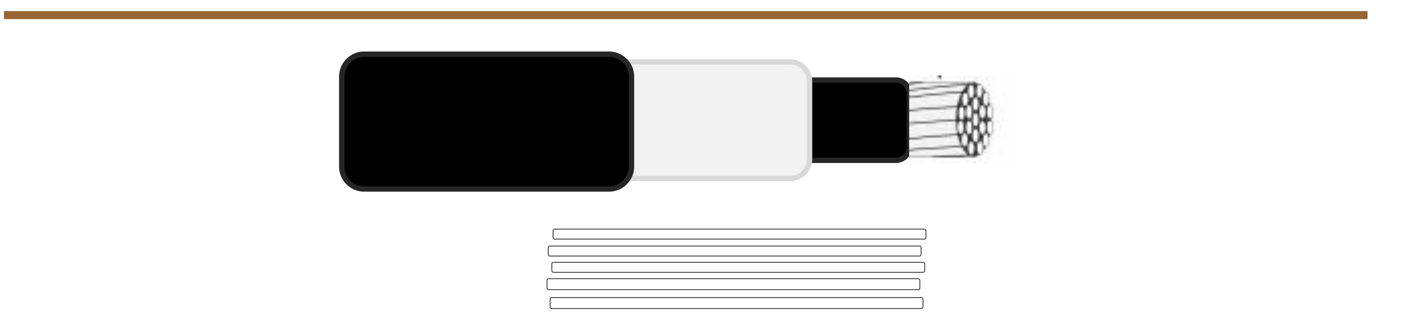


Figure 5.5.5.I Unjacketed Cable Underground Installation

VEC has an unknown quantity of both direct buried and unjacketed cable on its system and is not actively replacing locations simply due to this type of installation. However, VEC is in the process of determining the construction type of all its underground as part of its Maintenance plan. After this analysis is concluded and more information is known, we will develop a plan to address potential problem conductors.

Poles

Distribution

VEC has over 54,500 distribution poles on its system, the majority of which are treated with Pentachlorophenol, more commonly referred to as Penta. All VEC's poles are manufactured following American National Standards Institute (ANSI) and American Wood Protection Association (AWPA) guidelines to ensure the desired size, strength, material quality, original treatment loadings, and decay resistance properties. From a depreciation perspective, the average pole life expectancy of a utility distribution pole is 30 years; however, with proper maintenance, including inspection and treatment, life expectancy can exceed 60 years. VEC replaces poles when their condition requires it, assuming they meet clearances (height) or mechanical (tension/weight) requirements. VEC uses 60 years as a guide for asset planning but will not replace a pole that an inspection identifies is still structurally solid simply because it reaches 60 years old.

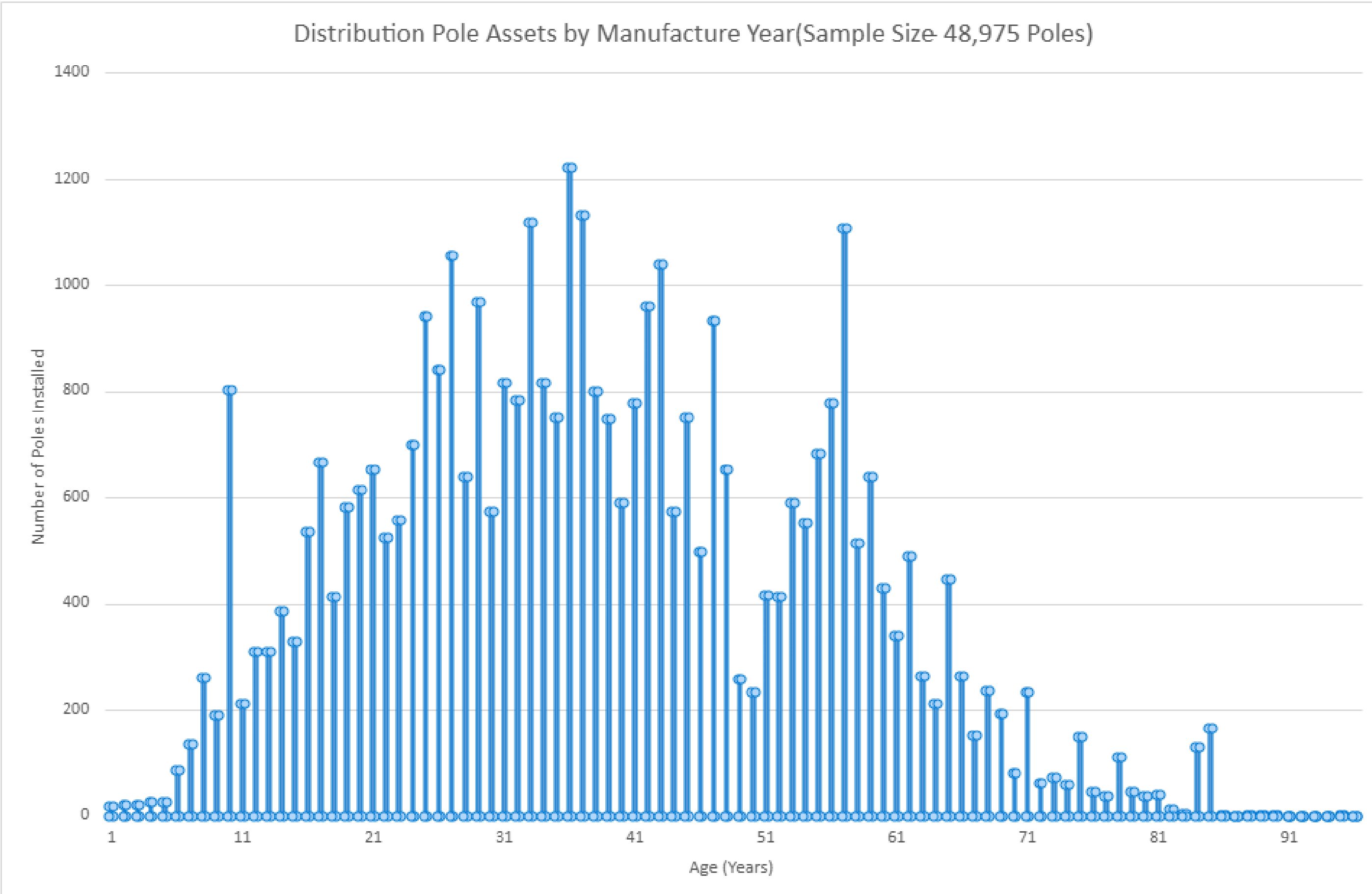


Figure 5.5.5.J Distribution Pole Assets by Manufacture Year

In fact, approximately 2,800 of VEC's poles are over 60-years old. VEC's average distribution pole manufactured age is 1986 (35 years old). The chart above shows the number of VEC distribution poles by manufacture year using a sample size of 48,975 poles.

VEC follows Appendix 1 of the Best Management Practices (BMPs) documented in PSB Docket No. 8310 associated with the use of Pentachlorophenol-treated utility poles in Vermont.

VEC continues to increase the number of poles it replaces annually due to change in use or because of VEC's pole inspection program. The last four-year average is over 390 poles replaced annually, compared to the prior six years where VEC averaged only 320 poles replaced annually. The pole inspection program identifies approximately 75 deficient poles annually. The chart below shows the height (in feet) and quantities of poles replaced since 2011.

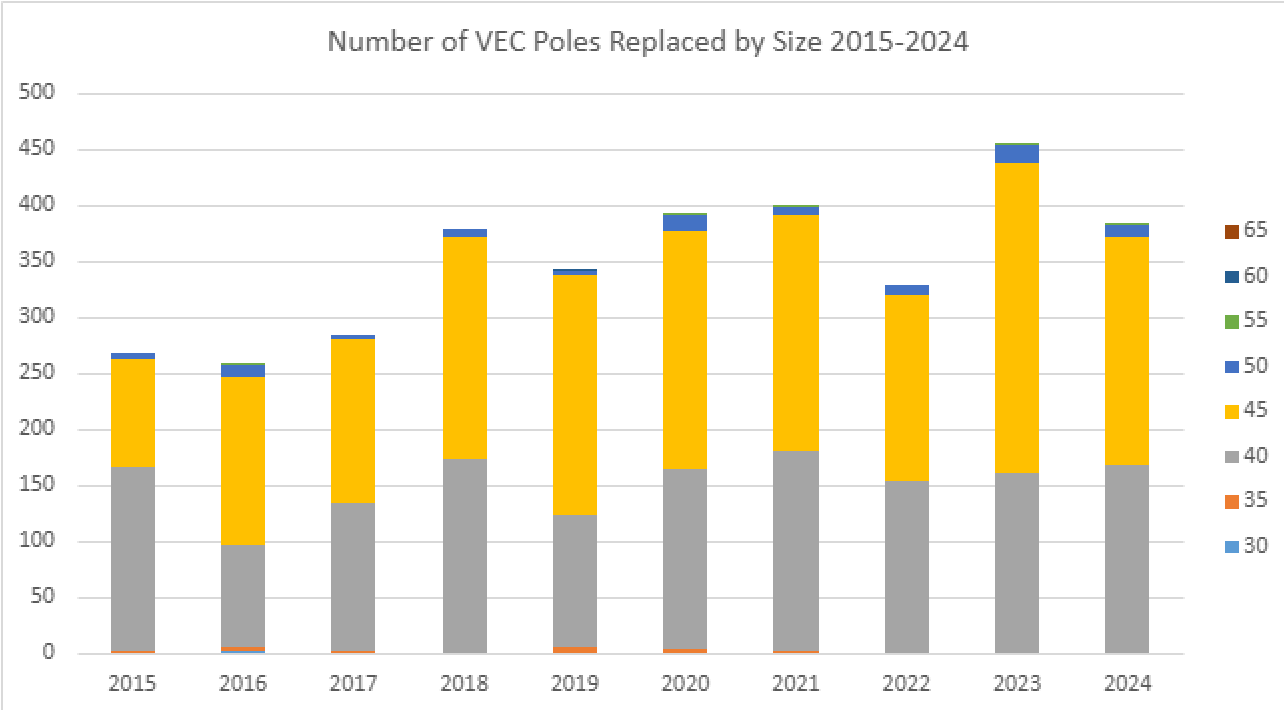


Figure 5.5.5.K Number of VEC Poles Replaced by Height 2015-2024

VEC is replacing approximately one percent of its pole assets annually; at this rate it would take approximately 100 years for all poles to be replaced on VEC's system. VEC expects the quantity of pole replacements to continue to increase in the future as VEC increases spending on reconductoring projects (requiring mid-spans and pole replacements), new construction (additional phases), and line relocations. In addition, the continued broadband rollout and associated make ready work will also affect the quantity of pole replacements.

Telephone Pole Replacements

Telephone pole replacements refer to any pole replacement within Franklin Telephone and Consolidated Communication's joint owned set area or at the request of Consolidated or Franklin Telephone. VEC replaces around 130 of jointly owned telephone poles annually.

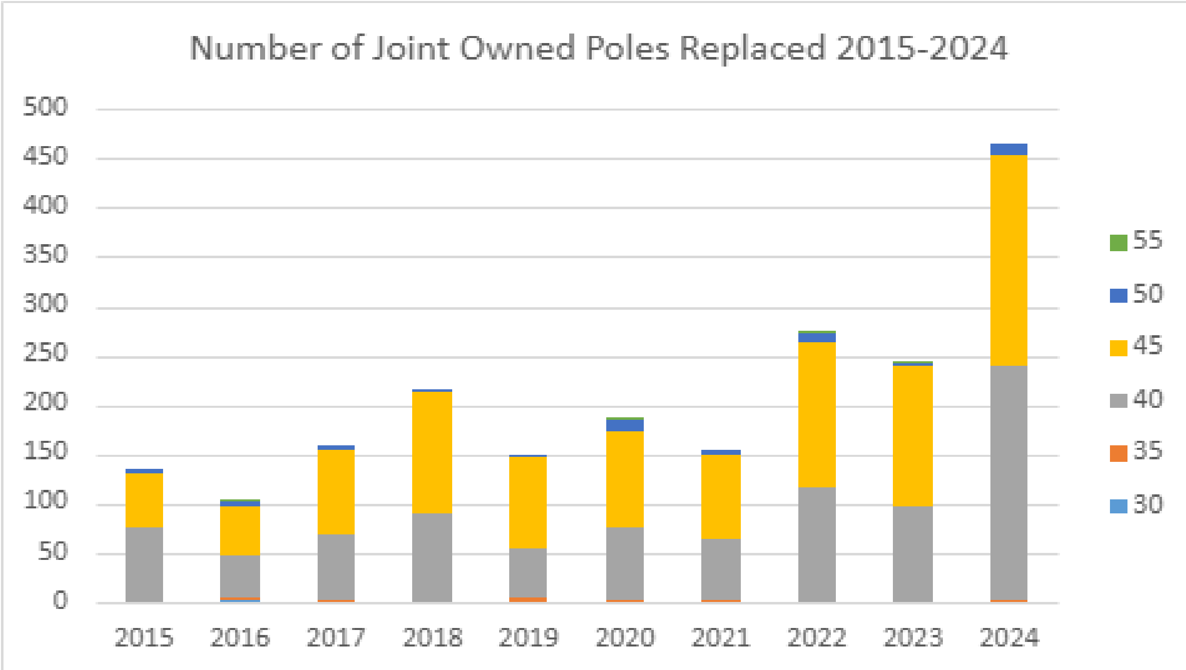


Figure 5.5.5.L Number of Telephone Poles Replaced by Height 2015-2024

Transmission

VEC has over 2,300 transmission poles on its system with around 162 poles (nine percent) older than 60 years. The average transmission pole manufacture year is 1990 (making the average pole 32 years old) with the oldest poles being on the Portland Pipe line (Barton Tap-to-Portland Pipe) and the South Alburgh line (Highgate to South Alburgh) The chart below displays quantity of VEC transmission poles by manufacture year using a sample size of 2,032 poles.

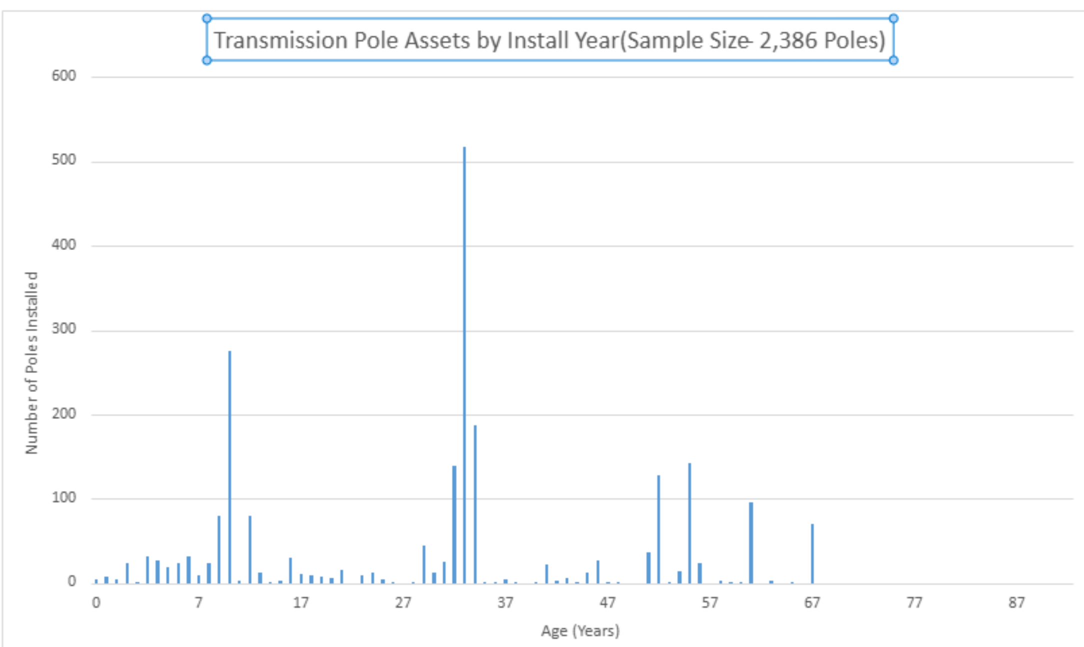


Figure 5.5.5.M Transmission Pole Assets by Manufacture Year

Pole Treatment - Penta Production and Alternatives

Most of VEC's poles are made from Southern Yellow Pine treated with Penta, a substance no longer used outside the United States. The last Penta plant in Mexico closed at the end of 2021, making new Penta poles unavailable by the end of 2022. After thorough research, VEC chose CCA as the best alternative. Here is a summary of CCA poles.

- **CCA -** Chromated Copper Arsenate (CCA) is a water or oil-based treatment that has been used in treating Southern Pine and Western Red Cedar poles for many decades. CCA provides effective protection for poles because it chemically "fixes" or bonds to the wood, reducing the chances of potential migration of the preservative into the soil or groundwater. VEC utilized a small quantity of CCA poles in the 1970's and 1980's but there were significant issues when trying to climb these poles. Unlike Penta, which stays soft through its lifetime, the CCA poles became hard, especially in winter, as they aged making it nearly impossible to safely climb these poles. In the early 2000's, newer treatments were developed that included an oil impregnation to soften the CCA poles.

  Currently Hydro Quebec uses Red Pine poles with a CCA treatment. Hydro Quebec (HQ) has been installing red pine CCA poles on its system since the late 1940's and standardized on CCA-PA (an oil-based additive to aid in climbing ability) in the early 2000's. HQ has performed 320,344 inspections on poles with a CCA treatment since 2009. Of those inspected only 0.3% were rejected comparing to VEC's reject rate of 2.45%. Even better, if the replacements are filtered out for all causes except natural decay the replacement rate is 0.02%.

							REPLACEMENTS		REPL RATE DUE TO NATURAL DECAY		
INTALL YR	EX	IN	RP	RU	RC	Total	Total	PCT	Total	PCT	PCT OF ALL REPL
1946 to 1950	55		3	2		60	5	8,33%	2	3,33%	40%
1951 to 1955	129	1	6	5	1	142	12	8,45%	5	3,52%	42%
1956 to 1960	41		3	2	2	48	7	14,58%	5	10,42%	71%
1961 to 1965	115	1	5	3		124	8	6,45%	5	4,03%	63%
1966 to 1970	131	1	3	4		139	7	5,04%	6	4,32%	86%
1971 to 1975	166	1	4	2	1	174	7	4,02%	4	2,30%	57%
1976 to 1980	5 481	138	71	57		5 747	128	2,23%	18	0,31%	14%
1981 to 1985	7 589	598	126	64	2	8 379	192	2,29%	13	0,16%	7%
1986 to 1990	912	2 461	16	9	2	3 400	27	0,79%	3	0,09%	11%
1991 to 1995	401	12 095	43	37	7	12 583	87	0,69%	6	0,05%	7%
1996 to 2000	121	3 940	11	4	1	4 077	16	0,39%		0,00%	0%
2001 to 2005	394	66 496	85	45	7	67 027	137	0,20%	3	0,00%	2%
2006 to 2010	401	117 704	144	60	3	118 312	207	0,17%	1	0,00%	0%
2011 to 2015	201	75 450	86	25	4	75 766	115	0,15%		0,00%	0%
2016 to 2020	61	23 865	16	3	2	23 947	21	0,09%		0,00%	0%
2021 to 2021		419				419	0	0,00%		0,00%	0%
Total	**16 198**	**303 170**	**622**	**322**	**32**	**320 344**	**976**	**0,30%**	**71**	**0,02%**	7%

Figure 5.5.5.N Pole Reject Information from Hydro Quebec – CCA Poles

Even after 40 years, none of the poles were below the minimum effective concentration level. While HQ still inspects their poles on a similar 10-year cycle to VEC, they have found cost savings both by not having to retreat CCA poles and, more significantly, the need to replaced fewer poles because of the inspections.

Material Supply Chain Challenges

Supply chain issues and inflationary pressures have a significant impact on VEC's ability to provide the most reliable and lowest cost electric service to our members. Both also play a part in our ability to meet our members' demands (e.g., upgrades, new services, etc.) in an expeditious manner. VEC continuously monitors market intelligence reports and weekly updates from our primary equipment vendor to understand current impacts, make judicious business decisions (e.g., reprioritization work), and forecast future effects.

The challenges with regards to VEC's supply chain of materials includes the following:

1. VEC's NISC system uses a blended price for major materials, so as we deplete old stock and replace them with new, the price is adjusted within the system. Since we have not depleted older material bought at lower prices, overall costs for internal and member work could increase for several months before leveling.
2. Lead times for major material purchases have posed a considerable challenge in recent years for VEC's ability to meet the required timeframes and expectations of its members. For instance, substation transformers have a lead time of up to 150 weeks. While most other lead times have reverted to pre-COVID levels, major projects need to be planned well in advance.

VEC is addressing these challenges by:

1. Increasing the amount of on-hand/in-stock major inventory to help counter the slower replenishment rate.
2. High turnover items such as transformers, cutouts, poles, etc. are closely monitored weekly for in stock quantities and orders placed, accordingly.
3. Sourcing material from other vendors outside of primary vendor WESCO such as Graybar, Irby, CED/Twinstate, Green Mountain Electric Supply, and United Utility Supply. We are using every avenue we have at our disposal to augment material that WESCO may be lacking or have longer lead-times. VEC is also working with other Electric Utilities to exchange and replace material as material is delivered to one utility or another.
4. Shifting from purchasing only new transformers to utilizing companies that rebuild transformers (e.g., T&R Electric, Emerald Transformers, Florida Transformers, etc.). Rebuilt transformers typically tend to have shorter lead-times but we are unsure to the longevity of these transformers which may impact future capital replacement schedules.

5.5.6 Duplicate Electric Facilities

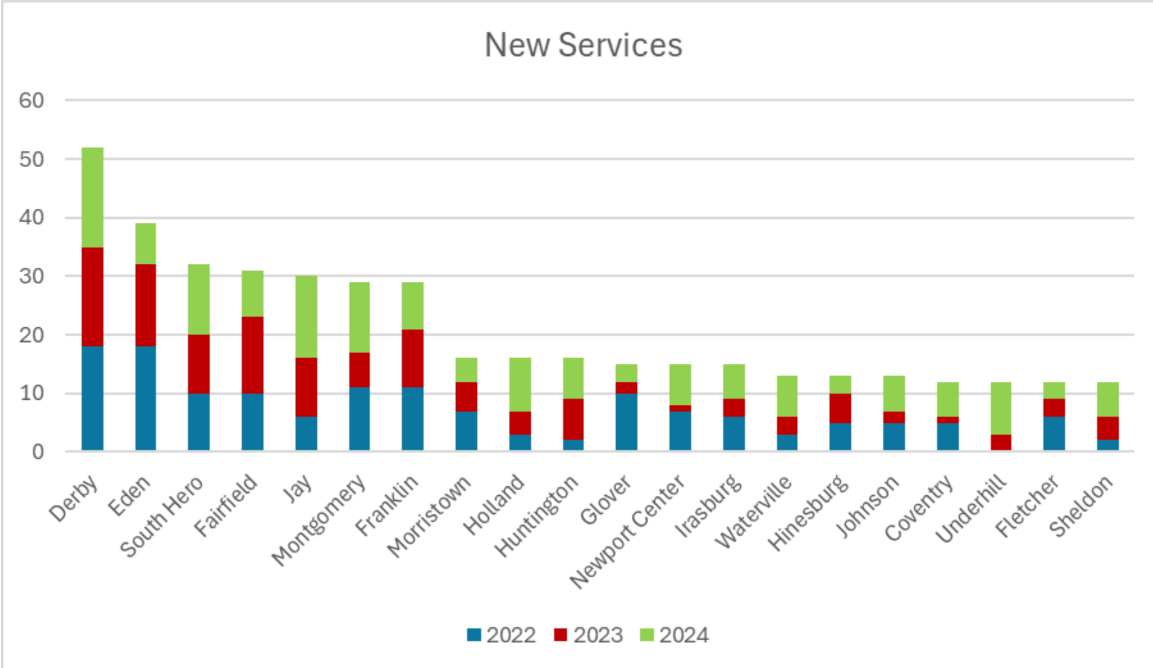
In 2004, VEC acquired Citizens Utilities, identified significant overlap of the two systems, and has since made efforts to consolidate the two systems resulting in operations and maintenance (O&M) cost savings and in many cases improved reliability to VEC members. VEC completed the below two projects in recent years:

- 11 Spans of cross-country single-phase line off Loop Road in Westfield.
- 3500 feet of single-phase line off Route 105 in Troy.

In cases where duplication exists with other utilities, VEC will work with the other utilities to eliminate this duplication.

5.5.7 New Services

VEC continues to see growth in new service applications and construction in its territory. Overall, the data shows varying trends across different towns, with some experiencing declines, others showing fluctuations, and some seeing increases in the number of new services over the three-year period.



A

Figure 6.6.7.A New services installed by town (Top 20) - 2022-2024

VEC installed 336 new services in 2024, up from 287 in 2023. This is a 15% increase.

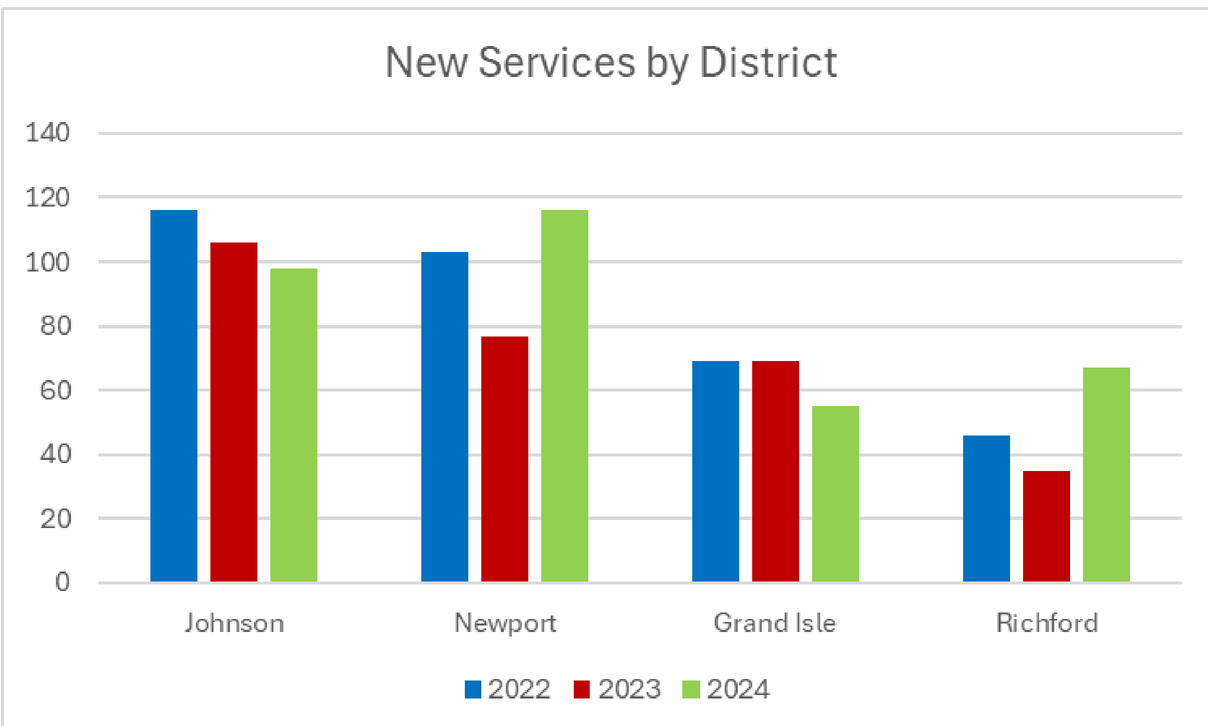


Figure 6.6.7.B New services installed by district – 2022-2024

5.5.8 Efficiency

2021 VEC Loss Study

VEC completed a loss study in August of 2021. Power loss values for VEC's solely owned sub transmission and distribution system as a percentage of total load were found to be approximately 1.8 percent for the transmission and 3.6 percent for the distribution and within the national averages for all electric utilities per the 2012 EPRI document titled, "Assessment of Transmission and Distribution Losses in New York State." VEC intends to complete another loss study in 2026.

		Annual Load (MWH)	Annual Losses Estimated (MWH)	% losses of MWH load
Distribution (VEC)		418960	**14873**	**3.6**
Transmission (VELCO)		393213	**7122**	**1.8**

Table 6.6.8.A 2021 VEC Loss Study Results

VEC's financial system power losses are derived by comparing ISONE's load settlement of VEC's monthly power purchases to VEC's metering software tabulation of kWH's sold that month. For 2018, the focus of this 2021 loss study, financial power losses were approximately seven percent. The bulk power transmission losses from the various ISONE's 'inlet' revenue meters to VEC's sole owned power system can be estimated by subtracting the total VEC system loss study results of 5.4 percent from 7 percent equaling 1.6 percent. The 2012 EPRI study found that on a national basis, distribution losses ranged from 1.9 to 4.6 percent and transmission system losses ranged from 1.5 to 5.8 percent, further validating the reasonableness of the VEC loss study results.

While there are some approaches to loss reduction that can be applied system-wide, such as load balancing and power-factor correction, most efficiency improvements are evaluated on a case-by-case basis.

The two main areas that utilities focus on to reduce losses are (1) replacing existing infrastructure and (2) changing design and planning criteria for future infrastructure investments to improve efficiency. The cost to replace existing infrastructure can be high compared to the cost savings through loss reduction; however, the incremental cost to build higher efficiencies into future capital projects could be low compared to efficiency gains.

Based on the work performed by the New York utilities, EPRI, and SAIC, as well as their reviews of other industry studies, electric losses can be reduced by system improvements on the distribution system. Generic or case-specific cost/benefit analysis is required to justify the required expenditure for these system improvements.

Efficiency Improvements

- Phase balancing – rearranging loads on each phase of the circuit to reduce the current in some phases, and the neutral.
- Reactive power optimization – adding or removing capacitor banks or altered switching scheme.
- Voltage conversions from lower to higher nominal voltages.
- Reconductoring replacing selected conductor sections with larger, lower-resistance conductors
- Replacing lower-efficiency line transformers with higher-efficiency transformers.

Phase Balancing

To achieve an efficient distribution system network, VEC developed the following design criteria for distribution line loading and voltage:

- Three-phase distribution line voltage shall be less than two percent unbalanced.
- The substation low side bus phase currents shall be not more than 20 percent unbalanced.
- Engineering model predicting loading shall not exceed 40 Amps on 7.2/12.47 kV single-phase taps per RUS Bulletin 1724D-101B and 1724D-101A. More detailed information regarding VEC's distribution criteria is available in Appendix-A.

Balancing load between phases improves the efficiency and operability of the distribution circuits. Balancing phase loading helps to keep voltage balanced and creates a better foundation for voltage regulation. A balanced system also reduces neutral current on three-phase lines, leading to a reduction in losses.

VEC aims to reduce the number of large radial single-phase lines to more easily manage the system from a load balancing perspective. Having multiple phases for load balancing improves VEC's ability to serve new load and can improve system voltage.

Power Factor

Power factor is the ratio between real power and apparent power. A common analogy that is used is a mug of beer. The beer has some liquid (real power or watts) and foam (reactive power or VARs). The whole mug is the apparent power (kVA).

Figure 6.6.8.A   Beer Mug Power Factor Analogy

VEC only bills for the liquid, which turns the meter. The foam is necessary to maintain voltage. That reactive power needs to come from somewhere, ideally as close as possible to where the real power is being used.

Regarding the VEC system, VEC is striving to maintain a power factor at or above 0.95 lagging and equal to or less than unity. To meet this goal, VEC measures the power factor at each of its substations. Using this information, VEC ensures that the system is operating as efficiently as reasonably possible. When appropriate, VEC may require that power factor correction equipment be paid for and installed by the member. The revenue meter for commercial accounts measures power factor for those services.

In addition, ISONE and VELCO require VEC to maintain a power factor of between 0.95 lagging and unity for all its primary metering points with other utilities. Commercial accounts are also required to meet a power factor value between 0.95 lagging and unity.

Typically, VEC achieves power factor correction using fixed capacitors on the distribution circuits. By placing the capacitors on the distribution circuits where the VARs (Volt Amperes Reactive, i.e., reactive power) are needed, we avoid excess current across the distribution lines, thus reducing losses. Placing capacitors on the distribution system also affects system voltage, and we take these effects into account. Fixed capacitors are a relatively inexpensive solution for voltage support and often also provide the necessary VAR support that the load requires.

In some cases, voltage support is required but the VARs are not, which can cause leading power factors and line losses. In these instances, a voltage regulator may be the appropriate solution. Voltage regulators are more expensive and require periodic maintenance to function properly. Increased conductor sizes, voltage conversions to higher voltages, and the addition of multiple phases to help balance loads and reduce phase line currents may also be required.

Voltage Upgrades

VEC continues to review alternative methods of improving system voltage such as adding voltage regulators and installing larger (to reduce resistivity) wire to reduce voltage drop on its long radial lines. VEC completes this analysis on an annual basis as part of the System Load and Voltage Study. The goal is to find a balance between low losses, affordability, and system operability.

Per VEC's Design Criteria, voltage performance must meet ANSI standard C84.1. Basic Criteria include:

- System voltage planning criteria lower and upper thresholds are approximately 0.96 and 1.04 per unit respectively.
- The lower and upper threshold consumer voltage at the meter is 0.95 and 1.05 per unit respectively.

While VEC attempts to analyze the system each time a new project is added and every three years, these proactive efforts do not guarantee acceptable power quality for all VEC's members. VEC prioritizes power quality complaints and investigates them immediately. VEC gives high priority to power quality incidents that require capital improvements.

5.5.9 Collaboration with other Entities

VEC maintains several joint substations with Green Mountain Power (GMP) and VELCO.

- GMP – Richmond #8 Substation, Cambridge #3 Substation, Jay Tap #39, Taft's Corners #9, and Lowell #5 Substation.
- VELCO - Jay Tap #39, Newport #44, South Hero #29, and Taft's Corners #9.

An example of collaboration includes a project VEC worked on with GMP at its jointly owned Richmond #8 Substation to add breakers to the two incoming GMP 35 kV transmission lines and VEC's radial line to Hinesburg. This improvement in system protection will automatically sectionalize GMP's lines keeping the Richmond and Hinesburg members energized if a fault exists on the GMP transmission system fed either side of the Richmond substation.

5.5.10 Fiber and Broadband

VEC has several telecommunications entities that attach to its distribution system. These entities are broken down into three categories: Joint Use, Joint Ownership, and Attachee. Each entity utilizes the National Joint Utilities Notification System (NJUNS) web-based electronic work management tool to communicate and monitor work requests. The system provides extensive reporting, tracking, and searching capabilities that helps construction and monetary timelines, defines responsibilities, and monitor dual poles.

VEC recognizes that jointly occupied pole lines require larger poles of higher cost, but there are substantial cost savings when compared to the total investment dollars required of multiple companies if they constructed their own separate facilities. In addition, aesthetic and environmental impacts are lower with one line versus multiple.

Make Ready Process

The VEC's make-ready process commences upon submission of an application by the attaching entity, accompanied by payment for the field survey. Utility Designers schedule the field survey in coordination with any joint owners and the applying entity. During the survey, all poles are assessed to confirm compliance with NESC standards. Poles that do not meet these standards due to structural issues or lack of space are corrected at the pole owner's expense. If a pole meets NESC standards but cannot support additional attachments, it will be replaced at the attaching entity's expense. All other basic make-ready tasks are also performed at the attaching entity's expense.

Following the completion of the survey, an invoice outlining the estimated costs of work, excluding NESC violations, is generated. Capital work, primarily pole replacements, is billed at actual labor and material costs, subject to reconciliation upon completion. Upon receipt of payment for this invoice, the work orders are released to the construction department.

To date, VEC has consistently met or exceeded the timeframe requirements specified in PUC Rule 3.700. Although future circumstances may necessitate reliance on contractors to meet these timelines, discussions with several contractors have been conducted to mitigate potential issues.

Upon completion of VEC's work, the signed license is provided to the attaching entity, allowing them to commence their construction activities (e.g., installation of cable, fiber, etc.). Concurrently, VEC reconciles all labor and material charges for capital work, issuing a credit or invoice to the attaching entity as appropriate.

Operating make-ready costs have exceeded billable amounts due to higher contractor expenses relative to the fixed rates applied for make-ready work. These rates were significantly adjusted upward to bridge the gap in 2025.

Minor make-ready activities across all companies in 2024 impacted 366 poles, including raising drip loops, repositioning neutral, relocating transformers, replacing neutral brackets, etc.

*Billable costs in 2024 were <u>reduced</u> by **$285,793** for tariff that ended on January 1, 2024. These were for projects submitted before the deadline. Capital make-ready tariff credits from prior years were applied in 2024. However, a new process rolled over any payments received in previous years and applied to projects completed in 2024.

Major make-ready between all companies for 2024 included 51 telephone and 44 VEC pole replacements.

2024 Make Ready Completed

Company	Attachments	Distance (Miles)

Comcast	42	2
NEK Broadband	3,555	189
VELCO	133	7
WCVT	181	10
Consolidated	22	1
TVC Firstlight	43	2
Totals	**3,976**	**211**

2025 Make Ready – Applications

Company	Attachments	Distance (Miles)
Comcast	119	6
NEK Broadband	3,395	180
NW Fiberworks	2,520	134
VELCO	1,258	67
WCVT	99	5
Totals	**7,391**	**392**

In 2024, there were a total of 104 make-ready applications. At the beginning of February, there are 67 open applications (construction not complete) from 2024, 33 from 2023, and 4 from 2021-2022.

Despite receiving fewer attachment miles in 2024 compared to 2023, the applications for 2025 will represent our heaviest lift yet as work progresses in the Northwestern corner of the state. Make Ready work will persist due to the ongoing focus on broadband initiatives in Vermont. We anticipate that this trend will continue for the foreseeable future.

The chart below details the number of make ready miles and poles VEC has replaced from 2020 to 2024.

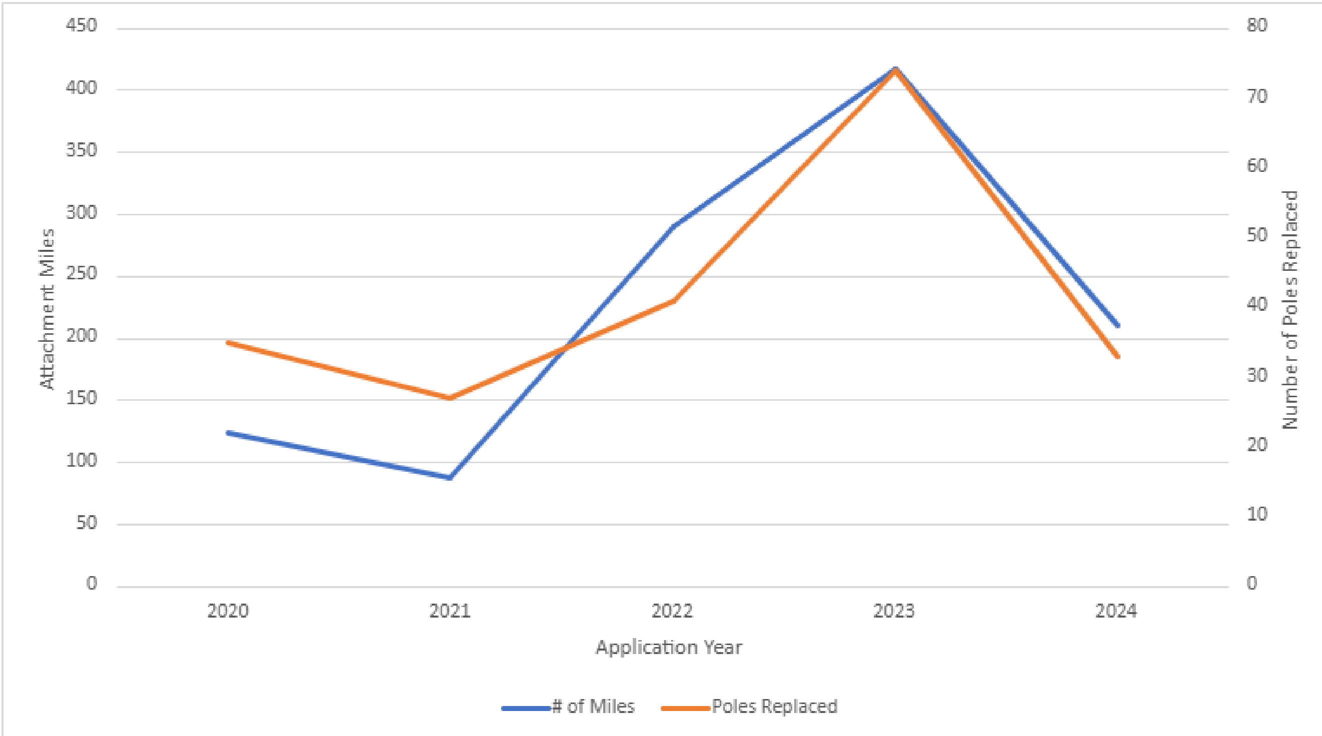


Figure 6.6.10.B Number of Make Ready Miles and Poles Replaced 2020-2024

Joint Use

Each entity owns their poles and can set or replace their own poles. The poles are jointly shared pursuant to rental agreements invoiced under 3.700 tariff rates. Both Waitsfield Telephone and FairPoint Classic are classified as Joint Use with VEC.

Attachee

Entities such as Comcast, Mansfield Fiber, Stowe Cable, and Verizon Wireless attach to VEC poles under Vermont PUC Rule 3.700. They pay an annual fee to be an Attachee to VEC's poles.

Joint Ownership

VEC has five existing joint ownership agreements:

- Consolidated Communications (CCI) – Approximately 28,000 poles.
- Franklin Telephone – Approximately 1,300 poles.
- Washington Electric Cooperative (WEC) – Approximately 100 poles.
- Barton and Orleans – Approximately 170 poles on the H16 transmission line.
- Green Mountain Power (GMP) – Approximately 450 poles.

VEC and the joint-ownership parties generally follow Inter-Company Operating Procedures (IOPs). Utility owners put these IOP's in place to ensure effective savings in capital investment for both companies.

<u>Consolidated</u>

CCI is VEC's largest joint owner with approximately 28,000 jointly owned poles. Each company has several designated "maintenance areas" – towns where it is responsible for pole sets - which are shown in the image below:

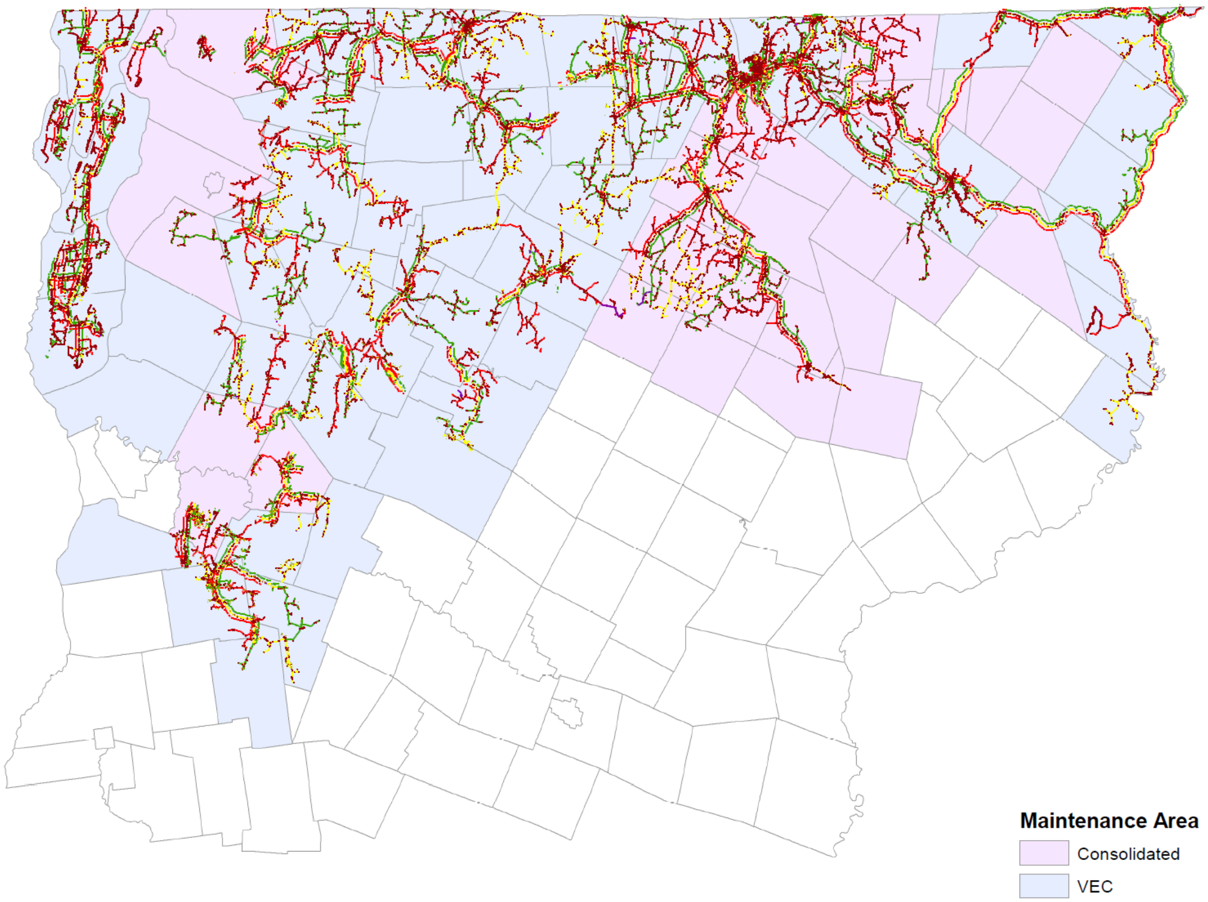


Figure 6.6.10.A VEC and Consolidated Communications Maintenance Areas

VEC continues to jointly own approximately 28,000 poles with CCI (~48 percent of poles).

5.5.11 Environmental Program

VEC has created an Environmental Guidance Manual (EGM) to support responsible installation, operation, and maintenance of its transmission and distribution lines. This manual serves as a practical resource for VEC employees and contractors, offering guidance on regulatory compliance, project planning, field assessments, and best management practices (BMPs). It covers relevant environmental concerns such as wetlands, streams, flood areas, rare species, cultural resources, soil disturbance, invasive plants, and impervious surfaces, aiming to ensure operations are sustainable and compliant.

The EGM is intended exclusively for the Vermont Electric Cooperative and all personnel involved with VEC's infrastructure receive training based on its content. A glossary clarifies terms and acronyms. VEC owns and maintains the EGM, updating it at least every five years or as needed when regulations change. The manual also references external sources to minimize the need for frequent revisions.

Before beginning any VEC project, employees and contractors must complete environmental training drawn from the manual, with content tailored as necessary. Additional training may take place during projects. To maintain compliance, VEC conducts routine and permit-driven inspections using a standard, customizable template developed with VHB. Inspections may be carried out by VEC staff or third-party consultants.

The EGM outlines standard work practices, BMPs, and permitting requirements, while recognizing that some projects may need extra field assessments and permits. In such cases, VEC experts or third-party consultants identify additional resource reviews or permit needs. Project-specific permit requirements may supplement or override EGM guidance. Examples of required permits include the Certificate of Public Good, Vermont Wetlands Permit, U.S. Army Corps of Engineers Section 404 Permit, and various stormwater and species permits.

This document is designed to be a tool used in conjunction with VEC's suite of guidance documents. These include, but may not be limited to:

- Vegetation Management Plan for Vermont Electric Cooperative, Inc. – Transmission and Distribution Systems
- VEC Operation Procedure 27: Oil Spill Reporting Procedure
- Best Management Practices (BMPs) Associated with the Use of Pentachlorophenol-treated Utility Poles in Vermont
- Facility specific SPCC Plans;
- Facility specific Operational Stormwater Management Requirements; and
- On-going Project-Specific Requirements and Permit Conditions