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ELECTRIC POWER RESEARCH INSTITUTE

Utility Line Inspections and Audits

A Power Quality and Reliability Guidebook

Utility Line Inspections and Audits

A Power Quality and Reliability Guidebook

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Final Report, March 2007

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PRODUCT DESCRIPTION

Utility Line Inspections and Audits provides utility engineers with a concise reference for the pros, cons, and "how to" related to performing various line inspections and audits.

Results & Findings

Utility Line Inspections and Audits provides utility engineers with the background needed to sufficiently understand and apply a variety of line inspections and audits, including

- visual line inspections,
- construction audits,
- outage follow-up reviews and audits,
- problem circuit audits,
- audits of tree exposure and vegetation management work,
- wood pole inspections,
- stray voltage inspections,
- thermal, grounding, and equipment specific inspections, and
- transmission and subtransmission inspections.

This document discusses commonly applied inspections and audits as well as some less common techniques that also yield valuable results. Many of the inspections and audits discussed in this document are suitable for both electrical distribution and transmission systems. An attempt has been made to provide inspection forms or checklists wherever appropriate. This guide also contains many pictures and illustrations to provide examples of the types of issues that will be encountered during the various inspections and audits.

Challenges & Objective(s)

This document is intended to provide the necessary background for utility engineers to quickly acquire a working knowledge of the issues associated with performing a variety of line inspections and audits. One particular challenge was finding the balance between providing enough background information to understand the "how and why" of performing each inspection and keeping the document concise and to the point. This document also contains several inspection report forms and checklists. These forms are designed in such a way that, should they not be suitable for an individual utility's needs, the form will still provide a starting point for utility personnel to prepare a customized form that does fit their needs.

Applications, Values & Use

Inspection programs are one tool that utilities can use to reduce failures on their circuits and minimize customer outages. By identifying problems for repair before they develop into failures, inspection programs can be a cost-effective method for enhancing the quality and reliability of electric service. This document provides a concise reference for how to perform a variety of utility line inspections, each serving a different inspection need. There are numerous visual examples of what to look for during inspections and audits as well as inspection reporting forms that can be copied directly from the text for use in inspection programs.

EPRI Perspective

By providing utilities with clear procedures for improving power quality through line inspections and audits, EPRI is enabling utilities to provide better customer service. Utilities can apply changes across-the-board or target specific feeders or customers that require enhanced power quality. By focusing on practical methods, the report provides a variety of methods for addressing various inspection and audit needs.

Approach

The project team began by researching all available information on various utility line inspections related to enhancing electric service reliability and power quality. Each chapter draws from this research to present the background necessary to understand the value of each inspection or audit presented. Wherever possible, the project team attempted to provide supporting data from actual utility experience with the different audits and inspections discussed in this document.

The project team reviewed many different checklists and reporting forms related to each inspection or audit. The team used this information to develop new checklists and reporting forms that are intended to meet the needs of a wide range of utilities. In producing the reporting forms and checklists, the project team attempted to provide documents that could be taken directly from this text and used in the field by inspection personnel.

Keywords

Inspection
Audit
Reliability
Problem circuit
Vegetation management
Infrared inspection
Stray voltage

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1
INTRODUCTION

Outages are costly for utilities and end-use customers. Electrical outages interrupt industrial processes and disrupt commerce. For residential customers, power outages are an inconvenient disruption at best, and pose a danger to health and safety at worst. For the utility, outages are costly since they increase worker overtime, disrupt the sale of energy, and draw the attention of regulators.

Routine inspections programs are one tool that utilities can use to reduce failures on their circuits and minimize customer outages. By identifying problems for repair before they develop into failures, inspection programs can be a cost-effective method for enhancing the quality and reliability of electric service.

Electrical circuits are composed of numerous parts, all of which can fail in one or more ways. There is a lot to look for when inspecting electric circuits. Many deficiencies can be found through a simple visible inspection. Broken or damaged equipment, severely aged equipment, and improperly built structures can be visually identified. Basic visual inspections are widely applied to evaluate circuit conditions and look for any problems that could lead to faults. Other specialized visual inspections, such as problem-circuit audits, are applied to specific circuits and can have a much narrower scope than general inspections. Some deficiencies are rather easy to spot (Figure 1-1), but others are not visible to the human eye and must be inspected for by other means. Infrared, stray voltage, radio interference, and grounding inspections all rely on specialized equipment to detect circuit defects that can not be found through visual inspection alone.

Figure 1-1
Some Deficiencies are Easy to Spot

Justifying Inspection Programs

Most inspection programs are funded though operations and management budgets. Construction audits are one notable exception since they can be incorporated into construction budgets. Many company's operations and management budgets are already stretched thin which can make it difficult to justify many inspection programs; especially those other than basic visual inspections. A further complication is that there is little quantifiable data available regarding the return on investment associated with various inspection programs. However, strong inspection programs can have a positive impact on the quality, reliability, and safety of electric service and should still be pursued. A robust inspection regimen is part of a proactive approach to providing a reliable and high quality electric supply to end-use customers. Inspection programs also help improve a company's responsiveness and the quality of their response to major events; both of which improve public perception of the company and help avoid further regulation.

Justifying some inspection programs is complicated by the fact that results, such as fault reduction, can take a few years to become evident. Because of this it can take some time to prove a program's effectiveness. One approach for gauging the usefulness of a program is to implement it on some circuits while leaving other circuits alone. For example, to judge the effectiveness of a worst circuit program, implement problem circuit inspections and outage follow-ups on half of the worst circuit list while operating the other half of the list per the status quo. If the circuits receiving inspections and follow-ups improve, then it is pretty clear that the inspections are merited.

Florida Power and Light used a multi-faceted program to dramatically reduce the duration of customer interruptions in their service territory. The program, referred to as Reliability 2000, used problem circuit identification and inspections, revised vegetation management, thermal inspections, and other initiatives to reduce customer interruption minutes from a 1997 peak of one hundred and fifty-seven minutes to seventy-five minutes by the end of 1999 (Bush 2000).

Legislative Mandates for Inspection

The recent trend towards deregulation has many regulatory agencies concerned that electric service reliability will decline in the deregulated environment. To address this issue, regulatory agencies have begun to regulate reliability by requiring utilities to file reports on annual reliability and reliability improvement plans. The push to regulate reliability has also caused many regulatory bodies to mandate certain inspection types and intensities. For utilities that are not currently required to inspect, a proactive approach with a strong inspection program may be beneficial in avoiding further regulation. If regulation is unavoidable, then a company's inspection experience can help influence the rules adopted by the regulatory body.

Increasing Customer Demands for Power Quality and Reliability

The design and construction of electric power distribution circuits has changed little over the past 40 years. While it is true that there have been modest improvements in some aspects of distribution construction, such as the use of new, lighter materials, one can make a strong case that the technology being implemented in distribution circuits has remained relatively stagnant. During this same time period the power quality needs of utility customers have evolved to the point at which simply providing high reliability is not good enough. Today's utility customers demand high reliability and improved power quality from their electric power supply. The primary driver behind this trend is the increasingly sensitive nature of customer loads. As we have ushered in the digital age, sensitive electronic loads have spread from industrial facilities to commercial customers and finally to widespread implementation in residential homes. The seemingly ubiquitous microchip has embedded itself in everything from multi-million dollar production facilities to inexpensive home appliances. The result of these advancements is that customers no longer tolerate the type of power quality events that would go unnoticed only a few years ago. In essence, the benchmark of what constitutes acceptable power quality is changing, as customer loads become more sophisticated and more sensitive to disturbances.

The increasingly stringent power supply needs of customers are forcing modern electric utilities to re-think the design, construction, and operation of electric distribution circuits. Forward thinking utilities are looking to robust circuit inspection programs as one component of a multi-faceted approach to improving service quality and reliability.

Inspecting for Safety

Electric transmission and distribution circuits can be hazardous to utility personnel and to the general public. Circuit conditions are not static. The natural environment, routine circuit operation, and interaction with humans (vandalism, car accidents, etc.) all impact circuits over time. Even circuits built with the safest possible design will change over time and could eventually pose a risk to utility workers or the public. Utilities can use routine circuit inspections to monitor how circuits change over time and identify any situations that require repair.

2
VISUAL LINE INSPECTIONS

Periodic visual inspections help ensure the safe, reliable, and economic operation of electric circuits. Inspections are primarily done to determine the condition of the circuit and to identify any deficiencies that require monitoring or repair. Many formal inspection programs have a number of goals including:

- Protection of the public
- Protection of utility personnel
- Increased service reliability
- Improved economics through calculated maintenance and capital improvements
- Code and regulatory compliance

Basic visual inspections are a tool best suited for discovering gross deficiencies such as broken or damaged line components, nesting materials, and some National Electric Safety Code violations.

Justifying Visual Inspections

Visual inspections are one of the least costly inspections that utilities perform. Although they cannot detect every failure mode, visual inspections are useful for identifying a wide variety of circuit defects and they tend to be considered highly cost-effective. Visual circuit inspections also help provide line managers with quantitative information on which they can evaluate line performance and determine if further action must be taken to improve service quality and reliability. The Canadian Electric Association found that many utilities in Canada and the United States use visual inspections on their overhead and underground circuits as shown in Table 2-1 (CEA 290-D-975 1995).

In addition to voluntary circuit inspections, many utilities are also bound by regulations requiring circuit inspections. Regulatory bodies are increasingly attempting to regulate service quality and reliability. This push to regulate reliability has caused many regulatory bodies to mandate certain inspection types and intensities. For utilities that are not currently required to inspect, a proactive approach with a strong inspection program may be beneficial in avoiding further regulation. If regulation is unavoidable, then the company’s previous inspection experience can help influence the rules adopted by the regulatory body.

Table 2-1
Visual Inspection Usage Shown by Percent of Respondents (CEA 290-D-975 1995)

Apparatus Examined by Visual Inspection	Percent of Respondents Indicating Use
Overhead	
Wood Poles	54%
Conductors	39%
Insulators	42%
Fuse	38%
Switch	44%
Arrester	37%
Transformer	40%
Regulator	87%
Recloser	69%
Capacitor	68%
Underground	
Cable	27%
Elbow / Splice	61%
Switch	68%
Transformer	75%

Visual Circuit Inspection Background

Inspection Tools

An inspector needs a proper set of tools to perform visual circuit inspections. There are only a few tools that are required but these tools are essential to assist line inspectors in working accurately, efficiently, and safely. The following tools are suggested for performing visual circuit inspections:

- *Circuit map* – The circuit map can be paper-based or digital but it must be complete and accurate. All major overhead equipment such as fuses, switches, reclosers, and capacitors should be identified. Additionally, the map should allow for straightforward differentiation between the circuit mainline and taps. Digital maps, often implemented via graphical information systems (GIS), have the advantage of presenting much more information than the basic requirements and will most likely show data such as pole numbers, conductors types, and the location of secondary equipment such as arresters. Paper based maps have the advantage of being easier to mark-up with problem locations, especially for issues such as overhanging trees which may affect large portions of the line.

- *Binoculars* – A high-quality set of binoculars with decent magnification power allow the inspector to get a better look at pole top equipment, conductors, and structures with limited access. Binoculars with image stabilization are not necessary.
- *Digital camera* – A digital camera with a 5-10x zoom allows the inspector to document problems in a format that is easily transferable and easily copied.
- *Hammer and screwdriver* – A hammer and screwdriver are useful inspection tools for probing suspected damage, particularly on wood poles.
- *Inspection forms* – Inspection forms are often overlooked as a required tool but it plays an important role in the inspection and reporting process. The inspection form allows for uniform inspection and reporting practices which in turn aid in prioritizing corrective action and building an inspection database.
- *Personal protective equipment* – Although these items don't necessarily aid in inspecting the line, they are important from a personal safety standpoint. The inspector should make use of a safety hat, safety glasses, and a high-visibility safety vest. Ear protection should also be worn as appropriate in construction areas or in other loud environments. Bright high-visibility colors are best since much of the line inspection work is done in close proximity to moving traffic. Personal protective equipment may also include specialized rescue equipment for working in and around underground structures.
- *Navigation equipment* – A circuit map is usually not a proper substitute for a traditional road map of the area. Road maps can be either paper-based, software-based computer programs, or GPS units.
- *Vehicle* – Visual inspections involve a mix of walking and riding. Even if no inspection is done from the vehicle, the inspector still needs to get to the circuit and move along its length. There may also be line sections that traverse rough/remote terrain and a four-wheel drive vehicle is preferable in these circumstances.
- *Two-way radio* – The radio can be vehicle mounted or portable and serves a communication link for the inspector to report hazardous situations that require immediate attention.
- *Flashlights and worklights* – For illuminating work areas.
- *Air quality analyzer* – For verifying air quality in underground structures during underground circuit inspections.

Inspection Personnel Qualifications and Training

Properly trained inspectors work more accurately and efficiently than those with no specialized training. In some cases, "specialized training" comes in the form of several years of utility experience in a variety of job positions. Some utilities also have specific training for their circuit inspectors. Ideally, a line inspector will have experience with line construction, operations, and maintenance. However, someone with that background can be hard to find and is often utilized in other important roles within the company. When considering line candidates for line inspection positions, it may be helpful to ask a few questions about their experience (APPA 2004):

- Do they have previous circuit inspection experience?
- Do they have experience with circuit construction, operation, and maintenance?
- Are they familiar with the company's design and construction standards?
- Are they familiar with the National Electric Safety Code?
- Why are they interested in performing circuit inspections?

These questions can help to quickly rank a candidate pool or gauge whether or not a candidate is suitable for circuit inspections. Obviously local company personnel are often well suited for circuit inspection work due to their familiarity with local circuits and company practices.

Inspector training varies from company to company and from intensive to almost nonexistent. At a minimum, basic periodic training should be undertaken to keep the inspection personnel up to date on code requirements, the changes to the company's design and construction standards, and any new inspection tools or techniques. More intensive training might also include a review of common circuit components and their failure modes with visual examples of each as well as field training on conducting inspections and common vegetation issues.

Walking Patrols versus Driving Patrols

Overhead line visual inspections are commonly performed by walking the line or by driving along the line and inspecting from the vehicle. Each method has distinct advantages and disadvantages. The characteristics of each type of inspection are shown in Table 2-2. Although driving inspections tend to be faster, they also require two people to adequately perform the inspection – one to drive the vehicle and one to inspect the line. The travel speeds associated with driving inspections allow for only a brief look at each structure. For this reason, driving inspections tend to be a "coarse" inspection tool while walking inspections permit a highly detailed examination of each structure and span. Obviously, the inspection personnel don't have physical contact with the pole structures during a driving inspection which makes it more difficult to spot pole decay, especially at the groundline.

Table 2-2
Characteristics of Walking and Driving Overhead Line Patrols

Walking Patrol	Driving Patrol
Slower but only requires 1 person	Faster but requires 2 people (driver and inspector)
Detailed inspection	Coarse inspection
Multiple viewing positions including circling structure	1 or 2 viewing positions
Permits physical contact with poles	No physical contact with poles

Inspection Frequency

If resources were limitless then all circuits would be inspected on a continual basis. This however is not feasible. In reality, company resources are limited and there are established budgets for performing circuit inspections. Determining how often to perform visual inspections is a decision that each company must make based on a number of factors including:

- The age and general condition of the circuits to be inspected
- What, if any, maximum permissible inspection cycles are mandated by the governing regulatory body
- The resources and budget available to carry out inspections
- The company's power quality and reliability goals
- The success (or failure) or previously used inspection cycles

It is common for regulatory boards to mandate circuit inspections but the specifics of how often inspections must be performed can be left rather vague. Consider as an example the inspection rules set forth by the Florida Administrative Code. Rule 25-6.036 – *Inspection of Plant* states the following (Florida Administrative Code):

> *Each utility shall adopt a program of inspection of its electric plant in order to determine the necessity for replacement and repair. The frequency of the various inspections shall be based on the utility's experience and accepted good practice. Each utility shall keep sufficient records to give evidence of compliance with its inspection program.*

This statement makes it clear that public utilities must inspect their circuits but leaves the inspection frequency up to the utility.

Other regulatory bodies take a more definitive approach to the issue of how often to inspect. Ohio's Administrative Code Rule 4901:1-10-27, *Inspection maintenance, repair, and replacement of transmission and distribution facilities (circuits and equipment)*, states the following in *Part D: Transmission and Distribution Facilities Inspections* (Ohio Administrative Code):

(1) Distribution – at least one-fifth of all distribution circuits and equipment shall be inspected annually. All distribution circuits and equipment shall be inspected at least once every five years.

The California Public Utilities Commission provides even more detail with their well-defined set of maximum allowable inspection cycles for different types of equipment as shown in Table 2-3.

Table 2-3
Maximum Allowable Intervals in Years, for Electric Company System Inspection Cycles Set Forth by the California Public Utilities Commission (California Public Utilities Commission 1997)

Apparatus	Patrol		Detailed		Intrusive	
	Urban	Rural	Urban	Rural	Urban	Rural
Transformers						
Overhead	1	2	5	5	--	--
Underground	1	2	3	3	--	--
Padmounted	1	2	5	5	--	--
Switching/Protective Devices						
Overhead	1	2	5	5	--	--
Underground	1	2	3	3	--	--
Padmounted	1	2	5	5	--	--
Regulators / Capacitors						
Overhead	1	2	5	5	--	--
Underground	1	2	3	3	--	--
Padmounted	1	2	5	5	--	--
Overhead Conductors and Cables	1	2	5	5	--	--
Street lighting	1	2	x	x	--	--
Wood Poles under 15 years	1	2	x	x	x	x
Wood Poles over 15 years which have not been subject to intrusive inspection	1	2	x	x	10	10
Wood Poles which passed intrusive inspection	--	--	--	--	20	20

The following terms are defined by the California Public Utilities Commission for use in the context of Table 2-3 as follows:

- *Urban* areas are those with a population of more than 1,000 people per square mile as determined by the United States Bureau of the Census.
- *Rural* areas are those with a population of less than 1,000 people per square mile as determined by the United States Bureau of the Census.
- *Patrols* are simple visual inspections intended to identify obvious structural problems or hazards.

- *Detailed inspections* are the careful examination of individual pieces of equipment and structures and can include diagnostics testing in addition to visual examinations.
- *Intrusive inspections* involve movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspection or instrument reading.

It is obviously important for each utility to follow the rules set forth by their governing body (if any). However, these rules are generally maximum allowable inspection cycles. What if a company wants to inspect more often? Examining the inspection practices of other companies can provide some insight into inspection cycles. EPRI distributed a survey of transmission and distribution practices during research for this report. Of the ten respondents, three respondents provided information about the frequency of their overhead distribution circuit inspections as follows:

- Two separate companies responded that they inspect all distribution circuits on a *three-year cycle*.
- One company responded that they inspect their distribution circuits on an *eight-year cycle*.

There were also two companies that responded that they inspect underground circuits with one company indicating a *three-year cycle* and the other indicating an *eight-year cycle*.

Some companies have even moved away from regular visual inspections all together. One utility in the northeastern United States foregoes routine visual inspections in favor of informal visual inspections completed by utility personnel as they perform their normal (non-inspection) duties (Liberty Consulting Group 2005). However, they do still perform some routine inspections such as yearly infrared inspections of their three-phase circuits and routine equipment specific inspections (such as capacitor banks and reclosers).

Circuit Prioritization

The most basic approach to prioritizing circuits for inspection is to simply inspect all circuits on the same cycle, effectively giving all circuits the same priority. Another option is to take a reliability-centered inspection approach with the goal of minimizing customer interruptions. Under this strategy, circuits (or circuit segments) with the biggest potential impact on reliability are inspected more frequently than those with less potential impact. Some options for implementing this type of inspection strategy include:

- Inspecting mainlines more frequently than taps
- Increased inspection frequency for problem circuits
- Increased inspection frequency for circuit segments serving high numbers of customers
- Increased inspection frequency for circuits with high-profile customers

Deficiency Priority Ratings

It is good practice to grade problems discovered during line patrols to ensure that significant problems are addressed in a timely manner. Grading line deficiencies also makes it easier to prioritize and schedule work to repair less significant problems in the most economical fashion. Table 2-4 provides one possible grading scheme for rating problems discovered during visual line patrols. Using this grading scheme, those problems identified as presenting an immediate hazard to personal safety should be addressed the same day that they are discovered. Less severe situations that aren't currently hazardous but have the potential to become hazardous should be repaired within 2 weeks. This methodology also allows for non-hazardous problems to remain on the line for up to 6 months to allow flexibility in prioritizing work orders. Some line equipment or construction, while not hazardous, no longer meets current design specifications. These instances can be noted and designated as such for upgrading when the opportunity arises.

Table 2-4
Priority Ratings for Deficiencies Discovered during Visual Line Patrols

Classification	Response Time	Description
1	Same day	A situation that presents an existing or probable hazard to person safety.
2	2 weeks	A situation that is currently non-hazardous but has the potential to become hazardous.
3	6 months	A situation that is non-hazardous and is likely to remain non-hazardous.
4	Not mandated	Equipment or construction that is non-hazardous but no longer meets specifications.

Some companies will go a step further and compile a list of possible deficiencies and their corresponding priority ratings. A few examples of this type of information are shown in Table 2-5. These lists can be as short as a single page or they can be several pages in length depending on how inclusive they are intended to be. Any listing of possible deficiencies should not be viewed as all encompassing since there are so many things that can go awry on an overhead line, many of which are unexpected. Although not all-inclusive, a list of potential deficiencies does serve a useful purpose as an educational tool and it helps keep some less common deficiencies fresh in the inspector's mind. Working from a cohesive list with specific priorities assigned to various deficiencies also adds a degree of uniformity to the inspection process.

Table 2-5
Example Priority Ratings for Visual Construction Inspections

Equipment	Priority 1	Priority 2	Priority 3	Priority 4
Conductor Damage	> ¼ of strands broken	< ¼ of strands broken	2 or less strands broken	None
Transformer	Leaking or leaking imminent due to extreme rust or damage	Severely damaged/rusted with high risk of leaking	Damaged or rusted with moderate risk of leaking	Damaged or rusted with a low risk of leaking
Crossarm	Broken or detached from pole	Serious cracking or partial detachment from pole	Moderate cracking or other deficiency	Minor cracking or superficial damage
Underground System Insulation Damage	Bare conductor	Severe Damaged	Moderate Damage	None
Cable Joint	Smoking	Severe Leaking	Minor Leaking	None

Overhead Circuit Visual Inspections

What to Look For During Visual Inspections

Overhead circuit deficiencies can result from poor work practices or from degradation due to time in service. Regardless of the source, a visual inspection should identify any type of visible deficiency on overhead lines.

Issues Related to Improper Line Work Practices

Line work is usually performed to specification and with quality workmanship. However, mistakes are occasionally made and should be checked for during visual inspections. A few improper line work practices seem to be the most common:

- *Inadequate clearances* – Tight clearances can lead to increased faults on a circuit. Look for unnecessarily tight clearances or clearances that are out of specification. Pay special attention to clearances between the conductors and between the conductors and guy wires.
- *Missing or improperly installed wildlife guards* – Wildlife guards are occasionally overlooked during construction or are installed improperly. Bushing covers should not be installed below the first insulator skirt (Figure 2-1) as this can eventually result in flashovers.
- *Automatic splice used in slack span* – Automatic splices rely on line tension to maintain their grip on the conductor. Slack spans may not provide enough conductor tension to maintain an adequate splice connection and may result in the conductor slipping out of the splice.

- *Excessive slack in slack spans* – Excessive slack in slack spans can result in increased circuit operations under windy conditions. While excessive slack is often due to pole movement resulting in the pole leaning and causing excessive slack, it can also be due to poor work practices. In either case, excessive slack in a slack span should be noted as part of the inspection along with a preliminary indication of the cause.
- *Excessive jumper length on lightning arresters* – Lead length is very important; the lead voltage can contribute as much as the arrester protective level for long lead lengths. Total lead lengths, phase plus ground lead length, less than three feet (one meter) are necessary to achieve a 50% margin for protecting overhead equipment for a 13.8-kV voltage system (Short 2004). Arrester lead lengths must be kept as short as possible. Arrester leads should *not be coiled*. Although coiled leads may look tidy, the coiling adds inductance and excessive lead length. Figure 2-2 and Figure 2-3 provide some examples of excessive arrester lead lengths.
- *Improper insulator location* – Sometimes insulators don't get placed in accordance with the design specifications. One example of this is placing the middle-phase insulator on the crossarm when design specifications call for it to be mounted on the

This is only a partial list which shows some of the most common improper work practices that can manifest into power quality issues. Please refer to Chapter 3 – Construction Audits for a more complete discussion of these issues.

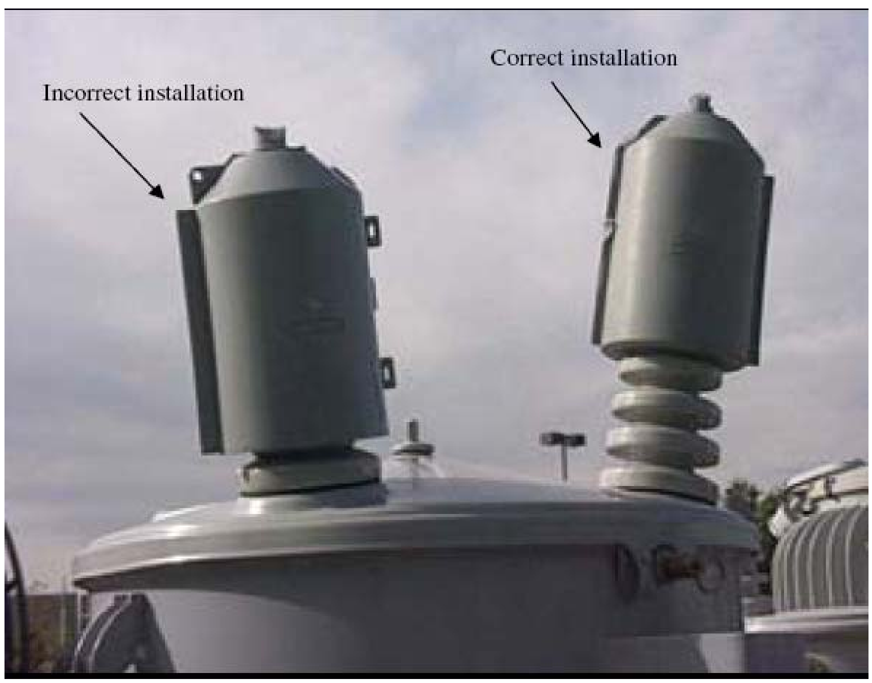


Figure 2-1
Examples of Correct and Incorrect Bushing Cover Installation

Figure 2-2
Example of Excessive Arrester Lead Length (both phase and ground leads)

Figure 2-3
Excessive Arrester Ground Lead Length
The phase lead is reasonably short but the arrester ground lead should be bonded directly to the termination.

Component Degradation, Equipment Failure, and Other Line Inspection Issues

There are numerous deficiencies be on the look-out for during visual inspections of overhead lines. Some of these deficiencies are equipment specific as outlined in the following sub-sections. There are also more universal signs of damage that the inspector should constantly be looking for. Any type of damage, decay, severe weathering, rusting, or leaking should be noted. It is best to immediately report leaking or severely damaged equipment or any situation that poses a public safety risk.

The inspector should be on the lookout for any construction that doesn't meet current company specifications. Also look for improperly applied or missing equipment. Animal guards are one such device which often gets improperly installed or are missing all together.

Inspectors should be cognizant of equipment that has been ordered removed from service. Certain makes or models of equipment sometimes perform so poorly that they are ordered removed from service. The sheer number of these units in the system can mean that a few get overlooked during the initial replacement. Those units that are initially overlooked should be discovered during routine line inspections.

Pole Structures Including Crossarms and Braces

Examine the pole from the groundline up for signs of rot, decay, infestation, woodpecker damage, splits, breaks, or burns. Pay particular attention to the pole top as that area has the greatest lightning exposure and tends to hold most of the equipment. Excessively leaning poles should also be noted. Make sure the pole has proper ID tags and other pertinent signage. See Chapter 8 - Wood Pole Inspections for a detailed discussion of performing wood pole specific inspections. Figure 2-4 through Figure 2-9 show a few examples of common pole-related maladies.

Verify the integrity of all crossarms – are any broken, split, cracked, twisted, rotating, detached, or otherwise deteriorated? Also look for burn marks. Examine all crossarm bracing for bends, splits, breaks, detachment, etc. Figure 2-9 shows an example of a crossarm that has detached from the pole top, also notice the bent crossarm brace.

Guys Lines

Examine any pole guy attachments and guy wires. Do all appear to be in good shape? Do any of the guy lines appear worn, frayed, or broken? Check that the guy lines are not slack or bent around any objects. Check that all guy lines have adequate clearance to energized equipment and conductors (Figure 2-10). Also verify that guy guards are in use when appropriate. Finally, check the anchor rods for damage or decay. Does the anchor rod appear to be bending or pulling? Is the anchor rod eye above ground level?

Conductors

Look for inadequate conductor clearances with buildings, roadways, other wires, etc. Check for excessive phase sag which is out of specification, violates clearance standards, or could resulting increased conductor slapping activity during windy conditions. Do any portions of the conductor appear frayed, broken, or burned?

Insulators

Look for broken, cracked, or chipped ceramic insulators. For polymer insulators, look for tears, punctures, and broken rods. For all insulators, do they appear excessive contaminated, flashed, or burned? Check for grossly misaligned insulators and uplifting or floating on non-dead end insulators. Are appropriate wire ties used? Is the conductor insulation stripped back when appropriate to prevent conductor burn-down?

Arresters

Verify that arresters appear to be in good working order. Does the arrester body have any tears, punctures, chips, or cracks? Sometime arresters even break completely apart as shown in Figure 2-11. Look for defects that could allow water to penetrate into the arrester. Are there any signs of flashing on the arrester body? Look for excessive lead lengths. As previously mentioned, it is vital for arrester installations to have the shortest lead length possible. Also check arrester clearances and make sure that if the isolator operates that the lead won’t swing into other energized conductors. Verify proper wildlife guard installation where required by company specifications.

Fuses and Cutouts

Do the cutout brackets appear to be in good working order? Are there any signs of flashing (Figure 2-12), damage, or sever weathering? Look to make sure that the brackets are plumb and do not appear to be pulling away from the crossarm.

Transformers

Examine transformers for rust or damage. Leaking transformers should be immediately reported for containment, clean-up, and replacement. Look for signs of overheating (Figure 2-13) or flashing, especially around the bushings. If required, are wildlife guards in place and properly installed? Do the transformer leads have adequate clearances? Verify that the transformer’s arresters and fuses appear to be in good working order as well.

Other Equipment

Line equipment such as capacitors banks, reclosers, and regulators should be examined for signs of rusting, leaking, damage or flashing. Verify that arresters and fuses are properly applied and appear to be in good working order.

Ground Wire

Examine pole grounds for cuts, breaks, abrasions, or other damage. Does the ground wire appear to be adequately supported on the pole? Verify that ground guards are in place. Is there adequate clearance between the ground wire and energized conductors, especially near the pole top?

Animal Damage

Look for any signs of animal damage such as bite or chew marks or nesting materials. Also make note of any sign of animal-induced flashes and any animal carcasses that appear to have fallen from the line.

Storm Damage and Out of Spec Construction

Some storm damage may go unnoticed, particularly if it does not cause an interruption. Other times storm damage is repaired but those repairs may not meet construction specifications (Figure 2-14) due to the unavailability of materials, time constraints, or out of town crews who are lending a helping hand. The line inspector should keep and eye out for storm damage and any construction (or repair) work that does not meet the construction specifications.

Vegetation and Right-of-Way

Vegetation inspections can be carried out as part of the visual inspection process or as a separate inspection. If vegetation inspections are performed separately, it is still good practice to note grievous vegetation issues encountered during the visual inspection process. See Chapter 6 - Audits of Tree Exposure and Vegetation Management for a more thorough discussion of vegetation management practices.

Note any areas of obvious or impending vegetation growth into the conductors as well as any trees that may allow a person to climb to a point at which they could contact the line. Unchecked vine growth can quickly cover poles and spread along the conductors (Figure 2-15). Also note danger tress that may fall onto the line. Note any excessive vine growth on poles and equipment.

The inspector should also make note of any other right-of-way deficiencies including encroachments by foreign structures, damaged or missing company gates, fences and signs, and limited structure access.

Visual Examples of Overhead Line Deficiencies

This section provides visual examples of some of the overhead line deficiencies mentioned in this section. The pictures have been referred to in the above discussion of what to look for during visual inspections.

Figure 2-4
Bending Pole

Figure 2-5
Leaning Poles

Figure 2-6
Lightning Damage to Pole Top

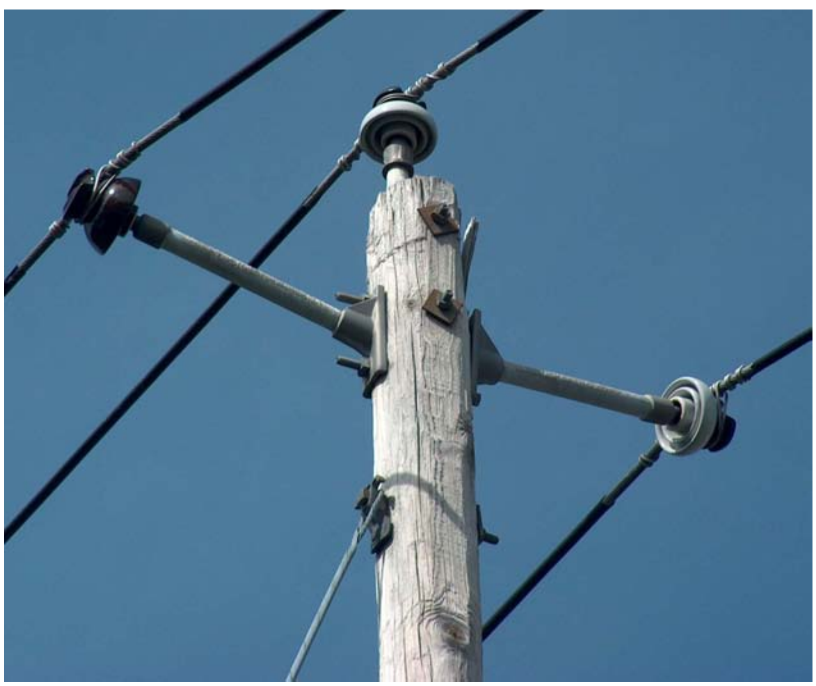


Figure 2-7
This Pole Top Appears to be Splitting and Allowing the Insulator Standoff to Pull-Away.
(Also notice the heavy surface degradation on the insulator standoffs)

Figure 2-8
Broken / Split Crossarm and Pole Showing Signs of Shell Rot

Figure 2-9
Partially Detached Crossarm and Bent Crossarm Brace
Note the metal pipe strapped to the underside of the crossarm. At the time of writing the purpose of this pipe was not clear

Figure 2-10
Poor Guy Wire Clearance
There is not adequate clearance between the guy wire and the primary conductors even though the guy is insulated with a ceramic compression insulator

Figure 2-11
Broken Lightning Arrester

Figure 2-12
Flashed Potheads, Cutouts, and Arresters

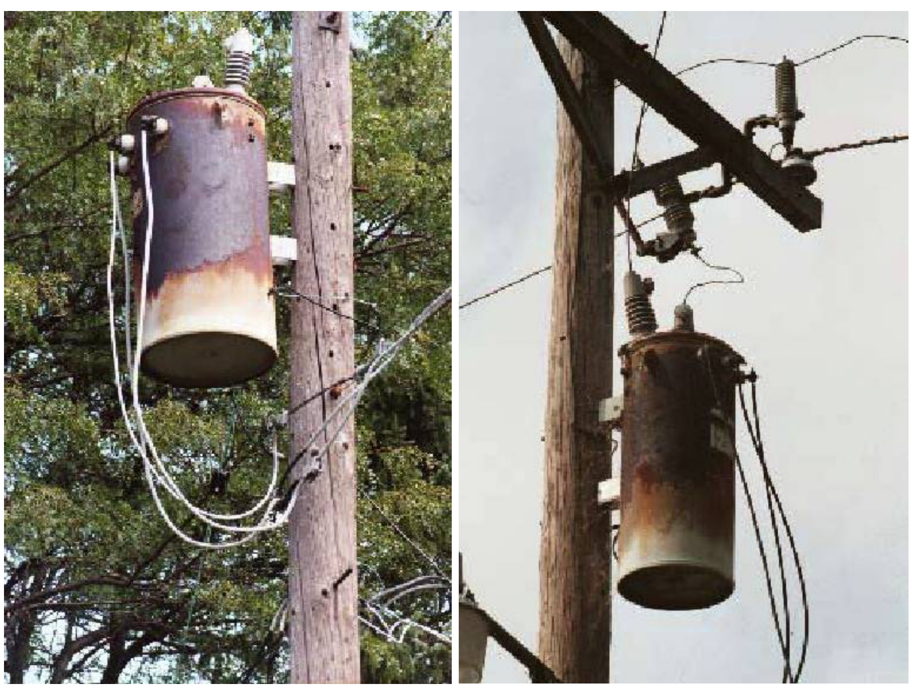


Figure 2-13
These Transformers Appear to have Gotten Very Hot (Overloaded)

Figure 2-14
Hastily Repaired Storm Damage Should be Identified During a Visual Inspection

Figure 2-15
Heavy Vine Growth on Pole

Overhead Circuit Visual Inspection Forms

A functional inspection program needs an accurate and efficient method for recording and reporting inspection results. The inspection report (also referred to as a checklist, check sheet, inspection form, etc.) has been the tool of choice for this task for many years and it is still widely used today. Inspection report forms come in a wide variety of configurations and complexities. They are often drafted in-house to suit the company's specific inspection needs. Inspection report form complexity can range from a few simple check boxes to detailed forms that capture highly segmented and defined data. The overhead visual inspection report shown in Figure 2-16 falls somewhere in the middle of the complexity range. This form records inspection data with a fair amount of detail but shouldn't be too tedious for the inspector to complete. It should also be noted that the inspection report form in Figure 2-16 has a lot of room for comments. The comments section provides space for the inspector to record detailed information about each deficiency. It is important to include enough detail so that work crews have an accurate picture of the repair work that needs to be completed. Comments should include information such as:

- The type of deficiency (i.e. decayed crossarm, broken insulator, flashed bushing, etc.)
- Which phase is affected (i.e. broken insulator – middle phase)
- Which side of the pole (north, south, east, west, etc.)
- Which unit if more than one on the pole (i.e. upper crossarm on east side of pole)

Deficiency codes can also be used to enter the comment field data and they are often used in conjunction with the inspection report to facilitate uniform data entry and analysis. Deficiency codes are set of defined codes (numbers or letters) for a variety of possible deficiencies that can be encountered during an inspection. Some companies use a list of only a dozen or so codes while some companies have deficiency code lists that stretch for pages with 75 or more individual items. Table 2-6 provides some deficiency code examples. The method outlined in Table 2-6 uses letter codes for equipment types and numerical codes for deficiency types. Deficiencies can thus be recorded as a letter-number combination such as C1 for a broken crossarm or T4 for a leaking transformer.

Many utilities are embracing newer portable electronics to aid in collecting, acting upon, and storing inspection data. Personal digital assistants (PDA) and laptop computers are now widely applied for collecting data in the field. Digitally capturing inspection data yields a few advantages:

- *Speed* – Most inspection items can be entered via radial buttons, check boxes, and pull down lists. Inspection data can be entered quickly once the inspector is familiar with the software interface.

- *Uniformity* – Digital approaches can aid in uniform collection of data through limited data entry options (although there must be enough flexibility to record any deficiency encountered). Uniform datasets allow make it easier to analyze and store data.

- *Data retrieval, analysis and reporting* – Inspection data can be quickly retrieved from digital devices (PDA, laptop, etc.) for analyzing and storage through a docking process back at the office. Once downloaded, the data can be compiled in a database for analysis and reporting. Work orders can be generated based on the priority codes assigned to each deficiency during the inspection.

- *Data storage* – Digital data is easy to transmit, store, access again at a later time.

Table 2-6
Example Deficiency Codes **(Not a complete list)**

Equipment Failure Code	Description
A	Arrester
B	Bushing
C	Crossarm
I	Insulator
P	Pole
T	Transformer
WG	Missing / damaged / improperly installed animal guard
Deficiency Type Code	**Description**
1	Cracked / broken
2	Excessive rusting
3	Evidence of excessive heating
4	Leaking fluid
5	Animal nest or interference

Overhead Circuit Inspection Report   Sheet #: ____ of ____

Date & Time: ________________   Circuit #: ________________

Inspector(s): ________________   Pole ID #: ________________

Location: ________________

Instructions

Report deficiencies for only one pole per inspection sheet. When possible record a digital image of the deficiency and record the image number on this inspection sheet. Use the comments area to provide further information about each deficiency (i.e. missing, damaged, which phase(s), unusual circumstances, etc.). Use the comments section if additional writing room is required.

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Circuit Inspection

Inspection Item	Deficiency Found	Priority Rating	Digital Photo #	Description / Comments
Pole				
Crossarm				
Guy wires				
Primary conductors				
Secondary conductors				
Insulator				
Arrester				
Fuse				
Transformer				
Switch				
Capacitor				
Recloser				
Regulator				
Groundwire				
Trees				
Vines / other non-tree vegetation				
Other right-of-way deficiencies				
Street lighting				
Other - specify				

Comments

Figure 2-16
Example Overhead Circuit Visual Inspection Form

Underground Circuit Visual Inspections

Underground circuits reside in a demanding environment in which water and debris are a constant threat. While overhead circuits utilize air as their main insulating medium, underground circuits do not have this luxury. Underground conductors must be insulated along their entire length. Cables and splices that rely on dielectric fluid for insulation are prone to leaking. Damaged solid insulation is cause for concern due to the tight spacing found in the underground environment. Corrosion and short circuits are a constant threat as water is often present in underground structures. The degree to which underground circuit components need to be insulated, coupled with the unique challenges of working in the confined underground environment, mean that repairs to underground circuits are often lengthy. It is far better to find and repair damaged equipment before it fails, possibly creating a hazardous situation, and subjecting customers to prolonged outages. Visual inspections of underground circuits are a fundamental part of finding circuit problems before they develop into faults.

Confined Space Work Practices

Confined spaces, such as those found in underground electric systems, can present unique hazards to personal safety. Confined subsurface structures such as manholes, vaults, and splicing boxes can accumulate combustible and/or toxic gases. These structures present increased risks of explosion, poisoning, and asphyxiation and require unique safety considerations and work practices. Although safe confined space work practices are not covered in detail in this document, it is important to note that any utility performing underground distribution inspections should have a detailed confined space work procedure. Furthermore, any personnel who perform underground inspections should receive routine training in safe work practices.

What to Look for During Underground Distribution Inspections

Above Ground

Make sure the cover is in good physical condition and fits the opening properly. If a vented cover is used to verify that the vents are clear of debris. Also check to see that the cover is at grade.

Water and Debris

Look for water and debris in the structure. Does the structure need to be pumped or cleared before inspection? Are the cables or equipment submerged? Are the ducts freed of debris? Verify proper operation if a sump pump is present (this can usually be accomplish by lifting the float switch and observing the pump starting).

Structure Conditions

Check the overall cleanliness and physical condition. Look for cracks, spalling or exposed rebar. Check the condition of the floor and roof in addition to the walls. If cover tethers are used verify that they are installed properly and appear to be in good physical condition.

Racks and Saddles

Do the cable racks, saddles, and other structural components appear to be in good working order? Are any saddles missing their porcelain inserts?

Ducts

Are the duct entrances chipped or cracked and in need of grouting? Are the ducts properly sealed?

Cables, Services, and Other Conductors

Inspect all cables for insulation wear or abrasion. Be especially mindful of exposed conductors and visible burnouts. Is the insulation swollen, damaged, peeling, cracked, or burnt? Do the cables show signs of excessive heating? Inspect for leaking cables.

Joints

Look for leaking, swollen, imploded, or otherwise deformed joints. Do any joints show signs of excessive heating? What about burning or arcing?

Neutral Cable and Connections

Do the neutral conductors and connections appear to be in good working order? Are any bonds broken? Does the neutral bus appear to be in good working order?

Transformers and Other Equipment

Does all equipment appear to be in good working order? Are there any leaks? Are there any cracked or damaged bushings? Does any equipment show signs of arcing, burning, or excessive heating?

Visual Examples of Underground Line Deficiencies

This section provides visual examples of some of the overhead line deficiencies mentioned in this section. The pictures have been referred to in the above discussion of what to look for during visual inspections.

Figure 2-17
Flooded Transformer Vault with Floating Debris
Source: (Stone & Webster Consultants 2001)

Figure 2-18
Partially Imploded Cable Splice

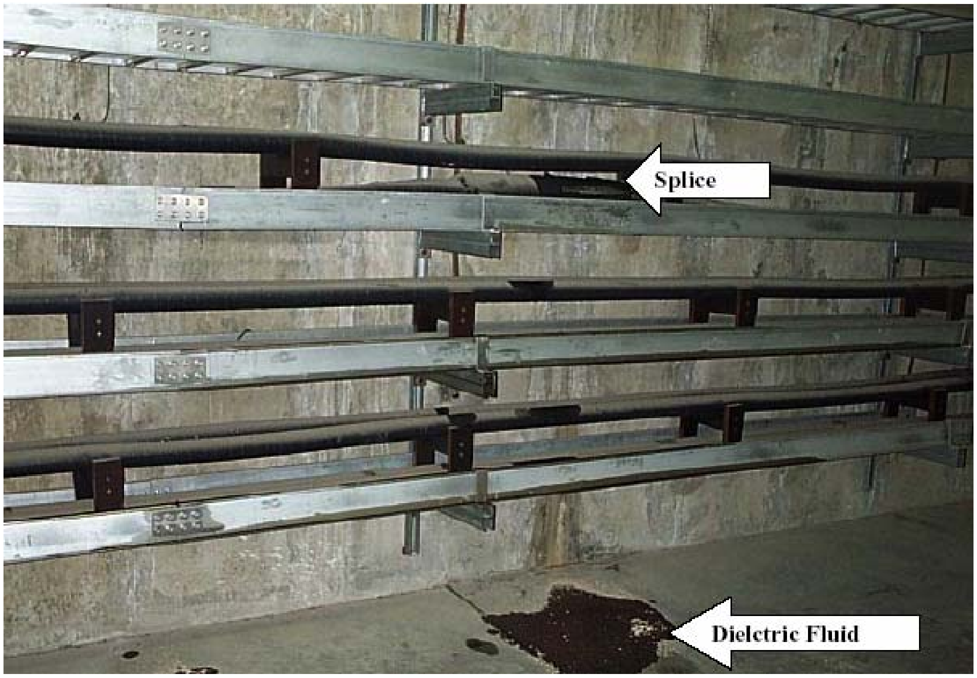


Figure 2-19
Leaking Splice on Primary Feeder in a Substation
Source: (Stone & Webster Consultants 2001)

Figure 2-20
Secondary Splice with Visible Signs of Overheating
Source: (Stone & Webster Consultants 2001)

Figure 2-21
Damaged 4 kV Cable
Source: (Siemens 2005)

Figure 2-22
Corroded Ground

Figure 2-23
Wood-Block Supports in Various Stages of Decay

Figure 2-24
Y-Bucket That Has Pulled Away From Support

Underground Inspection Forms

Inspection reporting forms are a crucial link between the field inspection and processing and storing the field inspection data. The reporting form helps prioritize repairs and maintain condition records for underground distribution facilities. The reporting form needs to be in agreement with the type of information sought from underground inspections. With that in mind, two different underground inspection reports are shown in Figure 2-25 and Figure 2-26. Figure 2-25 shows a basic reporting form while Figure 2-26 presents a more detailed inspection report. Utilities with small underground systems may find the basic report form more suitable for their inspection process since they are tasked with managing fewer underground structures. It should also be noted that underground inspection reporting shares many similarities with overhead inspection reporting. The topics of digital reporting practices and deficiency codes that were discussed in the previous section on overhead inspections are also applicable to underground inspections.

Underground Distribution Circuit Inspection Report

Sheet #: ____ of ____

Date & Time: ______________________ Circuit #: ______________________

Inspector(s): ______________________ Cable Termination Point ID #: ______________________

Location: ______________________ Temp. & Weather Conditions: ______________________

Instructions

Inspect the termination point itself and all conductors, equipment, and any other electrical utility infrastructure connected to it. When possible record a digital image of the deficiency and record the image number on this inspection sheet. Use the comments area to provide further information about each deficiency (i.e. missing, damaged, which phase(s), unusual circumstances, etc.). Use the comments section if additional writing room is required.

Follow confined space working procedures wherever applicable.

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Circuit Inspection

Inspection Item	Deficiency Found	Priority Rating	Digital Photo #	Description / Comments
Manhole / vault / pad				
Water in manhole / vault				
Primary conductor				
Secondary conductor				
Terminations				
Splices				
Conduit / conductor enclosure				
Network Protector				
Transformer				
Switches				
Arresters				
Grounding				
Street lightning wiring				
Right-of-way condition				
Signage				
Other - Specify				

Comments

Figure 2-25
Example Basic Underground Distribution Visual Inspection Form

Underground Distribution Inspection Report

Date & Time: ______________________ Circuit #: ______________________
Inspector(s): ______________________ Substation: ______________________
Weather: ______________________ Feeder Numbers: ______________________
Location: ______________________ Structure ID #: ______________________
Digital Photo #'s: ______________________

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Manhole Information

Gas Reading Percentage: _________%
Ambient Air Temperature: _________°F

Manhole Size:	□ Roadway Sidewalk
Manhole Condition:	□ Good Crowded Damaged:______________
Cover Size:	□ Loose Not to Grade Missing
Cover Condition:	□ Good Loose Not to Grade Missing
Type:	□ Roadway Sidewalk
Cable:	□ Primary Secondary Both
Debris:	□ No Below Ducts Ducts Blocked
Water:	□ Dry Below Cables Above Cables
Sump Pump:	□ Yes No Unknown
Sewer Con.	□ Yes No Unknown
Comments:	______________________

Cable and Joint Information

	Priority	Comments
Good - No Problems	—	
Cable Leak		
Joint Leak		
Joint Swelling		
Deformed Joint		
Racking Needed		
Burnout Visible		
Cable Smoking		
Joint Smoking		
Insulation Damaged		
Neutral Corroded		
Other		
Comments		

Transformer Information

Transformer Type: □ Network Subsurface Subway
□ Padmount Overhead Other:

*Examine for leaks, rust, damaged bushings, frayed wires, loose connections, and other deficiencies.

Enter separate information for each transformer:

Transformer Size	Phase(s)	Primary Voltage	Secondary Voltage	Deficiency	Priority	Comments

Equipment Information

Item	Good	Rusted / Corroded	Damaged	Other	Comments
Network Protector					
2-Way Switch					
3-Way Switch					
Fuse Box					
Fuse Pod					
Taphole					
Capacitor					
STOF Box					
URD Module					
Shunt Controller					

Comments

Figure 2-26
Example Detailed Underground Distribution Visual Inspection Form

3
CONSTRUCTION AUDITS

Adhering to construction standards is a key element of building reliable circuits. Construction deficiencies sometimes take months or years to manifest into faults so construction quality is often assumed rather than inspected. Never assume that crews will build according to specifications. Crews often make decisions based on misconceptions or because it's "the way we've always done it." A well-designed construction program utilizes a formal audit procedure as an integral part of the construction process. Systematic audits of new construction provide tangible confirmation that the construction adheres to company design standards and that field reports accurately reflect the construction performed. Construction audits also help educate crews on why things are done and how the designs minimize faults. Construction audits can apply to new construction but also to additions or changes to an existing structure, including work triggered by an outage follow-up.

Faults are the root cause of momentaries, voltage sags, and many customer interruptions. Because construction auditing programs help reduce faults, they also help improve the reliability and power quality of distribution service. Duke Power revamped their ineffective construction auditing program and dramatically improved the quality of their construction from 1999 to 2004 (Taylor 2006).

Who Should Perform the Audits?

The "who and how often" question is best answered by each individual utility. Although there is not a one-size-fits-all answer to this question, it is possible to give some guidelines. The personnel who perform the auditing fall into two basic categories: (1) utility personnel and (2) non-utility personnel (outside contractors).

Auditing responsibility can fall nearly anywhere within the company when utilities use internal personnel to perform construction auditing tasks. One issue here is that most companies do not have a well defined construction auditing programs and thus often do not have well defined guidelines on who should perform the audits. Some utilities use field technicians for auditing purposes. Yet other utilities rely on line crews or foremen to audit. In many utilities the auditing responsibility will fall to the field engineers or an engineer from a central office. In any case, it is good practice to use auditing personnel that are somewhat removed from the construction crews to help ensure impartiality.

There are also a few companies that offer specialized line inspection services including auditing new construction. In this case, the contractor would review the utility's construction designs, and any other pertinent information, and then perform routine inspections of all new construction.

Regardless of who performs the construction audits (utility personnel or outside contractor) it is best to include a representative from the construction department on the auditing team. The reasons for this are twofold:

- Including the construction department in the auditing process helps build respect for the auditing program and also helps allay fears that the auditors are "out to get" the construction crews.
- Including the construction department in the auditing process provides a direct feedback path for using the auditing process as an educational tool. Using the auditing process as a teaching tool is discussed in more detail later in this chapter.

Auditing Frequency

One of the first questions to come up when considering most field auditing programs is how often to audit. As with the question of who should perform the auditing, these are also questions that are best answered by each individual company. Norman offers a few guidelines that can help provide a starting point for auditing frequency depending on the size of the system and the amount of construction activity (Norman 1989; Norman 1991):

- For large utilities or those with very active construction programs it is suggested that they audit *monthly*, especially during construction season.
- For smaller utilities, or those with less active construction programs, it is suggested that they audit at least *quarterly*.

These are estimates, not hard and fast numbers. They provide a starting point for utility personnel considering implementing a construction auditing program. Successful programs continually refine their approach to ensure the most effective results within the constraints of a given structure. Periodic examination of your auditing program may reveal that auditing is being done too frequently (therefore burning capital without providing additional feedback) or too infrequently (thus diagnosing errors or poor work practices too slowly). In either case, the remedy is to adjust the auditing frequency to better achieve the program goals.

Other auditing frequency options include using random sampling to audit a certain percentage of all jobs, auditing jobs by region, or by job type.

What to Audit

Selection of construction work to be audited should not occur haphazardly. Work selection should be accomplished through a well defined process which ensures coverage of all work crews, types of construction, and geographical areas of the service territory. Many utilities audit 10-15% of all construction (Norman 1989). Work selection needs to be objective for the audit process to be credible. Work crews can easily feel like they are being singled-out for auditing which can harm moral and work performance. However, there is some room for tailoring the auditing process to target weak performers. Crews that consistently perform well require less auditing to ensure they are meeting design standards due to their strong track record. Crews that are consistent underperformers can be audited more frequently to use the auditing process as a teaching tool for enhancing performance. Additionally, work in challenging conditions should be audited more intensely to ensure that it is being performed as reported and to company standards.

A general rule of thumb is that auditing should be performed more frequently on complex jobs since they present a greater possibility of error. Additionally, jobs that are done frequently probably don't need to be audited as intensely as less frequent tasks. Transformer change-outs are a good example of a frequent job that probably doesn't need intense auditing. Auditing a small percentage these jobs will likely yield enough information to achieve the auditing goals.

Auditing as an Educational Tool

Education comes from identifying construction that does not meet company design standards or otherwise violates safety standards. The audit should take a positive approach. This is an important concept – the audit is a communication and teaching tool, not a mechanism for attacking the construction crew. That is not to say that consistently poor performance should go unchecked. The audit program could contain penalties for consistently poor performance. The audit program could also include rewards for consistently outstanding performance. The audit provides a vehicle for the timely discovery of work practices that either aren't being carried out correctly or are not effective. Once identified, appropriate action can be taken to remedy the deficiencies.

Construction Auditing Forms

The auditing inspection form is a key component of a successful construction auditing program. As Norman points out, an auditing inspection form provides a well-defined and consistent format for recording auditing data (Norman 1989). The auditing form is key to acquiring accurate and consistent data that can be used to build a construction performance database.

At a minimum, the construction auditing form should include spaces for the following information:

- Date
- Audited by
- Work location
- Work type
- Work order number
- Comments (there should be lots of room for comments!)

The above list details the bare basics of what should be included on the construction audit form. In reality, it is common practice for utilities to employ a form with much greater detail. The data collected in the inspection checklist should be tailored to the construction standards used at the individual utility, as well as local and national safety standards (such as the NESC). Options for a checklist for the auditor could include:

- Animal guards installed correctly on all bushings and arresters
- Covered jumpers used
- Correct crossarm used
- Spacings acceptable per guidelines
- Guy wire insulated properly
- Riser bracket not grounded
- Proper connectors used
- Equipment tanks grounded properly
- Site tagged correctly
- Correct usage of current-limiting fuses
- Performed work specified
- No NESC construction grade violations
- Proper framing for the given structure angle
- Proper insulators used
- Span lengths do not exceed design limits
- Pole class not too small
- Proper conductor ties used
- Fuse barrels left hanging down in open cutout
- No grounds near the primary
- Arrester phase and ground leads per standards to minimize lead lengths
- Proper phase and neutral conductor sizes used

An example Construction Audit Checklist is shown in Figure 3-1. Of course, there can be many variations of this checklist depending on each utility's design and construction practices and deficiencies. As experience is gained with the program, items can be added or taken from the list. With time, lessons learned during construction audits will spread through the company, construction will be more consistent, and the fault resistance of structures will increase.

In addition to factors affecting a circuit's power quality performance, other factors can be considered in a construction audit: NESC violations and other safety issues along with cost issues are the most common. For contract work, utilities can ensure that the contractors did the jobs that they took credit for.

Construction Audit Checklist

Date: ____________________ Sheet #: ______ of ______

Auditor: ____________________

Work Order ID: ____________________

Work Location: ____________________

Pole Hardware & Equipment — Comments / Location	Anchors, Guys, & Brackets — Comments / Location
____ Pole class too small	____ Guy and/or anchor installed incorrectly
____ Pole class too large	____ Guy insulator not installed / incorrectly installed
____ Angle exceeds allowable degrees for single insulator	____ Incorrect guy insulator
____ Angle exceeds allowable degree for double insulators	____ Guy not installed on tension span
____ Angle permits single insulator but double insulators used	____ Guy alignment off >3' on angle or 1' on tangent
____ Crossarm size too large	____ Guy not bonded to neutral
____ Crossarm size too small	____ Anchor rod too vertical or not inline with guy wire
____ Improper application of metallic tie wire	Conductors
____ Improper application of polymer tie wire	____ Pole ground not stripped to neutral level
____ Fault tamers not used in high fault area	____ Copper wire bonded on top of dissimilar metal
____ Animal guards missing	____ Coordination or fusing error
____ Animal guards improperly installed	____ Un-fused tap on backbone or recloser sub feeder
____ Cutout mounted in wrong location	____ Conductor #2 ACSR used for line exceeding 25 amps
____ Arrester mounted incorrectly	____ Conductor too small for mainline
Underground	____ Conductor span too long
____ UG Conduit straps missing or improperly installed	____ Conductor middle phase on arm instead of pole top
____ UG Primary riser bracket grounded - bad taping	____ Conductor middle phase dead ended on arm instead of pole top
____ UG Installed without treating pole afterwards	____ Inadequate conductor spacing
____ UG Cable not color coded or marked correctly	____ Undersized conductors
____ UG Secondary connection not rubber taped	____ Secondary hot leads on xfmr not insulated
Crew Work Practices	Other Comments
____ Work not completed as reported	
____ Work intentionally completed different from design specification	
____ See comments section	

Comments:

Figure 3-1
Example Construction Audit Checklist

Construction Audit Scoring Systems

Many utilities also find it helpful to have a scoring system for audits. Tracking scores also reveals how well a district is doing over time. The auditor could deduct points based on a defined checklist. The checklist shown in Figure 3-1 could easily be used for this task by simply adding a few locations for the score (or deductions) to be tallied as well as an "Overall Score" field at the top of the sheet. Auditing programs that utilize a scoring system will also have a Point Deduction Scoring Convention document that outlines the score or point deduction associated with a great variety of construction mistakes that are likely to be found in the field. Table 3-1 provides a few examples of how the Point Deduction Scoring Convention might be setup. Of course, the full document would have many more entries to account for at least every situation listed on the auditing checklist.

Scoring helps reinforce specific points, so it is good practice to penalize more severely those deficiencies which are more likely to be fault sources or those which cause larger faults (more customers). Not only are different infractions scored according to severity under the Point Deduction Scoring Convention, but often each infraction also carries a range of deductions based on where it occurs on the line:

- Three-point reduction for infractions at locations where the upstream protective device is the station breaker or three-phase recloser
- Two-point reduction for infractions on the mainline (or un-fused) tap where the upstream protective device is a single-phase recloser or fuse
- One-point reduction for infractions on fused taps
- A program could also categorize fractions as either major or minor. Major infractions receive deductions of 1 or more points while minor infractions can receive partial-point deductions. One method of accounting for minor infractions is to simply count all minor errors on the checklist as an overall one-point deduction.

Table 3-1
Examples of Point Deduction Scoring Conventions for Overhead Construction Auditing

Construction Inspection Point Deduction Scoring Convention					
Circuit Type	**Error Type**	**Description**	**Station Breaker or 3-Phase Recloser**	**1-Phase Recloser**	**Fused Tap**
Any	Equipment	Automatic splice in slack span	-3	-2	-1
Any	Guying	Physically bending guy stick around obstacle	-1	-1	-1
Any	Equipment	No pole tag	-0.25	-0.25	-0.25
Double	Framing	All 6 conductors on one ten foot arm	-3	-3	-3
Single	Span Length	Span exceeds limits of 200 ft. + 10% for 3 phases on 10 ft. crossarm	-3	-2	-1

Remember, a good auditing program is a teaching tool that improves line reliability by reinforcing good construction practices. In the spirit of teaching, some other general guidelines for scoring-based auditing systems are:

- Do not deduct more than once for the same error committed multiple times on the same job.
- Do not deduct more than once for an error that fits into multiple categories.

- Do not deduct for errors that are not documented in the design manual – if the issues is serious, then add it to the design manual.
- Give a grace period before deducting for new designs or design changes to allow the crews to get up to speed.

Results are important—*not appearances*. While it may be educational to point out sloppiness, that is not the main point. Bare jumper or ground leads can be very neatly applied on a structure but have insufficient clearances. In fact, sometimes the neatest looking path is not the path that gives the most electrical separation. Emphasize the most important issues that impact power quality and the fault resistance of a line: Are separations sufficient? Are animal guards applied correctly and securely? Are arresters mounted appropriately? Are arrester leads as short as possible?

Construction Upgrade Programs

Outage follow-ups and construction audits along with reviews of outage data help pinpoint the weaknesses in existing construction. Utilities can shore up these weak areas by any one of several construction upgrade programs:

- Animal-guard implementations
- Arrester replacements or new applications
- Tree clearance
- Danger tree programs
- Pole inspection and replacements
- Cable-replacement programs

Other options are possible, depending on past construction deficiencies. For example, if a utility has at some point built a number of lines with a shield wire (overhead neutral) that perform poorly, a program might target them for replacement or upgrades. A shield wire design can perform well if it has good insulation and grounding, but it can also perform poorly if not done right—the grounding downlead can reduce insulation levels and make lightning contacts more likely and can increase the likelihood of animal contacts and contacts from other debris. Then, a shield-wire upgrade program could target these sections for replacement or for insulation upgrades to reduce animal and lightning faults.

Equipment replacement programs also fall under the upgrade category. Many utilities have cable replacement programs. Program policies are done based on the number of failures (the most common approach), cable inspection, customer complaints, or cable testing. High-molecular weight polyethylene and older XLPE are the most likely candidates for replacement. Most commonly, utilities replace cable after two or three electrical failures within a given time period (Tyner 1998).

Because fault sources are most often at equipment poles, consider programs targeted specifically at equipment poles. For example, a transformer retrofit program could upgrade all transformer locations to the utility's design specifications. This could include replacement of old arresters with tank-mounted polymer metal-oxide arresters, animal guards on bushings and arresters, covered jumper leads, or elimination of grounded wires above the transformer tank (including grounded guy wires).

It costs much less to upgrade construction when a crew is already set up at a pole. Consider implementing procedures and checklists for the crew to fix problems on the pole *whenever* they are set up for work on a pole. Options to consider in such a program are:

- Add animal guards on unprotected bushings or surge arresters.
- Replace old surge arresters.
- Add fiberglass guy insulators to uninsulated guys near the primary.
- Strip out unnecessary grounds above the neutral wire (especially those near primary conductors or jumpers).
- Replace any flashed or damaged equipment.

4
OUTAGE FOLLOW-UP REVIEWS AND AUDITS

The three most-significant power quality concerns for most customers are: voltage sags, momentary interruptions, and sustained interruptions. These three power quality problems are all caused by faults on the utility power system, with most of them on the distribution system. Because faults are the *root cause* of voltage sags and interruptions, reducing the number of faults will obviously reduce the number of voltage sag and interruptions – and power quality will improve.

On-site outage reviews can help identify weak points and reduce fault rates. Faults tend to repeat at the same locations and follow patterns. Consider animal faults—one particular pole, which happens to be a good travel path for squirrels, may have a transformer with no animal guards. The same location may have repeated faults. By identifying the location of fault and any structural deficiencies that contributed to the fault, the deficiencies can be corrected to prevent repeated faults in the future.

Outage Review Process and Goals

The main goals of an outage-review program are:

- *Outage database improvement* – Did crews enter the fault code or outage code correctly based on available information? If not, feedback can correct the mistake, and lessons learned can help prevent future mistakes.
- *Training* – Field engineers and operating crews get more "on-the-job training" about specific design and construction deficiencies that lead to faults.
- *Source* – Identify the most probable cause of the fault (tree limb, animal, lightning, and so on)
- *Corrective action* – Construction deficiencies should be corrected to avoid repeat fault events. Corrective action is a prime goal of a fault review.

These goals are accomplished through a five-step process that begins with a site visit:

1. Field visit to the outage site.
2. Root cause investigation of the outage.
3. Review and update the outage record to ensure completeness and accuracy.
4. Draft work orders for any follow-up work related to the outage.
5. Complete follow-up construction work.

During an outage review, the main tasks of the reviewer are to review the data at hand and address the following questions:

- Where was the most likely location of the fault?
- What was the flashover path?
- What was the most likely cause of the fault?
- Was the outage code entered correctly?
- Was the faulted circuit adequately covered by protective devices? Was the fault on an unfused tap?
- Did protective devices operate as expected?
- What structural deficiencies contributed to the fault?
- Are the deficiencies likely to lead to additional faults?
- How could the deficiencies be corrected?

These questions are also presented in the example outage follow-up report shown in Figure 4-1. Besides the outage follow-up reporting form, the reviewer should also bring circuit maps, applicable construction standards, and list of local protective device settings and locations with them into the field.

Based on addressing these issues, corrective action can be initiated if it is warranted. Corrective action could include rebuilds on one or more structures and could include tree/branch clearance. Corrective action could also include fixing unrepaired damage related to the fault.

The first step is finding the most likely location of the fault that caused the outage. Permanent faults are relatively easy to pinpoint because the crew had to actually fix damage at one or more locations. Temporary faults are harder to pinpoint. If a fuse blows, the area narrows considerably. For areas with repeat fuse operations, careful patrols may identify areas where repeated faults occur. Still, if a tap fuse operates but is refused successfully, the cause may have been a squirrel across a bushing, a tree branch that fell onto then burned off of a line, or wind pushing two conductors together. It often takes a trained eye to determine the cause.

Many outages are classified as “unknown.” For some outages, the cause will remain unknown. While the exact cause may remain unknown, information about the outage can help point the way to finding deficiencies. The time of day and the weather during the fault can help suggest a cause. Clear weather may suggest an animal fault, especially if it happens during the daytime. Stormy weather suggests lightning. An outage history for the protective device may reveal patterns. The probable cause can help the outage investigator look for deficiencies that could have led to the cause.

Outage Investigation Report

Date: ______________________

Investigator: ______________________

Outage ID: ______________________

Outage Date & Time: ______________________

Investigation Site / Pole ID: ______________________

Where is the most likely location of the fault?
What was the most likely flashover path? Describe any evidence of flashover?
What was the most likely cause of the fault?
What outage code was entered? Is this correct? If no, update outage code.
Is the faulted circuit adequately covered by protective devices? Did the fault occur on an unfused tap?
Did protective devices operate as expected? If no, explain.
Did any structural deficiencies contribute to the fault? If yes, explain. If yes, how could the deficiencies be remedied? If yes, are other structures likely to exhibit the same deficiency? Explain.
Comments

Figure 4-1
Example Outage Follow-Up Form

Determining Which Outages to Review

Several options are available to decide which outages to review:

- All outages that impact over 500 customers (or some other number)
- All mainline outages
- All outages on "problem circuits"
- All outages on "critical-customer circuits"
- Outages on protective devices with excessive operations over a given time period (pick a threshold based on whether the device is a fuse, recloser, or circuit breaker)
- A random portion of all outages

Utilities could also use combinations of these options in forming criteria for outage reviews. Responsibility for outage follow-ups will normally fall to a local field engineer.

In general, the outage review should be performed as soon as possible and definitely within 2 weeks of the outage. Swift outage review is important because some fault indicators, such as animal remains or pole charring, can fade or disappear with time. Additionally, it is important to get to the review while the outage is still fresh in the minds of those who made the initial fault investigation and repair. It is important to include the field crew and supervisor that responded to the outage in the review process since these folks have firsthand knowledge of the fault.

Auditing Outage Reviews

In addition to regular outage reviews, a utility may audit a sample of the outage reviews. One auditing scheme is to select two major outages each quarter for each operating district. Audit the follow-up work on these outages for engineering, timely completion, and construction quality. A "reliability auditor" could visit the outage location with the local field engineer. The main point of such an audit is to educate and reinforce consistent approaches to outage follow-ups. Look for any of the common outage follow-up errors shown in Table 4-1. If at the time of the audit, the corrective action has been done, the auditor and the local field engineer can review the corrective action to determine if it was done properly. For example, check that animal guards were attached correctly and that sufficient clearances were maintained; other construction related checks are discussed in Chapter 3 - Construction Audits.

Some utilities find it useful to apply a scoring mechanism to outage review audits. A scoring system could be adapted from Table 4-1 by applying point deductions for the errors shown. Deduct one point for minor errors, 2 points for moderate errors, and three points for serious errors. Start all outage reviews with 10 points and then deduct for errors. This provides a convenient metric for measuring the quality of outage responses and tracking response quality over time.

Table 4-1
Common Errors in the Outage Follow-Up Procedure

Common Outage Follow-Up Errors
Follow-up not completed
Follow-up completed without site visit
Failure to fully investigate outage (such as not talking with the crew that initially fixed the outage)
Failure to prevent repeat outage at same location (assuming solution is within scope of outage follow-up)
Failure to completely fix outage related damage
Engineering errors on follow-up work
Improper or non-optimum solution implemented
Failure to initiate work order to repair outage damage

5 PROBLEM CIRCUIT AUDITS

Just as there are pole locations that can have repeated faults, faults can cluster on some circuits. These faults may be from consistently poor construction on a circuit, inadequate clearances, heavy tree exposure, or a few poor structures with repeated faults.

The goals of a problem-circuit audit are:

- *Source* – Identify the deficiencies that are most likely to be sources of faults.
- *Corrective action* – Correct construction deficiencies to avoid repeat fault events.

Justifying Problem Circuit Inspections

The recent trend towards deregulation has many regulatory agencies concerned that electric service reliability will decline in the deregulated environment. To address this issue, regulatory agencies have begun to regulate reliability by requiring utilities to file reports on annual reliability and reliability improvement plans. The trend towards regulating reliability also includes requiring utilities to report their worst performing circuits as well as their plans for improving performance on those circuits. Problem circuit inspections are an integral part of the process for improving reliability on poorly performing circuits.

Designating and Prioritizing Problem Circuits

Criteria for designating *problem circuits* can come from many options: circuits with critical customers that are having problems, circuits with excessive momentary interruptions, circuits with long-duration interruption problems (high SAIFI or SAIDI), or circuits with excessive customer complaints.

Brown examined problem circuit identification at Midwest Energy using historical data as well as predictive modeling to study how utilities can better identify and manage problem circuits (Brown 2004). Through his work, Brown concluded that many existing worst circuit programs do not adequately identify the true worst performing circuits. One significant concern is that an individual circuit can simply have a bad year. A normally reliable circuit can get placed on the list of worst performers causing resources to be spent unnecessarily on improving the performance of a normally reliable circuit. There are some factors that should be kept in mind when ranking feeders for improvement:

- *Variability* – This is the biggest factor. Whether feeders are ranked by SAIFI or SAIDI, both indices exhibit significant variability. Ranking feeders just based on one year of data can give misleading results. Five or more years of data is preferable.

- *Major storms* – Including major storms increases variability, especially for SAIDI.

Brown offers these suggestions to help accurately identify poor performing circuits (Brown 2004):

- *Annual potential poor performer list* – Keep an annual list of potential poor performers based on average feeder SAIFI over the previous five-year period.
- *Add recent poor performers* – Add the worst performing circuits from the past year to the list of potential poor performers to focus attention on circuits that may be declining rapidly.
- *Determine a SAIDI-based criteria* – Identify acceptable feeder performance by determining the feeder SAIDI that should only be exceeded once in a ten years.
- *Model the potential poor performers* – Build the list of worst performing circuits by modeling the potential poor performers with predictive reliability tools to identify those that fall short of the acceptable SAIDI criteria.

Where to Look and What to Look for

The “problem” should direct the focus of the audit. If the problem is momentary interruptions, review the section covered by the circuit breaker or recloser that is excessively operating. Pay special attention to animal and lightning susceptibility on the circuit. If the problem is long-duration interruptions, concentrate circuit patrols and reviews on the feeder backbone. Pay special attention to susceptibility to trees; a review of the outage records for the circuit should reveal even more information on where to look for problems.

Some deficiencies are obvious during the field review of a problem circuit. Figure 5-1 shows a deteriorated pole top. Figure 5-2 shows a riser pole that has had multiple fault events. There are several paths that have very short clearances. The structure is highly susceptible to animal contacts, for faults both upstream and downstream of the fuse. The lightning protection is also less than desired; the phase and ground leads are longer than they could be. Both of these structures are obvious candidates for repair and upgrades.

Figure 5-1
Deteriorated Pole Top

Figure 5-2
Riser-Pole Installation With Evidence of Multiple Arc Burns

Tree exposure is another major consideration in a problem-circuit audit (Figure 5-3). The auditor must decide if the circuit warrants tree clearing. A danger-tree inspection is worthwhile to pinpoint trees and branches that are likely to fall. These include dead trees, leaning trees, or trees with major defects that threaten the line. Consider not just the immediate area around the

conductors but also the overhang (Figure 5-4) and danger trees outside of the normal right-of-way but still within striking distance of the line. Decisions on tree maintenance should also include the time since the last tree maintenance on the circuit and the history of tree-caused interruptions on the circuit. Consult Chapter 6 -
Audits of Tree Exposure and Vegetation Management for a more detailed discussion of mitigating tree exposure.

Figure 5-3
Trees Growing Into Lines

Figure 5-4
Lines With Significant Tree Overhang

Broken tree branches account for the majority of tree-caused interruptions. In one utility in the northeast United States, 63% were caused by broken branches compared to 11% from falling trees and only 2% from tree growth (Simpson 1997). Niagara Mohawk Corporation (NIMO) found that 86% of permanent tree-faults were outside of the right-of-way, and most were from major breakage (Finch 2001). Falling trees do the most damage; they often break conductors and even poles in some cases. Tree faults usually occur during storms, primarily from wind. Snow and ice also contribute to tree failures.

Protective device application is another consideration for problem circuit inspections. The main area of concern here is usually unfused taps. The more protective devices that are on the circuit, the more faults are isolated to smaller sections of the circuit. It is desirable to have as much of the exposed circuit on fused taps as possible (EPRI 1002188 2004). This way the impact of permanent faults is limited to as few customers as possible. If the taps are too long under this approach then consider using reclosers instead, especially for circuits with multiple main sections (Short 2004). Another benefit of fuses is that they limit the length of the circuit that must be searched to find faults when they occur – the blown fuse acts as a fault finder. Make sure to check for unfused taps during any problem circuit inspection. Many short unfused taps are taken for granted, especially during damage patrols and fault finding activities. Using fused taps will help improve reliability (Short and Taylor 2004).

Figure 5-5 shows a structure with several deficiencies that should be noted during a problem circuit inspection. By most accounts this is a fairly routine structure. However, if this line has a history of poor reliability then one might start to view the structure a bit differently. Unfortunately, structures like this are likely to be encountered over and over again on a problem circuit inspection. So, what are the reliability-related issues with this structure?

- *No local external protection* – Local fuses, external to the transformers, would limit faults at the transformer bank (animals, failed arresters, etc.) to only the customers served by this bank. This is particularly important since there aren't animal guards on the transformer bushings or lightning arresters. Since the line deadends at this transformer bank, another option would be to fuse this tap back at the mainline – one span to the right out of the frame. However, this was not done either. This would not be suitable if the line did not dead-end here, as fusing at the mainline would subject everyone on the tap to an outage for faults at the transformer bank.
- *No animal guards* – Bushing covers and arrester caps will greatly reduce the likelihood of animal-related faults on this structure.
- *Poor clearances* – This structure has poor clearances, particularly between the guy wires and phase conductors.

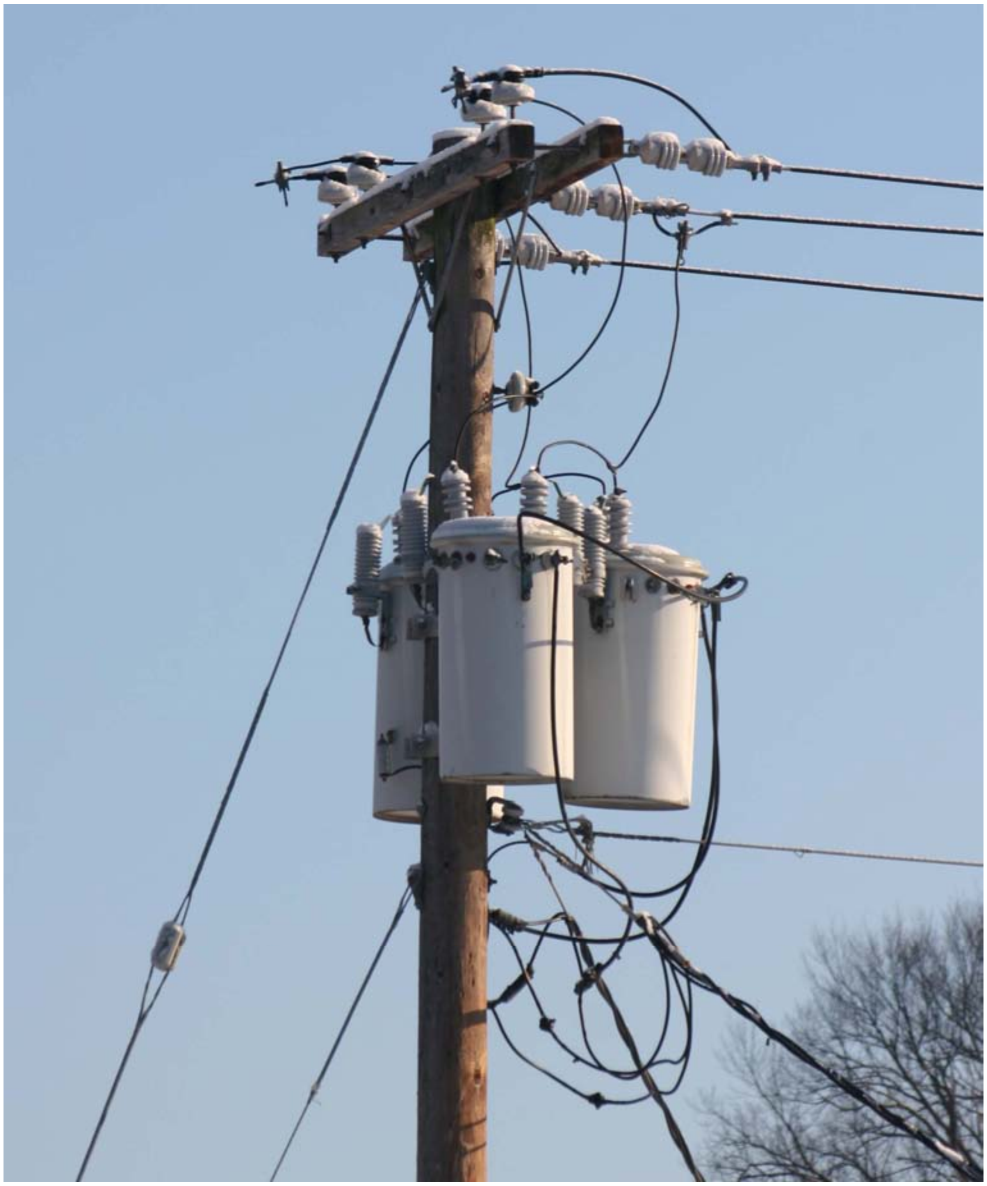


Figure 5-5
Distribution Structure with Multiple Deficiencies – No Local Fuses, No Animal Guards, and Poor Clearances

Some specific items for a repair checklist could include:

- Animal guards missing or improperly installed on any surge arresters or bushings
- Transformers without local, external fuses
- Guy wires without proper insulation
- Pole ground wires run near the primary
- Old arresters
- Heavy tree coverage

- Danger trees
- Overhanging dead limbs
- Damaged insulators or bushings
- Deteriorated or damaged equipment
- Poor clearances, including clearance with grounded guys
- Vines on equipment poles
- Broken / defective structures (broken crossarms, significantly leaning poles, etc.)
- Animal damage – chew damage, nest materials, excessive droppings

Conducting a problem circuit inspection should not be the only activity pursued when investigating a problem circuit. It is good practice to also review the protection schemes on the circuit and to review ways to reduce the impacts of faults on the circuit. Are reclosers and other devices coordinated properly? Does the circuit have enough protective devices? Are there any unfused taps (even very short sections can cause problems)? For more information, see the EPRI report *Power Quality Improvement Methodology for Wires Companies* (EPRI 1001665 2003).

Problem Circuit Inspection Forms

A well-defined and documented inspection process provides the foundation of a successful problem circuit inspection program. There are a great variety of deficiencies that can be responsible for a circuit's poor performance and none of them should be overlooked when inspecting a problem circuit. A standardized problem circuit inspection form helps ensure that all potential fault sources are examined. Figure 5-6 provides an example of one possible problem circuit inspection form. The type of outages, momentary or permanent, that the line commonly experiences can be helpful in determining what to look for during the inspection so this information can be filled-in at the top of the form prior to the inspection. During the inspection, each deficiency discovered is noted on a separate line in the report. There are enough blank lines to account for 20 individual deficiencies and additional pages can be added if necessary. The form also allows the inspector to indicate that a problem exists on the entire circuit as may be the case with an issue such as a lack of wildlife guards. The form also lists many of the most common deficiencies uncovered during problem circuit inspections for quick reference.

Problem Circuit Investigation Report

Date: ____________________________ Circuit: __________

Inspector: ____________________________ Sheet #: ____ of ____

Background Information

The outage history for this circuit indicates that the primary concern is: Momentary Outages Permanent Outages

The outage database indicates that faults on this circuit are primarily:

Animal-related Lightning-related Tree-related Weather-related Equipment-related Other:_____________

Circuit Inspection

Defect	Pole # or Entire Circuit	Comments

Common Deficiencies

Animal Guards - missing or improperly installed
Transformers without local external fuses
Unfused taps
Excessive mainline exposure
Protective device miscoordination
Susceptibility to conductor burndown
Old arresters (non-MOV arresters)
Insufficient arrester clearance for isolator operation
Poor clearances (including with guy wires)
Guy wires without proper insulation
Pole ground wires located too close to primary conductors
Broken crossarms or other structural components
Heavy tree coverage
Vegetation growth into conductors
Danger trees
Vines or other vegetation growth on poles / equipment
Damaged insulators
Damaged bushings
Evidence of arcing
Animal damage - chew/bite damage, nest materials, droppings, etc.

General Comments

Figure 5-6
Example Problem Circuit Inspection Report Form

6
AUDITS OF TREE EXPOSURE AND VEGETATION MANAGEMENT WORK

Vegetation is a leading cause of unplanned service interruptions for many utilities causing both momentary and long-duration interruptions. Trees impact power delivery systems to such a degree that vegetation management is often the largest expenditure in a utility's operating and maintenance budget (Goodfellow 2005). Utilities spent in excess of $2.5 billion dollars on vegetation management services in 2006 (Goodfellow 2006). With vegetation management representing a major maintenance expenditure for many utilities, it is essential that a utility's vegetation management programs operate as efficiently and effectively as possible.

Trees cause interruptions in a number of ways. Trees and branches may fall, be deflected, or grow into contact with conductors. Conductors may sag or be deflected into contact with trees. Trees also may provide a point of access for animals to come into contact with energized utility apparatus. When trees contact energized utility equipment, the resulting damage is often extensive, and repairs are expensive and time-consuming. The majority of tree-initiated faults occur on distribution circuits, but transmission circuits are not immune. This was dramatically demonstrated by the now infamous tree-caused fault on August 14, 2003 on a 345-kV line in Ohio, which resulted in an outage to 50 million utility customers.

This chapter is intended to provide general background on vegetation-related issues. It also addresses three different types of inspections and audits:

1. Field inspections of tree-related conditions as a means of assessing risk.
2. Post-work inspection audits of line clearance tree work.
3. General considerations for auditing vegetation management program effectiveness.

The Need For Tree Inspection and Vegetation Management

Tree-conductor conflicts are a dominant cause of interruptions, often accounting for 20% to 40% of customer interruptions (Deric and Hollenbaugh 2003). Since vegetation can have such a negative impact on system performance, most utilities approach vegetation management with service reliability and power quality goals in mind.

While improved reliability and outage reduction are often the primary goals of line clearance maintenance activities, there are other compelling reasons for implementing tree inspection and vegetation management programs:

Regulatory Considerations – Regulatory agencies at both the federal and state level are paying more attention to system reliability and vegetation management. Recent actions by FERC have lead to new NERC standards for vegetation management on transmission lines. State regulatory commissions have become increasingly active in this area, focusing primarily on vegetation management on distribution systems. Examples of regulatory involvement by state commissions include the establishment of mandatory clearances, mandatory cycle periods, mandatory spending, and commission-ordered vegetation management program audits.

Line clearance maintenance cycles are receiving greater regulatory focus. There is a relationship between budgetary commitment and maintenance cycles. When extended cycle periods coincide with decreased reliability or customer satisfaction, regulators may impose fines or mandate changes. For example, CILCO failed to meet its intended vegetation maintenance cycle of four years (Table 6-1) and was reprimanded in a Staff Report to the Illinois Commerce Commission (October 17, 2000); their tree-maintenance cycle had slipped to the equivalent of a ten-year cycle.

Table 6-1
Illinois Utility Tree Maintenance Cycle Targets

Utility	Tree-maintenance target in years: Urban	Rural
Alliant-Interstate Power Company	4	5
AmerenCIPS	3	4+
AmerenUE	3	4+
CILCO	4	4
ComEd	4	4
Illinois Power Company	3 to 4	3 to 4
MidAmerican Energy Company	3	3

Source: Staff Report to the Illinois Commerce Commission on October 17, 2000

Mitigating Storm Damage – Tree and branch failures cause considerable damage to energy delivery infrastructure during storms. Duke Power discovered this during an ice storm in 2002 that impacted their service territory: the circuits that had not been maintained in 13 years had five times the damage of circuits that had been maintained from one to six years previously (Taylor 2004). Duke justified increasing their vegetation management budget based on reducing storm repair costs.

Fire hazard – In areas with a high risk of wildfire, tree-conductor clearance requirements are often a concern, and may establish the need for more intensive line clearance tree maintenance. This is typically a concern in the western USA. As an example, the State of California Rules for Overhead Electric Line Construction specifies a minimum of 18-inch clearance between conductors and vegetation for all distribution and transmission circuits. In addition, California (Public Resource Code Section 4293) established minimum tree-conductor clearances for circuits in rural areas where wild land fire is a risk as shown in Table 6-2.

Table 6-2
Vegetation Clearances Specified by the State of California Public Resources Code Section 4293

Operating Voltage	CA Minimum Tree-Conductor Clearance, Wild Land Fire Areas
2,400 or more volts, but less than 72,000 volts	4 ft.
72,000 or more volts, but less than 110,000 volts	6 ft.
110,000 or more volts	10 ft.

Electrical Safety Hazard by Casual Contact – When trees *grow in to contact* with energized conductors, the potential for an electric shock hazard exists. In-growth contact is primarily a safety concern on transmission circuits, and generally a low risk on distribution circuits. In cases other than in-growth, tree contacts with energized conductors may create a touch and/or step potential hazard near the ground. The initial electrical resistance of a tree is high. Most contacts on the distribution system remain as high-impedance faults, not drawing enough fault current to operate a fuse or other protective device. There is a risk that the high impedance fault may be drawing enough current to create a risk of touch or step potential shock. This too is a greater concern at transmission voltages. The risk of a shock hazard developing is a function of the voltage of the electrical circuit with which the tree is in contact, the tree's resistivity, and the earth resistivity. The most dangerous conditions are when the site is wet. Wet soils lower earth resistivity and provides a better "ground" for the tree, so it draws more current from the line. Foot-to-earth and hand-to-tree contact resistances are also lower with drenched soil and wet bark.

Electrical Safety Hazard within a Tree's Crown: "Climbable Trees" **–** The risk posed by readily climbable trees is recognized by vegetation managers in the electric utility industry. These trees may be maintained to a higher standard of care than are the average population of trees in conflict with overhead conductors. Of all the trees adjacent to overhead utility lines, only some have structural crowns capable of supporting a climber in close proximity to energized conductors. A subset of these trees occur on sites with higher risk of the public being present and likely to be inclined to climb. While in theory every tree is climbable, only some are relatively easy for a child or adult to climb, further reducing the potential population of "climbable trees". The climber is potentially at risk of direct or indirect contact with high voltages.

Understanding How Trees Cause Interruptions

Trees are often found in close association with the overhead energy delivery system, both within the maintained right of way and in areas adjacent to it. Trees are living, growing, biological organisms that progress through their individual life cycles, responding to the environment in which they occur. The result is a dynamic system of interactions due to factors such as growth, decay, mortality, and loss of structural integrity.

There are two basic modes of failure associated with tree-initiated interruptions on the energy delivery system:

1. Mechanical Mode of Failure: structural failure of the tree or parts of trees (branches) causing physical damage to energy delivery infrastructure. An example would be a tree taking down conductors, arms, and poles as it falls.
2. Electrical Mode of Failure: the tree or parts of the tree provides a short circuit fault pathway between areas of unequal electrical potential. An example would be a branch lying between energized phases. In this failure mode, the electric system infrastructure typically remains intact.

A well-designed vegetation management program includes maintenance strategies that are intended to mitigate the risk associated with both failure modes. It is also possible to develop risk assessment criteria useful in inspecting overhead circuits for tree-related threats to service reliability as well as for other considerations.

The risk to reliability due to trees is mainly a function of (Goodfellow 2007):

- *Location of tree on the circuit* – The location of the potential tree-caused fault is an important consideration. A tree's location relative to that of overcurrent protection devices has a direct bearing on how a fault may be manifested in terms of the magnitude and duration of interruption.
- *Voltage gradient encountered by the Tree* – The voltage gradient encountered by the tree is a concern. Tree-conductor contacts that encounter high voltage gradients are at risk the electrical mode of failure. Note that it's the gradient (voltage/distance) between two areas of unequal potential rather than simply the nominal operating voltage that is of concern. Multi-phase circuits with tight phase spacing exhibit much higher gradients (phase-phase) than do single phase and phase-to-earth gradients.
- *Changing tree-conductor contacts* – Rapidly changing conditions that create a new tree-conductor contact represent the greatest risk. Rapid change can be due to branch and/or whole tree failure or deflection, or by conductor movements such as sag. Rapid change in the tree's position may result in either mechanical or electrical modes of failure. These changes are often the result of the loss of structural integrity of the tree. A more complete discussion of tree failure risk factors is included later in this chapter. Slow incremental change in tree-conductor contact through in-growth is generally considered low risk on distribution circuits.
- *Diameter of the portion of the tree impacting the energy delivery system* – Large-diameter contacts provide a much more conductive pathways for short-circuit current flow, increasing the risk of the electrical mode of failure. Larger diameter stems and branches also can do a great deal more mechanical damage to overhead lines when they fail structurally and contact conductors and supporting infrastructure.
- *Species of tree* – Tree species vary in a number of important ways with relevance to evaluating potential threats to reliability, including:
- Growth form, growth rates, and rates of re-growth following line clearance pruning
- Structural integrity; e.g,. susceptibility to wind-throw and strength of stems and branch attachment
- Mortality and response to pathogens

- Impedance (electrical conductivity varies by species)

In addition to trees, climbing vines can create conflicts that require attention (Figure 6-1). Vines can grow into contact with energized equipment quickly. They primarily represent a risk to the electrical mode of failure. They can envelop conductors and equipment such as transformers and fuse cutouts at pole tops, thereby encountering some of the highest voltage gradients (tight spacing) to be found on the overhead system. The intertwined stems potentially provide a path to ground for fault current. Faults caused by vines can be relatively persistent as the fast growing nature of vines make structures with vine coverage susceptible to repeat fault events.

Figure 6-1
Vine Covered Structure

Field Inspections: Identifying Tree Failure Related Risk Factors

While systematic risk assessments are best completed by an experienced forester or arborist, it is beneficial for anyone involved in field investigations to have some background knowledge of common tree failure risk indicators. This includes personnel involved in overhead line inspections, power quality or reliability inspections and outage investigations. Fortunately, many common risk factors are relatively easy to identify. These characteristics are helpful to understand for personnel performing problem circuit inspections, regular line inspections, and outage follow-ups.

The risk factors can be grouped into two broad categories:

1. Biological attributes for the tree.
2. Environmental attributes of the site on which the tree grows.

Line inspectors should be able to recognize the gross symptoms associated with each category of tree failure risk factors in the field. Once risk factors are identified near the right-of-way, the line can be marked for a thorough vegetation inspection by a utility arborist. A trained experienced arborist or forester may pick up on a problem before it is manifested by obvious symptoms, but their detailed assessment will generally consider these same categories of risk factors.

Biological Risk Factors

Defects in trees can usually be linked to previous wounding, insect infestation, other pathogens, or difficult growing conditions. Each places the tree under stress and often is manifested by visible indicators of structural problems. As with any structure, trees fail whenever the mechanical loading exceeds their mechanical strength. Structural defects can result in tree and branch failure when the defect reduces the mechanical strength.

Trees grow and respond to wounds in a manner that is fundamentally different to that of animals and humans. Unlike animals, trees never stop growing larger by adding to height and stem diameter. When we as humans are wounded, our damaged tissue responds and is repaired through a processing of healing. When the tissues of a tree are wounded, the tree responds by isolating and walling off the damaged area. The damaged tissue does not “heal”. By creating a barrier, the tree may be able to limit the amount of decay that occurs at the wound site. The ability of a tree to respond by walling off the damage varies substantially by species. By keeping these differences in a mind, an informed observer can better determine the health and structural condition of a tree.

The most common tree defects are as follows:

Deadwood – It is not uncommon to observe dead branches in the crown of an otherwise healthy tree. Deadwood is typically dry and brittle, and has lost the flexibility to bend easily under load (wind, ice, etc.). Dead branches also may be weakly attached to the main stem and thus prone to failure. Deadwood is easily detected during the growing season when healthy branches are in full leaf. Sloughing bark and the absence of fine branch tips are good indicators of deadwood in deciduous trees during the dormant season. Deadwood can occur as individual branches or on entire stems and trees. Suspended, detached branches hung up in the crown (a.k.a. “widow makers”) are of immediate concern.

Figure 6-2
Example of Deadwood

Cracks – A crack is a deep split that extends through the bark and into the wood. Cracks are a sign that the tree may have been subject to serious mechanical stress. They can also be due to other kinds of wounding. Cracks represent a breaching of the protective bark barrier, and create a point of entry for internal decay. There are four types of cracks (Figure 6-3):

- *Shear Crack* - A shear crack separates the stem into two halves and carries a high risk of failure. The crack will not "heal" and re-bond with itself. These cracks are typically relatively recent, so advanced internal decay is less likely.
- *In-rolled Crack* – The edges of this vertical crack are in-rolled, encompassing the bark and wood. The in-rolled appearance is due to the growth of callous tissue that has developed in growing seasons since the crack occurred. Because time has elapsed since the wound, trees with in-rolled cracks almost always have internal decay at the crack site.
- *Ribbed Crack* – A ribbed crack is a fissure in a raised rib of wood along the length of the stem. Like in-rolled cracks, the ribbed appearance is due to the growth of callous tissue that has developed in growing seasons since the crack occurred. Because time has elapsed since wounding, trees with ribbed cracks will have internal decay at the crack site.
- *Horizontal Crack* – These cracks run across the wood grain and are rarely seen since they develop just before the tree fails. They represent a very serious loss of mechanical strength. They generally are only observable on dead, bark-free areas.

Shear cracks

Inrolled crack Ribbed crack Horizontal crack

Figure 6-3
Examples of Tree Cracks

Weak Branch Unions – A weak branch union is a defect or weakness at the junction of two branches or between a branch and main stem. Weak unions typically occur with narrow branch angles that have a pronounced “V”-like appearance. They also exhibit a pronounced area of included bark below the crotch. A strong branch union is characterized by a “U”-like open form and a small bark ridgeline in the center of the union as shown in Figure 6-4. This indicates that the annual rings of the branch and stem are growing together, creating a strong union. Weak unions lack this ridgeline and may be an indication that bark is growing within the union (Figure 6-5) or that the union is an offshoot from a previously damaged spot. Weak branch attachments are also commonly found with "sucker" growth associated with improper pruning. They exhibit both an exaggerated growth response and are initially attached to the outer-most layers of woody tissue and are easily detached (Goodfellow 1987).

Notice the small ridge of bark in the center of the union

Figure 6-4
Example of a Strong Branch Union

Notice the absence of a bark ridgeline in the center of the union and the ingrown bark

Figure 6-5
Example of a Weak Branch Union

Decay – Decayed wood is the result of long-term exposure to decay-causing fungi. Decay is primarily an internal process and initially offers few outward indications. Areas of decay are commonly associated with earlier wounds that often remain visible. Wounds create a point of entry for fungal spores. Thus, prior wounds are a good place to begin looking for evidence of decay. Decay may occur in the root system, main stem, or in branches. Not all fungi cause decay and significant loss of strength. Decayed wood is always weaker than healthy wood and is therefore prone to failure. By the time fruiting bodies (conks, mushrooms,) of the fungi are readily apparent (externally in the stem or in the soil at the base of the tree), the decay process has reached an advanced stage and the loss of strength in the wood can be quite significant. (Figure 6-6.) It's also important to remember that some types of fruiting bodies such as mushrooms are relatively short lived and may not be present at the time of inspection.

Figure 6-6
Examples of Outward Signs of Tree Decay – Discoloration, Holes, and Fungal Activity

Cankers – A canker is a stem defect that can result in significant areas of deformity, dead tissue, and decay. They are typically found on main stems. Cankers stop or distort the growth of annual rings that normally would increase the diameter and strength of the stem. As a result, cankers are often a point of structural failure on a main stem. Figure 6-7.

Figure 6-7
Examples of Cankers

Biological risk factors often occur in groups. It is common for trees on a site to share a number of characteristics. The biological risk factors are often specific to individual species, to the species' suitability to the site, and its response to the local environment. If an individual tree is identified as a risk, a careful observer will pay particular attention to other trees in the vicinity, particularly those of similar species, looking for additional evidence of similar risk.

Environmental Risk Factors

Changes and Damage in The Root Zones – Physical damage to or loss of the root system is an area of major concern. Loss of roots adversely affects growth. It can place a tree under a great deal of biological stress leading to a loss of vigor, decline, decay, and ultimately structural failure. Loss of major structural roots makes a tree prone to physical uprooting. The potential for root loss can often be directly observed in the field by looking for:

- Evidence of recent disturbance on the site due to construction, including trenching, where major structural roots are often severed.
- Evidence of recent grade changes in the root zone that may have severed roots directly, or alter soil compaction and the availability of oxygen and soil moisture necessary for healthy root growth and development.
- Evidence of additional hard surfaces (paving, etc) reducing the availability of oxygen and soil moisture necessary for healthy root growth and development.
- Evidence of altered surface and changes in ground water levels and flow patterns. Changes in site wetness (both wetter and drier) can cause major root growth problems; including infection by decay-producing fungi and root loss.

The impact of damage to the root system on the above-ground appearance of the tree is often not immediately apparent. It typically will become indirectly observable over time (typically three to five years later) as the loss of roots causes declining vigor and dieback in the crown. Figure 6-8, Figure 6-9, and Figure 6-10.

Figure 6-8
Example of Root Damage Due to Excavation

Figure 6-9
Example of Crown Decline Due to Root Damage

Figure 6-10
Examples of Leaning Trees Due to Root Damage

Restricted Root Zone – In some cases the tree's roots may encounter natural site conditions that can be the cause of instability in the root zone. Soils in areas with a high water table, impermeable hardpan, and shall depth to bedrock may all result in very shallow or limited root systems leaving the tree susceptible to wind throw. In urbanized areas the presence of manmade soils and elements of below-ground civil infrastructure can have the same effect.

Changes in Exposure – Trees that have grown in close association with others in a forest stand have a structural form that is a product of this environment. They tend to be taller and have a more upright growth form than open-grown trees with thick stems and spreading branches. Stand-grown trees are particularly susceptible to wind throw and stem breakage when they are exposed by adjacent land clearing activities. Narrow strips of remnant forest that have been retained as visual buffers adjacent to areas of recent timber harvesting activities and new residential developments present a special challenge to utility vegetation managers.

Poor Tree Architecture – Poor architecture describes a structural crown form with structural imbalance or weakness. Figure 6-11. Poor crown architecture may develop over many years as the tree grows in response to poor environmental conditions, or rather quickly due to damage.

Asymmetry that develops over many years as a result of natural growth represents less risk than that which occurs rapidly due to damage or loss. Trees that have large branches that are out of proportion to the rest of the crown are particularly prone to failure.

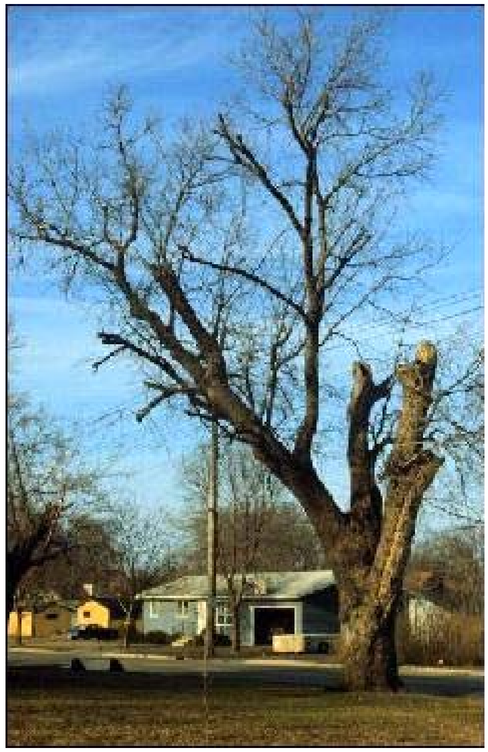


Figure 6-11
Example of Poor Tree Architecture

Not all leaning trees are at a high risk of failure. It is entirely natural for many species of deciduous trees to lean; this is not true of conifers.

- The growth of deciduous trees is greatly influenced by available light (phototropism). Their branches and crown will occupy any available opening. They will grow to areas of sunlight light even if it is well offset from their base. The tree may appear to lean precariously but remains stable. Deciduous trees develop tension and compression wood along their stems and branches in response to asymmetrical loads. However, a leaning deciduous tree with evidence of soil lifting opposite the lean may be increasingly unstable. In short, leaning that develops over time is stable, leaning that develops rapidly is a concern.
- The growth of conifers is primarily influenced by gravity (geotropism). They grow vertically. If a conifer stem is leaning, it is because something has changed since the stem grew into position. It may indicate problems with the individual tree or could be evidence of slope instability. In either case, leaning conifers are at risk of failure.

Other site features – The trees on some sites represent greater risk of failure because of physical features of the site itself. These factors are best identified and defined based on local knowledge and experience. Points to consider include:

- Slope steepness and stability
- Slope position
- Aspect: prevailing and storm wind directions
- Local wind patterns

Much of the above information came from the following sources which are recommended for further reading:

- *How to Recognize Hazardous Trees*, USDA Forrest Service Northeastern Area, Report NA-FR-01-96. Available on the web at: http://www.na.fs.fed.us/spfo/pubs/howtos/ht_haz/ht_haz.htm#what
- *Urban Tree Risk Management: A Community Guide to Program Design and Implementation*, USDA Forrest Service Northeastern Area, Report NA-TP-03-03. At the time of publishing, this report is available on the web at: http://www.na.fs.fed.us/spfo/pubs/uf/utrmm
- *A Handbook of Hazard Tree Evaluation for Utility Arborists.* International Society of Arboriculture, 1993.

Further information can also be found in:

- Fazio, J., *How to Recognize and Prevent Hazard Trees*. Tree City USA Bulletin No. 15. Nebraska City, NE: National Arbor Day Foundation 1989. At the time of publishing, this report is available on the web at: http://www.na.fs.fed.us/spfo/pubs/uf/sotuf/chapter_3/appendix_b/appendixb.htm
- Albers, J.; Hayes, E., *How to Detect, Assess and Correct Hazard Trees in Recreational Areas*, revised edition. St. Paul, MN: Minnesota DNR. 1993.
- The USDA Forrest Service Northeastern Area's website at: http://www.na.fs.fed.us/

Practical Considerations for Performing Field Risk Assessment Inspections

Types of Field Risk Inspections and Who Should Perform Them

Inspections of field conditions can take several forms. Three of the most common types of inspections include:

1. Systematic inspections are often completed in preparation for scheduled preventive maintenance tree work. These assessments form the basis for specific vegetation management prescriptions and are an important element of the work planning process. This kind of inspection is best performed by a trained and experience arborist. It should also be

noted that interactions with customers and property owners is a significant part of the inspection and work planning process.

2. Assessing the risk of tree failure involves both quantitative and qualitative criteria and is as much art as it is science. Practical experience with local species, conditions, and actual failures is invaluable. These same personnel can be trained to visually identify many of the readily apparent abnormal conditions found on overhead energy delivery infrastructure that can lead to outages.
3. Hazard tree and climbable tree inspections are two variants of systematic inspections that take place as part of the work planning process or occasionally as a discrete inspection activity. Each is discussed in more detail later in this chapter.
4. Failure Finding Inspection may be conducted following an outage or series of outages on a specific circuit. These inspections focus on identifying the need for corrective maintenance. Tree-caused outages often occur in relatively localized groups. Evidence that a particular tree has caused an outage should be relatively apparent. An inspection of other trees that exhibit similar characteristics is an effective method of identifying further risk. This kind of inspection can be completed by an arborist/forester or by a technician or engineer focusing on reliability problems.
5. Physical Inspections of trees at the time of work are also an important part of the vegetation maintenance work practices in the field. Line clearance personnel have the opportunity to make close inspections of individual trees at the time they are performing vegetation maintenance work. It is vitally important that line clearance crew personnel understand that their goal is risk identification and mitigation rather than simply thinking in terms of creating clearance.

Field Risk Assessment Inspection Checklist

Checklists provide an effective and efficient means of conducting inspections. They provide a structured inspection process and prompt the inspector to make a consistent and thorough assessment of potential risk factors. The most effective checklist includes risk assessment criteria based on actual experience with tree failures that have occurred on the system.

Useful checklists for each of the three inspection types should include specific inspection criteria from each of the following general subject areas:

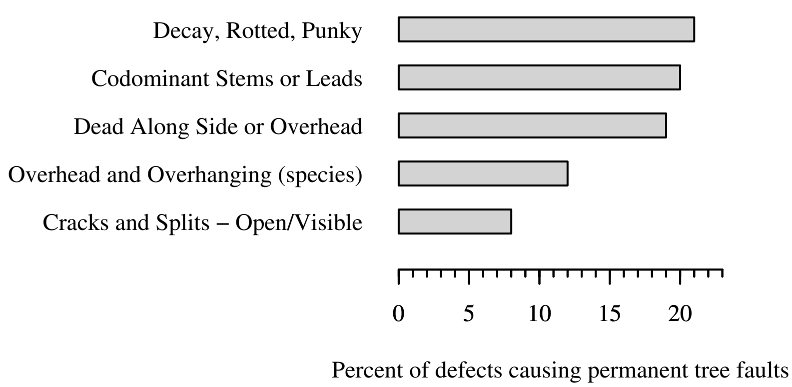
- *Site Characteristics* – Some sites are much more prone to problems than others. Examples include seasonally wet sites or highly exposed sites. The discussion of environmental risk factors found earlier in this chapter offers more information on site criteria. The checklist should include both above and below-ground environments. The best criteria are based on actual experience with the types of sites that cause problems on the system.
- *Species of tree* – Not surprisingly, trees vary in many ways including in their growth rates, overall structural integrity, conductivity, susceptibility to pathogens, and mortality. Many problems can be attributable to the “wrong” species growing on a site. Finally, pest and pathogen outbreaks are often species-specific, and occur in groups of trees of the same species. In short, risk varies by species. Here again the best criteria will be based on actual experience with the species of trees that occur on the system.

- *Visual Defects* – Visual defects are good indicators of risk. The discussion of biological risk factors found earlier in this chapter provides information on visual indicators of defects. It may also be useful to make a general assessment of overall vigor as an indicator of future problems. Once again, the best assessment criteria will be based on actual experience with the kinds of defects that are causing failure of trees in the area.

A checklist should include both a "punch list" of criteria and provide the opportunity for narrative comment. It should include information on the location and type of energy delivery system element (e.g., transmission line, three-phase, single-phase, etc.) that is potentially affected by the tree. It should also include risk mitigation actions that may be necessary. It is not enough to simply identify a potential problem.

Hazard-Tree Programs and Inspections

Danger-tree or hazard-tree programs target those trees that are typically located outside the clearance area for routine vegetation maintenance work. Line clearance tree pruning typically targets trees with branches and trunks that grow into a zone (e.g., within ten feet of conductors on a typical distribution line), not trees outside of this zone. Trees or branches from outside the clearance zone often represent the largest cause of outages. Hazard-tree programs target high-risk trees, even if they are out of the normal trim zone or right-of-way. Figure 6-12 shows some of the hazard tree defects that led to tree faults in a study by the Niagara Mohawk Power Corporation.



Data source: (Finch 2001)

Figure 6-12
Defects Causing Tree Failure for the Niagara Mohawk Power Corporation

Targeting hazard trees is an effective means of reducing risk, but requires expertise. Dead trees are the most obvious candidates for hazard-tree removals. However, dead trees are only part of the problem. In a sample of permanent tree faults, Niagara Mohawk found 36% were from dead trees; in another sample, Duke Power found 45% were from dead trees (Taylor 2003). Niagara Mohawk found that 64% of hazard trees causing outages were living. Finch also advises examining trees from the backside, inside the tree line (defects on that side are more likely to cause the tree to fall into the line).

Finch describes several defects that help identify hazard trees. He also notes the value of investigating the types of trees and conditions that have lead to outages, and using this information to develop risk assessment criteria. Finch showed how Niagara Mohawk evaluated a sample set of tree outages (Finch 2001). Niagara Mohawk compared the tree species that caused faults to the tree species in New York State. They found that black locust, aspen and sugar maple caused more than their share of damage (see Table 6-3). Finch also reported that much of the extra impact of aspens on outages was due to hypoxilon canker, which their crews often overlooked as a defect. The sugar-maple faults were mainly from large, old roadside maples in serious decline.

Table 6-3
Comparison of Trees Causing Permanent Faults With the Tree Population

Species	Percent of outages	Percent of New York state population
Ash	8	7.9
Aspen	9	0.6
Black Locust	11	0.3
Black Walnut	5	N/A
Red Maple	14	14.7
Silver Maple	5	0.2
Sugar Maple	20	12.0
White Pine	6	3.3

Source: (Finch 2001)

These findings are an example of how analysis of actual tree failures can be used to develop and refine risk assessment criteria.

It is important to note that while hazard tree programs can improve reliability, they will not eliminate tree-caused outages. There is simply too much exposure and uncertainty associated with predicting tree failures. Tree-caused outages will still occur even with the best programs in place. Many tree faults occur during severe weather that causes healthy trees to fail. Hazard tree programs are continuous. As (Guggenmoos 2003) shows in detail, with tree mortality rates on the order of 0.5 to 3% annually and the sheer number of trees within striking distance of transmission and distribution circuits, a danger-tree program cannot be a one-time expenditure. Hazard tree inspections occur as work is planned, during line clearance maintenance work, and may also be conducted as a separate inspection initiative.

EPRI 1008480, *Electric Distribution Hazard Tree Risk Reduction Strategies* (EPRI 1008480 2004), documents hazard-tree program results by Niagara Mohawk, Central Hudson, and BC Hydro. It also provides a process tree map to help guide utilities through the process of developing a hazard-tree program.

Right-of-Way Widening

Even with an effective hazard-tree program, many tree faults will occur, either from healthy trees brought down by severe weather or from trees that die or are missed between maintenance cycles. Theoretically the only way to drastically reduce tree faults is to clear a right-of-way to a width greater than the strike distance of the adjacent trees. This is impractical on all but the most critical transmission lines. The probability of a tree fault is determined by the width of the right-of-way and other factors, including tree density, tree mortality rates, and tree heights. Guggenmoos (Guggenmoos 2003) outlines a methodology for estimating the risk of trees striking lines based on these factors. This approach can be used to estimate the benefit of a tree clearance program to establish a right-of-way or to widen an existing right-of-way.

Readily Climbable Tree inspections

The risk posed by easily climbable trees is recognized by vegetation managers in the electric utility industry. These trees are typically maintained to a higher standard of care than are the average population of trees in conflict with overhead conductors. They are identified during pre-work inspections and during inspections at the time work is carried out.

Theoretically every tree is climbable. Of the trees adjacent to overhead utility lines, only some have structural crowns that would allow a climber to reach a position of risk in close proximity to energized conductors. Of these, some may be relatively easy for a child or adult to climb. Others may be difficult enough to climb that a casual climber would require assistance to enter the tree and climb to position of risk.

The hazard posed by climbable trees can be thought of as a function of three questions:

> *Clearance*: Is the structural crown of the tree in close proximity to energized high voltage conductors, allowing a person to achieve a position of risk?
>
> and
>
> *Climbability*: Is the structural crown of the tree easily accessed and climbed?
>
> and
>
> *Exposure*: Do individuals that may have an interest in climbing the tree make frequent use of the site that the tree occupies?

A climbable tree inspection involves an assessment of all three factors.

1. The question of clearance typically focuses on distance from energized distribution primary conductors. It also factors in the weight-bearing capacity of branches in the vicinity of a conductor to determine whether it would be possible for a person to occupy a position of risk. Clearances from low voltage secondary and system neutral conductors are inherently low risk. Trees in which the main stem and/or large diameter structural branches have been allowed to develop and remain in close proximity to energized high voltage primary conductors are considered higher risk.
2. The question of climbability involves an assessment of how easy it would be for a casual climber to enter the crown of the tree and climb to a position of risk. An example of an easily

climbable tree might include an open-grown tree where regularly spaced branches occur from low on the main stem up to the height of the energized primary conductors.

3. The question of frequency of potential adverse exposure is an important consideration. It focuses attention on trees that occupy sites where there is an elevated potential for members of the public to climb the tree and expose themselves to elevated risk. Trees adjacent to schools or in public parks are examples of higher risk.

Inspection Audits of Line Clearance Tree Work

Inspection audits of line clearance preventive maintenance work provide a means of assessing the quantity, quality, and effectiveness of the vegetation management work being performed in the field. As Eckert quotes David Van Bossuyt of Portland General Electric, "You don't get what you expect, you get what you inspect" (Eckert 2004; Eckert 2005). Many utilities perform post-work audits following vegetation maintenance. Post-work inspection audits ensure that the work is being done to specifications.

Use Audits as a Communication & Teaching Tool

Audits can be a useful means of educating tree crews at the same time that they ensure that the work is being done as required. This education comes as feedback in pointing out tree defects that were missed, pruning cuts that were improperly made, and failure to achieve specified clearances. The audit should take a positive approach. This is an important concept – the audit is a communication and teaching tool, not a mechanism for attacking the tree crew or contractor. A well-designed audit program will include both penalties for consistently poor performance and rewards for consistently outstanding performance. The audit provides a vehicle for the timely discovery of work practices that either aren't being carried out correctly or aren't effective. Once identified, appropriate action can be taken to quickly remedy these deficiencies.

Post-work Auditing Means Getting Into the Field

To accurately assess fieldwork, get out into the field. Outage reports, timesheets, and budget reports are all valuable information for auditing vegetation management programs, but some information can only be gathered in the field. There is no substitute for first-hand examination of fieldwork. Some key questions to ask are:

- Was the work completed?
- Was the work done to specification?
- Was the risk effectively identified and mitigated by pruning and tree removal?
- Was the quality of work acceptable, minimizing wounding that creates future risk?
- Did the crew accurately document and report the work performed?

These questions are best answered by field inspection. The focus of these questions is reliability. There are several others aspects of the crew's work that can be audited during the site inspection. Some examples include the proper application of herbicides, site clean up, and customer relations to name a few. An audit checklist based on detailed specifications and local knowledge should be developed and used in inspecting the work of line clearance tree crews.

The matters of risk mitigation and work quality warrant special consideration. Crews need to be thinking in terms of improving reliability by eliminating risk. Secondly, improper line clearance work can result in unnecessary damage to trees, creating the potential for future problems. Specifications based on risk identification, mitigation, and proper arboriculture practices will go a long way in improving reliability and in reducing the potential for unintentionally creating future risk of tree failure.

Not all line clearance crews will require the same inspection frequency. Inexperienced or consistently low-performing crews require more auditing than experienced and consistently high-performing crews. Eckert suggests that new or underperforming crews be audited at least weekly until their performance improves and that the work of experienced crews be audited at least monthly (Eckert 2004).

In general, an audit of 5-10% of a crew's work will provide a reliable representation of overall quality and compliance. The goal is to choose a general cross-section of worksites for inspection. It is important to choose a range of sites that encompasses all working conditions from easy to very challenging.

Figure 6-13 illustrates one possible inspection checklist used in auditing and scoring vegetation management work. A program auditor would complete a new score sheet for each crew/job inspected. The results of the inspection can be used in performance measurement and management. Another advantage of this type of checklist is that it can be easily adapted to electronic format. The score sheet shown in Figure 6-13 could be used with a laptop or personal digital assistant device to facilitate tabulating and reporting results.

Line Clearance Crew Recordkeeping & Reporting

Proper recordkeeping is an essential part of line clearance operations. A detailed time sheet typically is the primary source document used by crews to report work activities. It typically includes information regarding the type and quantity of work performed as well as who completed the work. This information is used in an assessment of productivity, cost, and effectiveness. The timesheet is also used in evaluating fieldwork during a post-work inspection audit. At a minimum the following data should be recorded for each job performed:

- *Work location* – The circuit name/number and pole(s) or address.
- *Description of work* – Specific references to trees pruned, trees removed, application of herbicide, disposal of cut material, etc.
- *Labor involved* – Personnel and classifications involved and hours worked.
- *Equipment use* – The types of equipment that were used and hours used.
- *Herbicide use* – The type of application, quantity, and type of herbicide used.
- *Other comments* – An opportunity for crew personnel to provide additional information.

Audits of Vegetation Management Programs

Programmatic audits of a utility's vegetation management activities represent the third type of audit covered in this chapter. They are intended as a means to assess the overall effectiveness of the vegetation management program.

Basics of Vegetation Management

Trees are an important cause of interruptions for most utilities. A considerable allocation of O&M dollars is required to reduce the risk they pose to overhead energy delivery systems. For most utilities, vegetation management is the largest maintenance item in their budget. Deferral of work leads to higher outage incident rates and can pose a safety risk. Excessive line clearance tree maintenance work is expensive and may cause unnecessary environmental impact. Well-designed vegetation management programs use an optimization approach to achieve a balance between reliability, safety, and cost.

Integrated Vegetation Management (IVM) refers to an approach to optimization based on a comprehensive suite of maintenances and management practices. The basic premise of IVM is the creation of site-specific vegetation maintenance prescriptions based on the conditions, species, electric system, and risk present. The maintenance prescription may include pruning type, tree removals, tree replacements, the use of herbicides, and potentially the use of growth regulators. IVM also makes use of data analysis in a continuous improvement process to assess and refine the effectiveness of the vegetation maintenance practices being used.

Contemporary IVM-based programs also recognize differences in electric delivery infrastructure as related to the risk and consequences of tree-initiated faults. The following risk-based hierarchy is used by many utilities in designing specific vegetation maintenance projects and work specifications:

- Bulk transmission: circuits from generating stations, switching stations, and inter ties. Typically this is 230 kV and above.
- Other transmission: ties between sub-stations, 115 kV and below.
- Distribution feeders: multi-phase trunk lines
- Single-phase laterals
- Low-voltage secondary

Auditing To Vegetation Management Program Goals

Successful vegetation management programs have clearly defined goals and objectives. After all, how can you succeed if you haven't defined success? Program audits are a means of measuring success. They provide valuable feedback on the current state of the system and the program. Audits also provide data that can reveal performance trends, which help evaluate a program's success.

Vegetation management programs in the industry often share some common goals. Examples include specific goals that address:

- Electric Service Reliability
- Safety Performance
- Work Crew Productivity
- Work Quality
- Cost Efficiency
- Customer Satisfaction
- Regulatory Compliance

Maintenance Cycle Optimization

Program level audits often include an assessment of the frequency of preventive maintenance as well as the need to perform corrective maintenance. There are at least three basic approaches to schedule preventative maintenance work (Appelt 2006):

- *Fixed-Interval Maintenance* - Preventative maintenance is performed on a regular cyclical basis. The cycle period is typically selected based on factors such as tree growth rates, tree failure rates, reliability expectations, and cost.
- *On-Condition Maintenance* - Periodic inspections (often on a fixed interval cycle) are used to determine when to schedule the circuit for work based on conditions observed.

  Mid-cycle maintenance work is often used in conjunction with the fixed-interval approach and can be thought of as a variant of the on-condition method. The mid-cycle maintenance "intervention" is conducted to address isolated threats to safety and reliability such as fast growing trees (sometimes called "cycle busters" or "cycle limiters") and hazard trees including recently damaged trees (Finch 2003).
- *"Just In Time" Maintenance* - An inspection of the entire system is conducted annually, and work is schedule on those individual trees that present an unacceptable risk. Under this system, every circuit receives maintenance each year, but only the trees posing an immediate hazard are trimmed or removed.

The need for vegetation management, and pruning in particular, is continuous. Clearances are temporarily achieved only to be lost again in subsequent growing seasons. In fact, improper pruning can trigger an exaggerated re-growth response (and excess wounds), having the opposite effect intended.

Fixed-interval maintenance is the dominant approach found in the industry today. On-condition maintenance is gaining acceptance. Generally, pruning and inspections are extended as long as possible while limiting the amount of tree growth into conductors. As cycle periods are extended, the average annual cost is initially reduced. However when significant tree growth begins to interfere with conductors, the cost to line clearance can increase dramatically because the crews must slow down and work very carefully to avoid causing outages and exposing themselves to electric shock.

In actual practice, line clearance tree work is often performed over a three- to five-year period. Shorter intervals are commonly found in urbanized areas and in temperate southern climates with long growing seasons. The optimal trimming frequency will depend on the management method used (see above) and on the:

- Species of trees, their growth rates, and growing conditions.
- Types of tree failures and how quickly these conditions develop.
- Community tolerance for trimming.
- Economic assumptions.
- Regulatory mandates.

Building a Successful Vegetation Management Auditing Program

There is no standard auditing plan that can be applied to every utility's vegetation management program. Auditing plans need to be tailored to an individual company's vegetation management program. However, there are common attributes to all successful auditing programs. As Eckert points out, a successful program audit utilizes the following components (Eckert 2004):

- *Clearly defined rating items and item weight* – The auditing program needs to clearly specify what items are rated and how those items relate to the specific goals and objectives of the vegetation management program. The list of rated items does not need to be extensive. It is often more useful to utilize a handful of well defined, field-measurable rating items rather than a long "grocery list." Eckert lists a few examples including:

1. Measuring *reliability* impact through periodic reliability reports including tabulations of tree-related outages (tree-outages per mile tends to be a convenient unit of measure).
2. Measuring *safety* performance through number and severity of injuries, work missed due to injury, and compliance with safe work practices.
3. Measuring *cost* containment through periodic budgetary reports, work productivity, work schedule compliance, equipment availability, and efficient work progress.
4. Measuring *customer satisfaction* through the number of vegetation management related complaints received. Customer satisfaction is maximized through direct communication with the customer, the use of proper arboricultural techniques, and proper work site clean-up.
5. A strong argument can made for adding two additional program audit elements:
6. Measuring *quality* through an assessment of specification requirements, compliances and fieldwork that minimizes site disturbance and excessive impact on the trees being maintained.
7. Measuring *regulatory compliance* through a review of regulatory filings and actual performance in the areas covered by specific regulations.

Although there are many important facets of a vegetation management program, they do not all have equal influence on the programs success. Each rated item must carry the appropriate weight in the overall auditing process to best reflect its impact on the overall program. The three biggest factors affecting the overall success of the program are usually crew productivity, quantity of line cleared, and quality of work (using proper arboricultural techniques). These items should therefore be given the greatest weight.

- *Well-defined thresholds for performance* – Clearly define minimal, satisfactory, and exceptional program performance goals. These thresholds not only explain the minimum expected performance; they can also motivate personnel to achieve greater goals by providing a target of exceptional performance. The thresholds should be based on reasonable/achievable performance targets as outlined in documents such as company policies, contract specifications, industry standards, etc.
- *Qualified auditors* – Auditing vegetation management programs requires specific knowledge of the work being audited. Typically, an independent person(s) performs program level audits. It is highly recommended that independent auditors be experienced professionals with a broad basis of relevant vegetation management experience.
- *Auditing frequency and intensity* – Program-level audits are performed on a relatively infrequent basis. The intended maintenance cycle period is a useful guide. It would be reasonable to conduct a program-level audit within a five-year period, or following a major change. Auditing intensity (sampling intensity, level of detail, comprehensiveness, etc.) is also a concern. Auditing intensity will depend on the degree of diversity of practices, system diversity, variability in the tree species and stocking density, and the nature of problems that may be discovered.

Auditing a proper vegetation management program should be done in a highly structured and uniform manner. Working from a consistent set of documentation tools helps ensure that auditing activities are performed efficiently, consistently, and accurately. Figure 6-13 illustrates one possible scoring method for auditing vegetation management work. A program auditor would complete a new score sheet for each crew/job audited and then enter that information into the vegetation management auditing database for use in performance tracking and monitoring. Another advantage of this type of system is that it can be easily adapted to computer use. The score sheet shown in Figure 6-13 could be implemented in a laptop or personal digital assistant device to facilitate easier reporting and tabulating of the results.

Scoring System
0 - Requires immediate attention
1 - Poor
2 - Fair
3 - Average
4 - Excellent

Contractor / Crew: ______________________
Week Ending: ______________________
Work Location: ______________________
Work Description & Difficulty: ______________________

		Grade		Weight		Points	Comments
Clearance	Adequate clearance around conductions (under, side, top)		x	5	=		
	Appropriate number of trees removed		x	3	=		
Methods	Proper directional pruning		x	6	=		
	Proper stump height & herbicide application		x	2	=		
	Overall shape and appearance of trees		x	3	=		
	Minimal stubs, ripped cuts, & wounding		x	5	=		
	Crew productivity / efficiency		x	5	=		
	Chip quality & disposal method		x	5	=		
Supervisor	Maps / skips / refusals (accurate?, prompt?)		x	3	=		
	Area planning & notification		x	4	=		
	Job knowledge / training		x	4	=		
	Initiative / attitude / cooperation		x	3	=		
	Lost time due to labor issue		x	3	=		
	Lost time due to equipment issue		x	3	=		
Safety	Safe work practices & methods		x	3	=		
	Proper public safety measures (flaggers, cones, signage)		x	3	=		
	Protective equipment (hardhats, ear plugs, protective eyewear)		x	2	=		
Professionalism	Customer communication		x	3	=		
	Complaints / settlements		x	3	=		
	Appearance of workers and equipment		x	3	=		
Reporting	Work reporting timely, accurate, and legible		x	3	=		
	Billing/Invoicing timely & accurate		x	1	=		
							Total Points (out of 300 possible)

General Comments

Divide total points by 3 to get ______ % - **FINAL SCORE**

____
____
____

Figure 6-13
Example Vegetation Management Work Performance Evaluation Score Sheet

7 STRAY VOLTAGE INSPECTIONS

Utilities receive numerous complaints of customers being shocked each year. Most of these stray voltage complaints are the result of customers receiving a relatively mild shock that poses only a minor threat to public safety. However, there are also infrequent cases of animals and occasionally humans being killed by particularly severe shocking incidences. The potentially deadly nature of stray voltage incidences means that all instances of stray voltage, reported or yet undiscovered, must be taken seriously. For this reason, many utilities are taking a more proactive approach to searching for and identifying instances of stray voltage; particularly in urban environments where there is more public contact with lamp poles, manhole covers, and similar metallic fixtures.

Stray voltage shocking complaints tend to increase in the summer since people tend to have more exposed skin during warm weather and are therefore more likely to make skin contact with points energized via stray voltage. The majority of shocking complaints involve swimming pools, water faucets, ductwork, manhole covers, and lamp posts. Although females and children tend to be more sensitive to stray voltage than adult males, stray voltage poses a health risk to all people (and animals) regardless of sex, age, or size.

This chapter is based on the detailed procedures and methods outlined in two separate EPRI reports for diagnosing and resolving stray voltage issues (EPRI TR-113566 1999; EPRI 1010652 2005). The reader is encouraged to consult the aforementioned EPRI reports for a more detailed discussion on the topic of stray voltage.

Definitions

To make sense of the confusion surrounding the terminology associated with stray voltage, energized metallic objects, and neutral to earth potentials, the following terms are defined:

- *Remote Earth* -Is defined as an earthing or grounding point that is at the same voltage potential as other points on the earth in the surrounding area. Electrical current flowing through grounding or neutral conductors, or even through earth itself, will cause voltage variation from point to point. The remote earth point is hypothetically “beyond” or outside of the influence of these current paths. Thus, the remote earth point is at zero potential with respect to the voltage source and provides a consistent and repeatable reference point.
- *Neutral Grounding* - The IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems (IEEE C62.92.5-1992) recommends limiting utility equipment to earth voltages by grounding the circuit neutral conductor at least four times per circuit mile, as well as at all utility hardware such as transformers, lightning arrestors, and capacitor banks. This tends to limit any developed voltages to less than 25 volts, which is generally accepted

as a relatively non-lethal voltage level. The unavoidable consequence of grounding power system neutral conductors is that some currents will always be returning through the earth. Because of the current flowing through the earth impedance, any time the power system is energized there will be some level of voltage present relative to the remote earth point.

- *Neutral-to-Earth Voltage or NEV* - Is a measure of the voltage potential between a neutral-to-ground (N-G) bonding point and a "remote earth" point. In essence, any time current is flowing through a neutral conductor, there will be a voltage potential with respect to the earth. This voltage potential can be metallically transmitted over to a remote earth point through "code-required" grounding and bonding of water pipes, neutrals and other conductive paths. It is important to note that NEV is a normal occurrence caused by the "intentional" grounding of the power system.
- *Metallic-Object-to-Earth Voltage or MOEV* - is caused by an accidental or "unintentional" energization of a metallic object. The most common scenario for MOEV occurs when an energized electrical conductor comes in direct contact with a metallic object, such as a streetlamp, a service box, a manhole cover, or virtually any type of metallic object, thereby energizing the object as well. MOEV potentials to remote earth can range anywhere from just a few volts to 120 volts or more, depending upon the source. MOEV can also occur when a pipeline or other insulated metallic object is close enough to an electric field from a power line to receive an induced voltage from that electric field.
- *Stray Voltage (from intentional actions)* - The U.S. Department of Agriculture Publication 696 (USDA 1991) defines stray voltage as "a small voltage (less than 10 volts) that can develop between two possible contact points." Contact points are generally considered to be points close enough between the voltage source and a remote earth path that would allow a current to flow through any human, animal, or other object that contacts both points simultaneously. Another important note about publication 696 is that the document summary states: "While stray voltage cannot totally be eliminated, it can certainly be reduced to an acceptable level." While this definition focuses primarily on NEV sources which result from the intentional grounding of the power system neutral conductor, many cases have been identified where improper wiring and load faults on the customer side of the meter contribute to the measured voltages.
- *Stray Voltage (from unintentional actions)* - The New York Public Utility Commission uses the term stray voltage to describe the unintentional or accidental energization of manhole covers, street lamps and other urban street level metallic objects (IEEE Std. 1159-1995). This definition focuses on MOEV sources such as contact with the power system phase conductor or in some cases as the result of induced voltages from electric fields.

While the previous two definitions have created some confusion the common element is that stray voltage could be considered an undesirable voltage potential across any two points that can be simultaneously contacted by an animal or a human. In summary, to develop a stray voltage we can consider the following sources: 1.) currents flowing on primary and secondary neutral conductors, 2.) faulted phase conductors, and 3.) induced voltages from currents flowing through power lines.

Test and Measurement Equipment

The stray voltage investigator must be versatile and familiar with a wide assortment of test and measurement equipment in order to diagnose the source(s) of the voltage concern, a wide variety of measuring equipment is available to support the stray voltage investigator. The challenge is in selecting the most appropriate instrumentation for a given test or measurement. The intent of this chapter is to provide the reader with an overview of the types of measurements of interest, the available equipment, its functions, capabilities and field use suitability.

Voltage Measurements

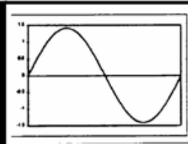
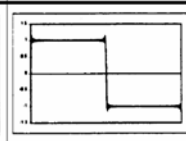
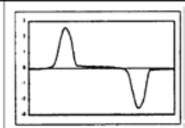
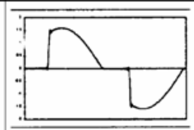
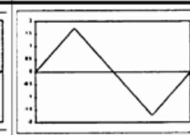
Accurate measurements of voltage potentials at human and animal contact points are essential to the stray voltage investigation. The challenge is that measurement resolution down to the tenths of a volt must be accomplished and just a few tenth of a volt error can result in the difference between no action required and expensive mitigation requirements. This section contains trademarked names and references to specific brands of metering equipment however these callouts are simply for reference and *in no way imply endorsement of that particular brand.*

AC Voltmeters – It is *recommended practice* that all readings be taken with ‘true rms” responding voltmeters. True rms reading voltmeters indicate the square root of the sum of the squares of all instantaneous values of the cyclical voltage waveform. These meters will indicate the correct or true rms value for every type of waveshape from sinusoidal waves to pure square waves, and are therefore the preferred voltage measuring instrument for the stray voltage survey.

Average responding rms voltmeters and peak responding voltmeters are not recommended as they assume a sinusoidal waveform and calculate the rms equivalent based on that assumption. With the average responding voltmeter, a multiplier called the “form factor” is used to convert the averaged value to the equivalent rms value. The 1.1 multiplier used by these instruments is based on the assumption that the rms value of a sine wave is 1.1 times the average value of the same rectified sine wave. With peak responding voltmeters, the peak value of the waveform is detected and a 0.707 multiplier is used to convert the peak value to the equivalent rms value. Like the average responding circuit, the waveform must be sinusoidal or the displayed value will be erroneous.

Table 7-1 shows several waveshapes and the percent error recorded by the peak and averaging responding meters. This emphasizes the importance of using a true rms meter.

Table 7-1
Percent Error vs Type of Instrument Used for Differing Waveshapes

Meter type	Circuit	Sine wave	Square wave	Distorted wave	Light dimmer	Triangle wave
						
Peak method	Peak/1.414	100%	82%	184%	113%	121%
Average responding	Sine avg. 1.1	100%	110%	60%	84%	96%
True rms	RMS converter	100%	100%	100%	100%	100%

DC Voltmeters – The true rms voltmeters suitable for measuring AC voltage are typically suitable for measuring DC voltage as well. When performing a comprehensive stray voltage assessment, it is *recommended practice* to record both the AC voltage and the DC voltage across the contact points of interest.

Current Measurements

AC current measurements are slightly more difficult to perform during a site survey compared to voltage measurements, but there are many instruments available to simplify the process. As with voltage measurements, *recommended practice* is to use true rms-reading meters when performing a site survey. True rms ammeters include two types of indirect reading ammeters: current transformers and Hall-effect types.

Current-transformer (CT) ammeters – A transformer is commonly used to convert the current being measured to a proportionately smaller current for measurement by an ac ammeter. There is very little resistive loading with these ammeters, and when a split-core transformer is used, the circuit to be measured is not interrupted. Clamp on CT's cannot be used to measure DC currents. Caution is recommended when interpreting readings obtained with a CT-type device because some of these ammeters may not be true-rms-reading meters. Sensitivity wise, the CT must be capable of measuring accurately in the milliampere range. For current measurements the investigator may need multiple CT's to cover a range of currents from one milliampere flowing into the earth via a ground rod to as much as a few hundred amperes on a circuit phase conductor.

Hall-effect ammeters – The "Hall-effect" is the ability of semiconductor material to generate a voltage proportional to the current passed through the semiconductor, in the presence of a magnetic field. This is a "three-dimensional" effect, with the current flowing along the x-axis, the magnetic field along the y-axis, and the voltage along the z-axis. The generated voltage is polarized so that the polarity of the current can be determined. Both ac and dc currents can be measured.

Additional Measurement Considerations

Spectral Content (Harmonics) **–** There are a number of documented cases where an elevated NEV concern is caused by harmonic currents flowing through the power distribution system neutral conductor and the earth. Since these currents do not cancel like the 60 Hz currents, they can be the dominant component in some NEV investigations. A true rms meter will quantify the total voltage, but a harmonic analyzer with resolution to capture frequencies out to at least the 50^{th} harmonic (3000 Hz) must be used to determine the harmonic content and the individual harmonic contributions. It is therefore *recommended practice* to measure the harmonic spectrum for stray voltage investigations where the suspected source is a multi-phase wye-grounded distribution system or where the suspected source of the elevated NEV is from customer equipment.

Peak versus RMS **–** Animals and humans respond to the peak of the voltage waveform in terms of the related current flow through the body. Most recommended limits or levels of concern are based on a conversion to the equivalent rms value. When capturing peak values it is *recommend practice* to either capture the associated waveform or if the meter is not capable of waveform capture to insure the meter is set to record the instantaneous millisecond peak and not an average over multiple cycles.

Event Duration Considerations **–** For the purposes of this document, the duration of a voltage or current variation will be defined per recommendations from IEEE std 1159-1995 Recommended Practice on Monitoring Electric Power Quality [3], for:

- Transients
- Short Duration RMS Variations
- Long Duration RMS Variations

Where transient events are in the millisecond range and rms variations last at least one half of an electrical cycle. The rms variations are then subdivided into short duration variations lasting less than 2 minutes and long duration variations lasting 2 minutes or more. It is the rms variations and most particularly the long duration rms variations that are of most interest for the stray voltage investigator. It is a recommended practice to take when taking voltage readings, to take several readings over a few minutes to confirm that the readings are fairly consistent.

Trending Equipment vs Snapshots

Depending upon the type of investigation there may be a need to trend data over several weeks and a number of data loggers (either voltage or current) are available to accomplish this. In certain situations, a single snapshot of the voltage or the current is inadequate. For example, as the loading of a distribution system varies during the day, the NEV contribution from the distribution system can change proportionally. For distribution induced NEV, the major contribution is due to the non-canceling currents (unbalance and triplen harmonics) flowing on the distribution neutral conductor. By logging 15 minute snapshots at a contact point and comparing this to 15 minute loading data, comparisons can be easily made to rule out or to confirm potential causes. Example products that are useful to conduct snapshot measurements and data logging include the Metrosonics™ SRV-4 and the AEMC™ L205.

Other Diagnostic Equipment

The stray voltage investigator may sometimes find useful additional diagnostic equipment to accomplish the objectives of the audit. These other devices are described in the following section to include both function and suitability for various types of investigations.

Non-Contact AC Voltage Tester (Pen Light) **–** Several manufacturers supply non-contact capacitive voltage testers suitable to determine if AC voltage greater than the specified voltage is present on an object that can become energized. Care should be taken to closely evaluate the data sheets as each of the devices has a different sensitivity range (anywhere from 5 volts to 50 or 100 volts) but they do allow the investigator to detect and cautiously deal with objects that may become energized such as street lamp posts, manhole covers, service boxes, conduits, concrete and other objects.

The preferred units come with a test capability to insure that the indicator light glows or an audible alarm sounds when placed near an energized object. Example companies that manufacture low voltage (less than 24 volt sensing) versions of these non-contact AC voltage testers are Extech™ and Fluke™. These testers are suitable for determining the presence of AC voltage, but not suitable for accurately measuring the value of the AC voltage.

Load Boxes **–** For residential as well as animal stray voltage investigations, a load box capable of testing 240 volt and 120 volt secondary systems is useful. These load boxes contain switchable resistors and allow the facility load to be shut off while the box is connected to determine the value of neutral to earth voltage contributed as the load is varied. This method also enables a way to determine resistances of the secondary neutral conductor via phase to neutral loading and a way to determine facility load NEV contributions of the service transformer primary neutral grounding point via line to line loading.

Test Resistors **–** Provide a means of determining if the voltage source is capable of driving adequate current between two contact points. The literature and the test protocols describe 500 ohm and 1000 and 20,000 ohm test resistor configurations. These are relatively easy to obtain and can be built into a switch-able configuration for banana jack connection to a voltmeter.

Metal Detectors **–** For location of metallic pipes, conduits and other potential sources of stray voltage the metal detector can provide the investigator with a useful tool for identifying these sources.

Earth Ground Resistance Testers **–** The resistance of the earth grounding electrode can be tested with a ground resistance tester. The ground resistance tester injects a known voltage at a known frequency and measures the current driven by the known voltage. With the voltage and current known, the resistance is easily calculated.

Miscellaneous Equipment **–** Other equipment that may be useful to the stray voltage investigator that is not detailed here include: Metallic Plates, Gauss Meters, Electric Field Sensors and Infrared Diagnostic Equipment.

Calibration and Calibration Verifications

To ensure that test instrumentation remains within calibration standards throughout all of the handling during annual field measurements, it may be useful to devise a set of calibration boxes. To serve as a reference, the signals from these calibration boxes can be measured by NIST traceable calibrated equipment not taken into the field. These boxes can provide reference signals for ac and dc voltages and currents at different levels to test resolution accuracy of the metering equipment. The box can then be used in the field to periodically validate the test instrumentation used throughout the year as a way to insure that the transported instrumentation remained in calibration. Resistance clamp-on meters such as those manufactured by AEMC usually come equipped with calibration-verification resistance loops. These resistance loops can be used in the field to verify the accuracy of the resistance measurements. "Field Calibration Data Forms" are also recommended to record measured data and to provide file-name references to saved waveforms associated with the periodic calibration-verification checks. These calibration checks and the associated forms should be completed and signed at every location where measurements are taken.

Residential Stray Voltage Inspections

Reports of shocking at swimming pools, hot tubs, showers and faucets have been common since the 1970s, but the subject was not readily discussed in a collaborative way and utilities did not share cases until the 1990s. Most of the investigative and measurement procedures were developed in the 1980s, and refinements continue today. Key causes of such shock hazards include:

- Metallic parts not being properly bonded per requirements of the National Electrical Code (NEC)
- Unbalanced voltages on the distribution circuit
- High currents through a neutral impedance
- Customer load faults
- Open neutral conductors and connections

The efforts to identify and resolve shock hazards at swimming pools and hot tubs include field measurements, information on human perception (levels of concern), implementation of solutions, and a number of papers and documents related to cause and remedy.

This section details the measurement protocols and procedures for measurements at service panels, swimming pools, hot tubs, water faucets and conduits. The procedures follow the basic techniques described in the 1999 EPRI Document TR113566 "Identifying and Diagnosing Residential Shocking Complaints" with some noted supplemental materials related to some of the more advanced diagnostic measurements using harmonics analyzers.

Safety Precautions

Energized metallic object measurements should only be attempted by persons with appropriate electrical safety training and experience. It is a *recommended practice* to perform these measurements in pairs and only with proper safety gear. Workers involved in performing energized object testing should abide by the prescriptions of NFPA 70E, concerning appropriate protective equipment, as well as government regulation codified in OSHA CFR 1910 and CFR 1926 and in the National Electrical Safety Code® (NESC)® (Accredited Standards Committee C2).

Workers trained in performing any of the prescribed measurements throughout this document should be trained in and abide by the appropriate utility safety documents related to:

- Use of Proper Personal Protective Equipment
- Work Area Protection
- Hazard Communication
- First Aid CPR
- The proper use of voltage detectors and meters
- Working near electric sources
- Others as deemed necessary by local, state or federal regulations

Measuring Voltage Between Pool (or Hot Tub) Water and Ladder Steps or Handrail

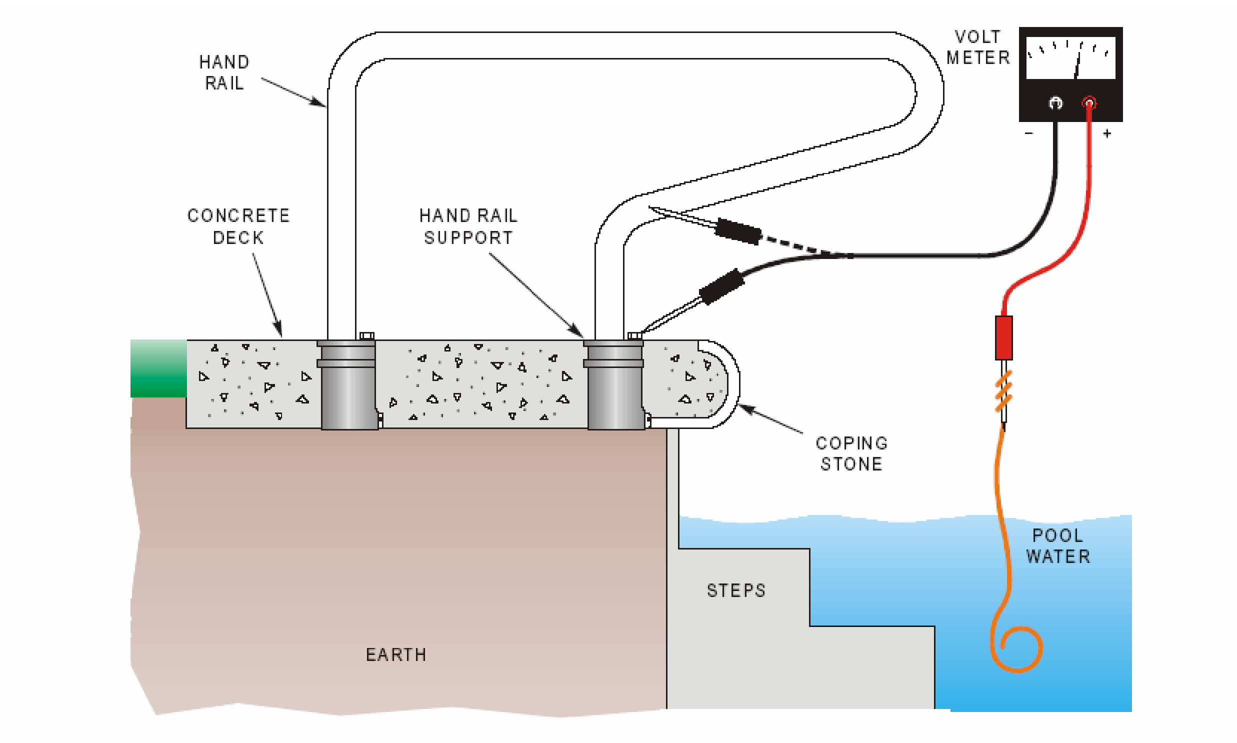


Figure 7-1
Measuring Voltage Between Pool Water and Ladder Steps or Handrail

Materials Needed:

- High-impedance AC voltmeter
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Wet the concrete area around the ladder or handrail supports.
2. Drop the "+" probe of the AC voltmeter in the pool water. Caution: To prevent damage to the volt meter probe, use a short length of wire attached to the "+" probe to dip into the water.
3. Place the "-" meter probe against the metal of the ladder or handrail to measure the voltage between it and the pool water.

4. Measure the voltage between the pool water and the ladder/handrail supports.
5. Record the measurements and time of day they were taken.
6. Repeat steps 1, 2, 3, 4 and 5 for each ladder or handrail indicated as a shocking voltage location by the customer.
7. Repeat entire process with DC voltmeter.
8. Repeat entire process with a Harmonics Analyzer and save the voltage spectrum info.

Measuring Voltage Between Pool Water and Coping Stone

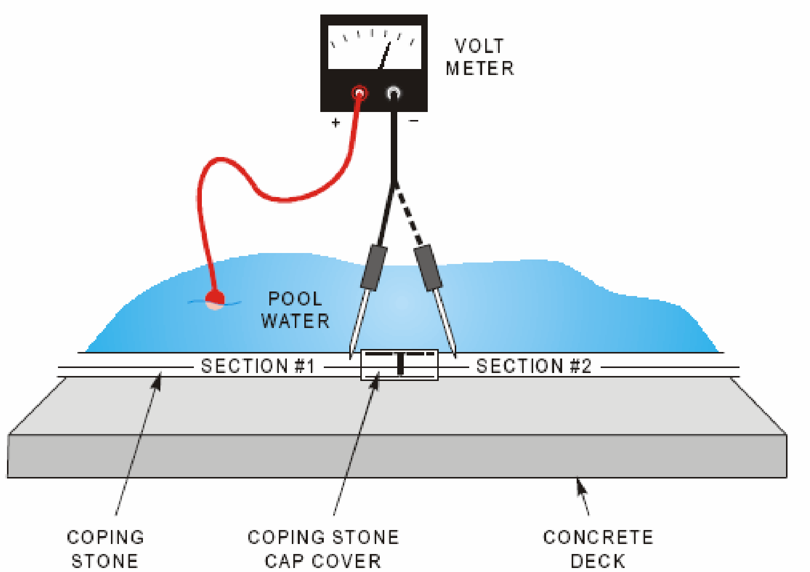


Figure 7-2
Measuring Voltage Between Pool Water and Coping Stone

Materials Needed:

- High-impedance AC voltmeter
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Make a top-view (or plan view) sketch of the swimming pool, noting each section of coping stone around its edge.
2. Find a scratch or small spot of exposed metal on a section of coping stone.
3. Drop the "+" probe of the AC voltmeter in the pool water. Caution: To prevent damage to the voltmeter probe, use a short length of wire attached to the "+" probe to dip into the water.
4. Measure the voltage between the pool water and the bare spot on the coping stone.
5. Record the reading and time of day on your sketch.
6. Repeat for each section of coping stone in areas indicated as shocking voltage locations by customer.
7. Repeat steps 2, 3, 4, 5 and 6 with a DC voltmeter.
8. Repeat steps 2, 3, 4, 5 and 6 with Harmonics Analyzer and save the voltage spectrum info.

Measuring Voltage Between Pool Water and Concrete Deck

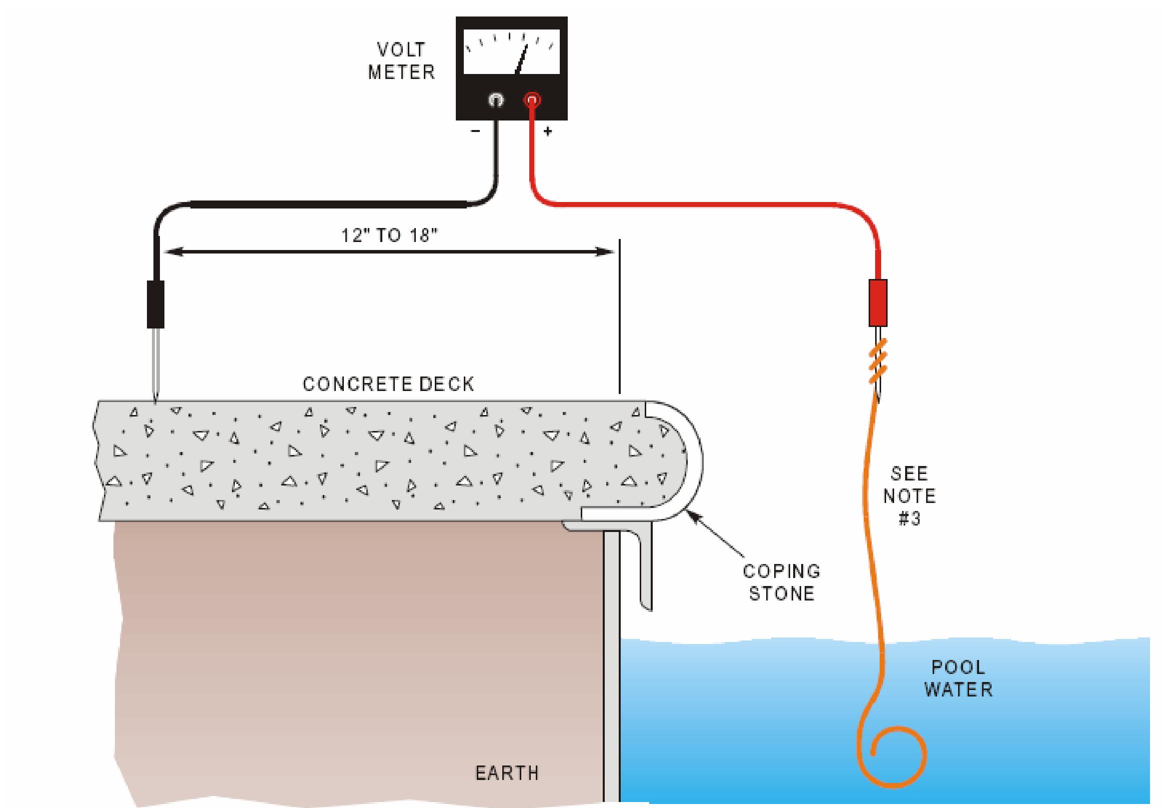


Figure 7-3
Measuring Voltage Between Pool Water and Concrete Deck

Materials Needed:

- High-impedance AC voltmeter
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Wet the concrete deck.
2. Drop the “+” probe of the AC voltmeter in the pool water. Caution: To prevent damage to the voltmeter probe, use a short length of bare wire attached to the “+” probe to dip into the water.
3. Place “-” voltmeter probe on wet concrete deck, 12” to 18” from edge of pool (clear of coping stone).
4. Measure voltage from the pool water to the wet concrete deck.
5. Record voltage reading and time of day it was taken.
6. Repeat steps 2, 3, 4 and 5 with a DC voltmeter.
7. Repeat steps 2, 3, 4 and 5 with a Harmonics Analyzer and save the voltage spectrum info.

Measuring Voltage Between a Water Faucet and Earth

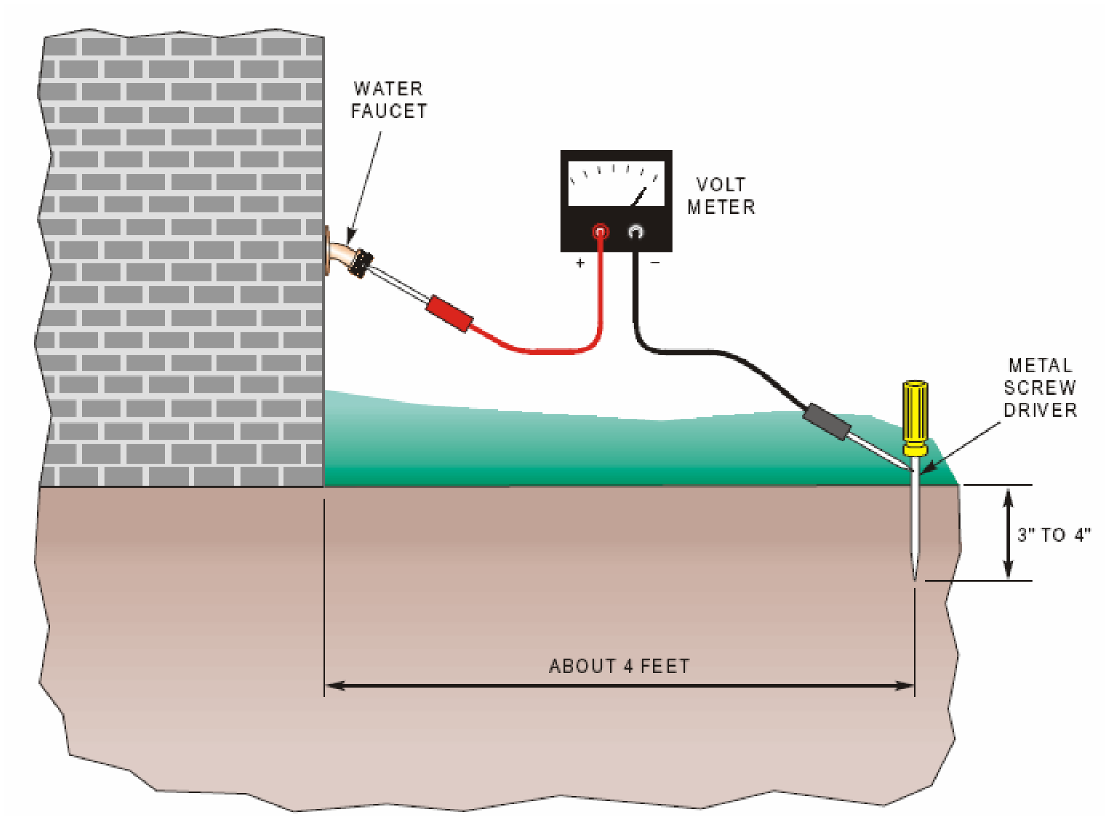


Figure 7-4
Measuring Voltage Between a Water Faucet and Earth

Materials Needed:

- High-impedance AC voltmeter
- Screw Driver
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Push a metal screwdriver into the ground to a depth of 3” or 4”, approximately 4 feet from the water faucet.
2. Place the “-” probe of the AC voltmeter against the screwdriver, and the “+” probe on the faucet.

3. With a high-impedance AC voltmeter, measure the voltage from the screwdriver to the water faucet.
4. Record the measurement and time of day it was taken.
5. Repeat steps 2, 3 and 4 with a DC voltmeter.
6. Repeat steps 2, 3 and 4 with a Harmonics Analyzer and save the voltage spectrum info.

Measuring Voltage between an Air Duct and Earth

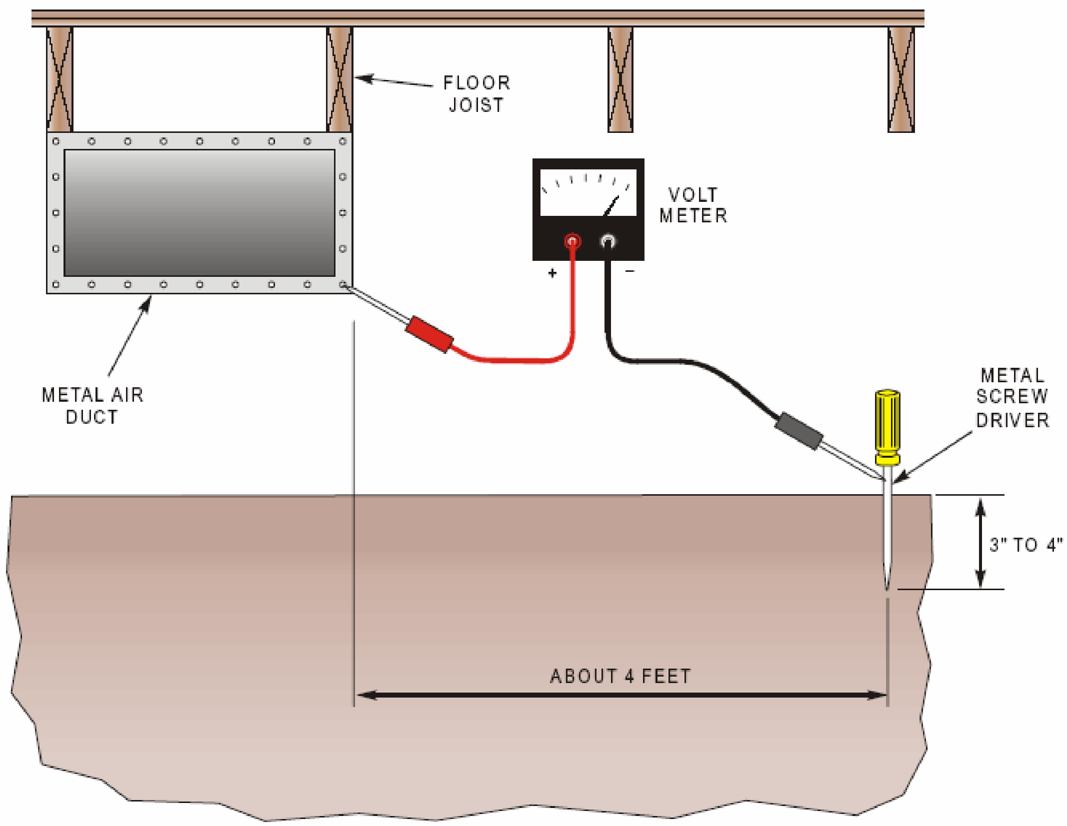


Figure 7-5
Measuring Voltage Between an Air Duct and Earth

Materials Needed:

- High-impedance AC voltmeter
- Screw Driver
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Push a metal screwdriver into the ground to a depth of 3” or 4”, approximately 4 feet away from the metal air duct.
2. With a high-impedance AC voltmeter, measure the voltage from the screwdriver to the air duct (“-” probe on screwdriver, “+” probe on air duct).
3. Record the measurement and the time of day it was taken.
4. Repeat steps 2 and 3 with a DC voltmeter.
5. Repeat steps 2 and 3 with a Harmonics Analyzer and measure and save voltage spectrum info.

Measuring Voltage Between Pole Ground and Earth

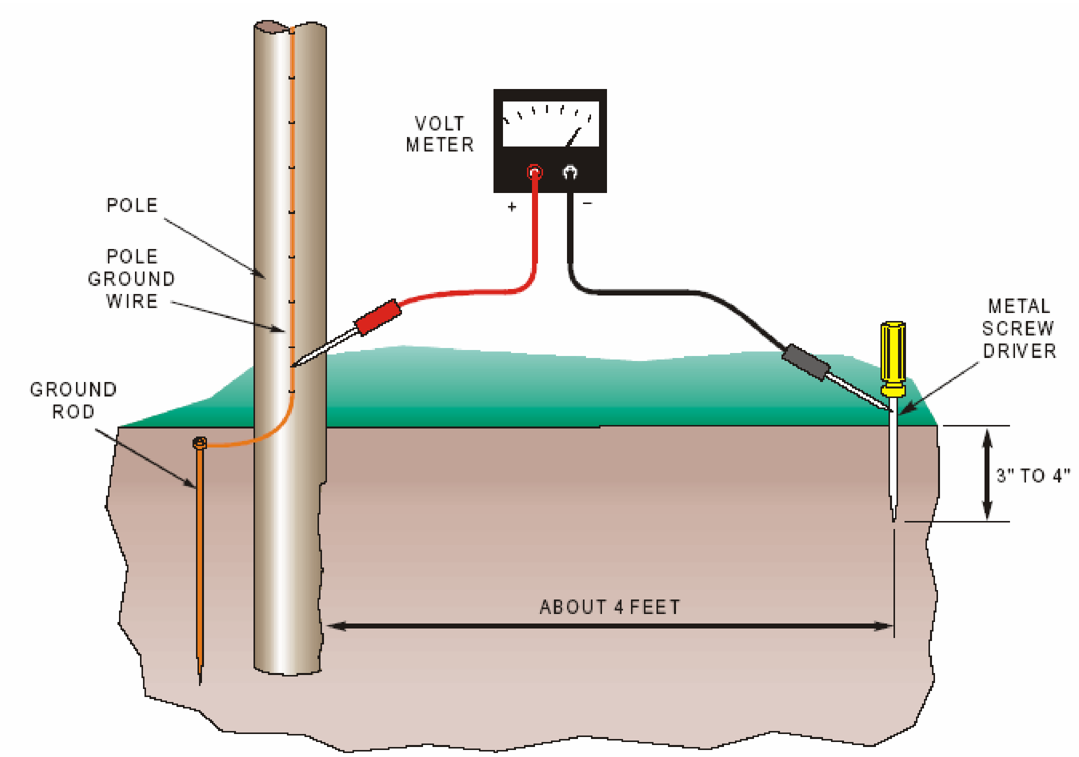


Figure 7-6
Measuring Voltage Between a Pole Down Ground and Earth

Materials Needed:

- High-impedance AC voltmeter
- Screw Driver
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure:

1. Push a metal screwdriver into the ground to a depth of 3” or 4”, approximately 4 feet away from the power pole. Note: When pushing the screwdriver into the ground, do not let it contact the pole’s ground rod, down guys, primary and secondary cables, metal pipes, or any other obstructions that might influence the voltage measurement.
2. With a high-impedance AC voltmeter, measure the voltage from the screwdriver to the pole ground.
3. Record the measurement and the time it was taken.
4. Move the screwdriver 45 degrees around the pole from its initial location, push it into the ground, and take another voltage measurement to verify the first one.
5. Record the second measurement and the time it was taken.
6. Repeat steps 2, 3, 4 and 5 with a DC voltmeter.
7. Repeat steps 2 and 3 with a Harmonics Analyzer and measure and save voltage spectrum info.

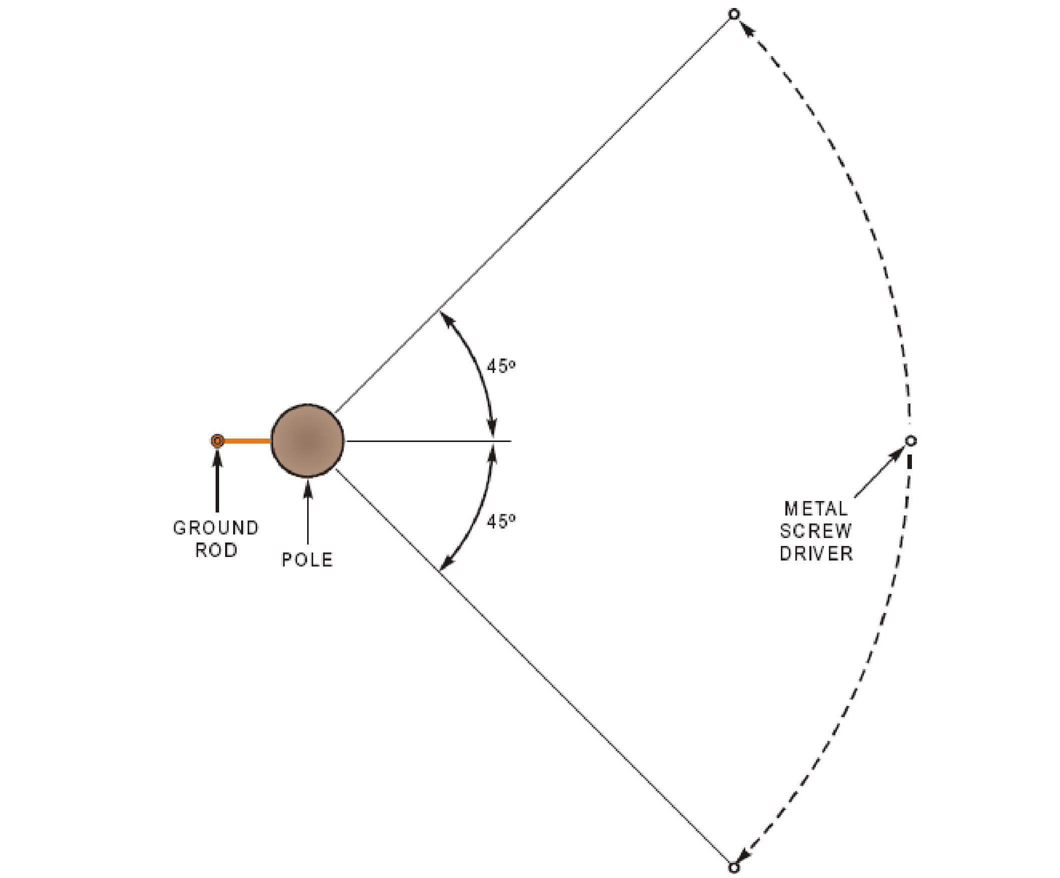


Figure 7-7
Making Multiple Measurements to Insure Accuracy in the Readings

Urban Stray Voltage Inspections

Background

Test and Measurement procedures for identifying electrically energized objects vary considerably depending upon the objectives of the investigation. For example, performing checks of energized objects as part of a recurring maintenance survey process typically requires only verification of the presence of voltage with a capacitive light tester. Once an accidental energization has been identified, more sophisticated diagnostic and metering equipment is required to quantify the voltage and source characteristics. It is also important to follow proper testing and measurement protocols in order to adequately document the level of voltage found, the source, and the level of voltage after remediation efforts have been taken.

When identifying energized metallic objects, the first objective is to assume that an electrical hazard is present unless the metering equipment provides an indication that it is not. If an electrical hazard is present, it is important to secure the area with warning or caution barriers such that humans and animals are unlikely to contact the energized object(s) until they can be de-energized and repaired.

This protocol focuses on determining the presence of the energized object and measuring the voltage related parameters associated with the object. Future efforts will supply measurement techniques that will aid the investigator in determining whether the source of the voltage is induced, radiated or conducted.

Safety Precautions

Measurements of electrical quantities where the electric power system supplies the energization source have some common safety precautions as follows: Energized metallic object measurements should only be attempted by persons with appropriate electrical safety training and experience. It is a recommended practice to perform these measurements in pairs and only with proper safety gear. Workers involved in performing energized object testing should abide by the prescriptions of NFPA 70E, concerning appropriate protective equipment, as well as government regulation codified in OSHA CFR 1910 and CFR 1926 and in the National Electrical Safety Code® (NESC)® (Accredited Standards Committee C2).

Workers trained in performing any of the prescribed measurements throughout this document should be trained in and abide by the appropriate utility safety documents related to:

- Use of proper personal protective equipment
- Work area protection
- Hazard communication
- First aid and CPR
- The proper use of voltage detectors and meters
- Working near electric sources
- Others as deemed necessary by local, state or federal regulations

When entering enclosure and manholes, there are other specific safety considerations that should be followed such as the use of barricades, gas detectors, etc.

Objectives

Defining the objectives of the investigation will define the procedure to be followed. The generic objectives are as follows:

1. Energized Object Survey: When the objective is to quickly assess the presence of electrically energized objects throughout a service territory, the requirement is fairly simple requiring only recording forms and voltage indicators or volt meters.
2. Voltage Source or Level Quantification Survey: When complaints are received or an energized object is detected during a routine survey, more detailed investigation is typically useful to insure that statistical objectives may be met when analyzing the information from a database. More detailed recording forms plus instrumentation capable of voltage and or current quantification is required.

Measuring Voltage Between a Metallic Pole and a Remote Earth Reference Point

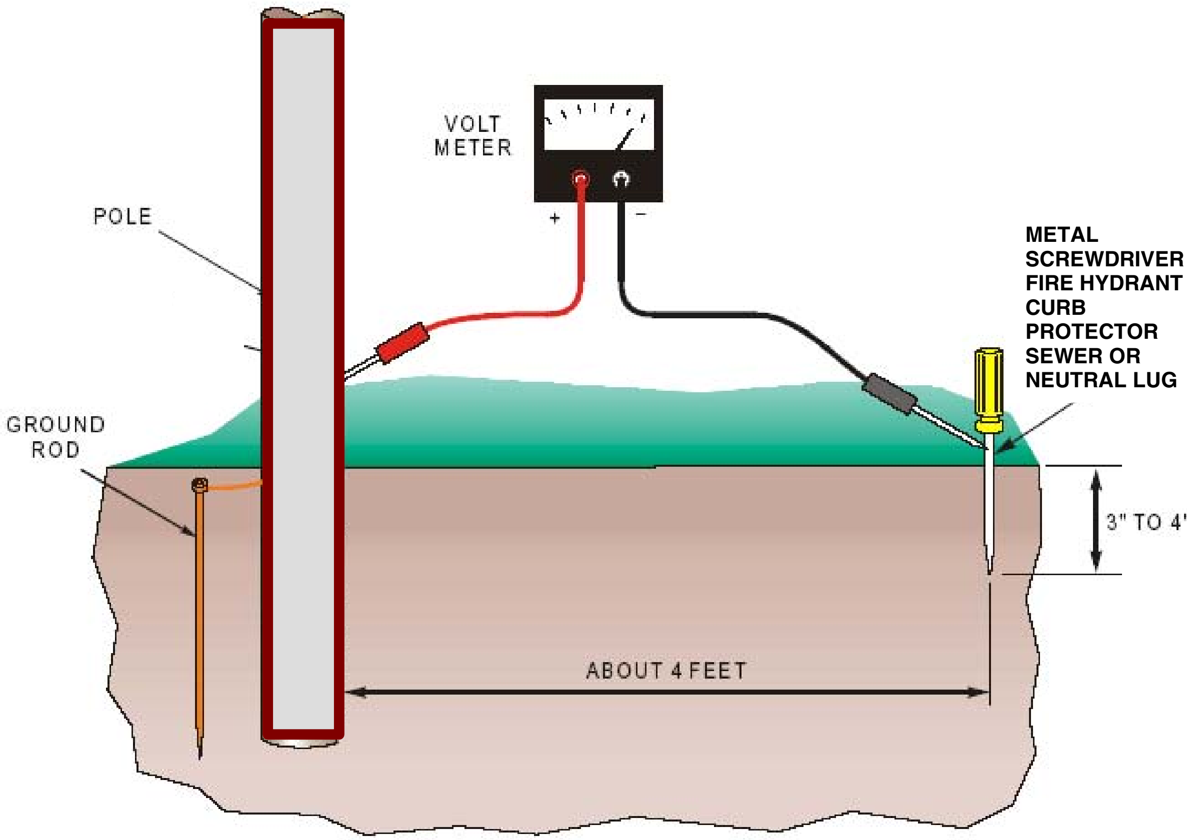


Figure 7-8
Measuring Voltage Between a Metallic Pole and a Remote Earth Reference Point

Materials Needed:

- Capacitive voltage tester
- High-impedance AC voltmeter
- Screw Driver (or paint scraper)
- Harmonics Analyzer
- DC voltmeter
- Recording Forms
- Watch

Procedure When Gravel or Earth is Readily Available:

Note: Depending on the survey objective, this procedure may be as simple as step one only or as complex as the complete set of steps 1 through 8.

1. Using an operational non-contact voltage indicator, such as the EXTECH LM5™, position the unit within 6 inches of the object under test. If the unit indicates the presence of a voltage, go to step 2.
2. Push a metal screwdriver into the ground to a depth of 3" or 4", approximately 4 feet away from the metallic object. Note: When pushing the screwdriver into the ground, do not let it contact the pole's ground rod, down guys, primary and secondary cables, metal pipes, or any other obstructions that might influence the voltage measurement.
3. With a high-impedance AC voltmeter, measure the voltage from the screwdriver to the pole ground.
4. Record the measurement and the time it was taken.
5. Move the screwdriver 45 degrees around the pole from its initial location, push it into the ground, and take another voltage measurement to verify the first one.
6. Record the second measurement and the time it was taken.
7. Repeat steps 2, 3, 4 and 5 with a DC voltmeter.
8. Repeat steps 2 and 3 with a Harmonics Analyzer and measure and save voltage spectrum info.

Procedure For Urban Investigations (No Gravel or Earth Readily Available)

Note: Depending on the survey objective, this procedure may be as simple as step one only or as complex as the complete set of steps 1 through 9.

1. Using an operational non-contact voltage indicator, such as a the EXTECH LM5™, position the unit within 6 inches of the object under test. If the unit indicates the presence of a voltage, go to step 2.
2. Located one or more suitable ground reference points. These ideal reference points are clean, unpainted metallic surfaces such as curb protectors at least 10 feet in length, neutral lugs, bare metal locations on fire hydrants, uninsulated water pipes, earthed metallic conduits etc.
3. With a high-impedance AC voltmeter, measure the voltage from the object under test to the ground reference.
4. Record the measurement, time it was taken, the ground reference object used and the condition (rusty, painted, scraped metal point, etc.)
5. Select a second suitable ground reference point and confirm the initial reading.
6. If a second suitable ground reference point is unavailable, select other local metallic objects and measure between those objects and the object under test. Attempt to verify the readings taken in 1.

7. Record the second measurement and the time it was taken.
8. Repeat steps 2, 3, 4 and 5 with a DC voltmeter.
9. Repeat steps 2 and 3 with a Harmonics Analyzer and measure and save voltage spectrum info.

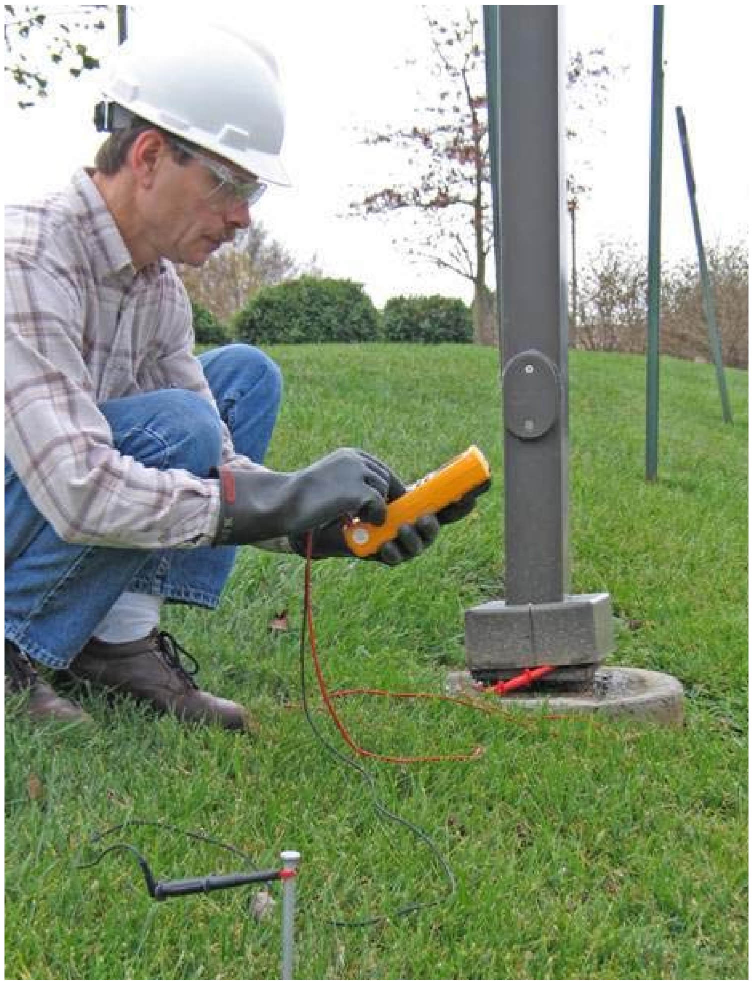


Figure 7-9
Sample Measurements Between a Metal Light Pole and a Reference Ground

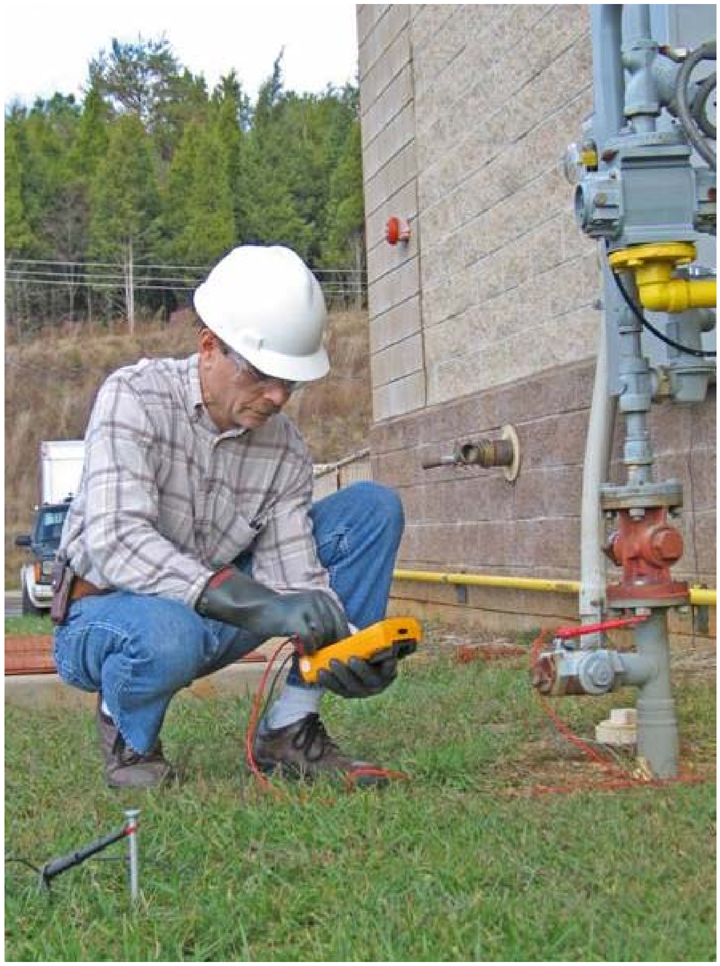


Figure 7-10
Sample Measurements Between a Gas Service Point and a Reference Ground

Figure 7-11
Sample Measurements Between a Grounded Meter Base and a Reference Ground

Figure 7-12
Sample Measurements Between a Pole Down Ground and a Reference Ground

8
WOOD POLE INSPECTIONS

Utilities inspect poles mainly for asset management, getting the most useful life out of equipment in a safe, orderly fashion. Public and crew safety and regulatory concerns also drive pole inspections. Line performance is generally a secondary concern.

Pole failures are not generally a significant contributor to line failure rates. For example, SAIFI and SAIDI due to pole failures is normally a low percentage. Because pole failure is intimately tied in with external forces (especially trees and wind), pole failures occur disproportionately during severe weather. The main performance benefit from managing pole failures is survivability from severe storms. Because pole failures require more than normal expense to restore, reducing pole failures will reduce storm restoration costs.

The main inspections and audits related to wood poles are:

- *Pole inspections* – Because of the specialty work, routine pole inspection work is often contracted out. Pole inspection programs are typically performed on an eight- to sixteen-year cycle.
- *Audits of pole inspections* – Audits of pole inspection work helps control quality and pole inspection efficiency. These audits are normally done by internal personnel. It is important that audits consider accuracy, not just the number of poles inspected.

Spotting deteriorated poles is also useful for inspectors doing problem circuit audits and regular line inspections. Note that visual inspections can reveal poletop decay, external damage (commonly lightning or woodpeckers), and pole splits (Figure 8-1). Visual inspections cannot reveal internal decay, the most common form of serious degradation.

Figure 8-1
Obvious Wood Pole Deterioration Examples

For more information on tailoring pole inspection programs, especially from an asset-management viewpoint, see the following:

- *Wood Pole Management Issue Assessment*, Electric Power Research Institute, Palo Alto, CA and EDM International, Inc., Fort Collins, CO, 2004. 1002093.
- *Guidelines for Intelligent Asset Replacement:* Volume 4: Wood Poles (Expanded Edition). EPRI, Palo Alto, CA: 2006. 1012500.

Inspection Cycles

Utilities normally inspect poles approximately on a fixed cycle. An Oregon State University survey reported that utilities generally inspect distribution poles more frequently than transmission poles (Table 8-1). In a survey of mainly Canadian utilities, the CEA found less widespread usage of pole inspections (the survey is also older). See Table 8-2 for a summary. In the CEA survey, at least 69% of respondents thought that each type of inspection was cost effective. The Rural Utilities Services recommends similar inspection cycles (Table 8-3) based on different decay zones given in Figure 8-2.

Table 8-1
Average Years Between Pole Inspections (EPRI 1002093 2004)

	1997 survey n = 261	2003 survey n = 8
Distribution poles	8.1	11.4
Transmission poles	7.2	9.8

Table 8-2
Percent of Utilities Performing the Given Pole Inspection Program (CEA 290 D 975 1995)

				Periodic inspections			
	Never	Ad hoc	One time	5 years	10 years	15 years	20+ years
Visual inspection	12	32	2	34	18	2	0
Hammer test	50	23	5	11	9	2	0
Sonic test	77	7	0	0	7	9	0
Bore test	41	11	14	9	16	7	2

Table 8-3
Recommended Inspection Cycles for RUS Utilities (RUS 1730B-121 1996)

Decay zone	Initial inspection	Subsequent inspection intervals
1	12 to 15 years	12 years
2 and 3	10 to 12 years	10 years
4 and 5	8 to 10 years	8 years

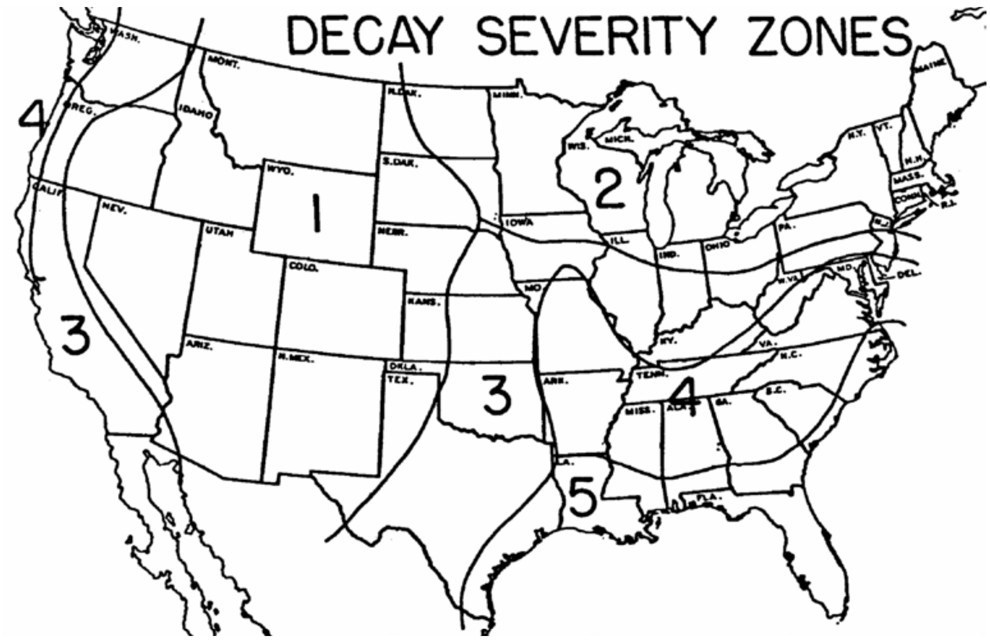


Figure 8-2
Wood Pole Decay Zones (RUS 1730B-121 1996)

Wood Pole Aging and Deterioration

Pole decay tends to begin at one of three locations on a distribution pole, as follows:

- Approximately two feet above and two feet below groundline, where moisture tends to concentrate because of the proximity to soil that may retain water for long periods
- At locations where hardware has been attached, if field-drilled holes expose untreated wood beyond the depth of preservative
- At the pole top, where the wood cross-section is more directly exposed to weathering and loss of preservatives occurs due to gravity

Some of the common causes for wood pole deterioration and replacement are as follows:

- Biological degradation caused by decay fungi and insect attack predominantly near the ground level.
- Mechanical damage
- Woodpecker attack
- Fire damage
- Bacterial attack and weathering contribute to the degradation of wood poles, albeit to a significantly lesser degree.
- Also, in areas with relatively high annual precipitation, pole top decay can be a significant issue.

Wood Pole Inspection Processes and Technologies

Visual Inspection: A visual inspection of the above ground portion of the pole is usually the first step in the inspection process. The inspector generally looks for defects in the pole itself, such as woodpecker holes and deteriorated tops, as well as defective hardware such as insulators, guy wires, and crossarms. Utilities obtain visual findings from frequently performed “detailed” patrols and through intrusive inspection programs conducted on a less frequent basis.

Sounding: Sounding with a hammer typically follows the visual inspection. The pole is hammered around ground level and upward for as far the inspector can reach. The inspector listens for the dull thud indicative of a hollow pole. This practice is effective for detecting severe internal decay, but does not detect early stages of decay.

Drilling: The inspector drills one or more 3/8-in diameter holes. The holes are drilled at a steep slope (45 to 60 degrees) to intersect as much wood as possible. Drilling will detect internal decay pockets, but will not detect the early stages of decay. In some cases where the poles will be fumigant treated, a series of larger, 7/8-in inspection holes are drilled, beginning at ground level, then moving upward and around the pole in a spiral pattern. These holes serve as application holes for fumigant treatment, as well as inspection holes.

Shell Depth Indicator: Used in conjunction with drilling, a shell depth indicator is a graduated metal rod with a hook at the end that is inserted into the drill holes and then pulled back along the hole. The hook catches along voids or other internal defects. The depth of sound wood (or residual shell) can then be measured and used to calculate remaining pole strength. This device will tend to overestimate shell depth due to the transitional wood which feels sound but has started to decay, but it is simple to use and reasonably effective.

Sonic/Ultrasonic Testers: A number of test sets use sound waves to determine pole integrity. In decayed wood, sound waves travel slower and are attenuated more. Different instruments operate over different frequency ranges and have different algorithms for detecting decay.

Electrical Resistance Testers: This works like an ohm meter and measures the internal moisture content of the pole between probes drilled to different depths. Decayed wood has lower resistivity than sound material. The pattern of measurements at different locations can help locate the location of decay.

Subsurface Inspection

Because subsurface decay is a normal decay mode, inspections below the ground are sometimes warranted. The pole is normally excavated to a depth of 18 inches to expose the surface where decay is most likely to occur. In some cases, only one side of the pole is excavated initially, and further excavation only occurs if the inspection indicates that surface decay or mechanical damage is present. Partial excavations are also used in arid areas to allow the inspection bore to be taken well below ground since the internal decay may not be present until 18 to 30 in below ground, where subsurface moisture is present. Partial excavations are useful for older poles that have not previously experienced surface decay. As the name implies, full excavations extend to a depth of 18 to 24 in around the pole’s circumference based on the pole owner’s specifications.

Sounding: As in above ground inspection, sounding below ground can help detect poles with significant internal decay pockets and serve to identify locations to inspect in more detail.

Surface Scraper: A surface scraping tool is used to remove dirt below ground to allow the pole surface to be accurately assessed.

Chipping Tool: A chipping tool is used to remove weakened wood from the pole surface so that the residual circumference can be measured. The decayed wood is removed since it is considered to have little or no structural integrity and will consume supplemental treatments without adding substantially to pole performance. Care must be taken to remove only decayed wood.

Drilling: Internal examination is often used to inspect the below ground zones of poles in drier regions where decay tends to occur well below ground level. The same criteria used for above ground drilling apply to this practice.

Treatment Options

Treatments are often done as part of inspections. Crew expertise, training, and capabilities are very similar for treatment as for inspecting. Treatment when done with inspections generally does not add to costs considerably.

Treatment options are divided into internal and external applications. External treatments are primarily used to prevent external decay by supplementing the original preservative treatment as it depletes with time; while internal treatments are applied to prevent or arrest internal decay or insect attack both above and below ground level.

External Treatments: These are typically applied below the ground level either as pastes which are brushed on the wood surface, then covered with a plastic barrier or as self-contained ready-made preservative bandages. In both cases, the goal is to supplement the original preservative treatment to prevent or arrest surface decay. Most systems have two components, an oil-soluble component that stays near the surface and penetrates to approximately one half inch and a water-soluble component that moves more deeply into the wood to provide additional protection. Protection is dependent upon the ability of the active ingredients to penetrate and remain in the treatment zone, and is limited to the depth of penetration. Pastes will have no effect on internal decay beyond this point.

Internal Treatments: Internal degradation caused by advanced decay can be arrested using fumigants, water diffusible pastes or rods, or internal void treatment. Each of these materials has specific attributes that make it effective in specific applications. In some cases they are applied using the holes created for the original inspection process. These treatment holes are generally used for future retreatments by removing the plugs that were used to plug the original application holes.

Fumigants are either applied as liquids or solids that then convert to a gas to move several feet from the point of application. Fumigants tend to work quickly, within one year of treatment, and provide five to ten years of protection, depending on pole species, geographic location and the type of fumigant used.

Water diffusible rods are capable of moving with moisture in the wood. These treatments tend to move more slowly through the wood than fumigants because they must be in contact with sufficient moisture to first dissolve and then to diffuse. Their EPA labels are less restrictive. The primary active ingredients in these systems are boron and fluoride, both of which have good efficacy against fungi and generally move several inches through the wood from the point of application. The slow initial movement can allow for decay to progress further than it might were fumigants used. The use of rods has been limited as compared to fumigants, and U.S. data supporting their ability to control and prevent decay is only just beginning to emerge.

General inspection and treatment approaches depends on tree species, decay level, and historical results. Table 8-4 shows commonly recommended inspection and treatment practices for one species depending on original treatments.

Table 8-4
Recommended Inspection and Treatment Practices for Southern Pine Poles Treated with Various Wood Preservatives (EPRI 1002093 2004)

	Inspection Practice			Treatment	
	Excavate	Sound	Bore	External	Internal
CCA	+/-	+	+/-	-	+/-
Penta-oil	++	+	+	+	+/-
Penta-gas	++	+	++	++	+/-
Creosote	++	+	+	++	+/-

Where += recommended, ++= strongly recommended, +/- = as needed, and -= seldom necessary. Internal treatments can include fumigants and/or internal void treatments.

Statistical Interpretation of Inspection Results

Like any inspection program, having data helps utilities tailor the inspections and justify the program's existence. Pole rejection rates tend to remain fairly constant with age up to a point at which failures increase significantly. Table 8-5 shows typical inspection failure rates. Numbers such as these can be used to optimize pole inspections (see EPRI 1012500 (2006)).

Table 8-5
Typical Annual Pole Rejection Rates without Treatment (EPRI 1012500 2006)

Decay Zone	Steady-state rejection rate	Age at turn-up	Rejection rate at age = 60 years
Zone 1	0.04%	30 years	0.85%
Zone 2	0.2%	25 years	1.1%
Zone 3/4 Northwest US	0.2%	25 years	1.0%
Zone 3/4 Northeast US	0.3%	25 years	1.7%
Zone 5	0.2%	25 years	1.8%

Translating pole inspection data into survivor curves or hazard curves is tricky. It's been done a number of different ways in previous reports and papers, many of them incorrect. The data source for estimating the pole hazard rates shown here is an Osmose database of pole inspections summarized in EPRI report 1002093, *Wood Pole Management – Issue Assessment* (2004). Osmose Utilities Services Inc. (Osmose), maintains electronic records for inspections performed on millions of poles. Osmose maintains inspection records on over 40 million poles and, most importantly, has records on repeated maintenance cycles of the same poles. These poles are classified by utility, wood species, initial treatment, degree of internal or external decay, and remedial treatment.

The main data we start with is shown in Figure 8-3, which has two types of data: initial inspections, and second inspections. Each gives us different information.

- *Initial inspection* – These are the initial inspections. We know the age of the pole and whether or not it passed an inspection.
- *Second inspection* – These are the points labeled "recycle" in Figure 8-3. These are interval-samples. We know the age of the pole, the age at which it was previously inspected, and whether or not it passed an inspection.

Hazard curves are developed differently for each type of data.

We also need to be careful about what type of hazard curve we are looking for. Some possibilities are:

- *Decayed* – The rate at which poles turn from the state of "good" to the state of "decayed". The states of "good" and "decayed" are determined by inspections.
- *Rejected* – The rate at which poles turn to the state of "rejected". Once rejected, the pole will normally be replaced or reinforced. One can actually have two hazard rates here: one the rate at which poles become rejected when either good or decayed or the rate at which poles become rejected when decayed.
- *Failed* – The rate at which poles actually break or are otherwise removed from the system.

The normal progression is *decayed* → *rejected* → *failed.*

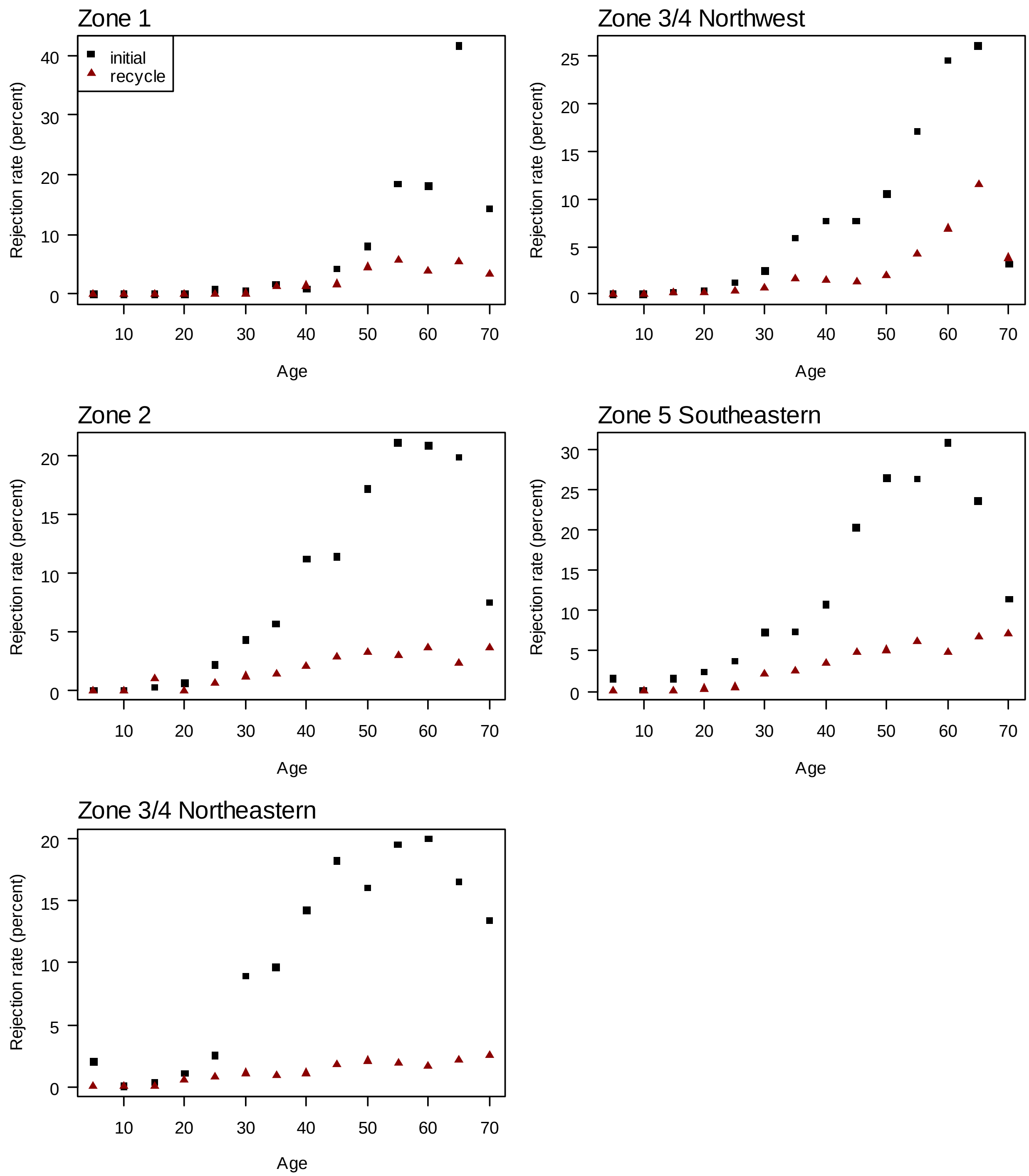


Figure 8-3
Pole Rejection Rates from the Osmose Data Summarized in EPRI 1002093

Initial Inspections

The initial pole inspections are *censored* survey data. Poles that pass an inspection are *right-censored*, meaning that the pole will become "rejected" at some age after the inspection time. Poles that fail an inspection are *left-censored*, meaning that they became "rejected" at some age before the inspection time. This is sometimes called doubly censored survey data. Meeker and Escobar (1988) and Nelson (1982) both describe this problem well. A crude estimate of the survival curve for pole rejections is:

$$S_i = 1 - r_i / n_i$$

where,

r_i = number of rejections of poles within a given age range

n_i = number of poles within a given age range

This should be an ever-decreasing function. Using this estimate, the survival curves in Figure 8-4 and Figure 8-5 were derived from the Osmose data in Figure 8-3. Hazard functions were found from survival curves using:

$$\lambda = -\frac{d}{dt}\log(S)$$

Nelson provides a more refined estimate of the cumulative hazard function by using maximum likelihoods.

The pole data does not quite follow this. We should not expect the hazard function to decrease over time. What's missing is that the rejection rates based on inspections is missing some data. Consider the set of poles inspected at age 50. The estimate of the survival rate is the number of poles that passed the inspection divided by all poles within that age group. This would be an appropriate estimate if the set of poles inspected included all poles of age 50. What's missing from the set is poles that were installed 50 years previously, became decayed, and failed or were otherwise removed because of decay. These are missing from the inspections because they are no longer in the field. The portion of poles removed would tend to become bigger with age, so this explains why the hazard rates level off or start to reduce with age. To account for this factor, only use the hazard curve up to the point where it starts to level off or reduce. It's unknown what it really does beyond the point where failures become significant, but we estimate it by linearly extrapolate beyond that kneepoint.

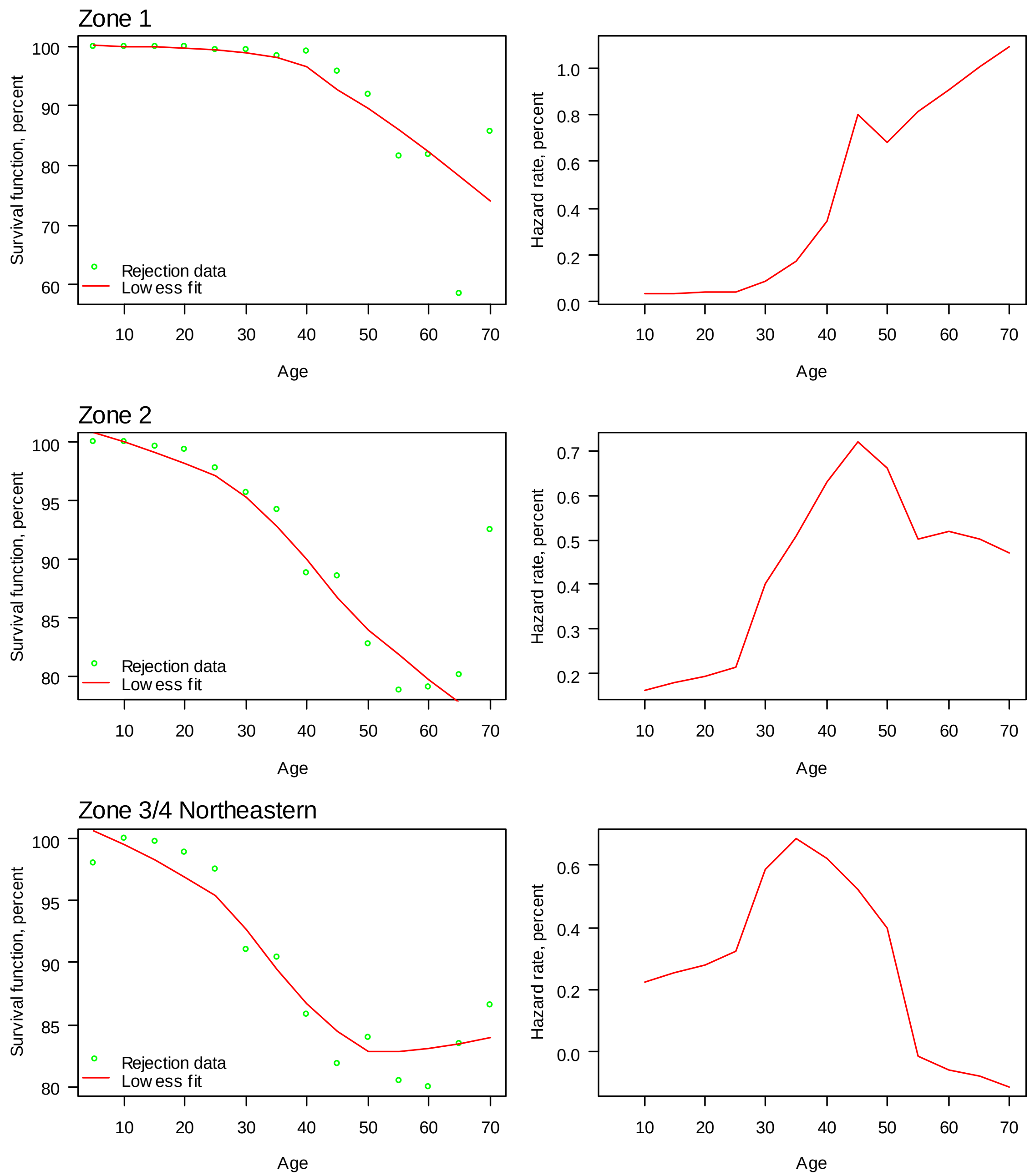


Figure 8-4
Estimates of Hazard Rates from Pole Rejection Rates (Zones 1 - 3).

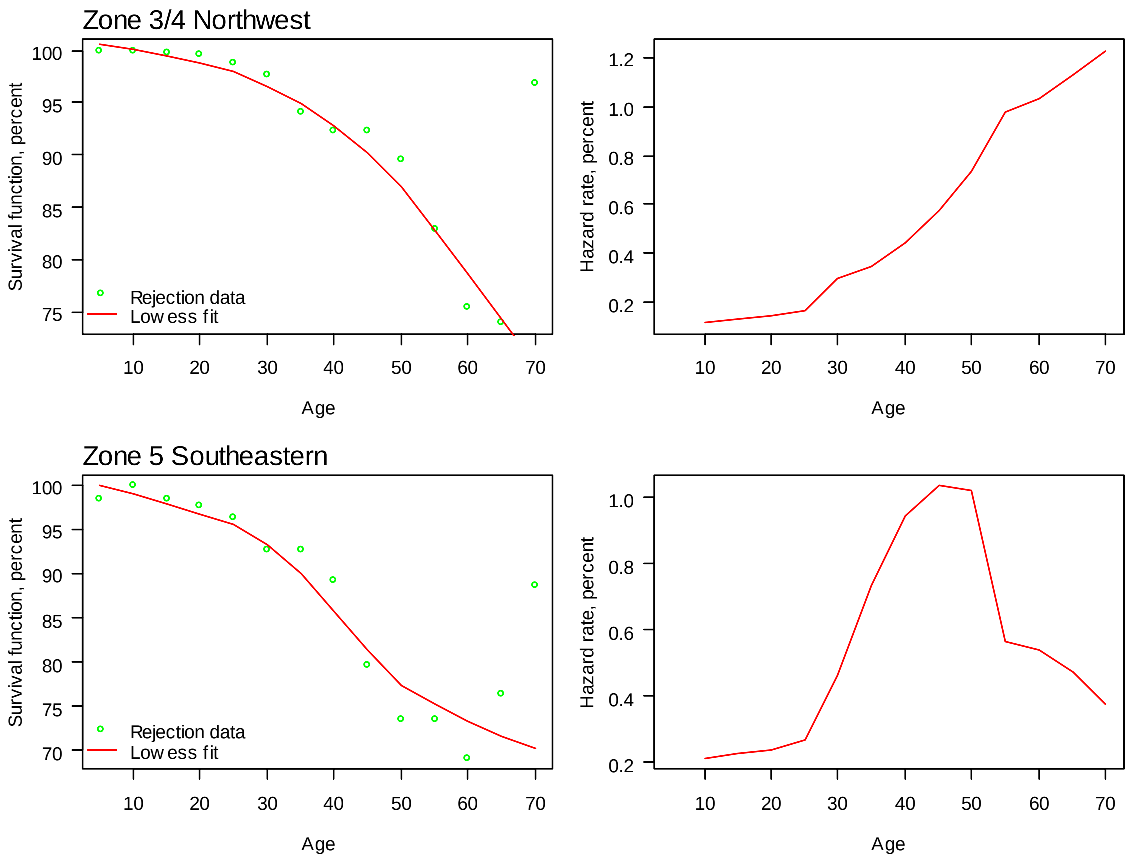


Figure 8-5
Estimates of Hazard Rates from Pole Rejection Rates (Zones 3 - 5).

Second Pole Inspections with Treatments

The Osmose data also includes rejection rates on the second inspection. This is *interval-censored* inspection data. If we take poles that passed inspection at age 30 and were inspected again at age 40, those that passed at age 40 are right censored, and those that failed the inspection at age 40 are interval censored (they became "rejected" some time between age 30 and age 40). With interval-censored data, we can directly estimate the hazard function by breaking the data into groups by age and time between the first and second inspection:

$$= r_i / n_i / t$$

where,

r_i = number of rejections of poles within a given age range and time between inspections

n_i = number of poles within a given age range

t = time between the first and second inspections

With the summarized Osmose data, we don't know the time between inspections. Assuming a ten-year interval (it is probably between 10 and 15 years), Figure 8-6 shows an estimate of the hazard rate from the rejection rates in Figure 8-3.

Figure 8-6 is an estimate of the hazard rate *with treatments*. The hazard rates in Figure 8-4 and Figure 8-5 are without treatments. If a utility has done periodic inspections without treatments, this approach will also estimate hazard rates without treatment.

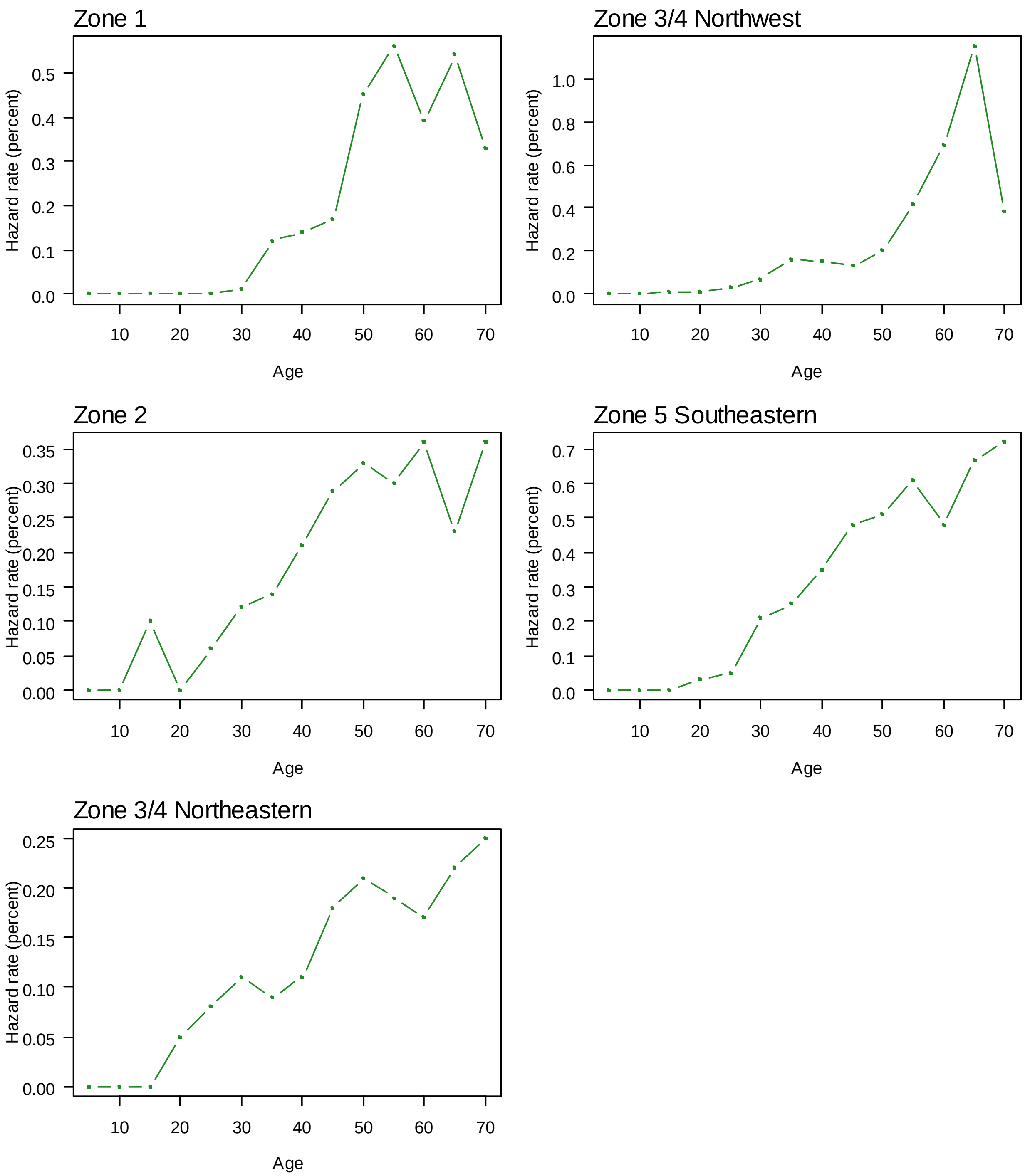


Figure 8-6
Estimates of Hazard Rates of Treated Poles from Pole Rejection Rates and Interval Inspections (Assuming 10-years from the Initial Inspection/Treatment)

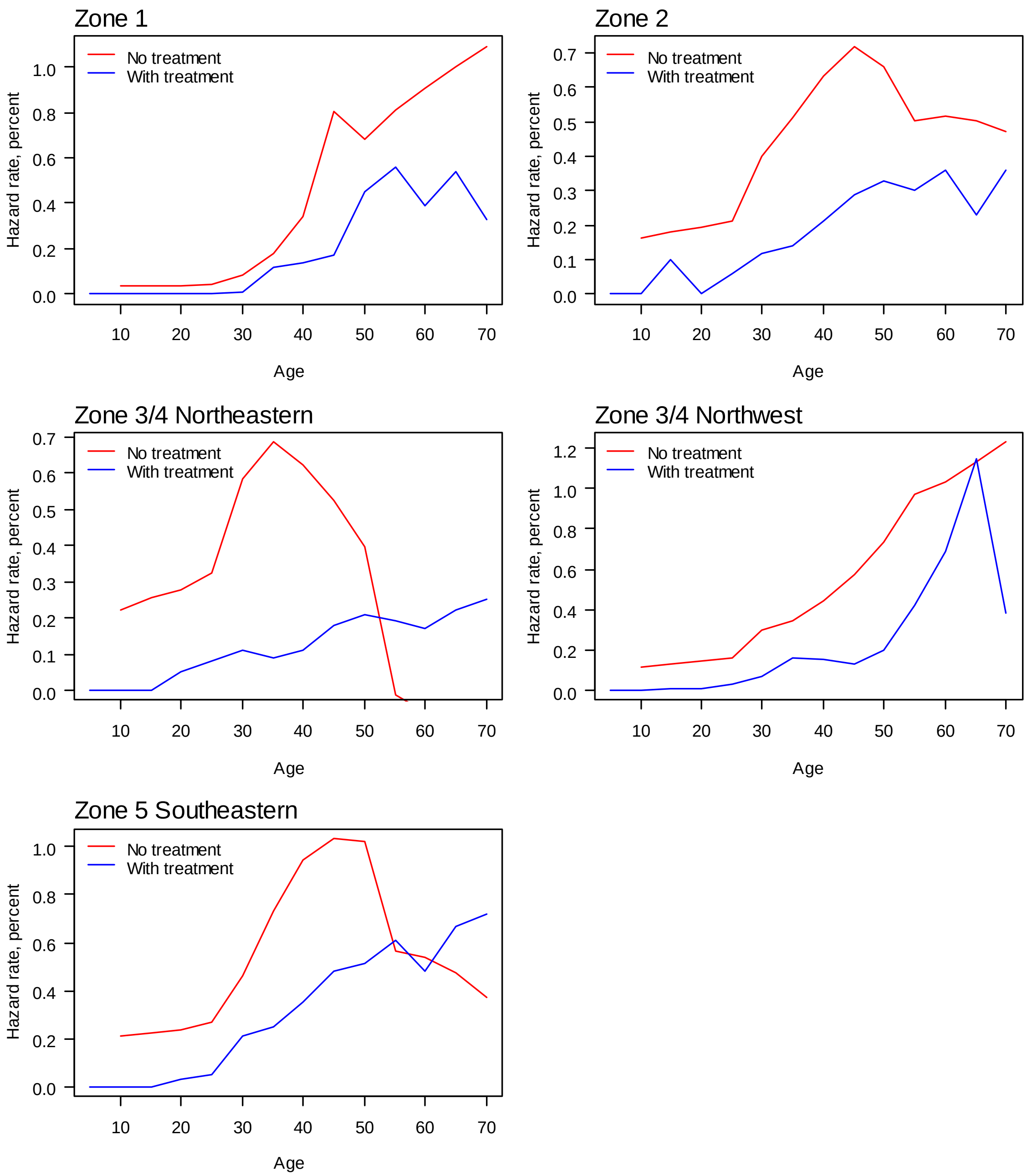


Figure 8-7
Estimates of Hazard Rates

Audits of Pole Inspections

Like most audits, audits of pole inspections (and treatments if any) should improve quality and efficiency. They should also improve crew training. Audits are especially important for contract inspection crews. Typically, only a small percentage of poles need to be audited. Figure 8-8 shows that of utilities surveyed, more than 60% audited less than five percent of poles.

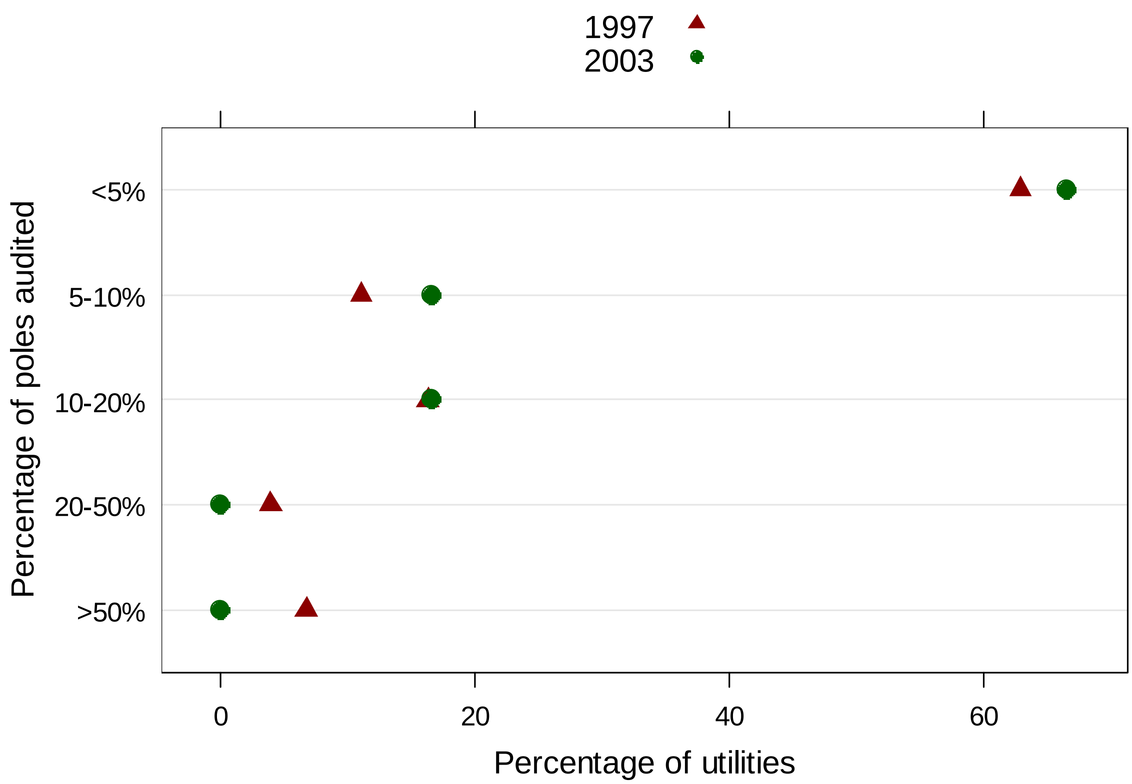


Figure 8-8
Portion of Utilities Surveyed on Portion of Pole Inspections Audited (EPRI 1002093 2004)

9
OTHER INSPECTIONS

Thermal Inspections

Thermal inspections, also referred to as infrared (IR) inspections, are used to locate equipment "hotspots" which can be a sign of impending failure for certain line components. Thermal inspections use specialized cameras that allow the operator to view the infrared portion of the light spectrum. Hotspots are identified by viewing a *thermal image* of the equipment under inspection produced by the infrared camera.

Overloading causes excessive heating in circuit components. Component heating is readily identifiable through thermal inspections, making the technology well suited for identifying overloaded circuits and failing splices. Thermal inspections are best applied during periods of high line loading since the anomalies identified through thermal inspections tend to be exacerbated at high loadings. Conversely, the same anomalies are much more difficult to find during periods of light line loading since the line components will operate at a lower temperature.

Justifying Thermal Inspections

Performing routine thermal inspections of distribution lines can yield several advantages including:

- *Increased system reliability* – Identifying deteriorating equipment before it fails permits scheduled repairs and prevents customer outages thereby improving reliability indices such as SAIFI, SAIDI, etc.
- *Reduced maintenance costs* – Identifying deteriorating equipment before it fails reduces maintenance costs by reducing the occurrence of emergency restorations and allowing repair work to be scheduled during normal working hours. Early detection of irregularities also limits equipment deterioration thus maximizing service life and limiting the scope of repairs to as little equipment as possible.
- *Verification of work quality* – Thermal inspection of new construction provides valuable feedback on construction work practices and quality by identifying any construction-related anomalies.

The deficiencies identified during thermal inspections are often difficult to determine though other inspection methods. Early identification of these issues allows them to be repaired before they manifest into faults and customer outages. A 1998 and 1999 thermal inspection of Orange and Rockland Utilities' overhead three-phase distribution system identified 294 anomalies; 9 of which were actually identified on transmission lines (EPRI 1000194 2000). Furthermore, the utility indicated that many of the anomalies would have eventually resulted in failed equipment and customer outages.

Thermal Inspection Basics

Thermal Camera Systems

Modern thermal imaging systems fall into two categories: (1) radiometric and (2) non-radiometric (EPRI 1000496 2000). Radiometric systems are quantitative meaning that they allow the operator in infer accurate radiometric temperatures from the thermal image. These systems have rigorous calibration requirements that can be expensive to achieve and maintain.

Non-radiometric systems are qualitative meaning that they allow the operator to make temperature comparisons from the thermal image (but do not provide radiometric temperatures). Non-radiometric systems are well suited for utility line thermal inspections since they allow the operator to identify anomalies by thermal comparison of line components (rather than using radiometric temperatures).

Non-imaging thermal camera systems are not well suited for performing thermal inspections, and their use is discouraged. Although they tend to be much lower in cost than imaging systems, non-imaging systems are also more difficult to use accurately. Non-imaging thermal cameras are slow and inaccurate for overhead line inspections, since they must be aimed at each individual device.

Handheld Versus Vehicle-Integrated Camera Systems

Thermal inspections of overhead lines can be performed with either handheld units or with vehicle mounted systems. Using a handheld system, the inspector can either ride along the line in an inspection vehicle (with or without a dedicated driver) or walk the line. Driving the line tends to be faster. The thermal camera can be mounted to a support that extends outside the vehicle's window to make the operator more comfortable. In this scenario, the camera is manually aimed, and the image is usually viewed on an auxiliary monitor mounted inside the vehicle.

Several utilities are moving towards using dedicated cargo vans or sport utility vehicles modified to perform thermal inspections. The vehicles usually have specially designed three-way mounts for the thermal imaging camera and integrated thermographer workstations. The systems are configured such that a technician, riding inside the vehicle, can remotely aim the camera and view the thermal image on a monitor while seated at the workstation. Note that a few utilities have identified slow pan/tilt mechanisms as a source of frustration, so consider camera aiming speed for any system still under design. Dedicated thermal inspection vehicles often have the following modifications:

- Thermal and visual cameras on a pan and tilt mount – located on an exterior bracket, roof-mounted, mounted on a "pop-up" fixture that extends through the vehicle's roof for inspections but houses the camera equipment inside the vehicle for storage.

- Front and rear warning lights
- Additional exterior lights for illuminating work areas
- Roof access via ladders or hatches
- Thermographer’s workstation with joystick camera controls, a large work surface, and equipment racks for TV, VCR, monitor, computer, etc.
- Driver’s workstation designed to display circuit maps, a GPS unit, etc.

Inspection Frequency

Which infrastructure is inspected and how often it is inspected varies from utility to utility. Inspection cycles can be as short as yearly. For example, Orange and Rockland Utilities inspects all three-phase overhead primary distribution lines, including transformers and secondary conductors on three-phase structures, on an annual basis (EPRI 1000194 2000). They also perform thermal inspections on stress cones, elbows, bushings, and pad-mounted transformers on their underground system. Others companies use longer inspection cycles such as the three-year scan cycle for overhead three-phase lines used by Commonwealth Edison (Kregg 2000).

The Canadian Electrical Association (CEA) polled 58 Canadian electric utilities and 42 American electric utilities regarding their distribution system monitoring and inspection procedures (CEA 290-D-975 1995). Respondents to the CEA survey indicated that they use infrared inspections for examining a variety of overhead and underground circuit equipment as shown in Table 9-1.

Although many utilities perform thermal inspections on a one- to three-year cycle, this doesn’t mean that one- to three-years is the right cycle for every utility. The age, condition, and load served by each feeder should be considered when determining the inspection cycle. New lines or those that serve few customers can be inspected less frequently. One method for fine-tuning the inspection cycle is to examine failure and inspection statistics. If failures are occurring less frequently or showing a plateau, then increasing the inspection cycle length can be considered. Lengthening the inspection cycle can also be considered if few anomalies are showing up during each inspection. Conversely, the inspection cycle should be shortened if failures are increasing or the number of anomalies found per inspection remains high (EPRI 1000496 2000).

Ideally, all thermal inspections would be performed during periods of heavy load since that is when the anomalies identified by the inspection would be at their worst (and most discernable). Of course, this is usually not possible given the quantity of apparatus that requires scanning. There simply isn’t enough time to scan everything during high load periods. Any anomalies that are found during periods of light and moderate load are worse during heavy system loading. Furthermore, any anomalies found during cold weather are worse during hotter ambient temperatures.

Table 9-1
Thermal Inspection Cycles Shown by Percent of Respondents (CEA 290-D-975 1995)

Inspection Cycle	Never	Ad Hoc	One Time	Six Months	One Year	Two Years	Five Years	Five+ Years
Overhead – Conductors, Splices, and Connectors	28%	18%	7%	0%	27%	7%	11%	2%
Overhead – Fuse Cutouts	42%	11%	9%	0%	20%	7%	11%	0%
Overhead – Disconnect Switches	36%	20%	9%	0%	20%	7%	7%	0%
Overhead – Surge Arresters	56%	16%	4%	0%	18%	7%	2%	0%
Overhead – Distribution Transformers	45%	18%	5%	0%	16%	7%	7%	2%
Overhead – Voltage Regulators	58%	13%	4%	4%	4%	9%	4%	4%
Overhead – Reclosers and Sectionalizers	45%	14%	7%	0%	14%	10%	7%	3%
Overhead – Capacitors	60%	4%	4%	4%	8%	12%	4%	4%
Underground – Elbows, Splices, and Connectors	34%	21%	5%	0%	16%	7%	12%	5%
Underground - Switches	39%	21%	5%	0%	16%	7%	12%	0%
Underground - Transformers	49%	16%	5%	0%	9%	5%	11%	5%

Priority Ratings

A grading system provides a method for prioritizing repair work for anomalies discovered during thermal inspections. Grading systems tend to be broken up into three to five grades ranging from severe (immediate action required) to minor (monitor / no action required). Kregg (2000) reported that Commonwealth Edison uses the priority grading system shown in Table 9-2. This system is based prior experience from substation thermal inspections, common utility practices, recommendations from thermography equipment manufacturers, and EPRI documentation (Kregg 2000).

Table 9-3 presents a similar priority grading system that is used by Asplundh Infrared Services during thermal inspections of Orange and Rockland Utilities' overhead distribution system (EPRI 1000194 2000).

The priority grading systems shown in Table 9-2 and Table 9-3 both follow a similar format in which those anomalies identified as presenting an immediate hazard to personal safety or system reliability are addressed the same day that they are discovered. Less severe situations are addressed in one week to three months. Minor anomalies are flagged for monitoring.

Table 9-2
Thermal Inspection Anomaly Priority Grading System Used by Commonwealth Edison (Kregg 2000)

Temperature Criteria	Priority
For *line of sight items* such as bolted connections, splices, disconnect jaws, etc.	
>135°F	Critical – corrective action immediately
64°F to 135°F	Serious – correction action as soon as possible
18°F to 63°F	Intermediate – corrective action as scheduling permits
< 18°F	Attention – no corrective action but monitor equipment
For *non-line of sight items* such as transformer and capacitor cans, cable up-feed and down-feed pot heads, arrester bodies, etc.	
>36°F	Critical – corrective action immediately
18°F to 36°F	Serious – correction action as soon as possible
1°F to 17°F	Intermediate – corrective action as scheduling permits

All temperatures are temperature rises above an appropriately selected reference point. The reference point is usually a similar component on another phase that is assumed to be under similar load.

Table 9-3
Anomaly Priority Grading System Used by Asplundh Infrared Services for Infrared Inspections of Orange and Rockland Utilities' Infrastructure (EPRI 1000194 2000)

Priority	Temperature Rise	Repair Status
1	50°C or more	Repair immediately
2	21°C to 49°C	Repair in 7 days
3	11°C to 20°C	Repair in 3 months
4	10°C or less	Monitor regularly

Performing Thermal Inspections

Calibration

It is important to check the calibration of the thermal imaging system at the beginning and end of each day of inspection. This can be done by viewing reference targets at a know temperature and in the temperature range encountered during the day's work. Buckets of ice water and water heated to 120°F (49°C) make good reference targets.

Inspection Procedure and Reporting Forms

The basic procedure for performing thermal inspections on overhead lines is the same for handheld and vehicle mounted camera systems. The inspector(s) travel along the line viewing it with the thermal imaging system. Vehicle-based thermal inspections are generally conducted at 15 to 30 miles per hour depending on the equipment used and the characteristics of the line being inspected. The vehicle is stopped when an anomaly is found, and the anomalous information is recorded. At a minimum, the recorded data should consist of:

- The inspector's name
- The time, date, and weather conditions
- Circuit and pole location
- Address location
- Phase on which the anomaly exists
- A written description of the anomaly
- Both a thermal image and a visual image of the anomaly
- The anomalous temperature (radiometric or relative)
- The anomalous priority rating

Figure 9-1 shows an example thermal inspection report form, which incorporates this information. The purpose of the inspection report form is to document each anomaly discovered in sufficient detail for the work crew to be have a good idea of what needs to be repaired before they arrive onsite. Inspection reports can either be manually completed or auto-generated by a computer system. Likewise, the reports can be paper-based or entirely digital with the day's work being downloaded back at the office.

Each anomaly discovered during the inspection should also be entered in to a thermal inspection log sheet like the one shown in Figure 9-2. The thermal inspection reports provide detailed information about each anomaly so that it can be repaired while the inspection log sheet simply keeps a running tally of all known anomalies. The log sheet is useful for keeping track of which anomalies have been repaired.

Thermal Inspection Report

Date & Time: ____________________ Circuit #: ____________________

Inspector(s): ____________________ Structure ID #: ____________________

Weather: ____________________ Location: ____________________

Anomaly Information

Description: ____

Temperature Information (°C)

Reference:	
Hot Spot:	
Temp Rise:	

Priority Code: ______

1	50°C or more -	Repair Immediately
2	21°C to 49°C -	Repair within 1 week
3	11°C to 20°C -	Repair within 3 months
4	10°C or less -	Monitor

Thermal Image

File name: ____________________

Visual Image

File name: ____________________

Comments

Figure 9-1
Example Thermal Inspection Report

Date	Circuit	Pole / Substation / Structure ID	Location	Description	OH	UG	Hot Spot Temp (°C)	Ref. Temp (°C)

Figure 9-2
Example Thermal Inspection Log Sheet

Equipment Inspections – Capacitors, Regulators, and Reclosers

It is not uncommon for capacitors, voltage regulators, or reclosers to suffer from problems that prohibit them from operating properly. They can suffer from several maladies including blown fuses, physical damage, and internal failures. Goeckeler reported that in one overhead fixed capacitor patrol cycle Kansas City Power & Light found 16% of capacitor banks with "as found" problems resulting in 8.3% of their fixed capacitor infrastructure being out of service (Goeckeler 2002). For these reasons, overhead capacitor installations require periodic inspection to make sure that they are working properly.

Inspection Frequency

Typical inspection cycles for overhead distribution equipment installations range from one to five years. The Canadian Electrical Association (CEA) polled 58 Canadian electric utilities and 42 American electric utilities regarding their distribution system monitoring and inspection procedures (CEA 290-D-975 1995). The majority of respondents in the CEA work reported using a capacitor inspection cycle of between six-months and five years as shown in Table 9-4.

Table 9-4
Overhead Distribution Capacitor Inspection Cycles Shown by Percent of Respondents to CEA 290-D-975

Inspection Cycle	Respondents
Never	12%
Ad Hoc	20%
One Time	0%
6-Months	16%
1-Year	20%
2-Years	8%
5-Years	24%
>5-Years	0%

Although the CEA report does not elaborate on these practices, it is possible that the six-month inspection cycle shown in Table 9-4 is the result of manually switching capacitors on a seasonal basis. If a work crew must travel to a capacitor installation to manually switch the unit then they might as well perform routine maintenance and inspection while they are there.

Automation reduces the need for regular inspections. Utilities that have installed capacitor control systems with remote switching capabilities have found that they can virtually eliminate routine capacitor patrols. Centralized control provides positive feedback of capacitor operation which allows failing capacitors to be identified from the control center rather than via field inspections. Communication capability with regulators or reclosers can offer similar benefits.

Capacitor Inspections

Visual inspections are used to asses the basic condition of the capacitor installation. The goal is to visually verify that the equipment is in good working order. The following items should be checked during capacitor inspections:

- Blown fuses (Figure 9-3)
- Hanging fuse tubes
- Broken or missing connections
- Leaking or weeping from the capacitor cans
- Bulging or otherwise deformed capacitor cans
- Broken or cracked bushings
- Missing or improperly installed animal guards

- Missing or broken groundwire
- Any visible to switches or pole-mounted control units
- Any signs of arcing, burning, or excessive heating

Figure 9-5 provides an example overhead capacitor inspection reporting form.

Fuse tubes should not be left hanging open in the cutouts when capacitor units are taken out of service for the year. It is poor practice to leave any fuse tube hanging open in a cutout since this effectively places the fuse tube in an upside-down orientation and allows water, ice, and debris to collect inside the fuse tube.

Figure 9-3
Overhead Distribution Capacitor Installation with Blown Fuse

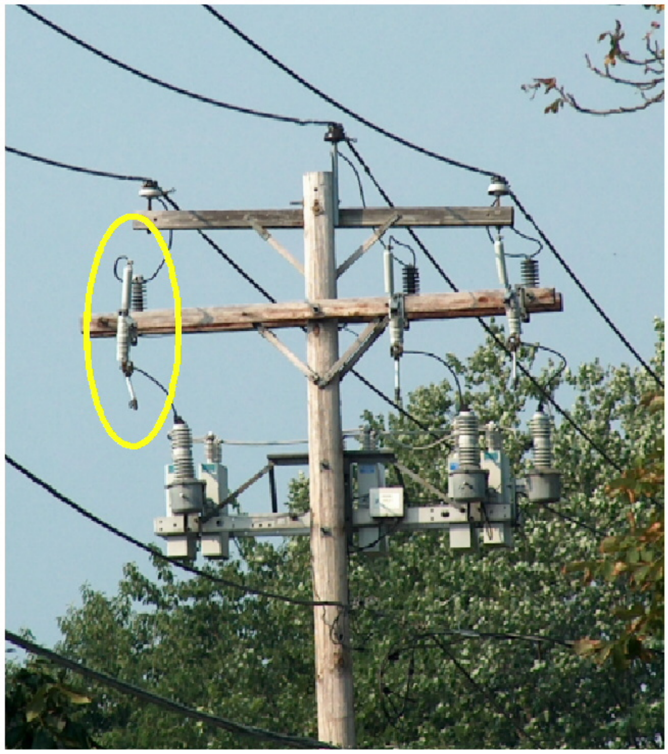


Figure 9-4
Fuse Tubes Should Not be Left Hanging Upside Down

Distribution Line Capacitor Inspection Report

Date & Time: ______________________ Device Location: ______________________
Inspector: ______________________ Address: ______________________
Digital Photo #'s: ______________________ Circuit: ______________________

Site Inspection

Safe Access	Yes No, explain: ____________________
Physical Accessibility	Good Seasonal Vegetation Other: ____________________
Vegetation	None On Pole Only Conductors Capacitor / Switches Other: _______________
Animals / Nests	Nests Animal Damage Other:

Equipment Inspection

General Condition	Good Fair Poor Comments: ______________________
Oil Leaks	None Capacitor Switch Transformer Other: ______________________
Evidence of Overheating	No Yes, explain: ______________________
Evidence of Arcing	No Yes, explain: ______________________
Bulging Capacitors	No Yes, explain: ______________________
Rusting	None Moderate Excessive Comments: ______________________
Cracked Bushing / Insulator	No Yes, explain: ______________________
U-Guard / Conduit	Good Damaged Missing Comments: ______________________
Supports	Good Loose Comments: ______________________
Bank Connections	Wye Delta
Bank Size	Single Phase 300 kVAR 600 kVAR 900 kVAR 1200 kVAR 1800 kVAR 2400 kVAR
Unit Size and Quantity	_____ / 100 kVAR _____ / 200 kVAR _____ / 300 kVAR _____ / 400 kVAR
Capacitor Blocking Units	Installed Pole Storage None
Cap. Blocking Unit Wiring	Correct Incorrect / damaged, explain: ______________________
Capacitor Switches	None Oil Vacuum
Switch Manufacturer	ABB Cooper Joslyn Westinghouse Other: ____________________
Same Type / Brand of Switch on Each Phase	Yes No, explain:
Primary Fuse Size and Type: ______________	
Fuse Barrel Condition	Good Found damaged and replaced

Control System Inspection

Condition	Good Damaged Enclosure Damaged Seals Moisture Burns Other: ______________
Control Type	None Local Paging DLC Cellular Other: ______________
Paging Frequency (if applicable): ____________________	
Paging Signal	Not Applicable Applicable Channel: __________ Strength: __________ dBm
DLC Signal	Not Applicable Applicable __________ MV __________ Volts
Control Manufacturer	Beckwith Canon EnergyLine Fisher-Pierce Maysteel Other: ____________________
Control Serial Number	______________________________
As Found State	Remote Local Closed Tripped UV/OV LED on UV/OV LED off COM LED on COM LED off
UV/OV Settings	UV Setting__________ OV Setting_________
UV/OV Accuracy Check	Accurate Not Accurate

Operation Inspection

Trip Voltage __________ Volts AC Riser Current - Trip: Field:_____Amps Center:_____Amps Road:_____Amps
Close Voltage __________ Volts AC Riser Current - Close: Field:_____Amps Center:_____Amps Road:_____Amps

Switch Operation All follow operation One or more does not follow operation, explain: ____________________________
Ground Resistance _______________ Ohms

Follow-Up Required No Yes - see comments

Comments

Upon Leaving

Bank left in "As Found" state
Controller left in REMOTE mode
As left controller frequency __________
(enter NA if not paging)

Figure 9-5
Distribution Capacitor Inspection Report

Voltage Regulator and Recloser Inspections

Voltage regulator inspections mainly involve assessing the regulators general condition. Does there appear to be any mechanical damage? Look for signs of arcing or burning. Also check for animal-related damage and nesting materials. Are arresters properly installed on the regulator unit? Make sure that animal guards are in place and properly installed. A more detailed inspection can also involve checking for voltage imbalance. Figure 9-6 shows a checklist that can be used during routine regulator inspections.

Recloser inspections chiefly consist of three basic components:

1. Assessing the general condition of the recloser
2. Operating the recloser
3. Recording the operation counts

Examine the general condition of the recloser. Does there appear to be any mechanical damage? Look for signs of arcing or burning. Also check for animal-related damage and nesting materials. Are arresters properly installed on the recloser unit? Make sure that animal guards are in place and properly installed. Follow the manufacturer's directions and company procedures recording the operation count and operating the recloser to verify that it functions properly. Figure 9-7 shows an example recloser inspection form that can be used in conjunction with the inspection tasks outline above.

Voltage Regulator Inspection Report

Location ID ________ Feedern ________ Substation ________

Physical Location: ____________________

Control Data

Control Serial Number		Control Mfg.		Control Type	
Original Equipment Counter		Date Installed		Control Fuse Size	
Control Offset Counter					

Voltage Regulator Data

Regulator Serial Number			Size:	Amp		kVA	
Primary Voltage:	7.2 kV		13.2 kV		19.9 kV		
Fuse Size			Connection:	Delta		Wye	
Equipment Serial Number			Design:	Straight		Inverted	
Percentage Regulation			No. of Steps		Phase		
Set Voltage			Bandwidth		Time Delay		
Load Voltage:	Low		Present		High		
Load Current:	Low		Present		High		

Drag Hand Readings

Date	Phase R/M/F	Min	Present	Max	Volt	Employee

Comments

Figure 9-6
Voltage Regulator Inspection Report

Recloser Inspection Report

Location ID ____ Feeder ____ Substation ____

Physical Location: ____

Control Data

Control Serial Number				Control Mfg.	
Original Equipment Counter		Date Installed		Control Type	
Control Offset Counter				Control Fuse Size	

Recloser Data

Recloser Serial Number			Size		Type		
Primary Voltage:	12 kV		23 kV		34.5 kV		
Operation Sequence:	Ground Trip		Lockout		Phase Trip		
Trip Resistors:	Phase		Ground				

Timing Plugs:

	Ground Trip	Phase Trip
1		
2		

Reset Delay ____

Battery Install Date ____

Date	Counter Reading	Battery Voltage	Employee	Date	Counter Reading	Battery Voltage	Employee

Defect Codes

Date	Code	Date	Code	Date	Code	Date	Code

Comments

Figure 9-7
Recloser Inspection Report

Radio Interference Inspections

Distribution line hardware can generate radio-frequency interference (RFI). Such interference can impact the AM and FM bands as well as VHF television broadcasts. Ham radio frequencies are also affected.

Resolving RFI issues are required by law. FCC regulations require utilities not to cause harmful interference and to stop operating any device that does cause interference when notified by the FCC. Under FCC Part-15 Regulations, most utility sources of radio interference will fall under the category of *incidental emitter* (Martin, Hollingsworth et al. 2004). An incidental emitter is one that does not intentionally emit radio energy but does so incidentally as part of their operation. Although incidental, all unlicensed emitters of radio energy are required not to cause harmful interference with licensed services. Furthermore, most radio interference generated on power lines is due to small gap arcing which can lead to equipment failure. Therefore, it is not only required by law, but also in the utility's best interest to address radio interference generation on their lines.

Sources of Radio Interference on Distribution Lines

Most power-line noise is from arcs, arcs across gaps on the order of 1 mm, usually at poor contacts. These arcs can occur between many metallic junctions on power-line equipment. Consider two metal objects in close proximity but not quite touching. The capacitive voltage divider between the conducting parts determines the voltage differences between them. The voltage difference between two metallic pieces can cause arcing across a small gap. After arcing across, the gap can clear easily, and after the capacitive voltage builds back up it can spark over again. These sparkovers radiate radio-frequency noise. Stronger radio-frequency interference is more likely from hardware closer to the primary conductors.

Arcing generates broad-band radio-frequency noise from several kilohertz to over 1000 MHz. Above about 50 Mhz, the magnitude of arcing RFI drops off. Power line interference affects lower frequency broadcasts more than higher frequencies. The most common from low to high frequency are: AM radio (0.54 – 1.71 MHz), low-band VHF TV (channels 2 to 6, 54 – 88 MHz), FM radio (88.1 – 107.9 MHz), and high-band VHF TV (channels 7 to 13, 174 – 216 MHz). UHF (ultra-high frequencies, about 500 MHz) are only created right near the sparking source.

Arcing across small gaps accounts for almost all radio-frequency interference created by utility equipment on distribution circuits. Arcing from corona can also cause interference, but distribution circuit voltages are too low for corona to cause significant interference. Radio interference is more common at higher distribution voltages.

Some common sources include [for more detail, see (NRECA 90-30 1992; Loftness 1996)]:

- *Loose or corroded hot-line clamps*
- *Loose nut and washer on a through bolt* — Commonly a problem on double-arming bolts between two crossarms.

- *Loose or broken insulator tie wire or incorrect tie wire* — Loose tie wires can cause arcing, and conducting ties on covered conductors generate interference.
- *Loose dead-end insulator units*
- *Loose metal staples on bonding or ground wires, especially near the top*
- *Loose crossarm lag screw*
- *Bonding conductors touching or nearly touching other metal hardware* — Anything less than 1 in (2.54 cm).
- *Broken or contaminated insulators*
- *Defective lightning arresters, especially gapped units*

Most of these problems have common characteristics—gaps between metals, often from loose hardware. Crews can fix most problems by tightening connections, separating metal hardware by at least one inch, or bonding hardware together. Metal-to-wood interfaces are less likely to cause interference; a tree branch touching a conductor usually does not generate radio-frequency interference.

While interference is often associated with overhead circuits, underground lines can also generate interference. Again, look for loose connections, either primary or secondary such as in load-break elbows.

Radio Interference Inspection Tools

With the exception of a radio interference detector, the tools required for radio interference inspections are similar to those used for visual overhead line inspections. The following tools are suggested for performing radio interference inspections:

- *Radio Interference Detector* – Many different interference detectors are available; most are radios with directional antennas.
- *Parabolic dish ultrasonic detector* – For pinpointing interference sources; generally used to find precise interference source after a radio interference detector indicates interference coming from a structure.
- *Circuit map* – The circuit map can be paper-based or digital, but it must be complete and accurate. All major overhead equipment such as fuses, switches, reclosers, and capacitors should be identified. Digital maps, often implemented via graphical information systems (GIS), have the advantage of presenting much more information than the basic requirements and will most likely show data such as pole numbers, conductors types, and the location of auxiliary equipment such as arresters. Paper maps have the advantage of being easier to mark-up with problem locations.
- *Binoculars* – A high-quality set of binoculars with decent magnification power allows the inspector to get a better look at pole top equipment, conductors, and structures with limited access.

- *Digital camera* – A digital camera with a five to ten power zoom allows the inspector to document problems in a format that is easily transferable and easily copied.
- *Inspection forms* – Inspection forms are often overlooked as a required tool, but it plays an important role in the inspection and reporting process. The inspection form allows for uniform inspection and reporting practices which in turn aid in prioritizing corrective action and building an inspection database.
- *Personal protective equipment* – Although these items don't necessarily aid in inspecting the line, they are important from a personal safety standpoint. The inspector should make use of a safety hat, safety glasses, and a high-visibility safety vest. Ear protection should also be worn as appropriate in construction areas or in other loud environments. Bright high-visibility colors are best since much of the line inspection work is done in close proximity to moving traffic.
- *Navigation equipment* – A circuit map is usually not a proper substitute for a traditional road map of the area. Road maps can be either paper-based, software-based computer programs, or GPS units.
- *Vehicle* – Visual inspections involve a mix of walking and riding. Even if no inspection is done from the vehicle, the inspector still needs to get to the circuit and move along its length. There may also be line sections that traverse rough/remote terrain, and a four-wheel drive vehicle is preferable in these circumstances.
- *Two-way radio* – The radio can be vehicle mounted or portable and provides a communication link for the inspector to report hazardous situations that require immediate attention.

Performing Radio Interference Inspections

Radio frequency interference patrols involve driving the line under inspection and "listening" for interference with RFI detector. Closer to the source, instruments can detect radio-frequency noise at higher and higher frequencies, so higher frequencies can help pinpoint sources. As you get closer to the source, follow the highest frequency that you can receive (if you cannot detect interference at higher and higher frequencies as you drive along the line, you are probably going in the wrong direction). Once a problem pole is identified, an ultrasonic detector with a parabolic dish can zero in on problem areas to identify where the arcing is coming from. Ultrasonic detectors measure ultra-high frequency sound waves (about 20 kHz – 100 kHz) and give accurate direction to the source. Ultrasonic detectors almost require line-of-sight to the arcing source, so they do not help if the arcing is hidden. In such cases, the sparking may be internal to an enclosed device, or the RF could be conducted to the pole by a secondary conductor or riser pole. For even more precise location, crews can use hot-stick mounted detectors to identify exactly what's arcing.

Note that many other non-utility sources of radio-frequency interference exist. Many of these also involve intermittent arcing. Common power-frequency type sources include fans, light dimmers, fluorescent lights, loose wiring within the home or facility, and electrical tools such as drills. Other sources include defective antennas, amateur or CB radios, spark-plug ignitions from vehicles or lawn mowers, home computers, and garage door openers. It is important to note that background noise can make it difficult to locate radio interference sources on distribution lines during field inspections.

Grounding Inspections

Proper grounding benefits both the utility and utility customers by helping to reduce lightning-related damage and outages. Maintaining adequate ground connections also helps improve line safety. For these reasons, it is sometimes necessary to check ground connections to verify that they offer a sufficiently low ground resistance. Grounding inspections can be completed on a stand-alone basis or as part of another inspection process such as an outage follow-up (Chapter 4) or problem circuit investigation (Chapters 5) as previously discussed in this document.

Be Aware of Underground Lines

Verify that there are not any underground lines at the test location before driving any rods, spikes, electrodes, or other apparatus into the ground. Contacting an underground cable with a ground rod will be problematic at best and could result serious bodily harm or death. Be aware of any buried infrastructure such as electric, gas, water, sewer lines. Also be aware of street lighting wires, traffic light cables, cable TV lines, and telephone lines.

Methods for Measuring Ground Resistance

Before measuring the ground resistance, check the following:

- Verify that a ground connection is present at equipment poles such as transformers, capacitors, arresters, etc.
- Verify that any equipment on the pole is bonded appropriately including neutral conductors, guy wires, and line apparatus.

There are several methods for measuring the earthing resistance of utility pole ground systems:

- *Clamp-on Method* – This method uses a clamp-on ground meter to measure electrode resistance to ground and offers the benefit of allowing ground measurements to be made without disconnecting the grounding electrode from the ground system.
- *Fall-of-potential method* – This is a commonly employed method of measuring the earthing resistance of pole grounds. This method is influenced by nearby buried metallic objects so it is not suitable for use near buried utility lines or other buried metallic objects.
- *Two-point method* – The two point method is place of the fall-of-potential method when there are nearby buried metallic objects or when space limitations or ground covering make the fall-of-potential method unworkable.

Clamp-On Method

Clamp-on ground meters inject a current pulse into the ground conductor and calculate the value of the ground conductor resistance from the current pulse amplitude. Unlike the fall-of-potential and two-point test methods, using a clamp-on ground meter does not require the ground electrode under test to be isolated from the ground system. Another benefit of the clamp-on test method is that it does not require the use of any auxiliary probes or spikes. However, clamp-on ground resistance meters are not suitable for use in single ground systems. The meters function in a manner such that they need a ground connection in front of and behind the meter. For calculation purposes, the meter assumes that the resistance of the multiple adjacent grounds is very small (Parker 2006).

The procedure for making measurements with a clamp-on ground meter is quite simple. Start by inputting the proper meter settings (such as setting the measurement type to ohms). The meter must be placed in the ground path and a few feet up the pole from the ground rod is usually a convenient location. If the ground conductor is inaccessible then the meter can be clamped around the ground rod itself (Dranetz-BMI 2006). Clamp the meter jaws securely around the ground conductor, trigger the unit to take the resistance measurement. The measurement should be recorded in an inspection log along with the inspector's name, location, time, date, and the weather conditions. Since it is much easier than other methods, this method is preferred for regular ground checks.

Fall-of-Potential Method

The fall-of-potential method is sometimes referred to as the two-spike method since it involves driving two auxiliary spikes or probes (A and B) in a straight line with the grounding electrode under test (E); usually the pole ground rod. The test set-up is depicted in Figure 9-8. It is best to place auxiliary probe B as far away from electrode E as possible; usually 60 to 100 feet is sufficient. A four terminal earth tester is used to circulate current in the loop formed by electrode E and auxiliary probe B. The voltage drop between E and probe A is measured. The resistance of the auxiliary probes A and B does not have a direct bearing on the test result (EPRI 1002021 2004).

To accurately measure the resistance, auxiliary probe A is driven in at a number of points roughly on a straight line between the earth electrode and C. Resistance readings are logged for each of the points and a curve of resistance versus distance is drawn. The true earth resistance is read from the curve where it flattens out. Under ideal conditions the generic fall of potential curve will always intersect the "true theoretical resistance" at 61.8% as shown in Figure 9-8. (Megger Limited 2005). This rule is only valid when there is proper spacing between E and B, the probes are laid out in a straight line, and the soil is homogeneous.

Taking numerous readings between points E and B can be time consuming. If time constraints limit the inspection to just a few readings start at 62% of the distance between E and B. Then take two more readings at 52% distance and 72% distance respectively. All three readings should be close to one another indicating that measurements are being made on the flat part of the curve shown in Figure 9-8.

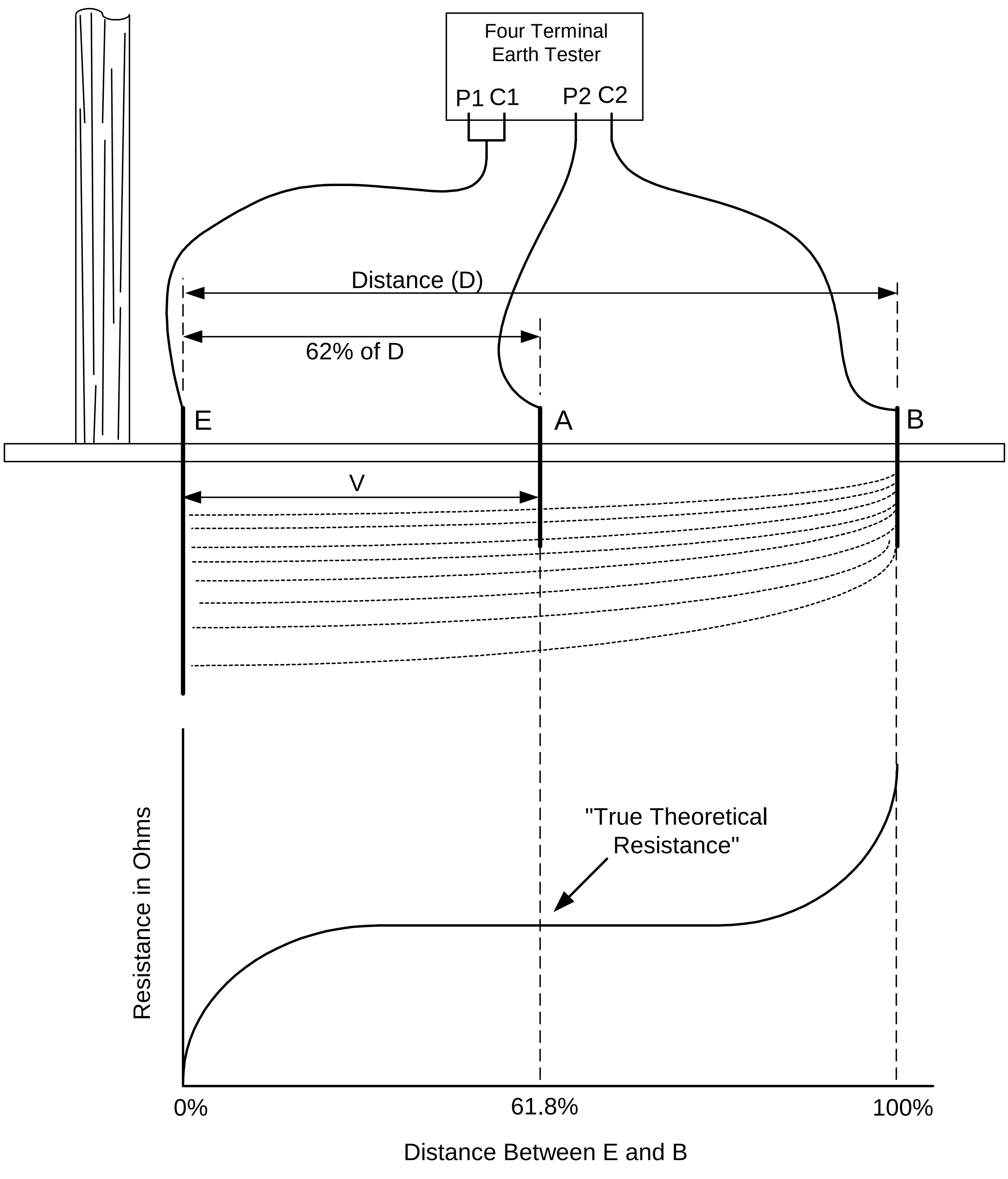


Figure 9-8
Fall-of-Potential Test Method

The test probes should be closer to the grounding electrode than any other external buried structures. If a buried metallic conductor is suspected to be nearby (but not so close as to pose a safety hazard for driving the probes) then moving B farther from E might help reduce errors. A local buried metal conductor could effectively nullify probe A thus making voltage V measured between E and B. If this occurs, the resulting measurement will be falsely elevated and appear to indicate a higher ground resistance than actually exists. Because of this possibility, the two-spike method is often used to verify unexplained high pole ground readings.

Also note that if the pole groundwire (and ground electrode) cannot be connected to the ground electrode of adjacent poles; this usually occurs through a connection to the system neutral near the pole top. If electrode E is electrically connected to adjacent pole ground systems then this test will actually be measuring the resistance to earth of not just the local ground electrode but of all the adjacent pole ground electrodes connected by the neutral as well.

Two Point Method

The two point method is used to verify fall-of-potential measurements that may have been corrupted by nearby buried metal objects. With the two point method, a four-terminal earth tester is used in a similar manner to the fall-of-potential method except that now only two separate points are used. Terminals C1 and P1 are jumpered together and connected to the electrode under test (E). Terminals C2 and P2 are also jumpered together, and they are connected to a nearby buried metallic object (O) protruding from the ground as shown in Figure 9-9. Current is passed through the loop formed between the electrode E and the buried metal object O, and the voltage between E and O is measured.

The two point method measures both the resistance of the electrode under test (E) and that of the buried metallic object (O). However, the resistance of O is assumed to be small enough that it does not appreciably affect the measurement and the result is presumed to be the resistance of E (Energy Australia 2005).

As with the fall-of-potential method, the electrode under test (E) cannot be connected to the ground electrode of adjacent poles; this usually occurs through a connection to the system neutral near the pole top. If the electrode E is electrically connected to adjacent pole ground systems then this test will actually be measuring the resistance to earth of not just the local ground electrode but of all the adjacent pole ground electrodes connected by the neutral as well.

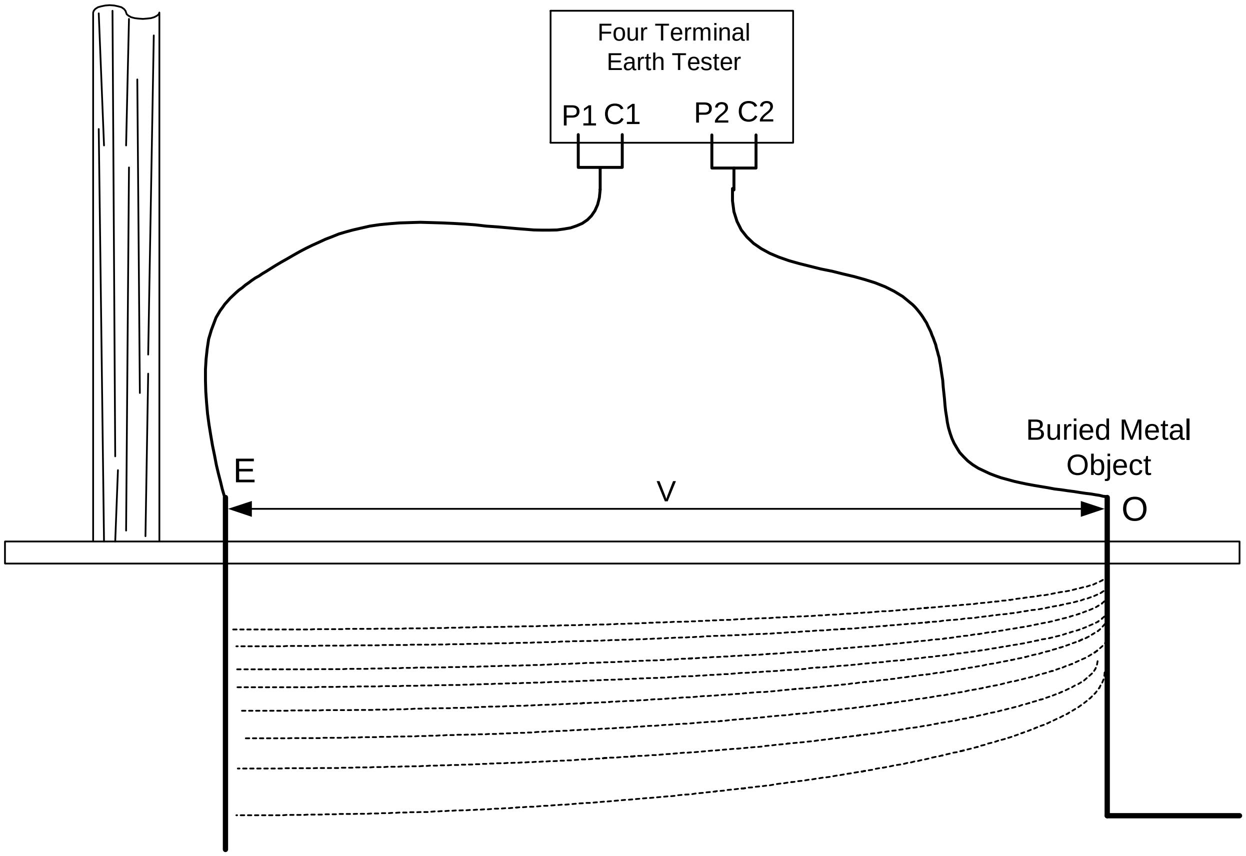


Figure 9-9
Two Point Test Method

Ground Inspection Forms

Figure 9-10 provides an example pole ground resistance inspection report. This report form is suitable for use with both fall-of-potential and two point ground resistance measurements. The report form provides space resistance measurements at thirteen different locations between electrode E and probe B although they don't all have to be used. Additionally, there is a blank graph section for plotting electrode ground resistance versus probe distance for use during detailed inspections. If the fall-of-potential method yields questionable results or is not suitable due to the presence of a buried metallic conductor then this can be indicated on the report along with the details of a two point method ground resistance test.

Pole Ground Resistance Inspection Report

Date & Time: ____________________ Circuit #: ____________________

Technician: ____________________ Pole ID #: ____________________

Location: ____________________

Meter Mfr.: ____________________

Model: ____________________ Ground System Type: □ Single Rod Rod Depth:_______ ft

Serial #: ____________________ □ Multiple Rod / Grid Longest Diagonal Dimension:_______ ft

Test Conditions

Weather: ____________________

Temp: ____________________

Soil Conditions

□ Dry Moist

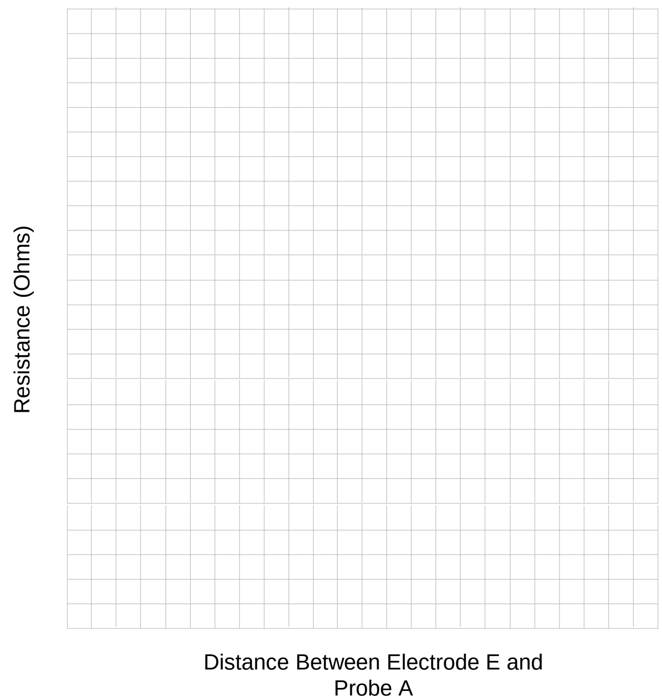
□ Loam Sand / Gravel Shale Clay Limestone Other:_________

Comments

Fall-of-Potential Measurements

Distance between electrode under test (E) and probe B:_________ft

% of Distance Between E and B	Distance Between E and A (ft)	Measured Resistance (Ohms)



Resistance Scale: □ 50 100

Multiplier: □ x1 x10

Fall-of-potential method unsuitable

Reason: Possible buried metallic conductor

Known buried metallic conductor

Distance from Electrode (E):_________ ft

Two point measurement taken, data shown below

Two Point Method

Measurement: ☐ Ohms

Distance between electrode E and buried object O:________ ft

Describe buried metallic object:

Comments

Figure 9-10
Example Pole Ground Inspection Report

10
TRANSMISSION AND SUBTRANSMISSION INSPECTIONS

Transmission departments are increasingly focusing on line reliability; often because regulatory bodies are also focusing on reliability. One of the primary means of ensuring reliable transmission line operation is an effective program of inspection and assessment. A comprehensive inspection program can help identify line anomalies before they cause interruptions and negatively impact reliability.

EPRI has compiled an outstanding body of work in the area of transmission line inspection and maintenance. Furthermore, EPRI continues to build upon this work through new research projects. The information in this chapter is drawn from several EPRI reports and the reader is encouraged to consult the full reports for in-depth examinations of the various aspects of subtransmission and transmission line inspection and maintenance:

- *Overhead Transmission Inspection and Assessment Guidelines – 2006: 4th Edition*, EPRI, Palo Alto, CA: 2006 1012310.
- *Managing Transmission Line Steel Structures*, EPRI, Palo Alto, CA: 2004 1002006.
- *Managing Transmission Line Wood Structures*, EPRI, Palo Alto, CA: 2005 1010247.
- *Field Guide: Visual Inspection of Polymer Insulators*, EPRI, Palo Alto, CA: 2006 1013283.

Line Patrol Methods and Patrol Frequency

There are five basic patrol methods commonly employed to inspect transmission line structures. Descriptions and basic information about each of them follows. A comprehensive resource that further describes these various inspection methods is EPRI's Project Report, "Inspection Methodology for Overhead Transmission Lines" (EPRI 108212 2000; EPRI 1012310 2006).

Fly-By Aerial Patrols – Aerial patrols are the fastest and lowest cost patrol method but they allow only a cursory inspection of line. While this method will turn up glaring deficiencies, more subtle damage is likely to go unnoticed. Aerial patrols are obviously not well suited for discovering groundline problems. Aerial patrols are generally done using either a helicopter or a fixed-wing aircraft flying at speeds between 25 mph and 150 mph. The aircraft is typically flown slightly above and to one side of the line with the inspector seated in the front of the aircraft, next to the pilot on the line side. In these types of patrols, inspection of each structure is done first with the naked eye and then sometimes with the aid of moderately powered binoculars. An assistant is sometimes used to record observations as dictated by the inspector.

Detailed Aerial Patrols – Detailed aerial inspections are similar to fly-by aerial patrols inspections, but they are performed at much lower speeds. The low-speed nature of these inspections dictates the use of helicopters rather than fixed-wing aircraft. Helicopters allow the inspectors to hover at each tower and even slowly circle individual structures. Gyro-stabilized binoculars and camera equipment are used to observe are record suspected damage and deficiencies. Detailed aerial inspections are more productive than fly-by aerial inspections but are also more costly. They are useful for finding damage or deficiencies in the upper portion of structures but are less effective at detecting the same things lower down or in observing groundline conditions.

Walking Patrols – This type of inspection entails approaching the structure and its foundation on foot. In most cases, the inspector will drive near to a structure, exit the vehicle, and walk up to and around the structure, viewing it from all sides. Binoculars and camera equipment are used to observe are record suspected damage and deficiencies. Walking patrols provide good observation of groundline conditions but limit the inspector's ability to see some types of deficiencies in the higher reaches of the structure. The angle of the sun can make observations from certain vantage points difficult.

Driving Patrols – For driving patrols one or more inspectors will drive the line, stopping as close as possible to each structure. The inspectors often use binoculars and camera equipment to observe and record suspected damage and deficiencies. This is an effective method of monitoring the overall condition of the line and the right-of-way. However, as a general rule, these inspections do not provide for observation of a structure and foundation from more than one or two vantage points. Driving inspections are moderately fast and low cost however they generally provide only a cursory inspection of the upper portions of the structure and almost no information about its groundline condition.

Climbing and Bucket Truck Inspections – This patrol method involves intimate inspection of each structure via climbing the structure or being lifted up to the structure. This is essentially a more detailed version of the walking patrol. Climbing the structure allows an inspector to carefully look for damaged, loose or missing components, and it allows most components to be viewed from multiple perspectives. A similar type of inspection involves having the inspectors work from bucket trucks rather than from the structures themselves. The use of bucket trucks will typically shorten the time needed for inspection, but it also limits the inspector's ability to see all areas close up. Climbing and bucket truck inspections afford the most thorough structure inspection but they are also typically the most expensive. They also require the use of line personnel that have training to work above the ground, sometimes near energized conductors. Also, it is important to note that not every site is readily accessible by bucket truck.

EPRI conducted a survey on types of patrol methods used by various utility companies as part of their research for the project report entitled "Inspection Methodology for Overhead Transmission Lines" (EPRI Project TR-108212). The survey, which focused on lines operating from 69- to 500-kV, found that utilities inspect all lines using at least two different patrol methods (EPRI 108212 2000). It should also be noted that in no case were both a foot patrol and a driving patrol used. It was found that most utilities favor one or the other and seldom use both when doing line inspections. Furthermore, aerial patrols were widely used on all voltage classes considered in the survey.

The frequency at which utilities commonly inspect transmission lines is influenced by many factors including the importance of the line, environmental conditions around the line, the age of the structures, and the historical performance of the line. The frequency of line inspections can vary from one line to another within a utility. Research for EPRI TR-108212 provided insight into the frequencies of patrol methods used by various utility companies. Table 10-1 details these findings (EPRI 108212 2000).

Table 10-1
Frequency of Transmission Line Inspections (inspection/year) by Voltage Class, Patrol and Structure Types

Voltage Class:	**69–161 kV**		**230–345 kV**		**500+ kV**	
Structure Type:	**Poles**	**Lattice**	**Poles**	**Lattice**	**Poles**	**Lattice**
Aerial Patrol	2.3	2.7	2.4	2.3	2.4	2.1
Detailed Aerial Patrol	0.2	0.2	0.4	0.4	0.3	0.2
Foot Patrol	0.8	0.8	0.6	0.6	1.0	0.8
Driving Patrol	0.7	0.9	0.4	0.7	0.5	0.5
Climbing Patrol	0.1	0.2	0.1	0.1	0.1	0.1

One thing that stands out is that aerial patrols are used on almost all lines and are used most frequently. From the previous discussion, it was also noted that aerial patrols cannot be expected to find any type of damage to a structure other than gross deficiencies. Thus, one or more of the other patrol methods need to be used to do a reasonable job of structure inspection.

Applying Inspections and Patrols to Solve PQ and Reliability Issues

Transmission inspections and patrols are often though of as asset management tools. While they certainly provide a great deal of value for asset management inspections, patrols are also useful tools for solving power quality and reliability issues. The first step to solving these types of problems is to create an accurate definition of the problem. Once the problem is defined, the appropriate inspection can be chosen to gain a better understanding of how to solve the problem. To define the problem, all available fault information should be analyzed to look for any trending. Review as much fault information as possible including:

- Fault types - momentary or permanent
- Fault dates and times
- Weather conditions during the fault events
- Any other fault information that may be available (i.e. Were any investigations conducted for individual faults?)

Look for trends in time or dates (are faults seasonal?). Are there any correlations between fault occurrences and weather conditions? For example, consider a line that exhibits a high number of momentary outages. If historical weather records indicate that the faults tend to occur during stormy weather then lightning is likely to blame. Lightning performance is most affected by the tower grounding characteristics so performing a grounding inspection on the line would be a reasonable place to start - particularly in those areas with the greatest lightning exposure. Table 10-2 lists some basic correlations than can be useful for determining which inspections to apply to solve power quality and reliability issues.

Table 10-2
Applying Inspections and Patrols to Solve PQ and Reliability Issues on Transmission Lines

Weather Conditions	Potential Cause	Inspection Type
Blue sky	Animal/raptor or damaged insulators	Aerial or ground-based. Look for evidence of animals or broken insulators.
Dawn, dusk, or other damp conditions	Insulator contamination	Ground-based or climbing. Look for insulator contamination and evidence of flashover or tracking.
Stormy	Lightning-related	Ground-based inspection of structure grounding characteristics. Aerial or ground-based inspections for broken insulators or missing shield wire.
Windy	Tree contact -likely permanent fault Conductor slapping – likely momentary fault	Aerial or ground-based. Inspect right-of-way for hazard trees and line for missing shield wire.

Fault location calculations can be applied to help narrow the scope of line inspections. Digital fault recorders or even modern digital relays can record the necessary information to perform these calculations. Estimating the location for just a few faults can greatly narrow the scope of inspections by providing evidence of fault grouping on certain sections of the line.

Some of the inspections and audits discussed in previous chapters of this document are also suitable for use in solving power quality and reliability issues with transmission lines. A few audits that could quickly be adapted for use with transmission line power quality and reliability improvement programs include:

- Chapter 3 - Construction Audits
- Chapter 4 - Outage Follow-Up Reviews and Audits
- Chapter 5 - Problem Circuit Audits

Although some of the particulars of what to look for during the audits would change, much of the basic information on the "why's and how's" for these audits is just as applicable on transmission systems as it is on distribution systems.

Steel Transmission Structure Inspections

This section provides a brief discussion on the inspection of steel transmission structures. However, there is a substantial amount of information that needs to be considered to properly inspect steel structures. The reader is encourage to consult the EPRI reports referenced in the opening paragraph of this chapter for a more complete discussion of steel transmission structure inspection.

What to Look For During Steel Transmission Structure Inspections

There are numerous deficiencies which can afflict a steel structure at any given time. Some problems develop slowly over time. Other issues are built-in to the structure via mistakes in the construction process. Luckily, most deficiencies can be detected through visual examination of the tower; if the inspector knows what to look for.

Coatings – Hot-dipped galvanized coatings, paint systems, and weathering steel are the most popular choices for protecting steel poles from corrosion. However, each of these coatings behaves differently and they each present different deficiencies to look for.

Historically, the initial *hot-dipped galvanizing* coating of structure members has been of a very high quality and problems associated with poor galvanizing have been rare. Unfortunately, the coatings do wear out over time. Freshly galvanized steel generally has a shiny surface. As the coating ages, it darkens and loses its sheen. The first signs of coating degradation will occur as rust blooms on the surface of the members. The first appearance of rust blooming should not be cause for great concern, but it is evidence that repainting will be needed sometime in the near future to protect the substrate and effectively extend the life of the structure. There are two main inspection tools for measuring the thickness of the galvanized coating on steel structures. The first type utilizes the pull-off technique that measures the amount of energy used to pull/lift-off the magnetic gauge tip from the galvanized surface. The second gauge type uses electronic digital technology to measure the distance from the magnetic gauge tip to the steel surface.

Paint coatings can present a variety of defects of which some indicate a lack of protection while others are just cosmetic. The primary paint defect to look for is any break in the paint surface that exposes primer or steel. This type of defect allows water to penetrate the coating and initiate oxidation. Flaking, blistering or peeling are all signs that something is wrong with the coating system. Water spotting, paint runs, fading, and chalking are cosmetic and do not indicate impending coating failure.

Weathering steel provides a coating that is as close to being maintenance free as any coating can be. However, these structures do require inspection to ensure that the weathering coating is forming properly. The oxide coating of weathering steel forms via cyclic wetting and drying cycles. Care must be taken that the steel is not keep constantly damp; often the result of contact with soil or vegetation. Weathering steel that stays wet, without cyclic drying, will continue to oxide and may actually corrode faster than other types of steel. The joints of weathering steel structures should also be inspected for “packout” which is a buildup of oxide between the faying surfaces of a bolted joint. Packout can cause a bulging of the joint but generally does not affect joint strength in all but the most severe cases. However, instances of moderate or severe packout should be noted during the inspection process.

Members – The primary types of member deficiencies include: wear of connection holes, deformation of members, development of cracks in members, and loose or missing fasteners. Most tower members are fabricated as straight pieces thus any sharp bends in members may indicate damage due to overloading. Generally speaking, any bend that is not significant enough to be found through visual examination is not a concern. Wear and elongation of holes is not uncommon and is especially prevalent near the top of the tower where line hardware is attached. Any severe wear or elongation should be noted.

Fasteners – Most steel structures use nuts and bolts, while a few older towers are joined with rivets. The primary form of degradation for these fasteners is corrosion. Fastener corrosion can be visually detected and significant corrosion should be given immediate attention. Although rare, tower inspectors should also look for loose hardware. After retightening of loose hardware, this same hardware should be rechecked during the next inspection to determine if it has remained tight. It should be noted that a few types of bolted connections do not have to be tight, especially in steel pole structures. One example is the davit arm connections that utilize long bolts that pass through the full width of the connection and intended to be only hand-tight. Therefore, it is important that the inspector be knowledgeable about the design requirements for bolt tightness of the various connections on the structure they are inspecting.

At the groundline – The area of the structure adjacent to the groundline presents the greatest need for inspection because there are a variety of ways in which it can be degraded. The area immediately below the surface of the soil is often the most corrosive environment that the steel is exposed to and immediately above groundline is the area that is the most vulnerable to damage from human interaction. Foundation movement, soil erosion, grout deterioration, vegetation growth, dents, and gouges are all problems that should be inspected for at the groundline.

Steel poles installed on concrete foundations often use anchor bolts and base plates. Grout is commonly installed in the area between the top of the foundation and the bottom of the base plate. This area needs close inspection for grout cracking since the ingress of moisture into cracks in the grout may corrode the anchor bolts. Water ingress can also further exacerbate grout cracking through freeze/thaw cycles.

Guy systems – Guys and anchors are integral parts of guyed transmission structures and should be inspected as one unit. First inspect to see if the guys are taut. Slack guys can prevent the structure from behaving as it was designed. Some guy attachments can become loose and begin migrating down the pole so any evidence of hardware movement should be closely scrutinized. Another thing to look for is guy wire abrasion, especially in and around areas where livestock congregate or in congested traffic areas. With regards to the anchor portion of the guy system, it is common practice in most organizations that the inspector will only perform visual inspections on anchor rods. Newly exposed or different oxidation levels along the steel rod could mean that either the ground cover has been removed, allowing for uplift to occur, or the soil has become so saturated that the anchor rod has migrated out of the ground. Below ground conditions are much harder to detect using visual inspection techniques and often are not addressed until a complete failure of the guy system occurs. However, there are non-destructive test techniques for assessing below ground condition and the presence of corrosion on anchor rods. The Corrosion Meter, CGWT and MsS techniques, and other nondestructive evaluation (NDE) technologies are available and the reader is encouraged to consult the EPRI reports referenced in the beginning of this chapter for further information.

Signage – Signs do not play a role in the structural or electrical integrity of the structure but they are important for safety considerations. Any missing signage should be noted during the inspection process.

Nesting materials – A variety of bird species nest on transmission structures. Bird nests are an undesirable appendage on a transmission structure, but extreme caution needs to be exercised when attempting to mitigate this problem. Most bird species are protected by various U.S. laws. Nest tampering or removal may result in prosecution by the U.S. Fish and Wildlife Service (USFWS). Permission must be granted by the USFWS before doing so.

Animal carcasses – Animal and bird carcasses found underneath transmission structures may be the result of electrocutions and therefore should be investigated. In the case of bird deaths, especially eagles, the cause of death needs to be determined and mitigating measures taken if electrocution was the cause. Also, the carcasses need to be left untouched as the USFWS can fine a utility for tampering with “evidence”.

Table 10-3 provides a summary of what to look for during steel transmission structure inspections as well as what patrol methods are suitable for examining each inspection item.

Table 10-3
Inspection Items to Look for when Inspecting Steel Transmission Structures and Applicability of Different Types of Patrols (EPRI 1002006 2004)

Inspection Item	Latticed Towers			Pole Structures			Effective Inspection Means		
	Self-Supporting			Self-Supporting					
	Conv.	H-Frame	Guyed Tower	Conv.	H-Frame	Guyed Tower	Aerial Patrol	Ground Patrol	Climbing Patrol
At the Groundline									
Evidence of foundation movement	X	X	X	X	X	X		X	X
Soil Erosion (scour or deposits)	X	X	X	X	X	X	X	X	X
Deterioration of Ground Under Base Plate	o	o	o	X	X	X		X	X
Dense Vegetation Around Structure	X	X	X	X	X	X	X	X	X
Deterioration of Exposed Embedded Coatings				X	X	X		X	X
Faulty Grounding	X	X	X	X	X	X		X	X
Abraded Coatings	X	X	X	X	X	X		X	X
Dents & Gouges	X	X	X	X	X	X		X	X
Overhead									
Bullet Holes	X	X	X	X	X	X		X	X
Bent/Buckled Members	X	X	X	o	o	o	X	X	X
Missing Connectors	X	X	X	o	o	o		o	X
Loose Connectors	X	X	X	o	o	o			X
Wear of Attachment Holes	X	X	X	X	X	X		o	X
Packout of Joints	X	X	X					o	X
Damage to Climbing	X	X	X	X	X	X		o	X
Damage/Missing Signage	X	X		X	X	X	X	X	X
Guy Systems									
Slack Guys			X			X	o	X	X
Loose/Missing Guy Hardware			X			X	o	X	X
Missing/Damaged Guy or Cattle Guards			X			X	o	X	X
Deterioration of Guys			X			X		X	X
Corrosion of Anchors / Anchor Rods			X			X		X	X
Miscellaneous									
General Appearance	X	X	X	X	X	X	X	X	X
Coating System	X	X	X	X	X	X	X	X	X
Nesting Materials	X	X	X	X	X	X	X	X	X
Animal Carcasses Beneath Structure	X	X	X	X	X	X		X	X

X = applicable or effective
o = potentially applicable or effective

Steel Transmission Structure Inspection Checklist

There are many variations of transmission structure inspection checklists or patrol forms. A company will typically utilize a patrol sheet that is tailored to the type of degradation that is common in their service territory. Some items, such as bent members or damaged coating are universal. Other items, such as particularly large bird nests, might not be as common in all service territories. Furthermore, each company will adapt their line inspection checklist to best accommodate the types of towers being inspected (steel versus wood pole) and the type of environment (wet, dry, moderate, etc.).

Figure 10-1 shows one example of a transmission structure inspection checklist. Some companies use specific notation for entering different grades for each item on the sheet. These notation sheets vary from just a few lines to multiple pages of notation with a high degree of precision. Other companies simply leave it up to the inspector to provide sufficient detail in the comments section to adequately describe the deficiency. However, it is important for the inspector to note any problems that need to be monitored or that require immediate remedial action. On the checklist shown in Figure 10-1 the inspector could indicate the need for immediate action in the comments section. Another option would be to use a basic rating system such as that shown in Table 10-4.

Table 10-4
Basic Condition Rating System for Use During Transmission Structure Inspections

Priority Rating	Definition
A	Good / like new. No Action required.
B	Minor damage, wear, corrosion, or decay. Monitor for future action.
C	Moderate damage, wear, corrosion, or decay. Consider remedial action.
D	Severe damage, wear, corrosion, or decay. Immediate remedial action required.
E	Field repair / replacement completed during inspection.

Steel Transmission Structure Inspection Report

Circuits on Structure: ____________________ Date: ________________

Structure Number: ____________________ Inspector: ________________

Structure	Rusty	Missing	Loose	Bent / Buckled	Comments
Steel Members					
Aluminum Members					
Nuts & Bolts					
Anti-Climbing Guards					
Danger Signage					
Circuit Signage					
Other:					
Coating	Thinning / Improper Forming	Peeling	Chipping	Blooming / Packout	Comments
Galvanized					
Paint					
Weathering Steel					
Groundline	Cracked / Spalling	Missing	Rusty	Bare	Comments
Concrete					
Nuts & Bolts					
Ground Connections					
Counterpoise Connections					
Animal Carcasses	--	--	--	--	
Other:					
Guy System	Slack	Corrosion	Abraded	Shifting	Comments
Guy Line					
Attachment Hardware					
Anchor Rod					
Anchor Point					
Signage	Missing	Faded	Incorrect		Comments
Circuit Labeling					
Danger Signs					

Right of Way	Comments
Danger Trees	
Encroachment	
High Vegetation	
Road Condition	
Fences & Gates	
Erosion	
Wet / Swampy	

Comments

Figure 10-1
Example Transmission Line Inspection Checklist

Visual Inspection of Non-Ceramic Insulators

It can be necessary to assess non-ceramic insulators (NCI) from time to time to determine if they are good electrical and mechanical condition. NCI, also referred to as polymer insulators, can be damaged in variety of ways, almost all of which degrade their performance. Damaged insulators pose a reliability risk to the transmission line. Periodic insulator inspections are used to identify damaged, high-risk insulators and remove them from service before they fail.

What to Look For During Visual Inspections

A few common sources of NCI degradation are aging due to environmental exposure in the field, mishandling during installation, and manufacturing defects (EPRI TR-111566 1998). Another concern with NCI is that defects that start small may manifest into larger problems that ultimately require the insulator to be removed from service. A small cut or abrasion in the insulators sheds or sheath can lead to significant problems with dry-band arcing, tracking, and erosion and to the eventual failure of the insulator.

Visually inspecting polymer insulators is done to assess the overall condition of the insulator and to identify any potentially serious defects. Any deficiency (crack, puncture, tear, etc.) that could allow water to contact the fiberglass reinforced polymer (FRP) core of the insulator is particularly serious as it can quickly lead to failure of the insulator. Data collected through routine insulator inspections can also be used to build an insulator condition database which can be useful in tracking performance and aging of non-ceramic insulators.

Table 10-5 lists the common NCI defects that should be looked for during visual insulator inspections. The reader is encourage to consult (EPRI 1013283 2006) for detailed pictures and descriptions of each defect listed. Each defect is listed along with its potential significance:

- *Minor* defects do not require action but should be noted for future monitoring.
- *Moderate* defects should be considered for remedial action. These defects should at least be monitored for future action if no current action is taken.
- *Severe* defects require immediate remedial action, usually resulting in replacement of the insulator.

Defects that show a range of significance must be assessed on a case by case basis but will generally fall within the indicated range. As mentioned earlier, any defect that could allow water to contact the fiberglass reinforced polymer (FRP) core of the insulator is particularly serious and thus receives and rating of “Severe – replace insulator”.

The non-ceramic insulator inspection checklist shown in Figure 10-2 can be used in conjunction with the defect list outlined in Table 10-5 for performing insulator inspections.

Table 10-5
Non-Ceramic Insulator Defects to Look for During Visual Inspections and Defect Severity (EPRI 1013283 2006)

Defect	Significance
Sheds	
Splits, cracks or punctures	Minor to
Tear or damage	Minor to
Gunshot damage (check for embedded bullets / shot)	Minor to
Sheath	
Any expose rod (split, crack, etc.)	Severe – replace
Splits / Cracks – core not exposed	Moderate to
Gunshot damage (check for embedded bullets / shot)	Moderate to
Sheds and Sheath	
Whitening	No threat
Tracking	Severe – replace
Animal Damage	Minor to Severe
Surface crazing	Minor to
Erosion	Moderate to
Surface Contamination	Minor to Severe
Corona Rings and End-Fittings	
Flashover Damage	Moderate to
Incorrect Position	Moderate –
Loose	Moderate –
Gunshot Damage	Minor to Severe
Degraded Fitting Seal	Minor to
Corrosion	Minor

Significance ranges indicate that each case must be assessed individually based on the location and extent of the defect.

Moderate significance indicates that the insulator should be monitored and replacement should be considered.

Severe significance indicates that the insulator should be replaced.

Non-Ceramic Insulator Visual Inspection Checklist

Date: ________________ Circuit: ______________________

Inspector: ________________ Structure Number: ______________________

Phase:

Defect Ratings: Minor - consider monitoring for further degredation
Moderate - monitor for further degredation and consider remedial action
Severe - requires remedial action

Weather Sheds

Sheds are numbered sequentially starting with 1 at the ground/tower end.

Possible shed defects are: split, crack, tear, gunshot, erosion, tracking, animal damage, surface crazing, surface contamination, & other (describe in comments).

Shed Location	Defect Type	Rating	Comments

Sheath

Sheath locatoin is identified by location between adjacent sheds. For example, sheath between sheds 3 & 4.

Possible sheath defects are exposed core (mandatory severe), split, crack, gunshot, erosion, tracking, animal damage, surface crazing, surface contamination, & other (describe in comments).

Sheath Location	Defect Type	Rating	Comments

Corona Rings & End Fittings

Label ring or fitting location as either tower-end or line-end.

Possible defects are flashover damage, incorrect position, loose, gunshot, degraded fitting seal, corrosion, & other (describe in comments).

Part & Location	Defect Type	Rating	Comments

General Comments

Figure 10-2
Example Checklist for Visual Inspection of Non-Ceramic Insulators

Practical Considerations for Visual Inspections

Visual inspection of insulators can be performed from the ground, via bucket trucks, by climbing the structure, or through aerial patrols. Each of these methods offers different combinations or cost, effectiveness, safety, etc. In general terms, inspections techniques that get the inspector closest to the insulator are the most effective at uncovering defects.

Visual inspection tools can run the gambit from low tech to highly sophisticated. The most common tools employed today include:

- Binoculars – units with image stabilization are a definite advantage for aerial patrols
- Spotting scope – often higher magnification than the binoculars
- Digital camera with moderate powered zoom lens

Other inspection tools that are often used to observe discharge activity include:

- Image intensifier – for viewing discharge activity
- Corona-specific image intensifier – image intensifier optimized for viewing corona activity
- Infrared imaging systems – for viewing insulator hot spots and relative material temperatures
- Parabolic microphones – to find acoustic emission sources

Data collected through routine insulator inspections can also be used to build an insulator condition database which can be useful in tracking performance and aging of non-ceramic insulators. For this reason it is good practice to capture one or more image of each insulator during an inspection. This should be fairly easy to accomplish with the prevalence of modern digital cameras. These images can be stored in the database as part of the inspection records. Probably the most challenging aspect of this process is to make sure that the digital image number (image number on the camera's memory card) is accurately recorded to reflect which insulator is pictured.

Aerial visual inspections – Aerial patrols should be performed at the slowest ground speed possible. As the aircraft speed increases, the time window for viewing each structure decreases. Helicopters are ideal for performing low-speed inspections and have the additional benefit of being able to circle problem structures. It is also good practice to make two passes to observe the line from each side (this is usually accomplished by flying the line in one direction then turning around and flying it again in the other direction). The best viewing angle is achieved when the aircraft flies off to one side of the line. For safety reasons, aerial inspections often require the aircraft to fly higher than the optimal insulator viewing altitude.

Ground-based visual inspections – Viewing insulators from directly underneath during ground-based inspections is not particularly effective as it offers a poor view of the sheath sections and makes is difficult to aim inspection equipment at the insulator. Practice has shown that it is better to set up approximately 50 feet (roughly 15 meters) to the side of the insulators and gain elevation with a bucket truck if possible (EPRI TR-111566 1998). Furthermore, it is often impossible to sufficiently view all parts of an insulator from one location. Thus visual inspections often involve viewing the insulator from two or more locations. The inspector(s) should also be mindful of the position of the sun as looking into the sun or harsh shadows can make visual observations more difficult.

Climbing and bucket truck visual inspections – Climbing and bucket truck inspections get the inspectors as close as possible to the insulators and allow for the most detailed examination. Inspectors may also use mirrors attached to hotsticks to view hard-to-see portions of the insulators. Utilities are increasingly using bucket trucks instead of climbing structures for all structures with sufficient access. However, terrain and right-of-way access make it unfeasible to setup bucket trucks at all structures.

Other Inspections for Non-Ceramic Insulators

Visual inspections are only one of several techniques commonly employed to assess NCI condition. Another set of inspections center around observing less-visible or invisible indicators of insulator defects. Discharges, called corona, commonly occur at defect sites and thus can be used as an indicator of insulator defects. Corona is particularly prevalent on defects near the energized and grounded ends of insulators due to the high electric-fields at those locations. Corona discharges are also more prevalent during wet conditions. In fact, a "healthy" and properly applied NCI should not exhibit corona under dry conditions. The same insulator may exhibit some corona under wet conditions but corona from defect sites is generally much stronger than that from wetting alone, making it possible to differentiate between the two. Corona discharges release light, sound and heat and there are different tools available for observing each of these markers (EPRI 1012310 2006):

- *Observed light* – Corona discharges radiates mainly ultraviolet light with a small portion of visible light. This light can be observed with the aid of image intensifiers, particularly those that are specially designed for corona inspections.
- *Observed surface heating* – Corona discharges create surface heating which can be observed through infrared (IR) imaging systems. Leakage current can also cause surface heating but that is generally observed along the whole length of the insulator whereas heating due to discharges is localized so it is possible to distinguish between the two.
- *Observed radio-interference* – Corona discharge activity produces high-frequency electromagnetic waves that are called radio-interference (RI). These waves can be observed with the aid of a parabolic microphone unit.

These observation tools can be applied from the ground or via aerial patrol with each method carrying its own advantages and disadvantages.

Transmission Structure Grounding Inspections

Transmission structure footing resistance has a profound influence on the lightning performance of a transmission line. Towers with high footing resistance are more likely to exhibit back flashovers and just a few poor performing towers can degrade the overall performance of an entire line. Figure 10-3 from the EPRI Transmission Line Grounding Guide (EPRI 1002021 2004) shows that high tower footing resistance can have a profound impact on the number of annual customer disturbances experienced on a transmission line. Tower grounding inspections are often used to investigate lines suspected of exhibiting unduly high numbers of lightning interruptions since tower footing resistance is a crucial part of the line's lightning performance.

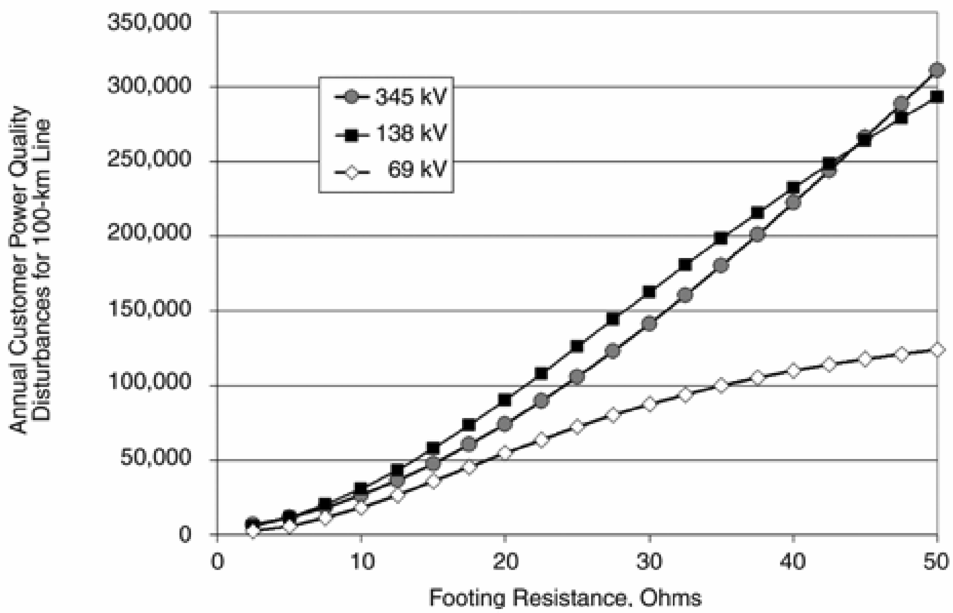


Figure 10-3
Annual Customer Power Quality Disturbances from Lightning

Measuring tower footing impedance values is fairly straightforward for lines that do not have an electrical connection between the ground electrodes of adjacent towers. This includes lines that do not have overhead groundwires or lines with electrically non-continuous overhead groundwires. Under these conditions the resistance of the tower to remote earth is measured by the fall-of-potential test method as outlined in (EPRI 1012310 2006). This method uses a four terminal earth resistance tester connected between remote earth and the tower to determine the tower footing resistance. However, the fall-of-potential method only gives meaningful results when the tower ground electrodes are isolated from the adjacent towers. Therefore the fall-of-potential method cannot be used when an overhead groundwire is present. Tower footing resistance values are often recorded during line construction, before overhead groundwires are installed, but those values only provide a reference for that point in time. Several things can happen after that point to increase the tower footing resistance including corrosion of the ground electrodes and changes in the soil chemistry of the earth surrounding the tower.

The towers of a transmission line are electrically bonded together by the overhead groundwire. This makes individual tower ground resistance measurements very difficult to obtain since most measurement methods would actually be measuring the resistance to earth of not just the local ground electrode but of all the adjacent towers connected by the groundwire. One way to overcome this problem is to temporarily isolate the overhead groundwire for taking grounding measurements. However, this is can be complicated and expensive to achieve and often requires live line work. EPRI is developing an alternative method for measuring the tower footing impedance of lines with overhead groundwires. The EPRI ZED-Meter uses transient pulse injection to determine the tower footing impedance on lines with attached overhead groundwires. Although still in the late stages of development, the meter has recently undergone successful field trials and should be available in the near future (EPRI 1008734 2004).

A
INSPECTION FORMS

The following pages contain all of the inspection reporting forms and checklists from each chapter of this report.

Overhead Distribution Circuit Inspection Report   Sheet #: ____ of ____

Date & Time: ____________________   Circuit #: ____________________

Inspector(s): ____________________   Pole ID #: ____________________

Location: ____________________

Instructions

Report deficiencies for only one pole per inspection sheet. When possible record a digital image of the deficiency and record the image number on this inspection sheet. Use the comments area to provide further information about each deficiency (i.e. missing, damaged, which phase(s), unusual circumstances, etc.). Use the comments section if additional writing room is required.

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Circuit Inspection

Inspection Item	Deficiency Found	Priority Rating	Digital Photo #	Description / Comments
Pole				
Crossarm				
Guy wires				
Primary conductors				
Secondary conductors				
Insulator				
Arrester				
Fuse				
Transformer				
Switch				
Capacitor				
Recloser				
Regulator				
Groundwire				
Trees				
Vines / other non-tree vegetation				
Other right-of-way deficiencies				
Street lighting				
Other - specify				

Comments

Figure A-1
Example Overhead Circuit Visual Inspection Form

Underground Distribution Circuit Inspection Report — Sheet #: ____ of ____

Date & Time: ______________________ Circuit #: ______________________

Inspector(s): ______________________ Cable Termination Point ID #: ______________________

Location: ______________________ Temp. & Weather Conditions: ______________________

Instructions

Inspect the termination point itself and all conductors, equipment, and any other electrical utility infrastructure connected to it. When possible record a digital image of the deficiency and record the image number on this inspection sheet. Use the comments area to provide further information about each deficiency (i.e. missing, damaged, which phase(s), unusual circumstances, etc.). Use the comments section if additional writing room is required.

Follow confined space working procedures wherever applicable.

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Circuit Inspection

Inspection Item	Deficiency Found	Priority Rating	Digital Photo #	Description / Comments
Manhole / vault / pad				
Water in manhole / vault				
Primary conductor				
Secondary conductor				
Terminations				
Splices				
Conduit / conductor enclosure				
Network Protector				
Transformer				
Switches				
Arresters				
Grounding				
Street lightning wiring				
Right-of-way condition				
Signage				
Other - Specify				

Comments

Figure A-2
Example Basic Underground Distribution Visual Inspection Form

Underground Distribution Inspection Report

Date & Time: ______________________
Inspector(s): ______________________
Weather: ______________________
Location: ______________________
Digital Photo #'s: ______________________

Circuit #: ______________________
Substation: ______________________
Feeder Numbers: ______________________
Structure ID #: ______________________

Priority Rating Scale (1-4): 1 - Existing or probable hazard. 2 - Currently non-hazardous but may become hazardous
3 - Non-hazardous and likely to as such. 4 - Non-hazardous but no longer meet specifications

Manhole Information

Gas Reading Percentage: _________%
Ambient Air Temperature: _________°F

Manhole Size:	□ Roadway Sidewalk
Manhole Condition:	□ Good Crowded Damaged:______________
Cover Size:	□ Loose Not to Grade Missing
Cover Condition:	□ Good Loose Not to Grade Missing
Type:	□ Roadway Sidewalk
Cable:	□ Primary Secondary Both
Debris:	□ No Below Ducts Ducts Blocked
Water:	□ Dry Below Cables Above Cables
Sump Pump:	□ Yes No Unknown
Sewer Con.	□ Yes No Unknown
Comments:	______________________

Cable and Joint Information

	Priority	Comments
Good - No Problems	—	
Cable Leak		
Joint Leak		
Joint Swelling		
Deformed Joint		
Racking Needed		
Burnout Visible		
Cable Smoking		
Joint Smoking		
Insulation Damaged		
Neutral Corroded		
Other		
Comments		

Transformer Information

Transformer Type: □ Network Subsurface Subway
□ Padmount Overhead Other:

*Examine for leaks, rust, damaged bushings, frayed wires, loose connections, and other deficiencies.

Enter separate information for each transformer:

Transformer Size	Phase(s)	Primary Voltage	Secondary Voltage	Deficiency	Priority	Comments

Equipment Information

Item	Good	Rusted / Corroded	Damaged	Other	Comments
Network Protector					
2-Way Switch					
3-Way Switch					
Fuse Box					
Fuse Pod					
Taphole					
Capacitor					
STOF Box					
URD Module					
Shunt Controller					

Comments

Figure A-3
Example Detailed Underground Distribution Visual Inspection Form

Construction Audit Checklist

Date: ____________________ Sheet #: ______ of ______

Auditor: ____________________

Work Order ID: ____________________

Work Location: ____________________

Pole Hardware & Equipment — Comments / Location	Anchors, Guys, & Brackets — Comments / Location
____ Pole class too small	____ Guy and/or anchor installed incorrectly
____ Pole class too large	____ Guy insulator not installed / incorrectly installed
____ Angle exceeds allowable degrees for single insulator	____ Incorrect guy insulator
____ Angle exceeds allowable degree for double insulators	____ Guy not installed on tension span
____ Angle permits single insulator but double insulators used	____ Guy alignment off >3' on angle or 1' on tangent
____ Crossarm size too large	____ Guy not bonded to neutral
____ Crossarm size too small	____ Anchor rod too vertical or not inline with guy wire
____ Improper application of metallic tie wire	Conductors
____ Improper application of polymer tie wire	____ Pole ground not stripped to neutral level
____ Fault tamers not used in high fault area	____ Copper wire bonded on top of dissimilar metal
____ Animal guards missing	____ Coordination or fusing error
____ Animal guards improperly installed	____ Un-fused tap on backbone or recloser sub feeder
____ Cutout mounted in wrong location	____ Conductor #2 ACSR used for line exceeding 25 amps
____ Arrester mounted incorrectly	____ Conductor too small for mainline
Underground	____ Conductor span too long
____ UG Conduit straps missing or improperly installed	____ Conductor middle phase on arm instead of pole top
____ UG Primary riser bracket grounded - bad taping	____ Conductor middle phase dead ended on arm instead of pole top
____ UG Installed without treating pole afterwards	____ Inadequate conductor spacing
____ UG Cable not color coded or marked correctly	____ Undersized conductors
____ UG Secondary connection not rubber taped	____ Secondary hot leads on xfmr not insulated
Crew Work Practices	Other Comments
____ Work not completed as reported	
____ Work intentionally completed different from design specification	
____ See comments section	

Comments:

Figure A-4
Example Construction Audit Checklist

Outage Investigation Report

Date: ______________________
Investigator: ______________________

Outage ID: ______________________________
Outage Date & Time: ______________________________
Investigation Site / Pole ID: ____

Where is the most likely location of the fault?
What was the most likely flashover path? Describe any evidence of flashover?
What was the most likely cause of the fault?
What outage code was entered? Is this correct? If no, update outage code.
Is the faulted circuit adequately covered by protective devices? Did the fault occur on an unfused tap?
Did protective devices operate as expected? If no, explain.
Did any structural deficiencies contribute to the fault? If yes, explain. If yes, how could the deficiencies be remedied? If yes, are other structures likely to exhibit the same deficiency? Explain.
Comments

Figure A-5
Example Outage Follow-Up Form

Problem Circuit Investigation Report

Date: ____________________________ Circuit: ___________

Inspector: ____________________________ Sheet #: ____ of ____

Background Information

The outage history for this circuit indicates that the primary concern is: Momentary Outages Permanent Outages

The outage database indicates that faults on this circuit are primarily:

Animal-related Lightning-related Tree-related Weather-related Equipment-related Other:_____________

Circuit Inspection

Defect	Pole # or Entire Circuit	Comments

Common Deficiencies

- Animal Guards - missing or improperly installed
- Transformers without local external fuses
- Unfused taps
- Excessive mainline exposure
- Protective device miscoordination
- Susceptibility to conductor burndown
- Old arresters (non-MOV arresters)
- Insufficient arrester clearance for isolator operation
- Poor clearances (including with guy wires)
- Guy wires without proper insulation
- Pole ground wires located too close to primary conductors
- Broken crossarms or other structural components
- Heavy tree coverage
- Vegetation growth into conductors
- Danger trees
- Vines or other vegetation growth on poles / equipment
- Damaged insulators
- Damaged bushings
- Evidence of arcing
- Animal damage - chew/bite damage, nest materials, droppings, etc.

General Comments

Figure A-6
Example Problem Circuit Inspection Report Form

Scoring System
0 - Requires immediate attention
1 - Poor
2 - Fair
3 - Average
4 - Excellent

Contractor / Crew: ______________________
Week Ending: ______________________
Work Location: ______________________
Work Description & Difficulty: ______________________

		Grade		Weight		Points	Comments
Clearance	Adequate clearance around conductions (under, side, top)		x	5	=		
	Appropriate number of trees removed		x	3	=		
Methods	Proper directional pruning		x	6	=		
	Proper stump height & herbicide application		x	2	=		
	Overall shape and appearance of trees		x	3	=		
	Minimal stubs, ripped cuts, & wounding		x	5	=		
	Crew productivity / efficiency		x	5	=		
	Chip quality & disposal method		x	5	=		
Supervisor	Maps / skips / refusals (accurate?, prompt?)		x	3	=		
	Area planning & notification		x	4	=		
	Job knowledge / training		x	4	=		
	Initiative / attitude / cooperation		x	3	=		
	Lost time due to labor issue		x	3	=		
	Lost time due to equipment issue		x	3	=		
Safety	Safe work practices & methods		x	3	=		
	Proper public safety measures (flaggers, cones, signage)		x	3	=		
	Protective equipment (hardhats, ear plugs, protective eyewear)		x	2	=		
Professionalism	Customer communication		x	3	=		
	Complaints / settlements		x	3	=		
	Appearance of workers and equipment		x	3	=		
Reporting	Work reporting timely, accurate, and legible		x	3	=		
	Billing/Invoicing timely & accurate		x	1	=		
							Total Points (out of 300 possible)

General Comments

Divide total points by 3 to get ______ % - **FINAL SCORE**

____
____
____

Figure A-7
Example Vegetation Management Work Performance Evaluation Score Sheet

Thermal Inspection Report

Date & Time: ____________________ Circuit #: ____________________

Inspector(s): ____________________ Structure ID #: ____________________

Weather: ____________________ Location: ____________________

Anomaly Information

Description: ____

Temperature Information (°C)

Reference:	
Hot Spot:	
Temp Rise:	

Priority Code: ______

1	50°C or more -	Repair Immediately
2	21°C to 49°C -	Repair within 1 week
3	11°C to 20°C -	Repair within 3 months
4	10°C or less -	Monitor

Thermal Image

File name: ____________________

Visual Image

File name: ____________________

Comments

Figure A-8
Example Thermal Inspection Report

Distribution Line Capacitor Inspection Report

Date & Time: ______________________ Device Location: ______________________
Inspector: ______________________ Address: ______________________
Digital Photo #'s: ______________________ Circuit: ______________________

Site Inspection

Safe Access	Yes No, explain: ____________
Physical Accessibility	Good Seasonal Vegetation Other: ____________
Vegetation	None On Pole Only Conductors Capacitor / Switches Other: ________
Animals / Nests	Nests Animal Damage Other:

Equipment Inspection

General Condition	Good Fair Poor Comments: ____________
Oil Leaks	None Capacitor Switch Transformer Other: ____________
Evidence of Overheating	No Yes, explain: ____________
Evidence of Arcing	No Yes, explain: ____________
Bulging Capacitors	No Yes, explain: ____________
Rusting	None Moderate Excessive Comments: ____________
U-Guard / Conduit	Good Damaged Missing Comments: ____________
Supports	Good Loose Comments: ____________
Bank Connections	Wye Delta
Bank Size	Single Phase 300 kVAR 600 kVAR 900 kVAR 1200 kVAR 1800 kVAR 2400 kVAR
Unit Size and Quantity	_____ / 100 kVAR _____ / 200 kVAR _____ / 300 kVAR _____ / 400 kVAR
Capacitor Blocking Units	Installed Pole Storage None
Cap. Blocking Unit Wiring	Correct Incorrect / damaged, explain: ____________
Capacitor Switches	None Oil Vacuum
Switch Manufacturer	ABB Cooper Joslyn Westinghouse Other: ____________
Same Type / Brand of Switch on Each Phase	Yes No, explain:
Primary Fuse Size and Type: ________	
Fuse Barrel Condition	Good Found damaged and replaced

Control System Inspection

Condition	Good Damaged Enclosure Damaged Seals Moisture Burns Other: ________
Control Type	None Local Paging DLC Cellular Other: ________
Paging Frequency (if applicable): ____________	
Paging Signal	Not Applicable Applicable Channel: ______ Strength: ______ dBm
DLC Signal	Not Applicable Applicable ______ MV ______ Volts
Control Manufacturer	Beckwith Canon EnergyLine Fisher-Pierce Maysteel Other: ____________
Control Serial Number	____________
As Found State	Remote Local Closed Tripped UV/OV LED on UV/OV LED off COM LED on COM LED off
UV/OV Settings	UV Setting______ OV Setting______
UV/OV Accuracy Check	Accurate Not Accurate

Operation Inspection

Trip Voltage______Volts AC Riser Current - Trip: Field:_____Amps Center:_____Amps Road:_____Amps
Close Voltage______Volts AC Riser Current - Close: Field:_____Amps Center:_____Amps Road:_____Amps

Switch Operation All follow operation One or more does not follow operation, explain: ____________
Ground Resistance ________Ohms

Follow-Up Required No Yes - see comments

Comments	**Upon Leaving**
	Bank left in "As Found" state Controller left in REMOTE mode As left controller frequency ______ (enter NA if not paging)

Figure A-9
Distribution Capacitor Inspection Report Form

Voltage Regulator Inspection Report

Location ID ______ Feeder ______ Substation ______

Physical Location: ______________________________

Control Data

Control Serial Number		Control Mfg.		Control Type	
Original Equipment Counter		Date Installed		Control Fuse Size	
Control Offset Counter					

Voltage Regulator Data

Regulator Serial Number			Size:	Amp		kVA	
Primary Voltage:	7.2 kV			13.2 kV		19.9 kV	
Fuse Size			Connection:	Delta		Wye	
Equipment Serial Number			Design:	Straight		Inverted	
Percentage Regulation			No. of Steps		Phase		
Set Voltage			Bandwidth		Time Delay		
Load Voltage:	Low		Present		High		
Load Current:	Low		Present		High		

Drag Hand Readings

Date	Phase R/M/F	Min	Present	Max	Volt	Employee

Comments

Figure A-10
Voltage Regulator Inspection Report Form

Recloser Inspection Report

Location ID ____ Feeder ____ Substation ____

Physical Location: ____

Control Data

Control Serial Number				Control Mfg.	
Original Equipment Counter		Date Installed		Control Type	
Control Offset Counter				Control Fuse Size	

Recloser Data

Recloser Serial Number			Size		Type	
Primary Voltage:	12 kV		23 kV		34.5 kV	
Operation Sequence:	Ground Trip		Lockout		Phase Trip	
Trip Resistors:	Phase		Ground			

Timing Plugs:

	Ground Trip	Phase Trip
1		
2		

Reset Delay ____

Battery Install Date ____

Date	Counter Reading	Battery Voltage	Employee	Date	Counter Reading	Battery Voltage	Employee

Defect Codes

Date	Code	Date	Code	Date	Code	Date	Code

Comments

Figure A-11
Recloser Inspection Report Form

Pole Ground Resistance Inspection Report

Date & Time: ____________________ Circuit #: ____________________

Technician: ____________________ Pole ID #: ____________________

Location: ____________________

Meter Mfr.: ____________________

Model: ____________________ Ground System Type: □ Single Rod Rod Depth:_______ ft

Serial #: ____________________ □ Multiple Rod / Grid Longest Diagonal Dimension:_______ ft

Test Conditions

Weather: ____________________

Temp: ____________________

Soil Conditions

□ Dry Moist

□ Loam Sand / Gravel Shale Clay Limestone Other:_________

Comments

Fall-of-Potential Measurements

Distance between electrode under test (E) and probe B:_________ft

% of Distance Between E and B	Distance Between E and A (ft)	Measured Resistance (Ohms)

Resistance (Ohms)

Distance Between Electrode E and Probe A

Resistance Scale: □ 50 100

Multiplier: □ x1 x10

Fall-of-potential method unsuitable

Reason: Possible buried metallic conductor

Known buried metallic conductor

Distance from Electrode (E):_________ ft

Two point measurement taken, data shown below

Two Point Method

Measurement: [ ] Ohms

Distance between electrode E and buried object O:________ ft

Describe buried metallic object:

Comments

Figure A-12
Example Pole Ground Inspection Report

Steel Transmission Structure Inspection Report

Circuits on Structure: ____________________ Date: ________________

Structure Number: ____________________ Inspector: ________________

Structure	Rusty	Missing	Loose	Bent / Buckled	Comments
Steel Members					
Aluminum Members					
Nuts & Bolts					
Anti-Climbing Guards					
Danger Signage					
Circuit Signage					
Other:					
Coating	Thinning / Improper Forming	Peeling	Chipping	Blooming / Packout	Comments
Galvanized					
Paint					
Weathering Steel					
Groundline	Cracked / Spalling	Missing	Rusty	Bare	Comments
Concrete					
Nuts & Bolts					
Ground Connections					
Counterpoise Connections					
Animal Carcasses	--	--	--	--	
Other:					
Guy System	Slack	Corrosion	Abraded	Shifting	Comments
Guy Line					
Attachment Hardware					
Anchor Rod					
Anchor Point					
Signage	Missing	Faded	Incorrect		Comments
Circuit Labeling					
Danger Signs					

Right of Way	Comments
Danger Trees	
Encroachment	
High Vegetation	
Road Condition	
Fences & Gates	
Erosion	
Wet / Swampy	

Comments

Figure A-13
Example Transmission Line Inspection Checklist

Non-Ceramic Insulator Visual Inspection Checklist

Date: ________________ Circuit: ________________________

Inspector: ________________ Structure Number: ________________________

Phase:

Defect Ratings: Minor - consider monitoring for further degredation
Moderate - monitor for further degredation and consider remedial action
Severe - requires remedial action

Weather Sheds

Sheds are numbered sequentially starting with 1 at the ground/tower end.

Possible shed defects are: split, crack, tear, gunshot, erosion, tracking, animal damage, surface crazing, surface contamination, & other (describe in comments).

Shed Location	Defect Type	Rating	Comments

Sheath

Sheath locatoin is identified by location between adjacent sheds. For example, sheath between sheds 3 & 4.

Possible sheath defects are exposed core (mandatory severe), split, crack, gunshot, erosion, tracking, animal damage, surface crazing, surface contamination, & other (describe in comments).

Sheath Location	Defect Type	Rating	Comments

Corona Rings & End Fittings

Label ring or fitting location as either tower-end or line-end.

Possible defects are flashover damage, incorrect position, loose, gunshot, degraded fitting seal, corrosion, & other (describe in comments).

Part & Location	Defect Type	Rating	Comments

General Comments

Figure A-14
Example Checklist for Visual Inspection of Non-Ceramic Insulators

B
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