Vermont Electric Cooperative Inc.

Maintenance Plan

1 Introduction and Objectives

As part of a concerted effort to maintain and document all T&D assets, VEC intends to implement a robust and comprehensive maintenance program on January 1, 2019. The plan is broken up into two major components:

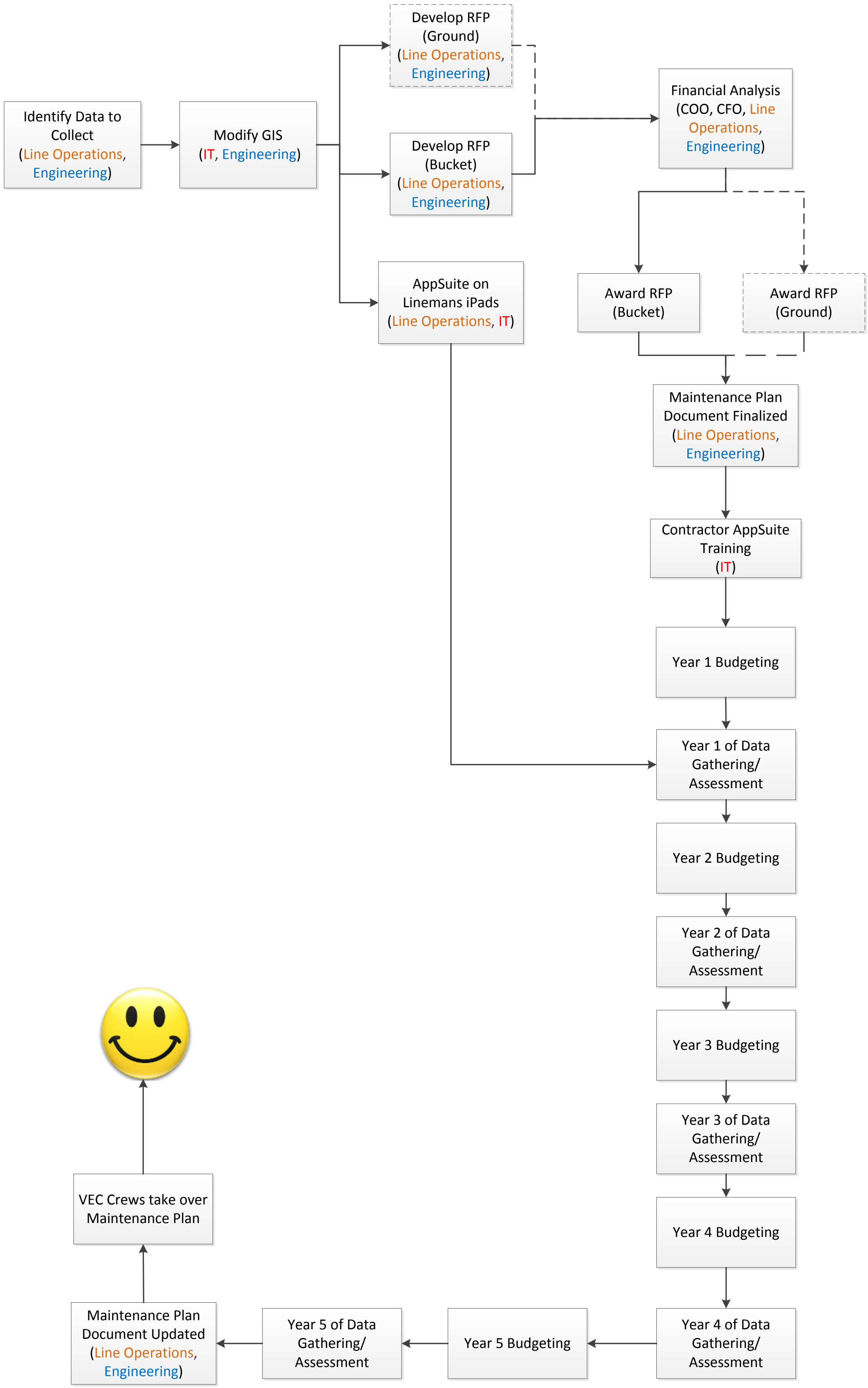
- A 5 year "System Assessment" with the goal of gathering of accurate asset data such as conductor and transformer sizes, manufacturers, serial numbers, proper phasing. The data will be populated in VEC's GIS system via NISC's AppSuite Inspections software utilizing both internal VEC personnel as well as contractors.
- An ongoing, scheduled, system-wide maintenance process on all hardware and major equipment.

This plan is updated annually during Q3 of the previous year to identify which circuits will be reviewed and also document any improvements in the plan. The objectives of VEC's electrical maintenance program include:

- Maintain VEC's electric transmission, substation, distribution, and metering system on a comprehensive schedule and scale that allows for work prioritization and changing requirements while complying with:
    - Rural Utility Service (RUS) requirements/recommendations
    - National Electric Safety Code (NESC) requirements
    - ISO-NE Regional Reliability Standards
    - Institute of Electrical and Electronics Engineers (IEEE) standards
    - American National Standards Institute (ANSI)
    - Manufacturers' recommendations
    - Prudent utility practices
    - VEC standards and operating policies
- Enhance reliability and proactively reduce preventable outages for VEC's members as measured annually by duration (SAIDI,) frequency (SAIFI,) and customer average (CAIDI) outage minutes as well as system-wide root cause analysis findings to drive maintenance and tightening programs related to VEC's worst performing circuits.
- Extend plant life of VEC's capital assets and thereby reduce upward pressure on member rates.
- Deliver accurate system data to various departments within VEC and ensure the highest level of data integrity.
- Provide a documented electric transmission, substation and distribution system maintenance policy that clearly defines VEC's system operations core business, employee expectations, and specific maintenance work functions. In addition, this program provides the information that ensures consistency across all maintenance guidelines to system operations personnel in the inspection, testing, and maintenance of VEC's electric system plant, equipment, and other facilities.
- Capture maintenance information by leveraging technology. This includes using mobile tablet devices so information can be inputted into a database by which reports can be written and other systems, such as GIS, can interface making the data useful for trending, work consolidation, understanding number and type of devices being changed, etc.

Once completed gathered data and inspection results will be provided to VEC Engineering and Operations for review. Severity ratings are used to identify conditionally poor assets with higher severity ratings applying to high risk concerns. In addition Capital Projects will be developed to replace assets as require and projects will be fed through VEC's prioritization scheme.

1.1 Overview


Identify Data to Collect (Line Operations, Engineering)
Modify GIS (IT, Engineering)
Develop RFP (Ground) (Line Operations, Engineering)
Develop RFP (Bucket) (Line Operations, Engineering)
AppSuite on Linemans iPads (Line Operations, IT)
Financial Analysis (COO, CFO, Line Operations, Engineering)
Award RFP (Bucket)
Award RFP (Ground)
Maintenance Plan Document Finalized (Line Operations, Engineering)
Contractor AppSuite Training (IT)
Year 1 Budgeting
Year 1 of Data Gathering/ Assessment
Year 2 Budgeting
Year 2 of Data Gathering/ Assessment
Year 3 Budgeting
Year 3 of Data Gathering/ Assessment
Year 4 Budgeting
Year 4 of Data Gathering/ Assessment
Year 5 Budgeting
Year 5 of Data Gathering/ Assessment
Maintenance Plan Document Updated (Line Operations, Engineering)
VEC Crews take over Maintenance Plan

1.2 Assets

- Number of Substations: 34
- Number of 12.47 kV circuits: 74
- Primary overhead line miles 2,438 miles
  - Single-phase:1,996 miles
  - Two-phase: 39 miles
  - Three-phase: 403 miles
- Primary Underground Conductor: 303 miles
- Number of transformers: ~23,000 (pole), ~2,000 (ground)
- Number of distribution poles: 55,263
- Number of transmission poles: 2,575
- Transmission line miles: 173 miles

1.3 Asset Inspection and Replacement Cycle

The following table lists out the assets that are covered in this document as well as the test or replacement cycle. It should be noted that VEC has equipment in its electric system is maintained or tested at varying frequencies some of which are on a five-year cycle. It should also be noted that assets such as distribution transformers are inspected as part of the system assessment but are not tested/inspected after the initial 5 year assessment.

Equipment Type	Test /Inspect Cycle	Tests Required
Hydraulic recloser	**Every 5 Years**	Visual inspection, testing, replacement
Line capacitors	**Annual**	Visual inspection, testing
Pad mounted transformers	**Every 5 Years**	Inspection
Fault finders	**Every 5 Years**	Replacement
Stray Voltage Checks	**Annual**	Visual inspection, testing
Distribution and transmission switches	**Every 5 Years**	Testing
Pole hardware (insulators, crossarms, etc.)	**Every 5 Years**	Inspection
Electronic recloser and relay	**Every 5 Years**	Visual inspection, testing
Breaker and relay	**Every 5 Years**	Testing
Substation transformers	**Every 5 Years**	Testing, visual inspection monthly, DGA annually
Substation batteries	**Annual**	Testing
Substation structure	**Every 10 Years**	Inspection
Substation switches	**Every 5 Years**	Testing
Substation control houses and RTU's	**Every 5 Years**	Testing
Line voltage regulators	**Annual**	Visual inspection, testing
Distribution poles	**Every 10 years**	Inspection and treatment
Transmission poles	**Every 10 years**	Inspection and treatment
Transformer rated metering	**Every 3 years**	Inspection and validation

Further details on testing and inspection requirements are provided in the Maintenance Procedures

1.4 Timeline

1.4.1 System Assessment

The following timeline indicates the rough timeline for the system assessment

Description	Timeline (by)
Identify what data to collect	**Mid-July 2018**
Attributes/Fields and modify GIS	**Early August 2018**
Develop and send out RFP for contractor	**Late August 2018**
Review bid proposals	**Early September 2018**
Develop and gain approval from Finance on ROI	**Late September 2018**
Award Contract	**October 2018**
Identify how communication from the field comes to the office with contractors (AppSuite? Verbal?)	**Late October 2018**
Finalize documentation (for fields, and for maintenance testing) and send out Maintenance plan for review	**December 2018**
AppSuite installed on all VEC line crews iPads	**December 2018**
GIS changes completed	**February 2019**
Training of Contractors via Pilot	**March 2019**
2019 Work begins, Maintenance completed	**April 2019**
2020 Work begins, Maintenance completed	**2020**
2021 Work begins, Maintenance completed	**2021**
2022 Work begins, Maintenance completed	**2022**
2023 Work begins, Maintenance completed	**2023**
Data gathering/assessment and contractor work complete	**December 2023**

While the timeline ends in 2023 VEC's maintenance plan will continue annually.

1.4.2 Distribution and Transmission Circuit Schedule

In 2018, VEC's Operations management team and Engineering personnel prioritized each of the five segments by outpost based upon historical reliability measures. Segment one is the worst performing area within each outpost and scheduled to have a "detailed transmission/distribution inspection" competed in that initial year. Segment two is the second worst performing area within each outpost and is scheduled to have a "line patrol distribution inspection" competed. Additionally, a transmission aerial inspection will be completed on the entire transmission system quarterly.

Substation	District	Timeline
Hinesburg #19	Grand Isle	**2019**
Cambridge #3, Fairfax #1	Johnson	
Sheldon #32	Richford	
Burton Hill #43	Newport	
South Hero #29	Grand Isle	**2020**
Johnson #14, St. Rocks #6	Johnson	
Richford #31	Richford	
Irasburg #42	Newport	

Future circuits are to be determined by September of the year prior to implementing the plan

1.5 Responsibilities

1.5.1 External Contract Resources

While VEC line and substation personnel are responsible for performing maintenance on the system, VEC will hire contract resources to perform a significant portion of the assessment described in the Introduction and Objectives. The contract resources will gather data on the following assets:

- Pole Inspection and Treatment
- Pole hardware and communications attachments
- Fuses/Cutouts
- Conductor
- Street Lights
- Overhead Transformers

1.5.2 Internal Resources

VEC line and substation personnel will inspect and gather the following information and perform any associated maintenance work on all identified concerns.

- Regulators (VEC substation group)
- Reclosers (VEC lineman)
- Capacitors (VEC lineman)
- Pad mounted Transformers (VEC lineman)
- Switches (VEC lineman)
- Substation Equipment(VEC substation group)
- Transformer rated metering (VEC Metering)
- Phasing
- Stray Voltage

1.6 Severity Ratings

Severity ratings are used to determine the response time and severity of an issue identified by either VEC crews or VEC hired contractor crews. The rating system is used on all assets and varies by asset. When an issue is identified it is forwarded on to the appropriate Operations Supervisor and E&O Coordinator who will generate a Maintenance type service order.

1.6.1 Severity Rating Table

The E&O coordinators will use priority codes to determine the severity of the issue that has been provided.

Priority Codes	Rating	Description	Time to Address
Low	1	Very minor condition but no immediate repairs are required at this time.	**180 days**
Normal	2	May cause a circuit outage or problem in the future	**60 days**
High	3	Likely to cause an interruption of service	**10 days**
Immediate	4	Immediate repair or replacement (this rating is used when there is an imminent threat to safety or reliability)	**1 day**

2 Maintenance Procedures – Distribution and Transmission

The next section of this document details the distribution and transmission procedures completed by VEC personnel and contractors working on behalf of VEC. It is broken out first by responsibility (VEC/Contractor) and then by asset. Each asset contains the following:

- Brief overview of the asset including:
  - What the asset is
  - Who will perform maintenance
  - How often the maintenance will be done
- Location of Associated attribute table, Inspection documentation, and CIS entry
- Test and inspection procedures, in general this includes the following:
  - Inspection - Visual and mechanical inspections shall be performed.
  - Verify/document nameplate data
  - Check that there are no broken or cracked parts or other physical damage. Check that screws are tight. This includes relays, synchronizers, cases, and covers.
  - Check devices for moisture or damage from moisture and foreign materials that could inhibit the proper operation and functioning of the devices.
  - Check for proper contact alignment and travel, disc rotation for freedom of movement, target operation, etc. Adjust mechanical alignments according to the manufacturer's specification.
- Conditions based on severity reporting as well as mitigation strategies.

2.1 Line Crew Responsibilities

2.1.1 Hydraulic Reclosers (OCR) and Trip Saver

This work is completed by the VEC Line Crew. All Districts will replace one fifth of the hydraulic reclosers within their District (Five year plan). Reclosers will be shipped to Salomon to be maintain and return to stock (Some will be retired).

When completing Hydraulic Recloser replacements VEC personnel will charge to a blanket work order and utilize the recloser change form.

In addition Trip savers will be inspected and maintained accordingly.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_overcurrent_device
- **CIS Entry-** Yes, CIS distribution equipment inventory
- **Inspection-** No

Inspection Procedure

All hydraulic reclosers will be replaced in the first 5 years of the maintenance plan. As such an inspection procedure is not required but will be developed for the next cycle. All hydraulic reclosers and trip savers should have both an inline disconnect and fused bypass per VEC standards.

2.1.2 Fuses and Cutouts

This work is completed by the VEC Line Crew. All Districts will inspect one fifth of the fuses and cutouts within their District (Five year plan).

In the event that either a broken cutout/fuse or flashover/burn marks are identified line personnel will replace the fuse/cutout and fill out the appropriate fuse form. This ensures that asset records can be updated as well as VEC's GIS.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_overcurrent_device
- **CIS Entry-** No
- **Inspection-** Yes, completed by VEC line crews

Inspection Procedure

1. Stop at each fuse
2. Inspection of fuse, identification of attributes listed in the inspection.

3. Identification of any condition based concerns (see Severity Reporting section below)
4. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Description	Rating	Time to Address
Fuse Cracked	2	**60 days**
Replace Cutout	1	**180 days**

2.1.3 Sectionalizers

This work is completed by the VEC Line Crew. All Districts will inspect one fifth of the sectionalizers within their District (Five year plan).

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_overcurrent device
- **CIS Entry-** Yes, Distribution Equipment Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each Sectionalizer
2. Inspection of Sectionalizer, identification of attributes listed in the inspection.
3. Jumper out the sectionalizer, remove cap and check for water.
4. Verify functionality of Sectionalizer
5. Identification of any condition based concerns (see Severity Reporting section below)
6. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Description	Rating	Time to Address
Sectionalizer not functional	3	**10 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order.

2.1.4 Capacitors

This work is completed by the VEC Line Crew. All Districts will inspect one fifth of the capacitors within their District (Five year plan).

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_capacitor_bank
- **CIS Entry-** Yes, Distribution Equipment Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each capacitor
2. Inspection of capacitor, identification of attributes listed in the inspection.
3. Verify functionality (is capacitor working)
4. Verify fuse is closed
5. Identification of any of any condition concerns (see Severity Reporting section below)
6. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Any condition concerns on Capacitors shall be immediately reported to VEC Engineering for further review and identification of potential capital budget impacts.

2.1.5 Switches

This work is completed by the VEC Line Crew. All Districts will inspect one fifth of the switches within their District (Five year plan).

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_switch
- **CIS Entry-** Yes, Distribution Equipment Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each switch
2. Inspection of switch, identification of attributes listed in the inspection.
3. Verify grounding
4. Verify blade seating properly
5. Check switch handle
6. Lubricate Pivot Points
7. Remove Nests/Sticks/Bee Hives
8. Test switch operation
9. Identification of any of any condition concerns (see Severity Reporting section below)
10. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Any condition concerns on Capacitors shall be immediately reported to VEC Engineering for further review and identification of potential capital budget impacts.

2.1.6 Fault Indicators

This work is completed by the VEC Line Crew. All Districts will inspect and replace if needed one fifth of the fault indicators within their District (Five year plan).

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_fault_indicator
- **CIS Entry-** Yes, Distribution Equipment Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each fault indicator
2. Inspection of fault indicator, identification of attributes listed in the inspection.
3. Verify manufacturer year, if greater than 2 years replace
4. Add coop number
5. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

2.1.7 Pad Mounted Transformers

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_transformer
- **CIS Entry-** Yes, Transformer Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each padmount transformer
2. Inspection of padmount and identification of attributes listed in the inspection.
3. Check arrestor installation
4. Check for rust holes
5. Check padmount labels
6. Check transformer connections
7. Very condition of ground connections
8. Check vault condition
9. Check for oil leaks

10. Check hinged condition
11. Check Elbow Condition
12. Remove obstructions if applicable.
13. Verify coop number
14. Take photo of nameplate
15. Take photo of transformer in location
16. Identification of any of any condition concerns (see Severity Reporting section below)
17. Verify Labeling - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Description	Rating	Time to Address
Oil leak	4	**1 days**
Broken bushing	4	**1 days**
Broken/blown lightning arrestor	3	**10 days**
Other transformer condition	2	**60 days**
Obstruction follow-up	1	**180 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order or work order.

2.1.8 Underground Conductor

This includes all primary underground conductor on VEC's system. **This work is done by VEC during the first 5-year cycle and will be done in tandem with the vault and padmounted transformer inspection**

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_span
- **CIS Entry-** No
- **Inspection-** Yes, completed by VEC

Test Procedure

1. Stop at each underground location
2. Inspection of underground conductor and identification of attributes listed in the inspection.
3. Identification of any of any condition concerns (see Severity Reporting section below) Photos and documentations showing all NESC violations. These photos shall be uploaded to DocVault via AppSuite Inspections

Severity Reporting

Description	Rating	Time to Address

Underground failure	4	**1 days**

If any of the above items are found the control center should be contacted.

2.1.9 Vaults

This includes all primary underground conductor on VEC's system. **This work is done by VEC during the first 5-year cycle and will be done in tandem with the underground conductor and padmounted transformer inspection**

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_surface_structure
- **CIS Entry-** No
- **Inspection-** Yes, completed by VEC

Test Procedure

1. Stop at each vault
2. Inspection of vault identification of attributes listed in the inspection.
3. Very condition of ground connections
4. Check vault condition
5. Check hinged condition
6. Check Elbow Condition
7. If no cabinet, verify if cover is secure
8. Remove obstructions if applicable.
9. Take photo of vault in location
10. Identification of any of any condition concerns (see Severity Reporting section below)
11. Verify Labeling - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Description	Rating	Time to Address
Cracked elbow	4	**1 days**
Water drainage needed	1	**180 days**
Other condition of concern	1	**180 days**
Obstruction follow-up	1	**180 days**

2.1.10 Stray Voltage

This work is completed annually by the VEC Line Crews and results are review by Engineering

VEC inspects all active farms within its service territory for stray voltage including all locations that have active neutral separation as well. A list of all farms on VEC's system is available in NISCs CIS via the service description field.

This list is updated every time a new account is added or when a stray voltage issue is identified. The VEC E&O Coordinator will add "STRAY" to the service location description field.

This list is reviewed annually by the E&O Coordinator to ensure that VEC has captured all of the potential stray voltage locations in the system. ***For specific information on tests please see the latest version of VEC's Stray Voltage Policy***

2.2 Contractor Responsibilities

2.2.1 Poles and Attachments

This work is done by Contractors during the first 5-year cycle. For more information VEC's pole inspections see the Pole Inspections and Treatment section of this document.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_support_structure
- **CIS Entry-** No
- **Inspection-** Yes, completed by Davey

Test and Inspection Procedure

12. Stop at each structure
13. Inspection from ground of pole, attachments and hardware of the items listed in the inspection.
14. Identification of any of the following concerns (see Severity Reporting section below)
    - Pole Ground rot
    - Pole broken
    - Pole leaning
    - Pole washing out
    - Woodpecker holes
    - Evidence of flashover
    - Severe pole damage
    - Damage to pole by snowplows/vehicles/etc.
    - Pole top rotted
    - Fill ground level
    - Missing pole ground
    - Missing guy guard
    - Missing guy
    - Broken guy
    - Attachment NESC violation
    - Broken cross arm
    - Burnt cross arm
    - Broken cross arm brace

- Broken Insulator
- Lightning arrestor not attached
- Broken/blown lightning arrestor
- Verify that cross arms are solid and straight
- Rotten/corroded anchor
- Damaged riser
- Broken riser standoff

15. Clear photos without obstructions of each pole tag as well as the associated VEC's equipment and attachments on the pole. These photos shall be uploaded to DocVault via AppSuite Inspections
16. Photos and documentations showing all NESC violations. These photos shall be uploaded to DocVault via AppSuite Inspections
17. Pole markings - See VEC standard for pole Markings in VEC's Transmission and Distribution Standards Manual

Severity Reporting

Description	Rating	Time to Address
Ground rot	2	**60 days**
Pole broken	4	**1 days**
Pole leaning	1	**180 days**
Pole washing out	2	**60 days**
Woodpecker holes	1	**180 days**
Evidence of flashover	3	**10 days**
Severe pole damage	3	**10 days**
Damage to pole by snowplows/vehicles/etc.	1	**180 days**
Pole top rotted	2	**60 days**
Fill ground level	1	**180 days**
Missing pole ground	2	**60 days**
Missing guy guard	2	**60 days**
Missing guy	2	**60 days**
Broken guy	2	**60 days**
Attachment NESC violation	2	**60 days**
Broken cross arm	2	**60 days**
Burnt cross arm	2	**60 days**
Broken cross arm brace	2	**60 days**
Broken Insulator	3	**10 days**
Lightning arrestor not attached	2	**60 days**
Broken/blown lightning arrestor	3	**10 days**
Rotten cross arm	2	**60 days**
Rotten/corroded anchor	2	**60 days**
Damaged riser	2	**60 days**
Broken riser standoff	2	**60 days**

Missing Communication guy	1	**180 days**
Pulled Anchor	1	**180 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order or work order.

2.2.2 Pole Inspection and Treatment

VEC pole inspection and treatment program is performed on a ten year cycle for distribution poles and once every ten years for transmission poles. These timelines are in line with RUS Bulletin 1730B-121. VEC's program consists of ground line inspection, treatment 18" below ground level and internally (Mitci-Fume), visual inspection of above ground condition and other maintenance work such as replacing missing guy guards and pole numbers.

VEC's joint ownership agreement with Consolidated Communications identifies set and maintenance areas. VEC inspects all of its sole owned distribution poles across the system as well as the joint owned poles with Consolidated in VEC's maintenance area. Consolidated Communications is responsible for pole inspection of joint owned poles in their maintenance area.

Any reject poles are replaced within twelve months of the pole inspection.

VEC does not maintain or inspect "tree poles" as part of its pole inspection process. While a tree pole is not a clear violation of NESC, it is the responsibility of VEC to maintain in a safe manner. VEC will visit these locations periodically to determine their adequacy to hold the lines up under expected and normal conditions. If replacement is required, VEC will work with the member to eliminate these types of poles.

A schedule for pole inspections is listed in the Annual Checklist section of this document.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_support_structure
- **CIS Entry-** No
- **Inspection-** Yes, completed by Smith Mountain

Test and Inspection Procedure

1. Stop at each structure
2. Sound and Bore.
    - Hammer each pole at ground level to six feet
    - If voids are discovered a shell thickness indicator shall be used to measure them
3. If concerns exist
    - Excavate to a depth of 18 inches and scrape pole clean to detect early surface decay.
    - Apply a preservative treatment
    - The pole shall then be backfilled and the dirt should be tamped firm every 6 to 8 inches.
    - The backfill should mound up around the pole to allow for future settling and drainage away from the pole

- Internal treatment will be completed if a void is present and

4. Inspection from ground of pole of the items listed in the above section
5. Identification of any of the following concerns (see Severity Reporting section below)
    - Priority Reject –
        - Less than 1 inch of pole shell remaining and less than 50% of good wood.
        - Decay, insect or mechanical damage has reduced pole strength at the groundline below code requirement.
        - Hazardous conditions exist above ground, such as split top
        - Severe woodpecker hole damage has weakened the pole below safety standards.
        - A priority reject shall not be climbed and needs to replaced immediately
    - Replace Pole –
        - Greater than 1 inch of pole shell remaining (greater than 50% of good wood remaining) but less than 2 inches of pole shell (less than 67% of good wood remaining)
        - Should be replaced within 12 months.
    - Reinforceable Reject –
        - A "reinforceable reject" is a replace pole which is suitable for restoration of the groundline bending capacity with a method of reinforcement. In general VEC will treat these as a replace pole.
    - Missing pole ground
    - Missing guy guard
    - Missing guy
    - Broken guy
6. Marking of reject poles and priority reject poles per VEC Standard 205 – Pole Inspection Markings
7. Clear photos without obstructions of each pole tag as well as the associated VEC's equipment and attachments on the pole. These photos shall be uploaded to DocVault via AppSuite Inspections

Severity Reporting

Description	Time to Address	VEC Action
Priority Reject	**30 days**	Open a OSMOSE POLE Service Order
Reinforceable Reject	**360 days**	Open a REPLACE POLE Service Order
Replace Pole	**360 days**	Open a REPLACE POLE Service Order
Missing pole ground	**360 days**	Open a OSMOSE MAINTENANCE Service Order
Missing guy guard	**360 days**	Open a OSMOSE MAINTENANCE Service Order
Missing guy	**360 days**	Open a OSMOSE MAINTENANCE Service Order
Broken guy	**360 days**	Open a OSMOSE MAINTENANCE Service Order

The pole inspection contractor sends reports to System Engineering. System Engineering reviews these reports and forwards on to the appropriate Operations Supervisor and E&O Coordinator to generate Work/Service Orders to complete the work

2.2.3 Overhead Transformers

<u>This work is done by Contractors during the first 5-year cycle.</u>

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_transformer
- **CIS Entry-** Yes, Transformer Inventory
- **Inspection-** Yes, completed by VEC line crews

Test Procedure

1. Stop at each overhead transformer
2. Inspection of padmount identification of attributes listed in the inspection.
3. Take photo of nameplate
4. Take photo of transformer in location
5. Identification of any of any condition concerns (see Severity Reporting section below)

Severity Reporting

Description	Rating	Time to Address
Oil leak	4	**1 days**
Broken bushing	4	**1 days**
Broken/blown lightning arrestor	3	**10 days**
Other transformer condition	2	**60 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order or work order.

2.2.4 Overhead Conductor

This includes all primary overhead conductor on VEC's system. **This work is done by Contractors during the first 5-year cycle.**

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_span
- **CIS Entry-** No
- **Inspection-** Yes, completed by Davey

Test Procedure

18. Stop at each span
19. Inspection of conductor and identification of attributes listed in the inspection.

20. Identification of any of any condition concerns (see Severity Reporting section below)

Severity Reporting

Description	Rating	Time to Address
Insufficient clearance	2	**60 days**
Sag	2	**60 days**
Damaged primary	3	**10 days**
Damaged neutral	3	**10 days**
Bird caging at splice	2	**60 days**
Phase wire off pin	4	**1 days**
Phase wire on ground	4	**1 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order or work order. For communications violations or concerns the Utility Joint Use Coordinator should be contacted.

2.2.5 Street Lights

This work is done by Contractors during the first 5-year cycle.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_span
- **CIS Entry-** Yes,
- **Inspection-** Yes, completed by Davey

Test Procedure

1. Stop at each streetlight
2. Inspection of streetlight
3. Take photo of streetlight in location
4. Identification of any of any condition concerns (see Severity Reporting section below)

Severity Reporting

Description	Rating	Time to Address
Damaged streetlight	3	**10 days**

If any of the above items are found an E&O Coordinator should be contacted and they will generate a Maintenance type service order or work order.

2.3 Substation Group Responsibilities

2.3.1 Electronic Reclosers (Line)

This work is completed by the VEC Substation Crew. Electronic Reclosers that are outside VEC's substations and on VEC transmission taps are inspected on a 5-year cycle.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_overcurrent_device
- **CIS Entry-** Yes, Distribution Equipment Inventory (separate entry for relay and recloser)
- **Inspection-** Yes, completed by substation group

Test Procedure Cooper VWE / VWVE38X

1. Stop at each electronic recloser
2. Inspection of fuse, identification of attributes listed in the inspection.
3. **Doble:** Perform the test to Doble standards using their software.
    a. Results: Compare to Doble expected results and compare to other units in service
4. **Oil Dielectric Test**: Test oil from near bottom of tank before any filtering and determine breakdown strength. If not a minimum of 22KV (cooper guideline) filter oil and retest continue filtering until a minimum of 22KV is obtained.
5. **Micro- Ohm**: With the breaker closed micro-ohm each phase at 200A to determine contact resistance, should be less than 200u Ohms.
6. **AC High Pot Test:** Follow Cooper test guideline in the VWE maintenance manual (S280-40-6) perform test at 75% of rated withstand voltage level for one minute. VWE 37.5Kv
7. Follow Cooper Maintenance Manual S280-40-6 for the operational tests, bushing inspection and closing coil checks.
8. Photo of Recloser
9. Photo of Relay
10. Identification of any of any condition concerns (see Severity Reporting section below)

Test Procedure for ABB OVR

1. Stop at each electronic recloser
2. Inspection of fuse, identification of attributes listed in the inspection.
3. **Doble:** Perform the test to Doble standards using their software.
    a. Results: Compare to Doble expected results and compare to other units in service
4. **Micro- Ohm:** With the breaker closed micro-ohm each phase at 200A to determine contact resistance, should be less than 150u Ohms.
5. **AC High Pot Test:** Need to investigate what ABB recommends for High Pot test voltage and procedure.
6. Follow the ABB Service Manual for the operational tests.
7. Photo of Recloser
8. Photo of Relay

9. Identification of any of any condition concerns (see Severity Reporting section below)

G&W Viper ST and S Tests

1. Stop at each electronic recloser
2. Inspection of fuse, identification of attributes listed in the inspection.
3. **Doble:** Perform the test to Doble standards using their software.
    a. Results: Compare to Doble expected results and compare to other units in service
4. **Micro- Ohm:** With the breaker closed micro-ohm each phase at 200A to determine contact resistance, should be less than 200u Ohms.
5. **AC High Pot Test:** Follow G&W recommendations for high pot test in their maintenance manual, located with each new breaker.
6. Follow G&W service manual for the operational tests.
7. Photo of Relay
8. Photo of Recloser
9. Identification of any condition based concerns (see Severity Reporting section below)

Severity Reporting

Any condition concerns on electronic reclosers shall be immediately reported to VEC Engineering for further review and identification of potential capital budget impacts.

2.3.2 Line Regulators

This work is completed by the VEC Substation Crew. Line regulators are inspected annually.

Asset Information

For more information on asset data, attribute tables, and entry into VEC's CIS system please see the Data Dictionary SharePoint Site

- **GIS Attribute Table-** gs_regulator
- **CIS Entry-** Yes, Distribution Equipment Inventory
- **Inspection-** Yes, completed by substation group

Test Procedure

It should be noted that the electric industry, as a whole, does not have a standard when a utility should conduct maintenance on their voltage regulators and the range of cycles acceptable to do that maintenance also varies greatly. When considering these factors, VEC has looked to manufacturers' recommendations as well as engineering best practices when developing this program.

1. Stop at each electronic recloser
2. Inspect physical and mechanical condition
3. Inspect anchorage, alignment, and grounding
4. Perform inspection and gather data as prescribed in the Inspections section above
5. Verify auxiliary device operation.
6. Verify correct liquid level in all tanks
7. Update panels, software, and firmware (e.g., Cooper CL-6B)

8. Photo of regulator
9. Identification of any condition concerns (see Severity Reporting section below)

Severity Reporting

Any condition concerns on Line Regulators shall be immediately reported to VEC Engineering for further review and identification of potential capital budget impacts.

2.3.3 KCW Infrared Testing

VEC conducts quarterly infrared inspections on the Kingdom Community Wind (KCW) transmission line at peak times of generation.

These inspections are coordinated by the Manager of Service Operations and Line Operations and are performed by Infrared Analyzers who specialize in this type of testing. This inspection makes use of infrared thermography which detects differences in temperature with sensitive, non-contact, non-destructive electronic equipment and converting the infrared energy into a video image.

The thermo-graphic images in the report show the temperature difference between the areas of concern/deficiency and corresponding reference ("normal") areas. However, temperature variances alone do not necessarily indicate the severity of the issue. The importance of each potential issue is reviewed within the framework of the system as a whole and the resulting report assists with the process of properly identifying area of potential maintenance or replacement. VEC utilizes the infrared criteria from 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

A report is provided by the external contractors with results and analyzed by VEC's Manager of Engineering and Manager of Service Operations.

2.4 Joint Engineering, Substation Group and GIS Responsibilities

2.4.1 Phasing

As part of the first 5 years of the maintenance plan a review of existing phasing will occur. By the end of each calendar year the maintenance plan circuits will have phasing that is consistent with VEC system phasing as determined by the EDM Phase Trakker.

In order to achieve this substation personnel will work with engineering to label and match substation distribution bus phasing to the VEC standard phasing as determined by the EDM Phase Trakker. This will involve:

- Utilization of Avistar phasing device to identify VEC standard system phasing
- Matching of AMI phases to VEC Phasing
- SCADA updates to RTU's at substations and generator sites (if needed).

In order for VEC GIS to match the substation and therefore VEC standard system phasing VEC AMI will be used to identify the correct phase on each circuit. The GIS department will need to update these phases in VEC's GIS system which will automatically update connectivity in OMS.

2.5 Metering Department Responsibilities

2.5.1 General Metering

When completing meter testing and verifications, VEC personnel will charge to GL account 586.00 for meter testing, communications, inspection and maintenance and 107.20 for new meter installations as follows:

10720	CONSTRUCTION LABOR	2018GEN	ALF self-contained (1S, 2S)
10720	CONSTRUCTION LABOR	2018GENDIS	AXR-SD self-contained w/disconnect
10720	CONSTRUCTION LABOR	2018COMM	Commercial meters (3S,4S,9S,12S,16S)
10720	CONSTRUCTION LABOR	2018IND	Industrial Meters (Nexus, Shark)

2.5.2 Meter Testing Standards

The formal regulations that VEC's meter testing and verification program must conform to:

VEC Schedule of Electric Rates and Rules Governing Service
https://www.vermontelectric.coop/images/pdf/vec-tariff-effective-01-01-2017.pdf

Specifically, (at Original Sheets #7 &8):

MEASURING OF SERVICE

a. All energy sold to customers and all energy consumed by the Cooperative, except that sold according to fixed charge schedules, shall be measured by commercially acceptable measuring devices owned and maintained by the Cooperative except where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the Board.

b. If any meter after testing is found to be more than four percent (4%) in error, either fast or slow, proper correction of the error shall be made of previous reading and adjusted bills shall be rendered for a period of up to one year immediately preceding the removal of such meter from service for test or from the time the meter was in service since last tested, but not exceeding one year since the meter shall have been shown to be in error by the test.

c. No adjustment shall be made by the Cooperative except to the customer last served by the meter tested.

d. A Meter Test Fee will be required for performing a second meter test on the same meter within a one-year period. The fee will be based on time to travel and perform the test at $90.00 per test. The fee will be refunded if the meter proves inaccurate by greater than plus or minus four percent (4%).

VEC's internal standard for meter accuracy shall be +/-2%. Target calibration, where applicable, shall be +/-0.5%. Unless stated elsewhere in this document, VEC's Meter Testing and Verification program will verify meter accuracy according to:

1. ANSI for Electric Meters Code for Electric Metering (ANSI C12.1)
2. American National Standard Sampling Procedures and Tables for Inspection by Variables for Percent Non-Conforming (ANSI/ASQ Z1.9-2008) for sampling

2.5.3 Meter Testing

VEC will meet the following qualifications:

1. 100% testing of all meters by the manufacturer prior to shipment to VEC. Testing information will be loaded into VEC's billing system for historical reference;
2. Quality assurance testing of any reconditioned meters by VEC personnel before initial installation;
3. Random testing of 10% of meters on all route audits (self-contained, 1S, 2S, 12S, 16S);
4. Ability to monitor all in-service meters for performance through daily reads;
5. Ability to monitor customer usage abnormalities on a route cycle basis (CIS, by query);
6. Random sample testing of meters after ten years in service.
7. Unless otherwise stated, the weighted average test results shall be calculated using the formula: [4HL + 2 LL + PF] / 7.
8. New CT/PT metered services shall be inspected within six weeks of the date of the installation, and the work shall be assigned to a Meter Technician other than the primary Technician responsible for the original install.
9. Meter test results shall be shared with the member on-site if the member is present, but a copy of the results shall subsequently be provided in written form.
10. Whenever possible, meters shall be tested on-site and in their existing socket.

2.5.4 Frequency of Meter Testing

Periodic breakdown for meter testing and verification will consist of the following in order to meet the qualifications and regulations stated earlier in this document:

1. VEC's Key Accounts, consisting of approximately 12 of the largest retail Industrial accounts served shall be tested biennially. Testing shall include the entire meter package, in parts, or in whole, and test results for these metering points will also be tested with test results stored in the NISC CIS system.
2. All single-phase and three-phase demand billed accounts including instrument rated metering accounts will be tested and verified at least once every three years. For 2018, this accounts for approximately 172 meter tests/verifications. Testing shall include the entire meter package, in parts or in whole, and test results for these metering points will be stored in the NISC CIS system.
3. All other CT metered services shall be tested every six years.
4. A 10% random sampling of meters shall be conducted during all scheduled route audits for all other meters and forms (specifically 1S, 2S,12S, and 16S), unless the area is part of an active scheduled meter replacement initiative.
5. Non-revenue substation and tie-point meters, as well as any SPEED Standard Offer (aka VT's feed-In tariff) metering shall be tested every five years. Non-revenue "own-use" and station service metering, if unique from generation, shall be tested every eight years.

Service Orders are generated out of information currently residing in VEC Customer Information System (CIS.) After field information is gathered/verified, VEC's billing system is matched/updated with all appropriate information.

2.5.5 Field Meter Testing and Verifications

When completing field meter test and verifications, VEC personnel will charge to GL account 586.00. For field meter tests and verifications, the following information will be gathered or verified:

- Meter number
- Secondary meter number
- Meter type
- Register type
- Number of wires
- Manufacturer
- NEMA form
- Class
- Test Amps
- Volts
- Base Kh
- Seal (Y/N)
- Billing multiplier
- Present reading
- Demand reading
- Power factor
- Service Address
- Transformer capacity, if available
- Date of test/verification
- Technician name

2.5.6 Instrument Rated Metering

When completing instrument-rated meter package tests and verifications, VEC personnel will charge to GL account 586.00. For field meter tests and verifications, the following information will be gathered or verified:

- PT number
- System voltage
- Ratio
- Accuracy Class
- Fused (yes/no)
- Service Address
- Date of test
- Technician name
- CT number
- System voltage
- Ratio
- Accuracy
- Brand
- Accuracy Class
- Service Address
- Date of test
- Technician name

2.5.7 Other Standards

In addition to the specifications above for the standards, VEC will also perform the following inspections, and assessment of the meter conditions:

General Inspection: observe meter environment and overall condition, including but not limit to:

- signs of heat or arching,
- meter display register (e.g. missing segments, discoloration),
- cracks in the meter face or housing,
- water/salt/ice damage,
- unprotected wires,
- broken conduit,
- unsecured meter socket,
- signs of tampering
- physical damage

1. The Meter Technician shall use best judgement, but the attached guide shall otherwise be used as a guide in determining the severity of risk for various issues, and as a guide for new meter installs. Substandard member service procedures are addressed elsewhere.

2. All meter bases that have a “push button” type of bypass disconnect will be replaced with one that has a lever type bypass disconnect.
3. All services which contain a secondary lightning arrestor will have the lightning arrestor removed and the hole to the meter base filled appropriately.
4. When doing a meter test or verification, test and/or replace batteries, if applicable. Upgrade meter firmware where applicable, or replace meter with reprogrammed meter.

3 Substation

3.1 Monthly Substation Inspections

- **Physical Yard Inspection –** Includes Fence, signage, locks, grounds, switch sticks, and lights
- **Structure Condition-** Check poles, wood and steel structures for condition
- **FR Cabinet inspection –** Includes Tags, Switching Pad, Heater, Shield, Jacket, Silicon Wipes
- **Insulator Check-** Insulators, switches, and bushings checked for chips and cracks
- **Switch Locking and Position –** Verify switches fully open/closed, locked
- **Control House Check-** Control House HVAC, Fire Extinguisher, eye wash, emergency lights, cleanliness, rodents, switching gear, tags, switching pad.

When completing monthly transmission substation inspections, VEC personnel will charge to GL account 592 VEC has 32 Distribution Substations, 3Sub transmission switching substations with 46kv breakers, and 5 distribution metering points. When completing monthly distribution substation inspections, VEC personnel will charge to GL account 582.

A visual inspection of all substations will be made each month utilizing VEC’s Monthly Substation Inspection Form. The visual inspection will include those items on the substation inspection form as specified in RUS Bulletin 1730-1. Any issues found will be fixed or corrected by the crew at the time of inspection, if possible. Any issues found that are not in danger of causing an outage but cannot be addressed while the substation is energized, will be noted on the inspection form and a service order will be created by the VEC Dispatch group and assigned to the Manager of Service Operations for scheduling. These will either be addressed at the next schedule substation outage, a special substation outage, or during the Detailed Substation Maintenance. Finally, any issues found that are in danger of causing an outage will be scheduled, in coordination with the Manager of Service Operations, within 30 days of the inspection.

The following guideline constitutes a monthly substation inspection.

- List date, time, substation number, inspector and outpost
- Transformer (all phases)
  - Winding temperature
  - Oil temperature
  - Nitrogen pressure
  - Nitrogen bottle
  - Ambient temperature
- Regulators (all phases)

    - Counter reading
    - Max boost
    - Min buck
    - Load indicator
    - Volts
    - Amps
    - Max amps
    - High voltage
    - Low voltage
    - Note any alerts or alarms
- Reclosers (all circuits, all phases)
    - OCR number
    - Amps
    - Operations (OP) counter
    - Target counter
    - Electronic reclosers
        - Reset OP and target counters (yes/no)
        - Battery test (pass/fail)
        - Lamp test (pass/fail
- Battery charger
    - Voltage
    - Amps
    - Target LED (yes/no)
- Breaker/circuit switcher (for each breaker/circuit switcher)
    - Number
    - Counter
    - Open/Closed
    - Note oil or gas levels
- Capacitors (testing of the capacitor control relay will be performed during five-year detailed testing)
    - Inspect capacitors and relays for any abnormalities/alarms
    - Check individual fuse for each bank

For each of the above apparatus the following visual inspections will be made, as appropriate, and specifically noted on the Monthly Substation Inspection Form according to RUS Bulletin 1724E-300 and NESC Code Part I: Rules for the Installation and Maintenance of Electrical Supply Stations and Equipment Sections 10 through 19:

- Review overall external condition of the apparatus
    - Oil leaks
    - Excessive rust
    - Unusual sounds, vibrations, odors
    - Nitrogen levels
- Check and document condition of bushings
    - Broken or cracked porcelain
    - Oil leaks
    - Oil levels
    - Burn marks or other indications of tracking
    - Proper grounding
- Check and document condition of lightning arrestors
    - Broken or cracked porcelain
    - Oil leaks
    - Burn marks or other indications of tracking

    - Proper grounding
- Verify and document oil levels and measures
    - Tank
    - Load and no load tap changers
    - Oil and winding (“hot spot”) temperature gauge readings
- Check and document readings of inert air system including spare nitrogen cylinders
- Check and document condition of cooling equipment
    - Radiators
    - Fans
    - Controls
- Review and document the condition of all pressure relief devices
- Review and document condition of buss work
- Review and document condition of disconnect switches
    - Verify that they are tagged
    - Verify that they are clearly marked/identified
- Review and document condition/type of fuses

3.2 Annual Substation Testing

3.2.1 Substation Infrared Inspection

Substation infrared inspections are performed on the VEC substation apparatus (e.g. reclosers, switches, transformer and voltage regulators) and, switches, SCADA operable devices (e.g., switches) twice per yea, typically in July and December

These inspections are coordinated by the Manager of Service Operations and are performed by Infrared Analyzers who specialize in this type of testing. This inspection makes use of infrared thermography which detects differences in temperature with sensitive, non-contact, non-destructive electronic equipment and converting the infrared energy into a video image. Since infrared energy is a direct and proportional function of temperature, the video image is designed to depict various shades of gray or color to indicate a difference in temperature levels. In color mode, lighter shades correspond with higher temperatures. In black and white mode, darker shades of gray correspond with lower temperatures, and lighter shades of gray or white correspond to higher temperatures; referred to as “hot spots.” The thermal-graphic information can be used to help solve a variety of issues and, in many cases, allow technicians to mitigate an issue before a failure occurs.

The thermo-graphic images in the report show the temperature difference between the areas of concern/deficiency and corresponding reference (“normal”) areas. However, temperature variances alone do not necessarily indicate the severity of the issue. The importance of each potential issue is reviewed within the framework of the system as a whole and the resulting report assists with the process of properly identifying area of potential maintenance or replacement. VEC utilizes the infrared criteria from 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

A report is provided by the external contractors with results and analyzed by VEC's Manager of Engineering and Manager of Service Operations. Corrective action is planned/implemented based on the Repair Priority and system outage impact.

3.2.2 Substation Transformer DGA Testing

Substation transformer oil samples are drawn twice per year and sent to SD Meyers for Dissolved Gas Analysis (DGA). The rainbow reports provided by SD Meyers are reviewed in accordance with IEEE C57.139 by the Manager of Engineering. Based on these test results recommendations are provided to the Manager of Service Operations.

3.2.3 Station Battery and Charger Tests

Batteries are tested annually for their specific gravity, strap resistance and voltage.

- **Check Batteries-** Check charger, leaks, corrosion, heaters, and fluid level

Annual Station Battery and Charger Tests are scheduled by the Manager of Service Operations and conducted By the substation crew. The tests include:

- Battery Cell Testing (stationary systems) based on IEEE 1188
  - Total system voltage
  - Charger output current
  - Ambient temp ventilation
  - Visual inspection
  - Post temperature of negative cell (5% of all)
  - Post temperature of negative cell (all for telecommunications)
  - Negative and positive buss temperature for telecommunications
  - Fastener torque values, once @ 2 years
  - Volts to ground (positive and negative)
  - Cell internal mhos readings conductance (replaces resistive tests) and voltages
  - Intercell connector conductance
  - Detailed internal visual inspection
  - AC ripple current and voltage
  - Thorough external cleaning

VEC Manager of Service Operations will review all reports that are written as part of the maintenance during the year, findings and recommendations for mitigation. VEC's Manager of Service Operations will be responsible to ensure issues and recommendations are completed through the proper scheduling to make any repairs necessary.

For the larger distribution and all transmission level substations, batteries for the SCADA, relay, and other controls are in an environmentally controlled space and are specifically designed for the load that is required. These will be tested according to engineering specifications for that application. However, for smaller distribution substations (e.g., Adon, Gap, etc.) the batteries used are "off-the-shelf" telecom batteries, sized for very light loads, and not currently stored in environmentally controlled areas. These batteries are subjected to severe temperature variations and a subject to failure rates much higher than manufacturer recommendations. An environmentally controlled unit will be installed for all 19-inch rack enclosures as part of the Detailed Substation Inspection for these smaller distribution substations as part of the 5-year maintenance cycle. Battery blankets will not be used for this purpose and will be removed if found.

3.2.4 Non-Native Invasive Species Monitoring

For some substations a post-construction survey for invasive plant species is required by the Certificate of Public Good ("CPG") issued by the Public Service Board ("PSB," now the Public Utility Commission) and described in the associated "OHM, Decommission, and Reclamation Memorandum" ("Plan")

The following substations have this requirement:

- Cambridge 03
- Madonna 15
- South Alburg 28
- East Berkshire 30

This is the responsibly of the ROW and Environmental Associate.

3.3 5-Year Substation Testing

3.3.1 Substation Transformers

When completing power transformer maintenance on distribution substations, VEC personnel will charge to GL account 592.

The following testing is conducted 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, oil levels in the transformer will be inspected and oil added as necessary. This will include replacing the nitrogen once refilling has been completed.

Substation Transformers are tested every 5 years the tests include: Power Factor Test (DOBLE), Insulation Resistance Test (Megger test), SFRA Sweep Frequency Reponse Analysis test (Doble),Transformer Turns Ratio Test (TTR) and visual Inspection. A Dissolved Gas Analysis (DGA) test is performed annually along with moisture content and other oil tests.

- **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

3.3.2 Substation Regulators

When completing voltage regulator inspections on distribution substations, VEC personnel will charge to GL 592.20 for distribution substations.

Maintenance and inventory documentation on all regulators will be stored in the CIS database. In this manner, Service Orders can be automatically created and information updated to ensure the status, location, and inventory of each voltage regulator is always current. As of November 2018, there were 84 Line Voltage Regulators and 101 Substation Voltage Regulators. There were also approximately 36 Voltage Regulators in stock.

It should be noted that the electric industry, as a whole, does not have a standard when a utility should conduct maintenance on their voltage regulators and the range of cycles acceptable to do that maintenance also varies greatly. When considering these factors, VEC has looked to manufacturers' recommendations as well as engineering best practices when developing this program. Refer to the Cooper Regulator Manual S225-10-10.

The main maintenance provider of VEC's voltage regulators is Solomon Corporation based in Solomon, KS. They service 38.1 to 833 kVA and from 2,400 to 24,940 volt regulators. It should be noted, as a "rule-of-thumb," if a repair or maintenance to a voltage regulator is more than 30% the cost of a new regulator, Solomon will recommend the purchase of a new regulator. This should be used as a guide in deciding when to purchase new regulators or continue with the maintenance and/or repair of an older regulator.

As per general manufacturer recommendations regarding voltage regulators, whether within a VEC substation or on a VEC line, will be removed from service and receive maintenance at the following intervals:

1. Voltage regulators which have reached 200,000 operations or ten (10) years in service for those regulators loaded to 50% or less of nameplate rating.
2. Voltage regulators which have reached 100,000 operations or five (5) years in service for those regulators loaded to more than 50% of nameplate rating.
3. During monthly substation inspections, raise and lower drag hands 1 or 2 positions both directions as described in the above Section 3.1.1 to ensure regulator is functioning properly.
4. If the regulator will not operate properly, change the control panel and verify the new to the old panel (side-by-side) before removing the unit from service.

When regulators are removed from service for maintenance, the company authorized to un-tank the unit will conduct the following work on the voltage regulator listed below, including replacing parts as required:

Fix existing issues if known. Linemen and Servicemen should leave a note with the voltage regulator about the location (substation or line GPS coordinates) the regulator came from, any maintenance issues, and contact information if further questions from the repair personnel should arise.

- Update panels, software, and firmware (e.g., Cooper CL-6B)
- Change to longer cords
- Move internal capacitors to control box
- Check and repair internal contact erosion

- Check and repair internal tracking
- Check and repair packing insulation (e.g., cores, coils, coil clamps, etc.)
- Check and repair leaks and bad welds
- Test oil for dielectric and moisture
- Hardware tightening
- If regulator has a spring drive, inspect holding switches, springs, and 'E' clips
- If regulator has a direct drive, inspect holding switches and 'E' clips
- Check for PCB's if no sticker is present, update information on regulator (external tag) when PCB's are adjusted
- Repaint regulator (e.g., rust spots)

Note: When replacing or updating a panel in the field or when brought in for maintenance, ensure the counter reading is programmed or left with counter reading when the voltage regulator was removed from service. This is important so the age and in-service date of the regulator can be determined for future maintenance.

Repair or inspections should include the items listed above but other items may be added as necessary.

3.3.3 Relay and Breaker System Protection

Any and all event reports from the relays under test shall be stored with the detailed substation test results.

VEC's protection system maintenance and testing program focuses on testing to verify that the functional performance of the protection system equipment is operating within manufactures' design specifications throughout the service life. All maintenance and testing intervals are based on manufacturer's recommendations, industry standards (where applicable), and prudent utility practices.

The protection system maintenance and testing program is condition based maintenance with scheduled interval maintenance, tests, and system operation evaluations. Where equipment calibration is verified, performance is tested and results are documented.

All relay operations under fault conditions are evaluated by the Control Systems Engineer for proper operation. Any protection system element suspected of not operating correctly is removed from service, the settings are checked and additional performance testing and maintenance is conducted. Repair or replacement of the element is made, if necessary.

Commission testing is performed on microprocessor and solid-state relays when a new relay scheme is installed or an electro-mechanical relay is replaced. The goals for this testing include:

- Ensure that all system AC and DC connections are correct
- Ensure that all relays function as intended using in-service settings
- Ensure that auxiliary equipment is functioning correctly

The relay shall be testing in accordance with the manufacturers recommendations. The following elements shall be tested in all applicable groups, zones and schemes:

- Phase element pickup and timing
- Ground Element pickup and timing

- Instantaneous phase element pickup
- Instantaneous ground element pickup
- Current differential test on 87 type relays
- Harmonic blocking tests on 87 type relays
- Line current differential
- Distance protection
- Under/Over frequency
- Under/Over voltage
- Synch Check
- Reclose
- Load Encroachment

Regularly scheduled testing is performed on microprocessor and solid state relays on five-year cycles or when there is an indication of a problem with the relay or system. The goals for this testing include:

- Ensure that the relay is measuring AC quantities accurately
- Ensure that the scheme logic and protection elements are functioning correctly
- Ensure that auxiliary equipment is functioning correctly

Transmission line end-to-end testing is performed as part of commissioning pilot wire protection systems and provides a record for reference in evaluation of operation performance for actual line fault activity subsequent to commissioning.

Microprocessor relays are all equipped with self-diagnostics and are monitored and alarmed through SCADA. Relay trouble alarms are Priority 1 and require immediate attention. All protective relays are inspected monthly during routine station checks for outstanding alarms, targets and physical condition. Any items requiring attention are called into dispatch and reported to the Manager of System Controls & Dispatch. All microprocessor relays are commission tested and regularly scheduled for maintenance testing every five years or when there is indication of a problem with the relay.

All solid-state relays are commission tested and regularly scheduled for maintenance testing every five years or when there is indication of a problem with the relay.

DC control circuits including auxiliary equipment are subject to commission tests when a new relay scheme is installed or when replacing an electromechanical relay or scheme. The goals for this testing include:

- Ensure all control, current transformer (CT), potential transformer (PT), and control panel board wiring is correct.
- Ensure the control system and protective relay is installed as designed.

DC relay control circuits are verified by viewing breaker indication lights during monthly sub inspections. Annually, breaker is tripped and closed to verify circuit integrity. Any problems are repaired as soon as detected. Circuit switches cannot be operated without interrupting power, so the DC circuit is tested by exercising the device when the substation has been taken offline.

Auxiliary tripping relays will have their trip coils verified when the associated protective relay is tested. Full testing will be done on occasions when the transformer or bus is out of service, so no inadvertent tripping will occur. The associated protective relay will be tested every five years or when there is indication of a problem with the relay or system.

Transformer sudden pressure relays will be tested when LTC or large voltage regulator maintenance in done. On transformers that can be de-energized sudden pressure will be tested when regular transformer maintenance is scheduled.

Additionally, all relay coordination settings will be verified to ensure proper functionality.

3.3.4 Recloser Control Testing

Substation recloser controls shall be tested in accordance with the form located on VEC's SharePoint site.

Recloser schemes shall be recorded and the following recloser control elements shall be tested:

- 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
- Batteries will be replaced for all relay controls on a 5-year rotating basis whether in substations on the line during DSI or DLI schedules, respectively.

3.3.5 SCADA

A functional point-to-point test of each transformer, relay, regulator, switches, and other SCADA points will be completed at the time of the transformer, regulator, and relay tests.

3.3.6 UFLS Testing

UFLS (Under Frequency Load Shedding) tests will be completed at the same time as relay tests. VEC has established a UFLS Maintenance Plan that requires testing every 5 years (NERC requires 6 but our cycle allows for us to complete a test in the 6th year if we identify any relay that needs to be repaired, replaced, adjusted, re-tested, etc.

4 Maintenance Procedures – General

4.1 Labeling

Labeling standards are listed below and available in VEC's Transmission and Distribution Standards Manual

Description	Drawing Number
Pole Markings (Neutral Separator, Normally Open, Information, Generator)	**201 (Page 1)**
Pole Markings (Pole Numbering, Member Owned, Fuse Labeling, Company Information)	**201 (Page 2)**
Hydraulic Recloser Labeling	**202**
Transformer Markings	**203**
Pad Mount Transformer Labeling – Single Phase	**204 (Page 1)**
Pad Mount Transformer Labeling – Three Phase	**204 (Page 2)**
Pole Inspection Markings (Priority Reject, etc.)	**205**
Pole Marking Ordering	**206**

4.2 Aerial Patrols

Qualified VEC personnel conduct aerial patrols and one infrared scan of all VEC transmission lines, as well as some major distribution lines, five times per year. The objective is to identify equipment concerns and danger trees and/or vegetation concerns, as well as any safety hazards that may exist, due to public activity taking place in close proximity to transmission structures or facilities.

When completing aerial transmission line inspection, VEC personnel will charge to GL account 571.45.

VEC's transmission facilities will be air patrolled through an aerial line inspection process on an annual basis. The aerial transmission line inspection will be completed by VEC's Manager of Line Operations or designee September through November depending on weather and atmospheric conditions. Pictures will be taken, as appropriate, for supporting documentation. Corrective work will have service orders prepared and the corrective action completed within 90 days. All corrective maintenance items will be documented on VEC's Aerial Transmission Inspection Form. All critical conditions identified that, in the judgment of the employee conducting the aerial inspection, pose imminent danger or are very likely to cause an outage in the next 30 days will be reported to Dispatch at the conclusion of each day's aerial inspection. Dispatch will create a service order, inform the Manager of Line Operations (if that is not the person conducting the aerial inspection) and schedule the corrective work for immediate, priority repair. If a pole is replaced on any transmission facility a detail inspection will be conducted. For all other repairs on a transmission facility the fixes will be recorded on the aerial inspection form.

Permits and or notifications to fly line will be provided by pilot of aircraft.

The following guideline constitutes an aerial transmission line inspection (at approximately 70 mph):

- Check overall condition of structures
- Look for and document any damage to structure
- Poles
- Cross arms

- Braces
- Insulators and ties
- Conductors
- Static line
- Pins
- Check hardware on structure
- Look for and document obvious gaps between bolts, nuts and washers
- Check for and document broken/tracking/burnt insulators and bells
- Review and document condition of conductor (if the issues can be seen from the air)
- Burn marks
- Broken strands
- Strands exposed and separated out of splices
- Strands exposed and separated out of armor-rod
- Check for and document broken guy wires
- Inspect for broken avian protection devices
- Visually inspect and document switch condition
- Document any obstructions or foreign objects on structures (e.g., bird nest, signs, etc.)
- Specifically check and document any trees in right-of-way
- Check and document any breeches in clearances in right-of-way (e.g., buildings, rock piles, cranes, chain hoists, etc.)
- Document all non-normal system switch line-up conditions

Transmission Inspection Verification: The aerial inspection will serve as verification to the Transmission Line Inspection process. Any issues will be reviewed by the Manager of Line Operations and provided to the appropriate Operation Supervisor.

5 Annual Checklists

The following tables identify the assets and associated maintenance and assessment to be done over the next 5 years (2019-2023). Further details on testing and inspection requirements are provided in the Maintenance Procedures.

5.1.1 2019

The following items need to be completed before January 1st 2020

Asset	Responsibility	Procedure	Location
Hydraulic reclosers	Line Districts	Replacement, testing	Substations 1, 3, 19, 32, 43
Line capacitors	Line Districts	Visual inspection, testing	Substations 1, 3, 19, 32, 43
Fault finders	Line Districts	Replacement, testing	Substations 1, 3, 19, 32, 43
Pad mounted transformers	Line Districts	Visual inspection, Labeling	Substations 1, 3, 19, 32, 43
Fuses	Line Districts	Assessment, Labeling	Substations 1, 3, 19, 32, 43
Switches	Line Districts	Assessment, Labeling	Substations 1, 3, 19, 32, 43
Stray Voltage	Line Districts	Inspection and testing	All locations
Underground Conductor	Line Districts	Assessment, Labeling	Substations 1, 3, 19, 32, 43
All Street lights	Davey Tree Resource Group	Assessment	Substations 1, 3, 19, 32, 43
Pole hardware (insulators, crossarms, etc.)	Davey Tree Resource Group	Assessment	Substations 1, 3, 19, 32, 43
Overhead Transformers	Davey Tree Resource Group	Assessment	Substations 1, 3, 19, 32, 43
Overhead Conductor	Davey Tree Resource Group	Assessment	Substations 1, 3, 19, 32, 43
Communication Attachments	Davey Tree Resource Group	Assessment	Substations 1, 3, 19, 32, 43
Distribution poles	SMI	Inspection and treatment	Multiple (Remaining 10%, and Consolidated additional)
Line voltage regulators	Substation Group	Visual inspection, testing	Substations All line regulators are inspected annually
Breakers and Relays	Substation Group	Testing	Substations 39
Electronic reclosers and relays	Substation Group	Testing	Substations 2,7,12,15,17,32,48,51
SCADA Field equipment	Substation Group	Testing	Substations 2,7,12,15,17,32,48,51
Substation transformer	Substation Group	Inspection and Testing	DGA is done annually on all power transformers in substations
Substation batteries	Substation Group	Testing and replacement	Substations 2,5,7,12,15,29,32,31,35,39,42,48
Phasing	Substation Group, Engineering, GIS	Assessment	Substations 1, 3, 19, 32, 43

Electronic line recloser testing	Substation and line districts	Inspection and testing	Substations 19-1Y, 19-3E, 43-3E

5.1.2 2020

This will be determined by November 01, 2019.

Asset	Responsibility	Procedure	Location
Hydraulic reclosers	Line Districts	Replacement, testing	Substations 6, 14, 29, 31, 42
Line capacitors	Line Districts	Visual inspection, testing	Substations 6, 14, 29, 31, 42
Fault finders	Line Districts	Replacement, testing	Substations 6, 14, 29, 31, 42
Pad mounted transformers	Line Districts	Visual inspection, Labeling	Substations 6, 14, 29, 31, 42
Fuses	Line Districts	Assessment, Labeling	Substations 6, 14, 29, 31, 42
Switches	Line Districts	Assessment, Labeling	Substations 6, 14, 29, 31, 42
Stray Voltage	Line Districts	Inspection and testing	Substations 6, 14, 29, 31, 42
Street lights	Davey Tree Resource Group	Assessment	Substations 6, 14, 29, 31, 42
Pole hardware (insulators, crossarms, etc.)	Davey Tree Resource Group	Assessment	Substations 6, 14, 29, 31, 42
Overhead Transformers	Davey Tree Resource Group	Assessment	Substations 6, 14, 29, 31, 42
Overhead Conductor	Davey Tree Resource Group	Assessment	Substations 6, 14, 29, 31, 42
Communication Attachments	Davey Tree Resource Group	Assessment	Substations 6, 14, 29, 31, 42
Transmission poles	SMI	Inspection and treatment	All, and CC poles acquired
Line voltage regulators	Substation Group	Visual inspection, testing	All line regulators are inspected annually
Breakers and Relays	Substation Group	Testing	NONE
Electronic reclosers and relays	Substation Group	Testing	Substations 19,28,29,41,43,46 UFLS 2,3,9,15,29,31,41,42,116R,343R418R,463R
SCADA Field equipment	Substation Group	Testing	Substations 19,28,29,41,43,46
Substation transformer	Substation Group	Inspection and Testing	DGA is done annually on all power transformers in substations
Substation batteries	Substation Group	Testing and replacement	5,19,28,29,32,31,35,39,41,42,43,46,48
Phasing	Substation Group, Engineering, GIS	Assessment	Substations 6, 14, 29, 31, 42

2020 is the year two out of five of the system assessment. In addition routine maintenance will continue including on substation equipment and all transmission poles will be inspected and treated. These poles were last treated and inspected in 2009.

5.1.3 2021

This will be determined by November 01, 2020.

Asset	Responsibility	Procedure	Location
Hydraulic reclosers	Line Districts	Replacement, testing	
Line capacitors	Line Districts	Visual inspection, testing	
Fault finders	Line Districts	Replacement, testing	
Pad mounted transformers	Line Districts	Visual inspection, Labeling	
Fuses	Line Districts	Assessment, Labeling	
Switches	Line Districts	Assessment, Labeling	
Stray Voltage	Line Districts	Inspection and testing	
All Street lights	Davey Tree Resource Group	Assessment	
Pole hardware (insulators, crossarms, etc.)	Davey Tree Resource Group	Assessment	
Overhead Transformers	Davey Tree Resource Group	Assessment	
Overhead Conductor	Davey Tree Resource Group	Assessment	
Communication Attachments	Davey Tree Resource Group	Assessment	
Distribution poles	SMI	Inspection and treatment	10%
Line voltage regulators	Substation Group	Visual inspection, testing	All line regulators are inspected annually
Breakers and Relays	Substation Group	Testing	NONE
Electronic reclosers and relays	Substation Group	Testing	Substations 13,30,31,32,44,51
SCADA Field equipment	Substation Group	Testing	Substations 13,30,31,32,44,51
Substation transformer	Substation Group	Inspection and Testing	DGA is done annually on all power transformers in substations
Substation batteries	Substation Group	Testing and replacement	Substations 5,13,29,30,31,32,35,39,42,44,48,51
Phasing	Substation Group, Engineering, GIS	Assessment	

2021 is the year three out of five of the system assessment. In addition routine maintenance will continue including on substation equipment. The distribution pole testing and treatment program will begin again with a new cycle.

5.1.4 2022

This will be determined by November 01, 2021.

Asset	Responsibility	Procedure	Location
Hydraulic reclosers	Line Districts	Replacement, testing	
Line capacitors	Line Districts	Visual inspection, testing	
Fault finders	Line Districts	Replacement, testing	
Pad mounted transformers	Line Districts	Visual inspection, Labeling	
Fuses	Line Districts	Assessment, Labeling	
Switches	Line Districts	Assessment, Labeling	
Stray Voltage	Line Districts	Inspection and testing	
All Street lights	Davey Tree Resource Group	Assessment	
Pole hardware (insulators, crossarms, etc.)	Davey Tree Resource Group	Assessment	
Overhead Transformers	Davey Tree Resource Group	Assessment	
Overhead Conductor	Davey Tree Resource Group	Assessment	
Communication Attachments	Davey Tree Resource Group	Assessment	
Distribution poles	SMI	Inspection and treatment	10%
Line voltage regulators	Substation Group	Visual inspection, testing	All line regulators are inspected annually
Breakers and Relays	Substation Group	Testing	NONE
Electronic reclosers and relays	Substation Group	Testing	Substations 11,40,46
SCADA Field equipment	Substation Group	Testing	Substations 11,40,46
Substation transformer	Substation Group	Inspection and Testing	DGA is done annually on all power transformers in substations
Substation batteries	Substation Group	Testing and replacement	Substations 5,11,31,32,35,39,40,42,46,48
Phasing	Substation Group, Engineering, GIS	Assessment	

2022 is the year four out of five of the system assessment. In addition routine maintenance will continue including on substation equipment. The distribution pole testing and treatment program will continue with 1/10th of all poles treated in 2022.

5.1.5 2023

This will be determined by November 01, 2022.

Asset	Responsibility	Procedure	Location
Hydraulic reclosers	Line Districts	Replacement, testing	

Line capacitors	Line Districts	Visual inspection, testing	
Fault finders	Line Districts	Replacement, testing	
Pad mounted transformers	Line Districts	Visual inspection, Labeling	
Fuses	Line Districts	Assessment, Labeling	
Switches	Line Districts	Assessment, Labeling	
Stray Voltage	Line Districts	Inspection and testing	
All Street lights	Davey Tree Resource Group	Assessment	
Pole hardware (insulators, crossarms, etc.)	Davey Tree Resource Group	Assessment	
Overhead Transformers	Davey Tree Resource Group	Assessment	
Overhead Conductor	Davey Tree Resource Group	Assessment	
Communication Attachments	Davey Tree Resource Group	Assessment	
Distribution poles	SMI	Inspection and treatment	10%
Line voltage regulators	Substation Group	Visual inspection, testing	All line regulators are inspected annually
Breakers and Relays	Substation Group	Testing	Substations 5,39
Electronic reclosers and relays	Substation Group	Testing	1,3,5,6,14,42
SCADA Field equipment	Substation Group	Testing	
Substation transformer	Substation Group	Inspection and Testing	DGA is done annually on all power transformers in substations
Substation batteries	Substation Group	Testing and replacement	
Phasing	Substation Group, Engineering, GIS	Assessment	

2023 is the final year of the system assessment. In addition routine maintenance will continue including on substation equipment. The distribution pole testing and treatment program will continue with 1/10th of all poles treated in 2023.