Power Quality Implications of Transmission and Distribution Construction

Tree Faults and Equipment Issues

Technical Report

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Final Report, March 2005

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PRODUCT DESCRIPTION

This report provides practical guidelines for improving distribution construction designs and programs to improve power quality.

Results & Findings

Because faults are the *root cause* of voltage sags and interruptions, reducing the number of faults will obviously reduce the number of voltage sags and interruptions—and power quality will improve. This report concentrates on construction practices and equipment that can be used to minimize faults and their impact on customers. This report specifically focuses on tree-faults, the number one cause of faults for many utilities. In addition, the report reviews conductor spacings and span lengths as it affects power quality. The report also considers various equipment issues, including fiberglass standoffs, polymer insulators, and porcelain cutout issues.

Challenges & Objectives

The main objective is to improve construction to reduce faults. On overhead distribution circuits, most faults result from inadequate clearances, inadequate insulation, old equipment, or trees or branches falling into a line. The challenge is identifying the structural deficiencies; from that, utilities can improve designs and implement programs to upgrade construction.

Applications, Values & Use

This report is meant for utility distribution engineers, standards engineers, field engineers, and power quality engineers. This report attempts to provide strategies to improve the performance of distribution lines to mitigate the most common power quality problems. Utilities can find valuable information on tree-caused faults and how to apply programs to target tree faults, including targeted tree-maintenance programs. The report also gives guidance on spacings and constructions that are the most fault resistant to give the best power quality.

EPRI Perspective

By providing utilities with clear approaches for improving power quality with changes on the T&D system, EPRI is enabling utilities to provide better customer service. Utilities can target changes to specific customers with high power quality needs or can apply changes that improve power quality across the board. By focusing on practical methods, the report provides solutions for many common power quality problems.

Approach

The project team identified the most common and most important power quality problems and the construction deficiencies that can lead to these power quality problems. Literature reviews and utility interviews helped the project team develop guidelines regarding several construction practices and hardware.

Keywords
Power quality
Construction
Vegetation maintenance
Reliability
Faults

ACKNOWLEDGMENTS

Duke Power deserves special thanks for its support of this project. Lee Taylor provided significant support and advice. Lee Taylor and Duke Power pioneered the strategy of identifying and removing sources of faults on the Duke Power system. Duke Power also provided a number of educational photographs that provide many useful examples.

EXECUTIVE SUMMARY

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 sags and interruptions—and power quality will improve. This report is part of a project that concentrates on construction practices and equipment that utilities can use to minimize faults and their impact on customers. The focus of this report is tree faults, line spacings, and equipment issues.

Tree Faults and Power Quality

The main power quality impact of trees is that they cause interruptions, and some of the damage from these faults can take considerable time to repair. Trees can cause faults in several ways: growth into conductors, failing trees or branches bridging gaps or pushing conductors together, and failing trees or branches causing mechanical damage. Results of utility surveys show that growth is normally less than 15% of permanent interruptions. Dead trees or branches account for about 30 to 40% of tree faults, and trees with significant defects account for another significant portion.

One southeastern US utility uses detailed tree outage codes, allowing them to target causes more precisely. See Table ES-1 for their breakdown of tree-faults and their impact on outages. Note that trees falling (whether from inside or outside of the right of way) cause a much larger impact on the customer minutes of interruption relative to the actual number of outages. Likewise, vines and tree growth have relatively less impact on outage duration.

Table ES-1
Percentage of Tree Causes in Each Category

	Outages	CI	CMI
Tree Outside Right of Way (Fall/Lean On Primary)	26.0	37.2	42.5
Tree/Limb Growth	21.1	14.4	13.3
Limb Fell from Outside Right of Way	18.0	20.1	18.1
Tree Inside Right of Way (Fall/Lean On Primary)	12.6	14.8	15.2
Vines	10.0	3.6	3.1
Limb Fell from Inside Right of Way	8.7	9.8	7.5
Tree on Multiplex Cable or Open Wire Secondary	3.6	0.2	0.2

Source: Southeastern US utility, 2003 – 2004
CI = Customer interruptions
CMI = Customer minutes of interruptions

Reviews of utility outage databases show the following:

- *Major storms*—For many utilities, most faults and most damage during major storms are from trees. Tree faults are strongly a function of the weather, with wind and ice being major sources of tree failure.
- *Protective device*—Tree faults on the circuit mainline cause the most impact to customers. Trees also tend to be a higher percentage of fault causes on three-phase circuits than on single-phase circuits.
- *Feeders*—Tree interruption effects on customers can cluster significantly by circuit: some circuits have much more impact on overall customer interruptions. These are circuits with high numbers of customers and high exposure to tree faults.
- *Voltage*—Higher voltage circuits tend to be impacted by tree faults more, mainly because of more circuit exposure.

Tree faults also can cause momentary interruptions and voltage sags. Although trees have been reported to cause flicker, analysis in this report shows that tree contacts that cause flicker are unlikely: the impedance of the tree is too high to draw sufficient current to cause noticeable flicker. Once a tree limb arcs and breaks down, it will become a short circuit.

Strategies to Reduce Tree Faults

Utilities should attempt to gain more information about tree faults to help target these faults more efficiently:

- *Outage cause codes*—Use more specific outage cause codes to help develop strategies to reduce tree faults. Rather than just having a code for "trees," use more specific codes or sub-codes like: vines, tree from out of right-of-way, tree in the right-of-way, limb from in the right-of-way, and limb from out of the right-of-way. Use a separate code to track weather at the time of the fault. Consider using a separate code to indicate the damage done: none, pole down, wire broken, and so on. Also, consider doing a follow-up audit on a certain portion of outages to ensure that outage cause codes are not being misused.

- *Sample surveys*—Use sample follow-up surveys of tree outages to identify more specifics for the particular region. Use follow-up visits to the outage site with a forester to identify the tree species that caused the fault, the type of fault (trunk failure, small branch, growth, and so on), and any identifiable tree defects. This information will help when targeting hazard trees.

To most efficiently apply tree maintenance for the best power quality, consider vegetation management programs to target those circuits where tree faults would impact power quality the most and where tree faults are more likely, including:

- Mainline portions of circuits
- Circuits with more customers or critical circuits feeding industrial parks or other important customers
- Circuits with a history of tree faults
- Circuits with higher voltage

With a targeted program, don't just use a uniform maintenance cycle and pruning specification, but use a targeted approach to more effectively reduce the fault rate from trees on the targeted sections:

- *Maintenance cycle*—Vary the maintenance and/or inspection cycle. For example, a utility may be able to improve power quality and reduce costs by tightening the mainline cycle and lengthening the single-phase cycle.
- *Clearances*—On targeted sections (such as mainlines), use wider clearances, do more tree removal, and clear more overhangs.
- *Hazard-trees*—On targeted sections, clear trees that are the most likely to fail and fall on conductors. These are trees that are dead or have another significant defect and are likely to fall on the line because of the defect.

Each of these factors could be handled differently. For example, a utility could choose to have a fixed maintenance cycle of four years on all circuits, remove overhangs on all circuit mainlines, and remove hazard trees on the mainlines of the worst 25% of circuits (where worst could be some tree-related benchmark like five-year customer interruptions from trees). A comprehensive tree-maintenance strategy should include economics as well as impacts on power quality and reliability.

Several construction options are available to make overhead circuits more resistant to tree faults:

- *Wider spacings*—At spacings with voltage gradients less than 1 to 2 kV/ft, tree branches across conductors are unlikely to fault. A 12.5-kV structure with a 10-ft crossarm and with the center phase pin on the pole has about five feet between phases; this is about 2.5 kV/ft, a spacing that can still have tree faults. Wider spacings may be possible by raising the middle phase or using a vertical structure.

- *Covered conductors*—Covered conductors can help reduce faults from tree limbs bridging conductors or trees pushing conductors together. If using covered conductors, take extra measures to protect covered conductors from arcing damage from faults—try to make sure that relaying and fusing adequately protects the conductors, and/or consider using arc protective devices. Also, account for the other drawbacks of covered conductors, including increased weight, increased wind and ice loading, and increased possibility of conductor corrosion.
- *Spacer cables*—Spacer cables offer the advantages of covered conductors and offer some extra mechanical protection as well. The spacer cables also have most of the disadvantages of covered conductors to consider. In addition because of reduced spacings, the insulation to lightning may be lower, so lightning-caused faults may increase.
- *Mechanical coordination*—Consider equipment component failures in structure designs, and try to coordinate the mechanical design such that when tree and large limb failures occur, equipment fails in a manner that is easier for crews to repair. When a tree falls on a line, crews will have an easier repair if it just breaks the conductors rather than breaking poles and other supports (see Figure ES-1). The fault still occurs, but crews are able to more quickly repair the damage and restore service.

Figure ES-1
A Pole Broken in Half by a Tree Falling onto the Line Structure During a Windstorm

Conductor Slapping Faults and Conductor Spacings

When a fault occurs on a circuit, the magnetic forces from the flow of fault current can cause conductors to swing together. This causes another fault upstream of the original. The result is a deeper voltage sag and a possibility that more customers are interrupted as an upstream protective device may operate. Conductor slapping due to short-circuit current forces is not just an obscure problem, but instead one that is widely encountered at most utilities. Long spans, tight conductor spacings, and excessive sags are especially susceptible. Avoiding these can reduce the probability of conductor slapping. On horizontal crossarm designs, an easy but effective way of reducing the chance of conductor slapping faults is to always mount the middle-phase pin insulator on the pole rather than on the crossarm. In addition to gaining more horizontal separation, the additional vertical separation helps separate the conductor swinging motions. In addition, shortening the duration of faults by using faster tripping times for circuit breakers and reclosers is another technique to reduce the problem. Also, covered conductors can be used.

Equipment Issues

In this project, several miscellaneous equipment issues that might impact power quality were reviewed. These include:

- *Fiberglass standoffs*—Fiberglass distribution apparatus does not possess a long service history and thus questions remain about its degradation characteristics and service expectancy. Anecdotal evidence as well as samples removed from service indicates that fiberglass standoff brackets in particular may be prone to flashover (Figure ES-2). This phenomenon can contribute to degraded power quality and poses a possible safety risk.
- *Polymer insulation*—While they have not yet gained wide-spread acceptance in the utility industry, polymer based insulators are being used to a greater extent than ever before in the construction and repair of electrical distribution lines. Unfortunately, the constantly evolving nature of the polymer or non-ceramic insulator (NCI), coupled with its relatively recent development, has made it difficult to obtain long-term field performance data. However, there is a strong case that polymer insulation can outperform ceramic over relatively short service intervals, especially under heavily polluted conditions, and there is growing evidence that non-ceramic insulators also perform satisfactorily in the long term.
- *Fuse cutouts*—Some utilities have reported that a portion of their porcelain fuse cutouts are experiencing stress cracking of the insulator that can lead to it breaking apart. These failures can pose a risk to crews working on circuits as well as the public, and they can degrade power quality and reliability. The nature and extent of this problem is currently under study within the industry. For the most part, the problem appears to be limited to one type of porcelain fuse cutout (manufactured mainly 10+ years ago). However, there is a distinct possibility that the problem is more widespread, and the industry needs to collect more data on this issue to determine the scope of the problem.

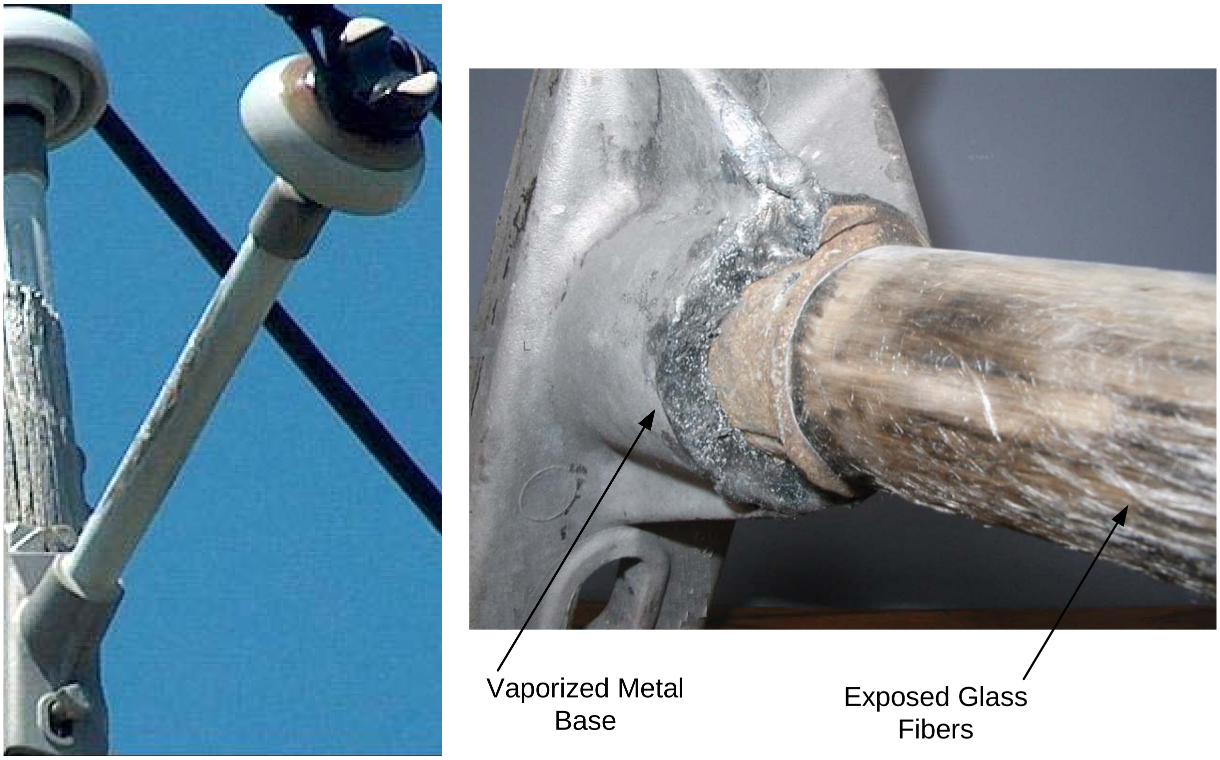

Figure ES-2
Fiberglass Standoff Surface Degradation and Damage from Flashover

Future Work Plan

This project is part of a multi-year effort to concentrate on ways to improve power quality using practical methods on transmission and distribution systems. More work is planned on developing a base of knowledge from utilities, particularly in developing a set of case studies and sharing cost and performance data for construction-improvement projects. In 2005, work will focus on consolidating work done in 2002 through 2004 and providing tools that utilities can use to help design and operate their T&D systems with better power quality. Specifically, online resources will be created with the following information and features:

- Reports
- Online calculators
- Case studies
- Interactive forums

A focus for the 2005 work will be gathering case studies from utilities, and as this project continues, the online resources will continue to grow in content and capabilities.

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1
INTRODUCTION

This report is part of a multi-year effort to concentrate on ways to improve power quality using practical methods on transmission and distribution systems. The previous work was:

- Power Quality Improvement Methodology for Wires Companies, EPRI, Palo Alto, CA: 2003. 1001665.

  The 2003 report concentrated on practices and equipment that can be used to minimize the effect of faults on customers. This concentrated mainly on reconfiguration or protection-oriented changes: reclosing practices, single-phase reclosers, recloser coordination, and others.

- Power Quality Implications of Distribution Construction, EPRI, Palo Alto, CA: 2004. 1002188.

  The 2004 report concentrated on construction practices and equipment that can be used to reduce faults and concentrated specifically on animal-caused faults and lightning-caused faults.

This report is the second in a series of efforts directed at T&D construction practices: how construction practices affect power quality, making construction immune to animals, falling trees, lightning, and other external causes of faults. This report focuses mainly on tree faults and equipment issues.

The three most-significant power quality concerns for most customers are:

- Voltage sags
- Momentary interruptions
- Sustained interruptions

Power quality problems affect different customers differently. Most residential customers are affected by sustained and momentary interruptions (also known as momentaries). For commercial and industrial customers, sags and momentaries are the most common problems. Each circuit is different, and each customer responds differently to power quality disturbances. The three power quality problems discussed here are caused by faults on the utility power system, with most of them on the distribution system. This report continues the work focusing on construction practices and equipment that can be used to minimize faults and their impact on customers. Faults can never be totally eliminated, but their frequency can certainly be reduced.

2
TREE FAULTS

Trees are the source of many power quality issues on distribution and transmission circuits. For many utilities, trees are the number one or number two cause of interruptions. When trees contact utility equipment, damage is often extensive, and repair is expensive and time-consuming. Most of these vegetation faults are on distribution circuits, but transmission circuits are not immune as highlighted by the famous tree-caused fault on August 14, 2003 on one of FirstEnergy's 345-kV lines in Ohio. In addition to long-duration interruptions, the faults from trees cause voltage sags and can cause momentary interruptions.

For most utilities, vegetation management is by far the largest maintenance item in the budget. So, in addition to improving power quality, more efficient tree maintenance and more tree-resistant designs can also reduce maintenance.

Previous Work

A great deal of work on tree faults has been done since 1990 that should help utilities design more tree-resistant structures and optimize vegetation management.

Rees et al. [1994] reported on pioneering investigations by Baltimore Gas and Electric (BGE) that focused on a seven-year outage-review study and staged tree-fault testing:

- *Outage review*—Based on a review of over 3000 tree-related outages, BGE concluded that 98% of tree-caused outages were from trees or tree parts falling on lines.
- *Field tests*—In tests of tree limbs across line-to-ground voltage (7.6 kV), BGE found that the tree limb did not immediately fault. Burning and arcing starts at the ends and moves inward. The burning carbonizes a highly conductive path. Prior to full development of the carbon path, the tree limb remains a high impedance. Once the carbon path fully develops, the impedance drops to near zero and lead to a fully bolted fault. BGE also staged tests with a live 7.6-kV (line to ground) circuit pulled into contact with a tree from line to the ground. The circuit did not fault and drew currents of less than one ampere in all tests.

Based on these findings, BGE switched to a more prioritized vegetation management program on its distribution system (13.2 kV mainly). They focused less on trimming for natural growth and attempted to remove overhangs where possible. They implemented a three-year maintenance cycle on the three-phase system, and delegated the one and two-phase system to "trim only as necessary." BGE crews also removed hazard trees. On the 34.5-kV subtransmission system, they moved to a biannual inspection program with the goal of achieving reliability approaching that of their transmission lines.

Duke Power has done considerable work on using their outage database as a resource to learn about tree-caused faults to help guide vegetation management. Chow and Taylor [1993] developed a strategy to analyze Duke Power's outage database to learn more about specific causes of faults. They found the following trends:

- *Weather*—When looking at the likelihood of tree-caused faults, weather strongly affects tree faults, especially wind but also rain, snow, and ice.
- *Season and time of day*—The most tree faults occurred during summer and the least occurred during the winter. More tree faults occurred during the afternoon and evening. Tree faults were not greatly influenced by the day of the week.
- *Phasing and protective device*—Multiple-phase faults are more likely to be caused by trees. Along these same lines, lockouts of a substation circuit breaker or a line recloser were more likely to be caused by trees than were operations of other protective devices.

More recent work reported by Xu et al. [2003] found many of the same trends and extended the concept to include a statistical regression analysis to identify the variables that most influence the likelihood of a tree-caused interruption. They found that weather, time of day, and protective device were most statistically significant indicators of the likelihood of a tree-caused interruption.

Niagara Mohawk (a National Grid company) used several investigations to restructure its vegetation management programs for distribution systems [Finch, 2001; Finch, 2003a]. Niagara Mohawk used its outage cause codes to categorize the source of tree-caused interruptions, and also used sample studies to provide more in-depth details on tree-caused interruptions. Niagara Mohawk also staged live tests with trees in contact with distribution lines to learn more about momentary interruptions. They also reviewed a sample of tree-caused outages for tree defects. Based on these results, Niagara Mohawk modified its program to target the worst circuits, the 13.2-kV system, the circuit backbone, and danger-tree removal.

With Allegany Power, Niagara Mohawk, and Portland General sponsoring the work, Environmental Consultants Inc. (ECI) performed a large number of tests on various species and sizes of tree branches to extend the BGE testing work [Appelt and Goodfellow, 2004; Finch, 2003a; Goodfellow, 2000]. ECI generally found similar results to the BGE tests: a phase-to-phase or phase-to-neutral contact was required to cause a fault. They also found that the probability of a fault and the time to fault was a function of the voltage gradient and to some degree a function of the species and moisture content. In addition, ECI surveyed utilities on their tree-caused outages to identify the sources of these outages.

Types of Tree Faults

Faults caused by trees generally occur from a handful of conditions:

1. Falling trees or major limbs knock down poles or break pole hardware
2. Tree branches blown by the wind push conductors together
3. A branch falls across the wires and forms a bridge from conductor to conductor

4. Natural tree growth causes a bridge across conductors

The results from several utilities outlined below show that broken tree branches or falling trees account for the majority of interruptions. Growth only accounts for a small percentage of interruptions.

Baltimore Gas and Electric

The survey of Rees et al. [1994] of over 3000 tree-related outages over seven years found the following breakdown of tree-caused outages:

- 75% were caused by dead shorts across a limited distance.
- 23% were from mechanical damage to utility equipment.
- Less than 2% were due to natural growth or burning branch tips beneath the lines.

BGE concluded that 98% of tree-caused outages were from trees or tree parts falling on lines.

Eastern Utilities Associates

Simpson [1997] reported on a survey of tree-caused faults at Eastern Utilities Associates (a small utility in Massachusetts that is now a part of National Grid). The main results were that tree-caused outages broke down as follows:

- 63% from broken branches
- 11% from falling trees
- 2% from tree growth

BC Hydro

EPRI 1008480 [2004] documents surveys by BC Hydro of their tree-related interruptions that were as follows:

- 70% from tree failure
- 18% from branch failure
- 12% from growth

Niagara Mohawk

Finch [2001] reported on a survey that Niagara Mohawk Power Corporation (now a part of National Grid) performed in 2000. Significant results were:

- 86% of permanent tree-faults were from outside of the trim zone (+/- 10 feet).

- Growth only accounted for 14% of outages (Figure 2-1), and Finch also reported that most of these were outages on services.
- In a sample of 250 tree-caused outages from 1995, 36% were from dead trees, and 64% were from live trees. In this sample, 75% came from outside the trim zone, and 62% were caused by a broken trunk or branch.

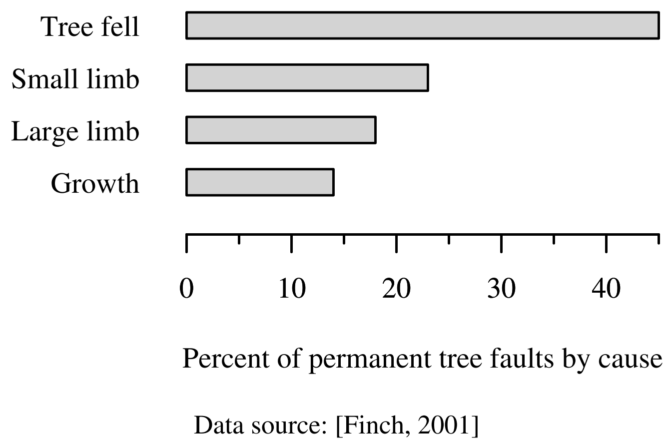


Figure 2-1
Niagara Mohawk Survey of Tree Outage Causes

Duke Power

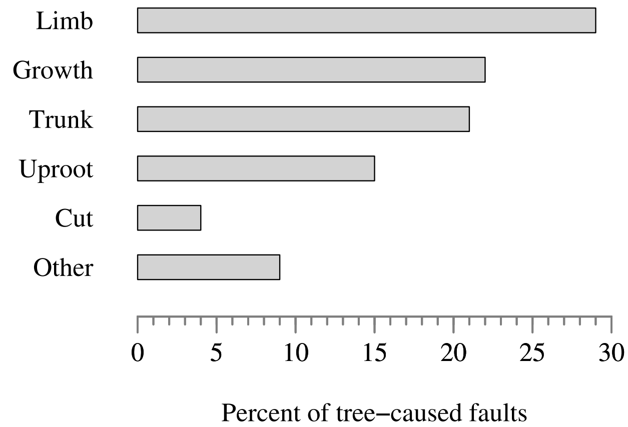
Taylor [2003] reported on a 1995 sample survey of tree-caused outages with the following results:

- 73% of tree outages occurred when an entire tree fell on the line. 86% of these were from outside of a 30 foot ROW.
- Dead limbs or trees caused 45% of tree outages.

In addition, Duke Power's investigations of the sample outage set found that 25% of outages reported as tree-caused were *not* caused by trees. This highlights the importance of good outage code recording when investigating fault causes.

Environmental Consultants Inc.

Finch [2003a] reported on results of a 1995 Environmental Consultants Inc. (ECI) survey of over 20 utilities and a total of 2328 tree outages. The ECI survey found that tree failures and limbs caused the most tree outages (see Figure 2-2).



Data source: [Finch, 2003a]

Figure 2-2
ECI Survey of Tree Outage Causes

Southeastern US Utility

One southeastern US utility uses detailed tree outage codes, allowing them to target causes more precisely. See Table 2-1 for their breakdown of tree-faults and their impact on outages. Note that trees falling (whether from inside or outside of the right of way) cause a much larger impact on the customer minutes of interruption relative to the actual number of outages. Likewise, vines and tree growth have relatively less impact on outage duration.

Table 2-1
Percentage of Tree Faults in Each Category

	Outages	CI	CMI
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Source: Southeastern US utility, 2003 – 2004
CI = Customer interruptions
CMI = Customer minutes of interruptions

Characteristics of Tree Faults and Interruptions

The outage database is a prime source of information for a utility in targeting tree-caused faults. Tree-caused faults are the most significant contributor to reliability indices. Figure 2-3 shows a breakdown by outage cause code for a utility in the northeast US over a ten-year period (with major storms excluded).

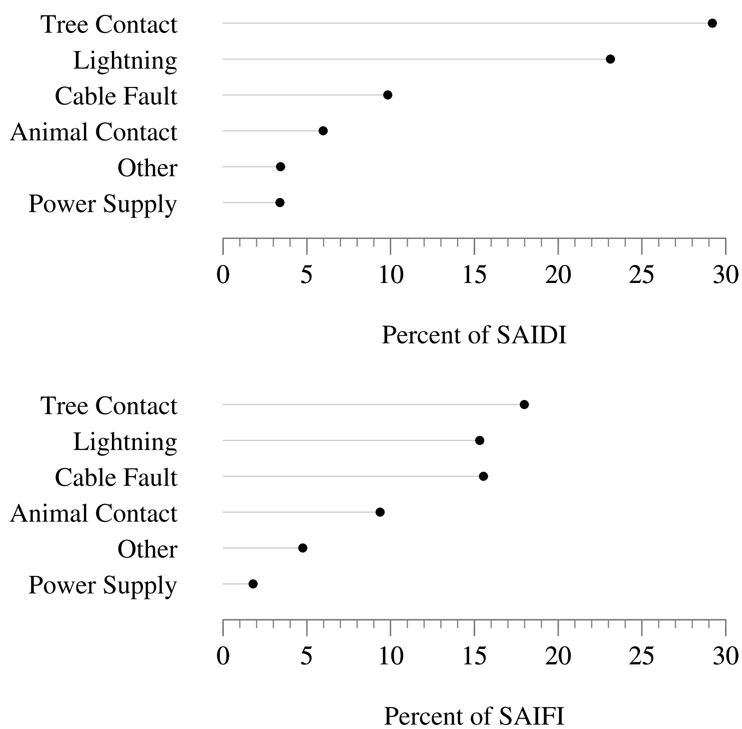


Figure 2-3
Breakdown of Reliability Indices for a Northeastern Utility

Analyzing cause codes along with weather codes can reveal significant trends for tree faults. For one northeastern US utility, Figure 2-4 shows the breakdown of outages by weather classification. For this utility, “Tree Contact” leads all other outage categories during stormy weather; and it especially stands out during wind and ice/snow. This highlights the fact that tree-caused faults increase rapidly during storms. Figure 2-5 shows the same data but rearranged to focus on comparing tree faults to other common outages caused by weather.

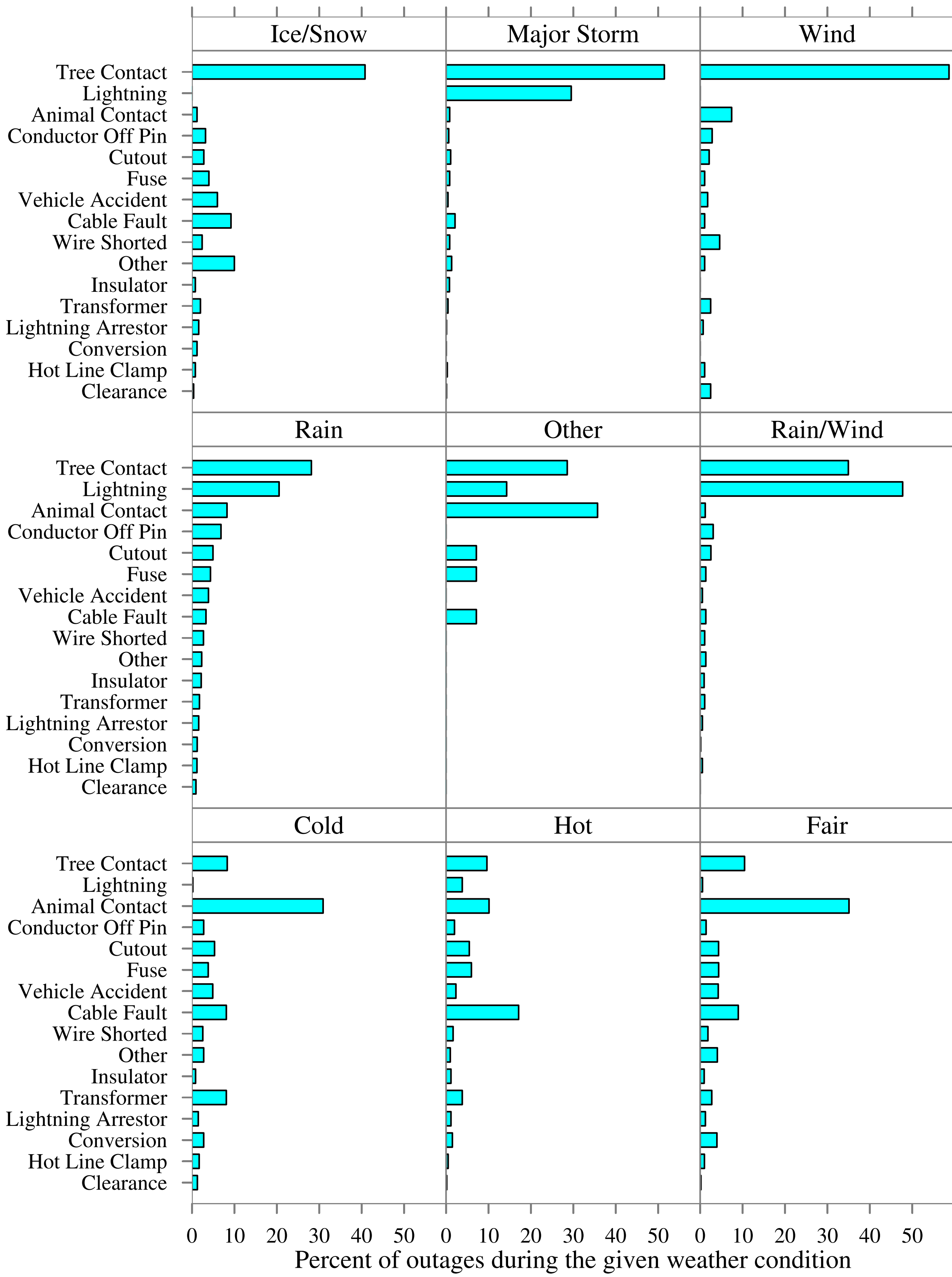


Figure 2-4
Percentage of Interruptions by Cause for the Given Weather for a Northeastern Utility

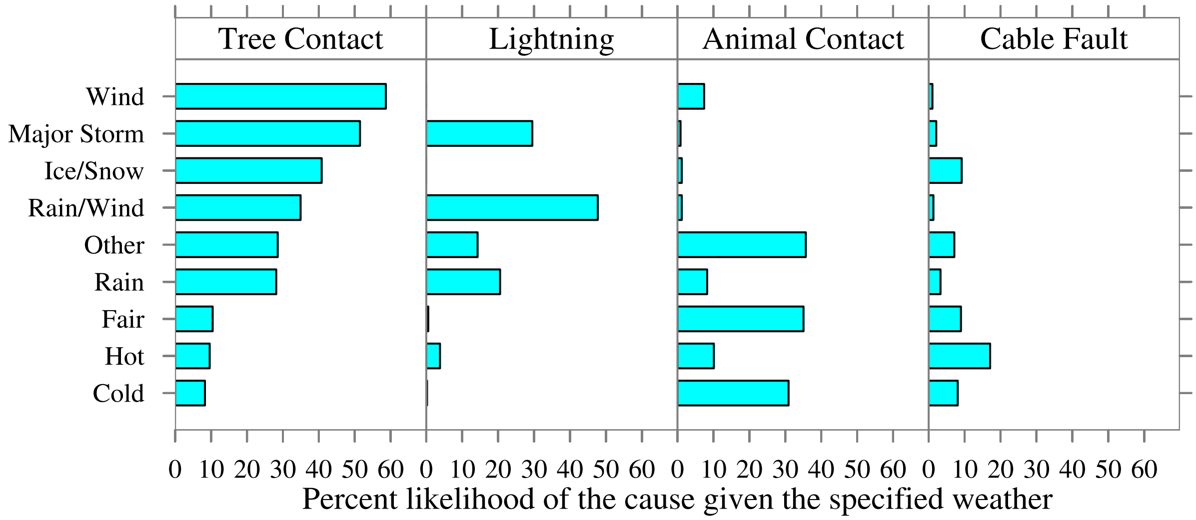


Figure 2-5
Likelihood of the Given Cause for the Specified Weather for a Northeastern Utility

For many utilities, tree-caused interruptions are the main cause of interruptions during "major storms" or "major events" (the IEEE terminology). Duke Power found that trees account for 81% of their outages during major event days [Taylor, 2004a]. The data for a northeastern US utility in Figure 2-6 also shows tree-contact as the main cause during major events (with lightning a close second). The effect of trees during major events depends on the dominant storm patterns and the utility's definition of a major event.

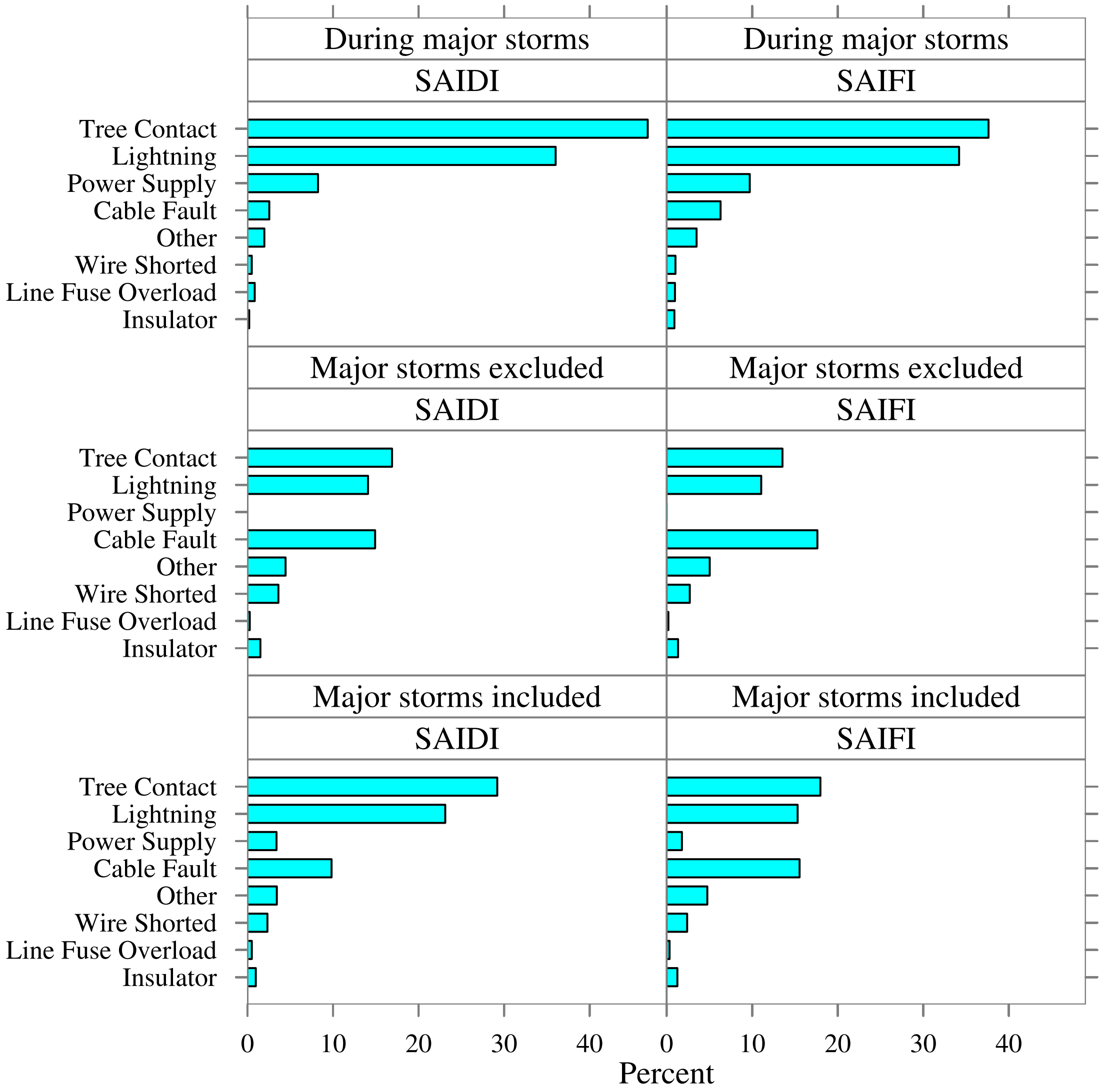
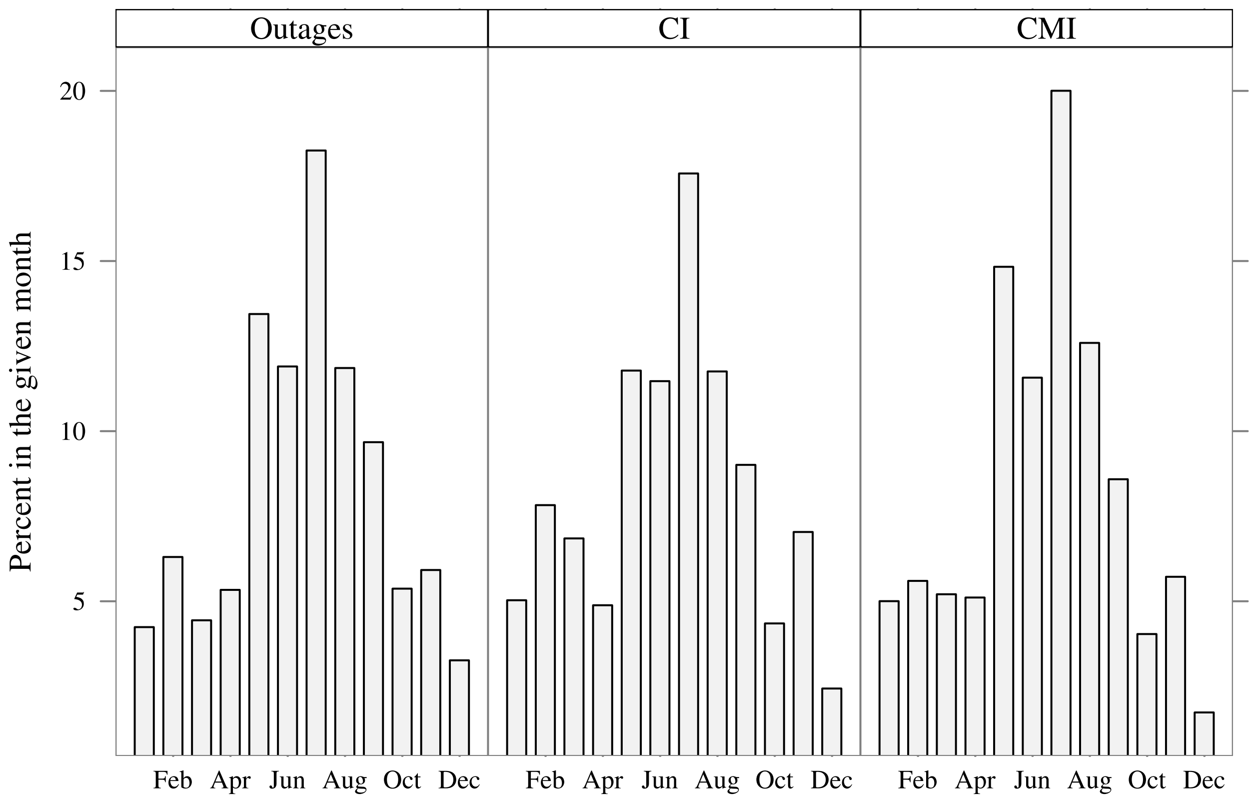


Figure 2-6
Interruption Indices by Cause During Major Storms and With and Without Major Storms

Being highly correlated with weather, season has a large impact on tree-fault rates. Duke Power has the most tree-caused faults during the summer and the least during fall [Chow and Taylor, 1993; Xu et al., 2003]. Another southeastern US utility also has the most outages during the summer as shown in Figure 2-7 as does a northeastern US utility as shown in Figure 2-8.



Source: Southeastern US utility, 2003 – 2004
Major Events Included
CI = Customer interruptions
CMI = Customer minutes of interruptions

Figure 2-7
Tree-Caused Outage Impacts by Month

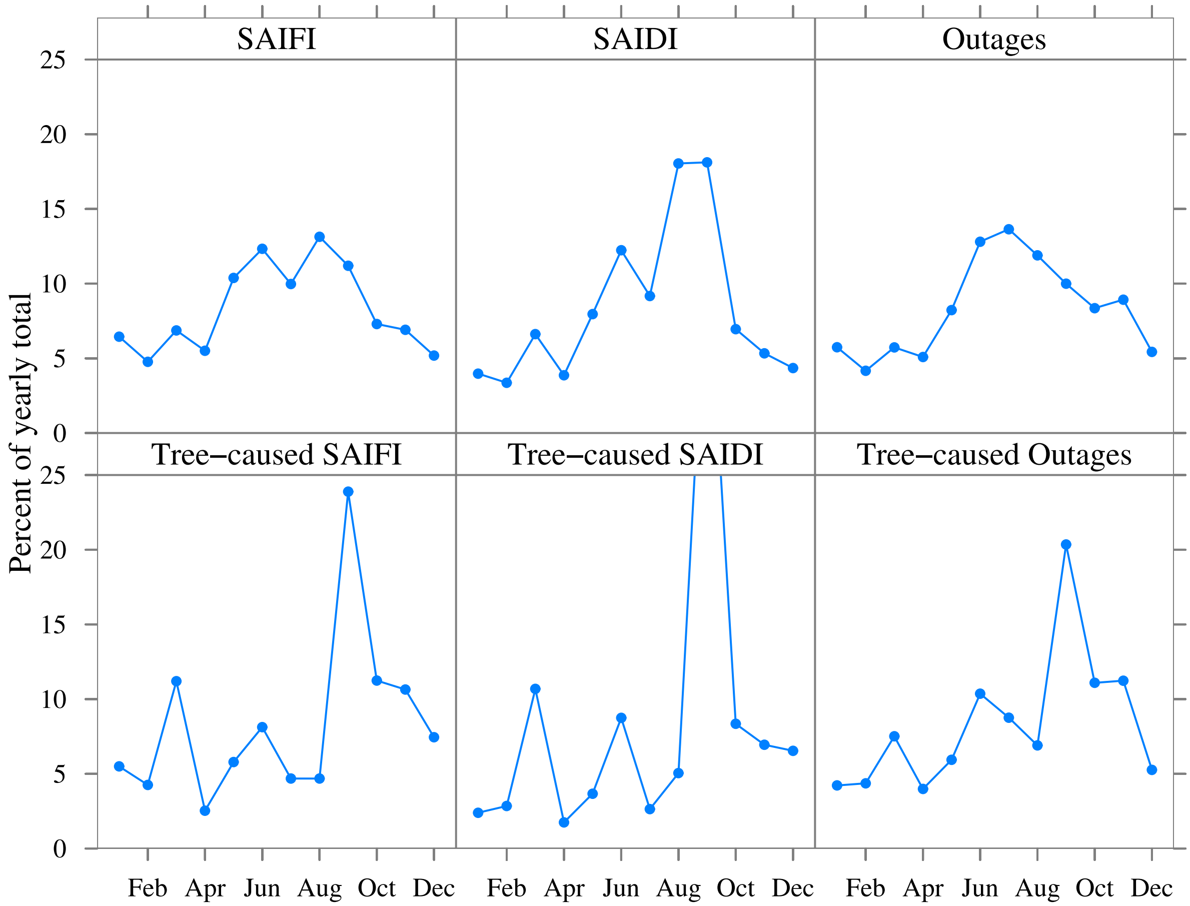


Figure 2-8
Interruptions by Month for One Northeastern Utility (Major Events Included)

Interruptions on the mainline affect the most customers. Figure 2-9 shows the breakdown of tree-caused SAIFI for one northeastern US utility. This utility had almost 60% of tree customer interruptions from breaker lockouts. Duke Power [Chow and Taylor, 1993; Xu et al., 2003] also found that of circuit breaker and recloser lockouts, trees caused 35 to 50% of the lockouts, which is over twice the rate of all tree outage events (trees cause 15 to 20% of all of Duke's outages).

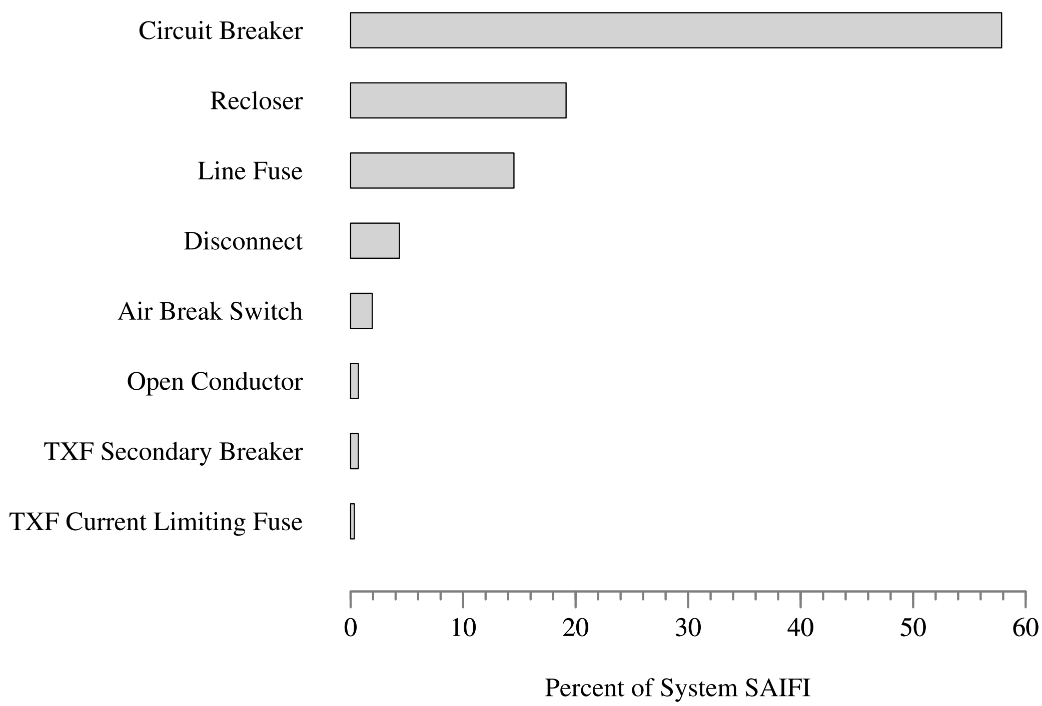


Figure 2-9
Tree-Caused Customer Interruptions by Interrupting Device for One Northeastern Utility (Major Events Included)

Of tree-caused faults, a small number cause the greatest contribution to SAIFI and SAIDI. These are mainline faults. Restoration time is longest during major events and tree failures normally have the longest (and most expensive) cleanup and repair. Finch [2003a] reported that on Niagara Mohawk's system with over 2000 feeders in a given year, more than half of tree faults, half of customer outages, and half of customer hours of outage occurred on just 100 circuits (5% of feeders). Another utility in the northeast shows similar trends in Figure 2-10; half of the customer outage hours were from outages on just 4% of feeders. This data included major events, which tends to exaggerate the "clustering" effect.

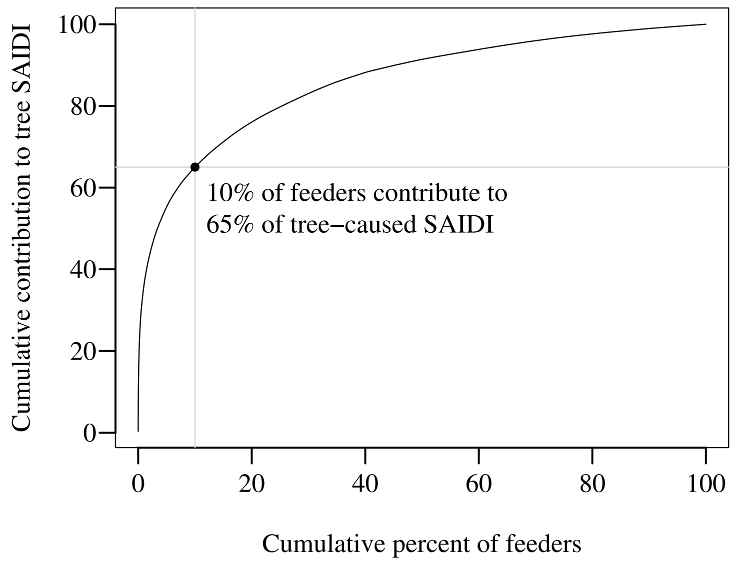


Figure 2-10
Allocation of Tree-Caused System SAIDI by Feeder for One Northeastern US Utility

Finch [2003a] also reported that Niagara Mohawk found 3% of all tree-caused faults contributed to 52% of the total tree-caused SAIFI. Another northeastern US utility has similar results as shown in Figure 2-11.

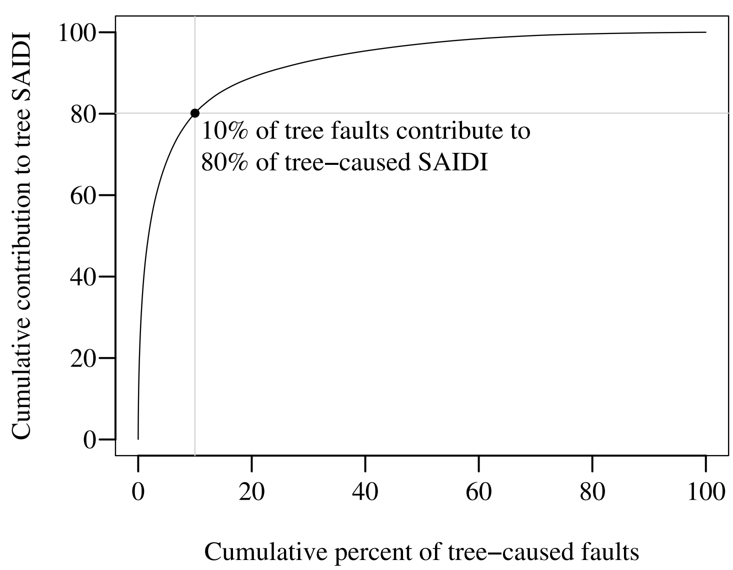


Figure 2-11
Allocation of Tree-Caused System SAIDI by Tree Outage for One Northeastern US Utility

Circuit voltage can also impact tree-caused faults. Tree-caused faults cause much less impact to customers on 5-kV class circuits. Finch reported that tree-cause outages on 2.4 to 4.16-kV circuits averaged 79 customers per tree outage, but 7.6 to 13.2-kV circuits averaged 206 customers out per outage. Table 2-2 shows similar trends for another northeastern utility. Contrary to the widely held belief that 5-kV class circuits have much lower fault rates from trees, this utility had similar fault rates; the main difference is that faults impact less customers on the lower voltage circuits. Table 2-3 shows data from a southeastern utility that shows similar tree-caused fault rates on 15- and 25-kV class systems.

Table 2-2
Tree Faults by Voltage Class for a Northeastern US Utility

Voltage	Tree SAIDI, minutes	Tree fault rate per 100 miles per year
2.4 kV	4	11.6
4.16 kV	22	9.6
13.8 kV	34	10.8

Includes major storms

Table 2-3
Tree Faults by Voltage Class for a Southeastern US Utility

Voltage class	Tree fault rate per 100 miles per year	
	With major storms	Without major storms
15 kV	68	27
25 kV	51	16

These findings strongly suggest that targeting should help improve power quality and more efficiently manage tree-maintenance budgets. Target tree maintenance and other tree-improvement strategies (like covered wire or increased spacings) to circuits with the most outages. To do that, focus on the following:

- Mainline portion of circuits
- Circuits with more customers
- Circuits with a history of tree faults
- Circuits with higher voltage

Physics of Tree Faults

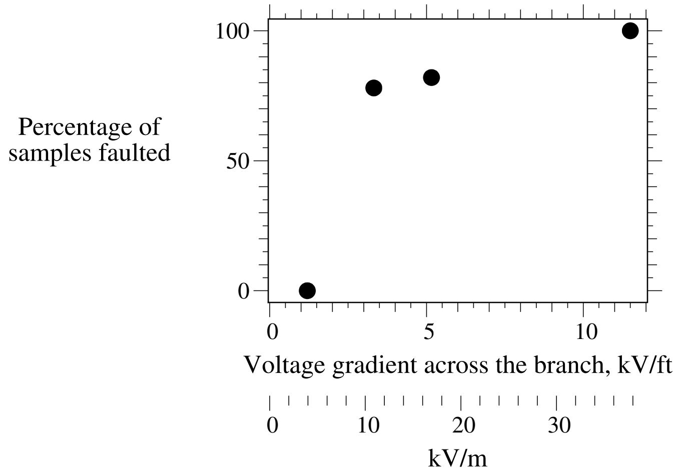
Baltimore Gas and Electric [Rees et al., 1994] pioneered some revealing tests on how trees cause faults. ECI [Appelt and Goodfellow, 2004; Finch, 2001; Finch, 2003a; Goodfellow, 2000] and Florida Power Corporation [Williams, 1999] followed this work with their own tests that showed much the same results. For a tree branch to cause a fault, the branch must bridge the gap between two conductors in close proximity, which usually must be sustained for more than one minute. A tree touching just one conductor will *not* fault at distribution voltages. The tree branch must cause a connection between two bare conductors (it can be phase to phase or phase to neutral). A tree branch into one phase conductor normally draws less than one amp of current under most conditions, this may burn some leaves, but it won't fault. On small wires in contact with a tree, the arcing to the tree may be enough to burn the wire down under the right conditions. While the tree in contact with one wire won't fault the circuit, there are some safety issues with trees in contact with overhead conductors.

A fault across a tree branch between two conductors takes some time to develop. If a branch falls across two conductors, arcing occurs at each end where the wire is in contact with the branch. At this point in the process, the current is small (the tree branch is a relatively high impedance). The arcing burns the branch and creates carbon by oxidizing organic compounds. The carbon provides a good conducting path. Arcing then occurs from the carbon to the unburned portion of the branch. A carbon track develops at each end and moves inward.

Once the carbon path is established completely across the branch, the fault is a low-impedance path (now the current is high—it is effectively a bolted fault). It is also a permanent fault. If a circuit breaker or recloser is opened and then reclosed, the low-impedance carbon path will still be there unless the branch burns enough to fall off of the wires.

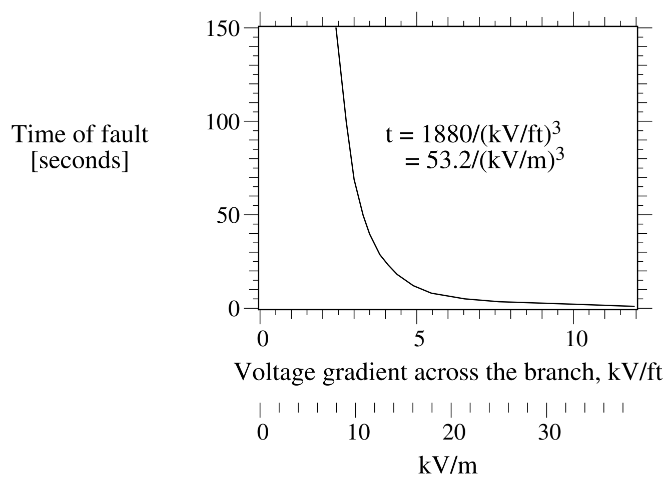
Some other notable electrical effects include:

- It makes little difference if the branch is wet or dry. Live branches are more likely to fault for a given voltage gradient, but dead branches are more likely to break and come in contact with the line.
- Little branches can burn through and fall off before the full carbon track develops. So, minor leaf and branch burning does not cause faults.
- The likelihood of a fault depends on the voltage gradient along the branch (see Figure 2-12).
- The time it takes for a fault to occur also depends on the voltage gradient (see Figure 2-13).
- Lower voltage circuits are much more immune to flashovers from branches across conductors. A 4.8-kV circuit on a 10-foot crossarm has about a phase-to-phase voltage gradient of 1 kV/foot, very unlikely to fault from tree contact. A 12.47-kV circuit has a 2.7 kV/foot gradient, which is more likely to fault.
- Tests by ECI [Goodfellow, 2000] found that branch characteristics affected the probability of failure. Thicker branches were more likely to flash over, and live branches were also more likely to flash over for a given voltage gradient. ECI found "no significant difference" between naturally occurring growth and suckers (a secondary shoot produced from the base that often grows quickly). Moisture factor was "less of a factor than one might guess". Surface moisture was "less of a factor": it may make the fault occur more quickly but not make the fault more likely. ECI did find differences between species. Florida Power Corp. [Williams, 1999] found variation: in their tests palm limbs faulted fastest (one minute in their setup), and pine limbs lasted the longest (15 minutes).



Data source: [Goodfellow, 2000]

Figure 2-12
Percentage of Samples Faulted Based on the Voltage Gradient Across the Tree Branch



Data source: [Goodfellow, 2000] with the curvefit added

Figure 2-13
Time to Fault Based on the Voltage Gradient Across the Tree Branch

These effects reveal some key issues:

- Trimming around the conductors in areas with a heavy canopy does not prevent tree faults. Traditionally, crews trim a "hole" around the conductors with about a 10-ft (3-m) radius. If there is a heavy canopy of trees above the conductors, this trimming strategy performs poorly since most faults are caused by branches falling from above.
- Vertical construction may help since the likelihood of a phase-to-phase contact by falling branches is reduced.
- Candlestick or armless designs are more likely to flash over because of tighter conductor-to-conductor spacings.

- Three-phase construction is more at risk than single-phase construction.

At transmission voltages, voltage gradients are high enough to cause a fault from a tree touching just one conductor. Hoffman et al. [1984] tested a 220-kV circuit in contact with a poplar tree across 8 m (26 ft). Burning and arcing started at the tip of the tree and worked its way to a full short circuit at the bottom of the tree in 30 to 40 seconds. That is a voltage gradient of 4.9 kV/ft (15.9 kV/m), which is also in the range of Figure 2-13. Hoffman et al. [1984] also tested a 110-kV circuit, but arcing lasted twice as long before completely shorting out. They also tested a 20-kV circuit which did not flash when contacting one phase; after burning near the tip of the tree for 10 to 15 minutes, the small carbonized branches broke, and the tree became disconnected from the line.

We are unaware of any tests on 34.5-kV circuits or other higher voltage distribution or lower voltage subtransmission lines. Given that a 34.5-kV circuit has 20 kV from line to ground, phase-to-earth-level distances of at least 20 to 30 feet have a voltage gradient of less than one 1 kV/ft, a gradient unlikely to cause a fault according to the ECI tests (but extrapolation to longer distances might be invalid).

Utility Tree Maintenance Programs

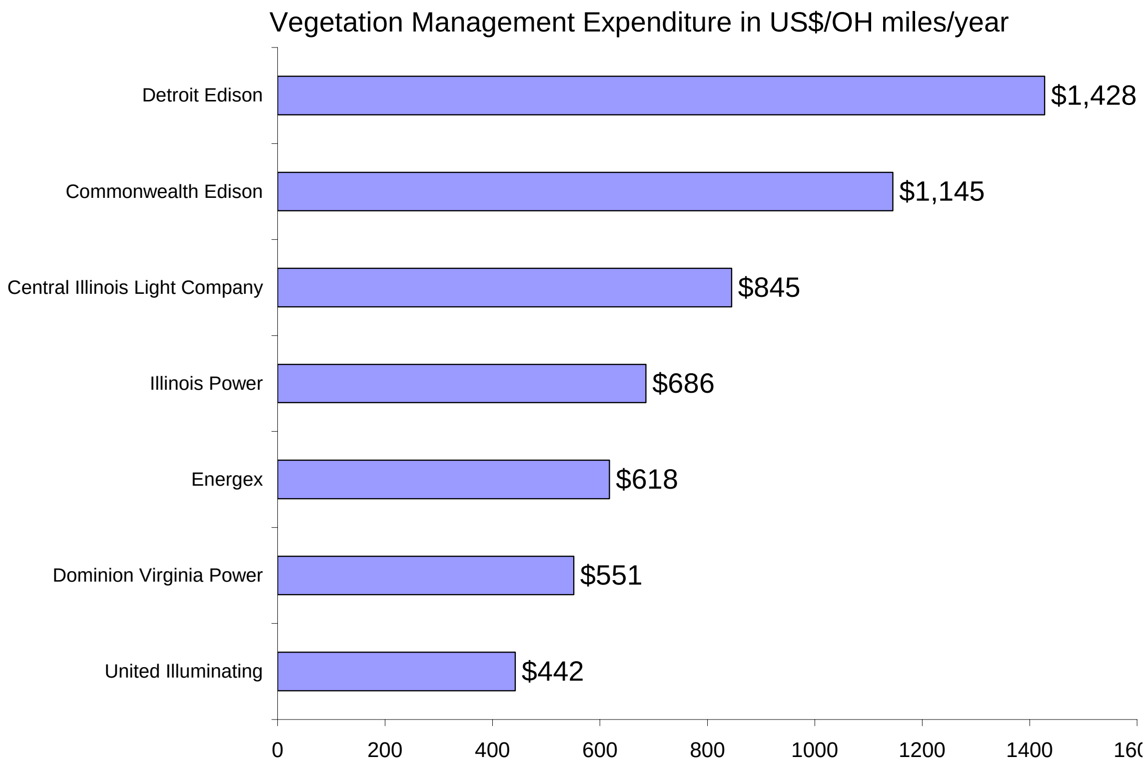
Cost

Tree trimming is expensive—an EPRI survey found that utilities spend an average of about $10 per customer each year on tree trimming ([EPRI TR-109178, 1998] and Figure 2-14). Trimming can also irritate communities. It is always a dilemma that people don’t want their trees trimmed, but they also don’t want interruptions and other power quality disturbances.

Data source: [EPRI TR-109178, 1998]

Figure 2-14
Utility Vegetation Management Costs of Five Utilities Surveyed

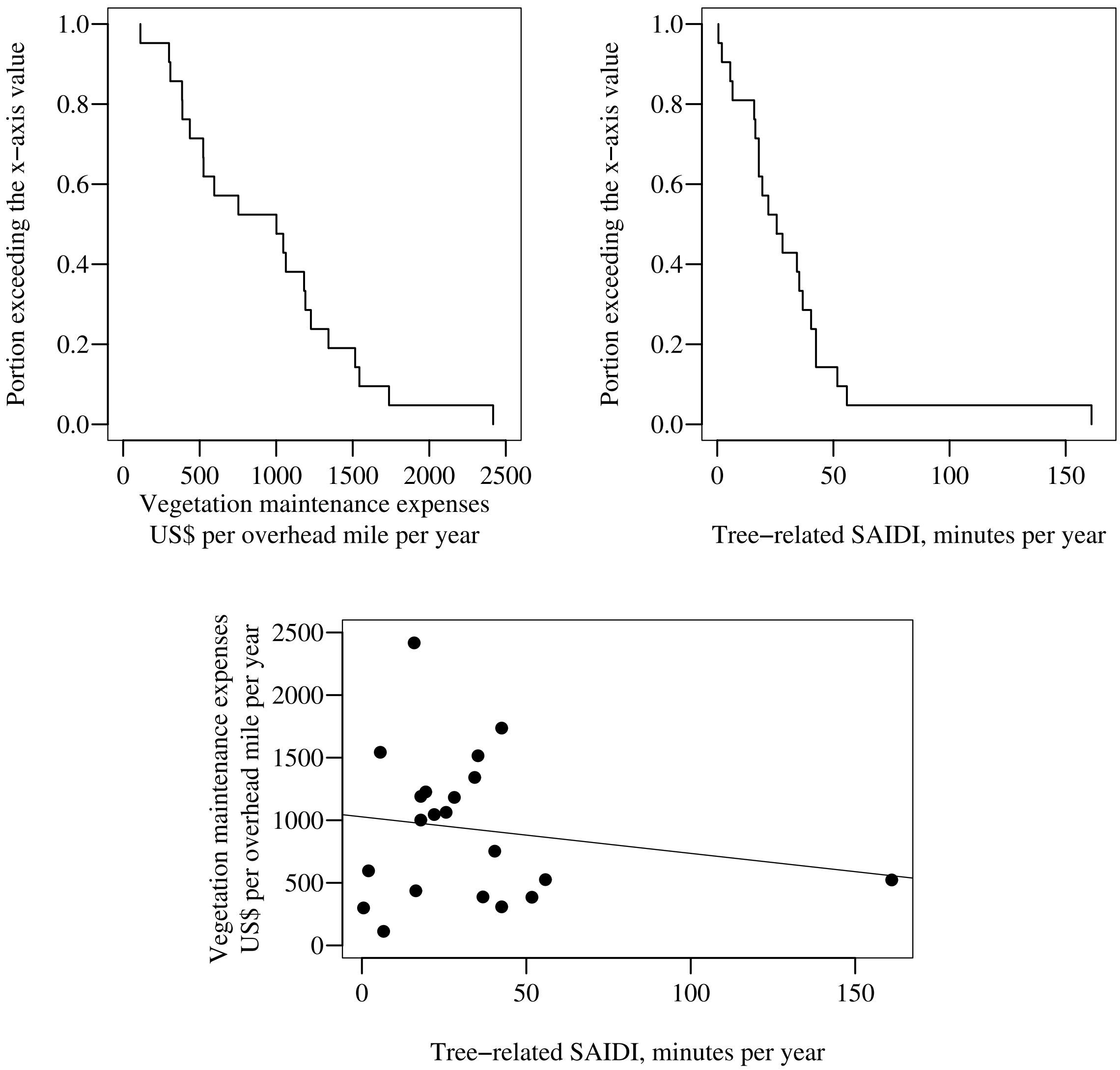
Figure 2-15 shows costs for other utilities from publicly available data (mainly regulatory filings). Costs vary significantly from utility to utility and reflect differences in tree coverage, load density (urban and suburban trimming is more difficult than rural tree maintenance), vegetation management cycle, and tree growth rates.



Data sources: various public regulatory filings to state agencies

Figure 2-15
Costs of Vegetation Management From Several Utilities

Figure 2-16 shows additional data on the costs of vegetation management programs and also ties that to performance using the SAIDI index. There is little direct correlation between spending and SAIDI between utilities. This is not surprising given wide variances in tree coverage, load and customer densities, and weather between utilities.



Data source: 2003 PA Consulting Benchmarking survey [BC Hydro, 2003]

Figure 2-16
Vegetation Management Costs Versus Performance

Cycle

Choosing a tree-trimming cycle is tricky. Many utilities use a three to five-year cycle. Longer tree-trimming cycles should lead to higher fault rates. The optimal trimming cycle depends on:

- Type of trees, growth rates, and growing conditions
- Community tolerance for trimming
- Economic assumptions, especially the chosen time value of money

The following graphs characterizes one utility's tree-caused outages from 1999 to 2003, including major storms. Each graph shows the effect of the time since the last tree trimming. So, the first datapoint in each graph is the given reliability index of all circuits that had tree maintenance during the previous year. One would expect that tree-caused outages would decrease immediately following tree maintenance, but the data does not show this. There is no strong trend for any of the benchmarks shown in the graphs.

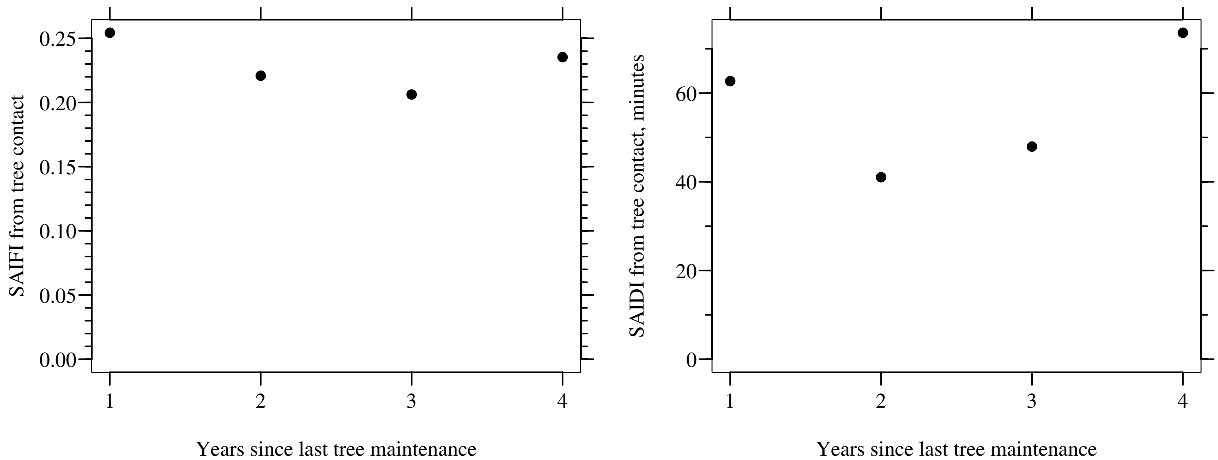


Figure 2-17
Tree Maintenance Effect on SAIFI and SAIDI for a Northeastern Utility

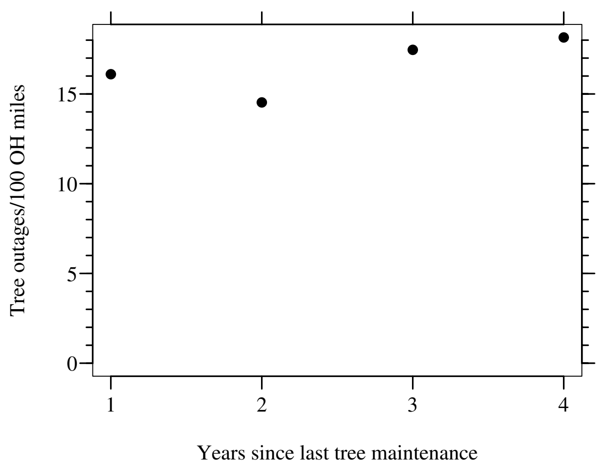


Figure 2-18
Tree Maintenance Effect on Tree Outage Rate Per Mile

This data is not unique. The following data is from another utility that also does not show a trend with regards to time since the last tree maintenance. One difference in these charts is that the numbers are for *all* faults, not just those caused by trees.

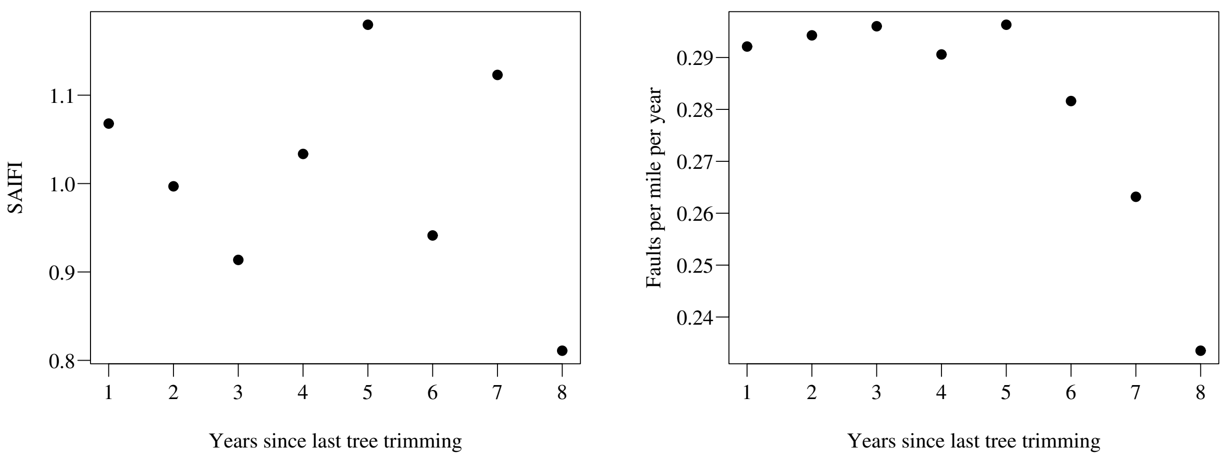


Figure 2-19
Tree Maintenance Effect on Tree Outage Rate Per Mile for a Southeastern Utility

Correlating the effect of tree maintenance and performance can be tricky. Some effects that can interfere with such correlations include:

- *Targeting*—Targeting poorly performing circuits for maintenance can help improve customer power quality, but it makes it difficult to gauge the effects of maintenance programs.
- *Maintenance approach*—Some utilities schedule vegetation maintenance using map sections, not by circuit, so it is impossible to correlate circuits to their performance.
- *Budget and tree maintenance*—Vegetation management budgets vary considerably and so do pruning specifications. Both can impact different years differently.
- *Reconfigurations*—Circuit reconfigurations can make it difficult to reliably judge the history of tree fault impacts.

The main point of this data is that tree-caused outages do not increase dramatically with longer times between tree maintenance when analyzed over reasonable time periods. Quoting Guggenmoos [2003b]: "Only a trim program that is substantially behind cycle results in increased outages. Might say that cycle trimming is not for reliability but public safety and the avoidance of higher costs associated with heavily pruning systems that have grown into conductors."

Effect on faults and interruptions is not the only reason for selecting a maintenance cycle. Several other factors include:

- *Shock hazard* – Trees can (rarely) cause a possibly dangerous shocking hazard. A tree in contact with an energized phase conductor may create a touch potential hazard near the ground. For a tree in contact with one conductor, the resistance of a tree is high enough to remain a high-impedance connection—it will not draw enough current to operate a fuse or other protective device, but it may be enough to create significant step potentials. St. Clair [1999] reported two electrocutions from tree contacts to 12.47-kV lines, one a tree trimmer and another at ground level where a man leaned against a tree that had fallen into conductors. The probability of developing a shock hazard is a function of the tree resistivity, the earth resistivity, and whether the tree is wet (see Daily [1999] and Short [2004]). The most dangerous conditions are when the ground is wet and the tree is wet. Low earth resistivity "grounds" the tree better, so it draws more current from the line. Foot-to-earth contact resistances are also lower with drenched soil, which draws more current through your body. A wet tree—due to rain or humid weather—is more dangerous as the tree's resistance drops appreciably. Cutting trees more aggressively or more frequently helps reduce the shock probability.

- *Fire hazard* – For areas in high fire-danger areas, tree clearance requirements may be more severe, requiring more frequent maintenance. The State of California Rules for Overhead Electric Line Construction specifies at least an 18-inch spacing between conductors and vegetation for all distribution and transmission circuits. In addition, California (Public Resource Code Section 4293) requires the following clearances for circuits in any mountainous land, or in forest-covered land, brush-covered land, or grass-covered land:
  - For any line which is operating at 2,400 or more volts, but less than 72,000 volts, four feet.
  - For any line which is operating at 72,000 or more volts, but less than 110,000 volts, six feet.
  - For any line which is operating at 110,000 or more volts, 10 feet.
  - To meet such spacing requirements normally requires more frequent vegetation maintenance.
- *Cost* – Longer maintenance cycles may actually cost more as the catch-up phase can be more expensive than maintaining a consistent budget. In a survey of three utilities, Environmental Consultants, Inc. (ECI) found that extending tree maintenance cycles beyond the optimum can increase overall costs [Browning and Wiant, 1997; Massey, 1998]. If cycles are increased, costs are higher because (1) it takes more time for crews to prune when trees are in close proximity to conductors, (2) crews must do more hot-spot maintenance in response to trouble calls, and (3) crews have more mass of debris to clear and dispose of. ECI estimated that for each one dollar saved by extending maintenance cycles would require from $1.16 to $1.23 in spending if the cycle was extended one year past its optimum, and if the circuit is four years past the optimum, the "catch-up" cost is 1.47 to 1.69 times the cost originally saved.
- *Storm repair* – Trees cause considerable damage during storms. Duke Power discovered that during the ice storm of 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 1 to 6 years ago [Taylor, 2004b]. Because of this, Duke justified increasing the vegetation management budget based on reducing storm repair costs.
- *Politics* – Regulatory bodies are paying more attention to performance and vegetation management. Tree-maintenance cycle is an easy indicator for regulators to understand. If a utility decreases budgets and/or increases tree maintenance cycles and that coincides with decreased reliability or customer satisfaction, regulators may impose fines or mandate changes. For example, CILCO failed to meet its target tree maintenance cycle of four years (Table 2-4) and was severely reprimanded by the regulator in a Staff Report to the Illinois Commerce Commission on October 17, 2000; their tree-maintenance cycle had slipped to the equivalent of a ten-year cycle.

Table 2-4
Illinois Utility Tree Maintenance Cycle Targets

	Tree-maintenance target in years	
Utility	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

Momentary Interruptions from Trees

A question that is difficult to answer is: how often do trees cause momentary interruptions? There is a common perception that trees cause momentary interruptions, especially during storms. Momentaries could occur in the following ways:

- *Temporary faults*—If trees cause a temporary fault (no permanent damage) from phase to phase or from phase to ground, a circuit breaker or recloser can open and then reclose successfully.
- *Permanent faults*—Permanent faults from trees on fused taps will cause momentary interruptions to the circuit if the utility uses “fuse saving”; the upstream circuit breaker or recloser will try to open before the fuse operates to reduce unnecessary fuse operations.

The second case is predictable. The first case is less predictable, and we are unaware of any tests or monitoring to quantify the number of temporary faults that trees might cause. Two possible scenarios for temporary faults are:

1. *Wind*—Wind could push trees into conductors and cause them to slap together. Once the conductors come apart, the insulation is restored, and the breaker or recloser can reclose successfully.
2. *Rain*—Rain could weigh down tree branches, causing them to sag into a circuit. The wet branches making phase-to-phase contact cause a fault. Then the heat and explosive blast from the fault arc will evaporate and shake water off of the tree branches causing them to rise away from the conductors and restore insulation. As more rain accumulates, the branches can again sag into the conductors.

One thing that cannot cause a temporary fault is a tree touching just one phase conductor. Several utilities and researchers have tested a distribution voltage phase in contact with a tree

(Germany [Hoffmann et al., 1984], Baltimore Gas & Electric [Rees et al., 1994], Florida Power Corp [Williams, 1999], Texas A&M [Butler et al., 1999], Niagara Mohawk Power Corporation [Finch, 2001]). In all cases, there may be burning near the contact point, but the contact draws little current, and it does not fault. So if temporary faults occur regularly from trees, they must be across *wire-to-wire* contacts in close proximity, and not just wire to tree.

To explore this further, outage data from a southeastern utility was used to estimate the relationship between feeder lockouts and momentary interruptions. This utility tracks momentary interruptions. Figure 2-20 plots the number of feeder lockouts in a day against the number of feeder momentary events per day on the utility's system. We're using feeder lockouts as a proxy for tree-caused faults (which were not available in this dataset) under the assumption that days with high numbers of feeder lockouts are during stormy weather, and most lockouts are due to tree faults. Figure 2-20 shows that momentary interruptions generally increase with increasing number of feeder lockouts. But there were days with 5 to 15 lockouts where there were not a lot of momentaries.

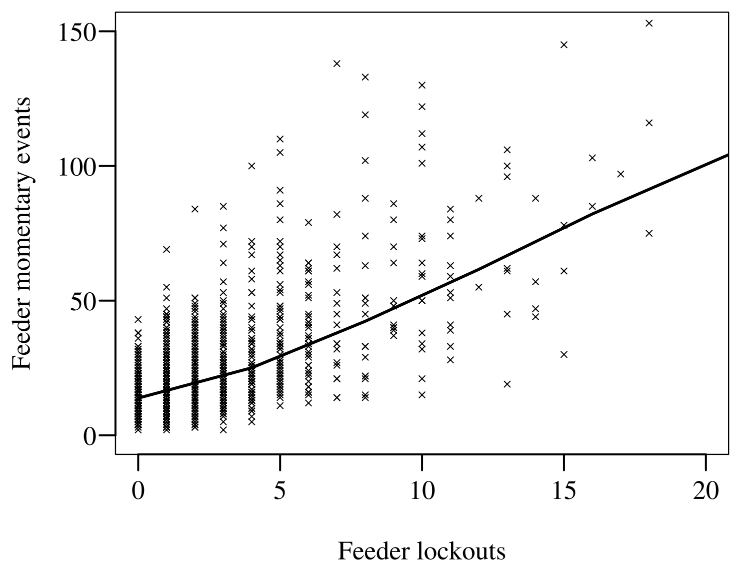


Figure 2-20
Feeder Lockouts Versus Momentary Events

Lightning and animals are thought to cause most temporary faults. During storms, lightning causes many faults, but animals cause few. To analyze this data in more detail, the data in Figure 2-20 was broken down by month in Figure 2-21. Note that the relationship between momentaries and feeder lockouts greatly increases during the summer months during the peak lightning season for this utility. During September through April when there is little lightning, the relationship is weaker (but it's still there). That suggests that if trees regularly cause momentary interruptions, they do so at a rate that's much smaller than lightning-caused faults. This is a rather shaky analysis, so more data or experimental data is recommended before drawing too many conclusions from this analysis.

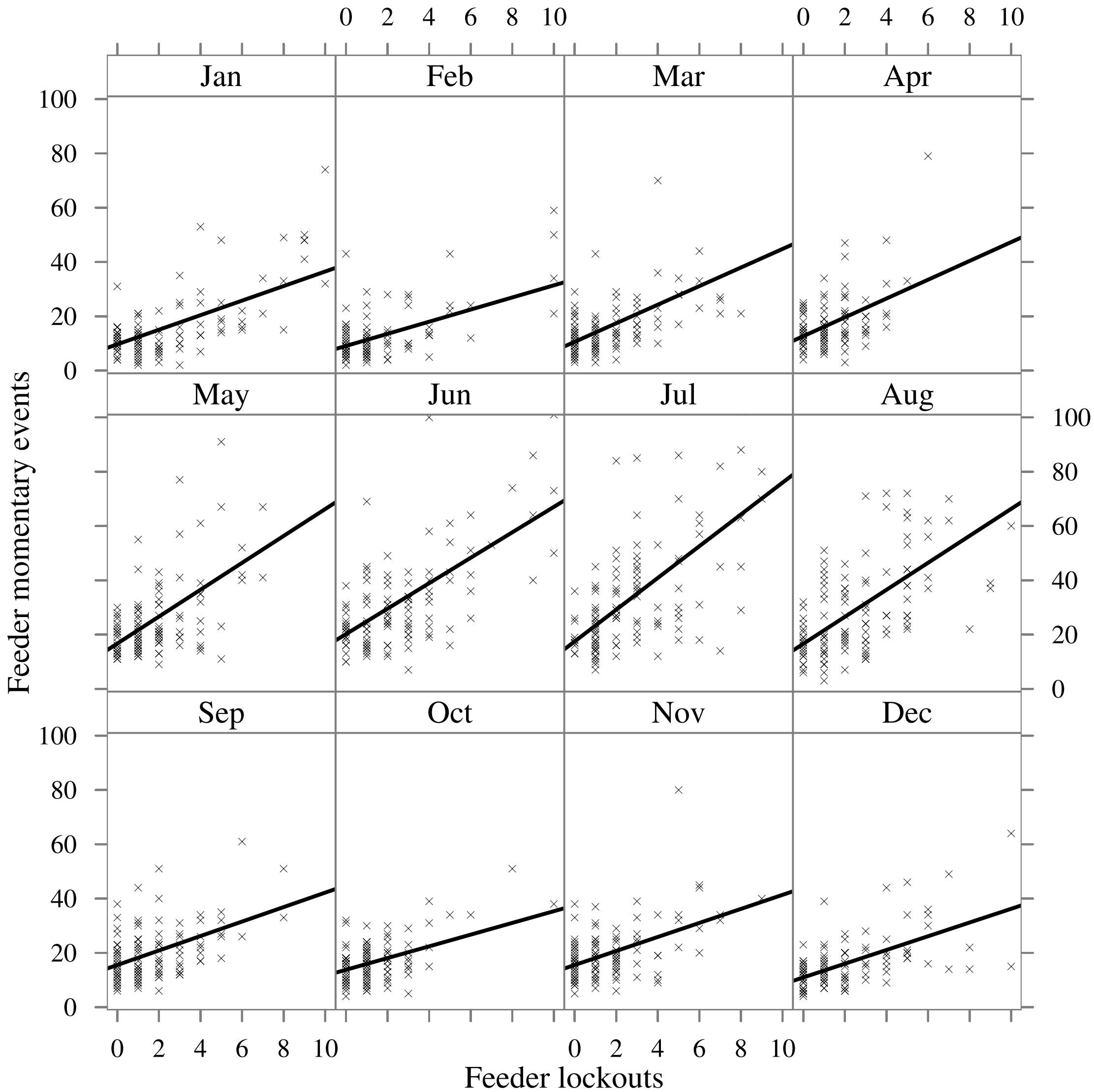


Figure 2-21
Feeder Lockouts Versus Momentary Events by Month

Voltage Sags From Trees

Tree faults cause voltage sags, as do other types of faults. Tree-caused faults are more likely to cause more severe voltage sags than other faults for two reasons:

- *Multiple-phase faults*—Trees often cause multiple-phase faults, and multiple-phase faults cause more severe voltage sags than single-phase faults.
- *Permanent interruptions*—Trees normally cause permanent interruptions. For faults on the mainline, this will cause the circuit breaker or recloser to cycle through its reclose sequence and lock out. The full reclosing sequence causes multiple sag events, and often long-duration sag events (because of the time-delay element of the circuit breaker) to customers on adjacent circuits.

Voltage Flicker From Trees

Can trees cause voltage flicker? Tests by BGE and others have shown that once a limb carbonizes fully, the arc is close to a solid short circuit with no sputtering or significant arc impedance. But before a tree limb fully carbonizes, can limb and branch burning and arcing draw enough current to cause flicker on a circuit? To try and answer this question, we need to examine how much primary current is necessary to cause flicker and what happens to the resistance of tree branches.

Small limbs can arc and burn off before the phase-to-phase or phase-to-ground path is fully bridged. This can happen repeatedly. The current drawn is mainly a function of the resistance of the tree branch bridging the gap. Whether this causes flicker or not depends on the stiffness of the utility system at this point. The widely cited GE flicker curve shown in Figure 2-22 can serve as a baseline for judging how severe voltage deviations need to be before utility customers notice light flicker. Because of the arcing nature of the progressing breakdown across a tree limb, we should assume the worst-case frequency on the flicker curve where voltage changes of 0.3% can be troublesome.

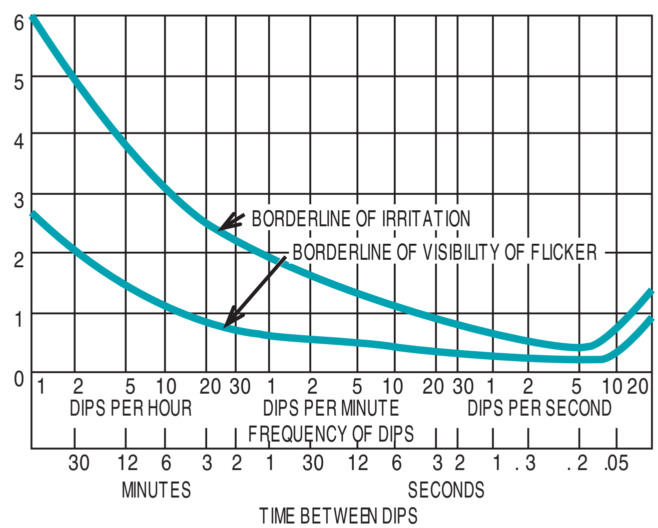


Figure 2-22
GE Voltage Flicker Curve

The voltage drop from current depends on the system impedance and the current as:

$$V_{drop} \approx R \cdot I_R + X \cdot I_X \quad \textbf{Eq. 2-1}$$

where R and X are the source resistance and reactance, and I_R is the resistive component of the load, and I_X is the reactive component of the load.

The impedance of an arc is primarily resistive, but it can be highly nonlinear. The arc nonlinearity will create higher frequencies in the current drawn by the arc. The higher frequency current will raise the resistance of the system impedance (wires and cables have higher resistance to higher frequencies). As a first approximation, let us assume that the effective resistance is three-times the fundamental-frequency resistance. We also assume that the current is all resistive. Based on these assumptions, Table 2-5 shows some ranges of current necessary to cause voltage flicker that could be observable.

Table 2-5
Current Draw Necessary to Cause Observable Light Flicker

Distance of the tree from the substation [miles]	Effective system resistance [ohms]	Current necessary to cause a 0.3% voltage deviation [amperes]	Tree resistance to draw that current [kiloohms]
5	3.2	6.8	1.1
10	6.4	3.4	2.1
20	12.7	1.7	4.2

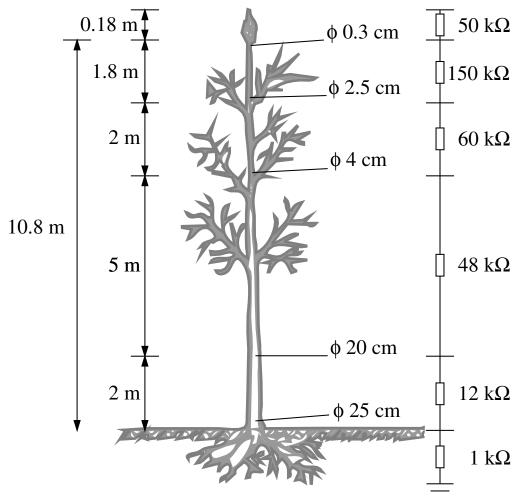
Assuming 7.2 kV line to ground

A tree in contact with just one phase conductor is unlikely to draw enough current to cause flicker. Several groups have tested or measured such contacts:

- *Germany*— Hoffmann et al. [1984] tested a tree in contact to a 20-kV line, which drew 80 mA initially then rose to 600 mA. They also measured a poplar tree and found the distribution of impedances shown in Figure 2-23 with impedances of 1.8 kΩ/foot (6 kΩ/m) near the base of the tree rising to 25 kΩ/foot (80 kΩ/m) near the top of the tree. The total impedance of this tree is 320 kΩ, which would draw from 0.2 to 0.7 A from a 12.47-kV line. Hoffman also found resistances from the base of the tree to ground of about 300 Ω for soil resistivities near 600 Ω-m.
- *Baltimore Gas and Electric*—Rees et al. [1994] reported on a sequence of tests on an abandoned distribution tap. Seven tests were performed with different tree species held in contact with a 7.6-kV_{L-G} circuit. Although measurements were difficult because of low readings, BGE calculated amperages from 6 to 41 mA. Two of the tests were done under “a constant spray of water that thoroughly saturated the trees and overhead equipment.” There was no significant difference when the same species of tree was tested with and without the water spray.
- *Niagara Mohawk*—Tested several trees at 7.62 kV from line to ground—the highest was just under 0.5 A (see Table 2-6).

- *Texas A&M*—These were the only tests to produce enough current to possibly cause voltage flicker. Butler et al. [1999] tested two different sized branches in contact with a 7.2-$kV_{L\text{-}G}$ distribution circuit. In a test of two trees in contact with branches from pencil thickness to about two inches in diameter, burning and arcing was noted during the tests. The current started and 1.2 A and then climbed to 2.2 A, but it did not fluctuate significantly. In another case with contact to a five-inch diameter branch, the current reached almost 2.5 A but again did not fluctuate.

Larger tree limbs have lower resistances, so the worst scenario is a primary conductor solidly contacting a large branch or the main trunk with a low soil resistivity. Even with that, drawing currents high enough to cause flicker is unlikely. The only test that showed current approaching that needed to cause flicker did not fluctuate significantly.



Source: [Hoffmann et al., 1984]

Figure 2-23
Resistance Measurements on a Live Poplar Tree

Table 2-6
Current Drawn by Several Trees in Contact With 7.62 kV From Line to Ground

Location	Specimen	Maximum current, mA
Test 1	Black Gum	92
Test 2	Black Gum	69
Test 3	Black Cherry	110
Test 4	Black Cherry	100
Test 5	White Ash	37
Test 6	Aspen	484
Test 7	Red Maple	125.5

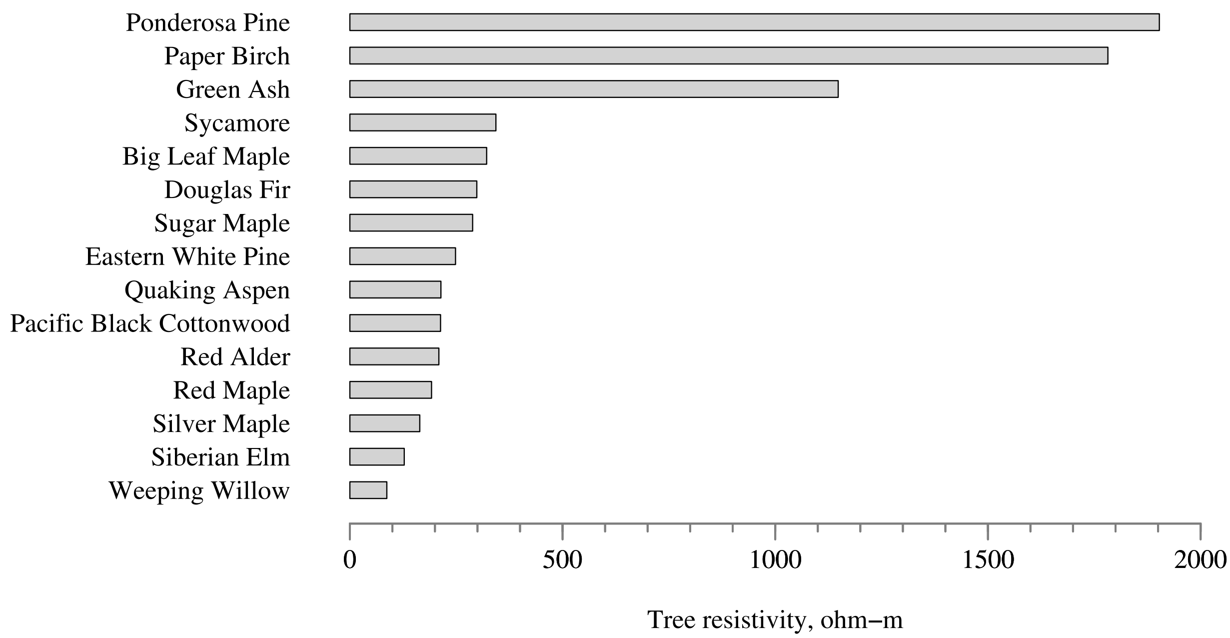
Source: [Finch, 2001]

If tree contacts from phase to ground cannot cause flicker, what about contacts from phase to phase or phase to neutral? The voltage gradient is much higher, so such contacts should pull more current. The current is a function of the tree branch resistances.

A number of groups have measured tree resistivities:

- Defandorf [1956] measured tree resistivities of a green tulip tree and found resistivities from 50 to 120 Ω-m. He reported that the effective resistivity increased for larger diameter branches and trunks.
- Hoffmann et al. [1984] reported resistivities of live poplar as having resistivity of 40 to 100 Ω-m.
- Daily [1999] measured resistivities of American elms and found values from 37 to 55 Ω-m.

Resistivities can vary significantly by species as shown in Figure 2-24. A one-inch diameter branch with a 50 Ω-m resistivity has a resistance of 30 kΩ/foot (see Table 2-7). To cause flicker, the impedances need to be less than 5000 ohms (per Table 2-5). It appears that branches less than one inch in diameter cannot cause flicker. To get to 5000 ohms across a three-foot gap with one-inch diameter branches, it would take 20 branches in parallel. Although 20 branches in parallel is easily possible on a heavily treed circuit, it is the sputtering of an individual branch that would lead to flicker. If each of 20 branches fluctuated in impedance, the randomness would cancel the flickering effect: all 20 paths would have to fluctuate together.



Source: [Appelt and Goodfellow, 2004]

Figure 2-24
Tree Resistivities

Table 2-7
Tree Branch Resistance

Diameter [inches]	Resistance [ohms/foot]
0.5	120,000
1.0	30,000
5.0	1,200

On higher voltage distribution circuits and on subtransmission circuits, the voltage gradient is higher across tree limbs. This will pull more current through tree limbs, and they will progress to a full-fledged fault faster. Limbs are less likely to burn clear before they fully fault. Also, because the source impedances are stiffer on higher-voltage circuits, it takes more current to cause flicker.

Based on this analysis, voltage flicker from trees is unlikely. During a severe storm, customers may interpret the voltage sags from tree-caused faults as “flicker,” but flicker from trees contacting phase conductors or from branch burning is unlikely.

3
COVERED CONDUCTORS AND OTHER CONSTRUCTION APPROACHES TO REDUCE TREE FAULTS

This chapter considers various construction options to make circuits more resistant to tree-caused faults. This chapter will focus mainly on covered conductors and spacer cable, two insulated systems that are widely used to make overhead construction less susceptible to faults from trees.

Underground Circuits

An obvious approach to controlling tree-caused faults is to place T&D circuits underground. Underground circuits are almost immune to tree-caused faults (not completely though: uprooted trees can still disrupt underground facilities). Utilities save on maintenance costs as underground circuits do not need regular tree pruning. Also, storm restoration and repair costs are less, since most storm-related damage is from trees.

Underground versus overhead construction has many tradeoffs in cost, power quality, safety, workability, and maintenance. Exposure to trees is just one of many variables that utilities should consider for the most appropriate type of circuit for a given location.

Circuit Location

To avoid tree falling faults, placing the line in locations not near trees or cutting down the large trees within falling distance of the line is possible – but not very practical in many locations. Furthermore, it is noteworthy that in higher lightning locations placing lines out in the open could actually worsen the fault rate since the line is now exposed to more direct lightning strikes.

Covered Conductors, Spacer Cable, and Aerial Cable

Utilities with heavy tree cover often use covered conductors, conductors with a thin insulation covering (Figure 3-1 shows an example). The covering is not rated for full conductor line-to-ground voltage, but it is thick enough to reduce the chance of flashover when a tree branch falls between conductors. Covered conductor is also called tree wire or weatherproof wire. Tree wire also helps with animal faults and allows utilities to use armless or candlestick designs or other tight configurations. Tree wire is available with a variety of covering types. The insulation materials polyethylene, XLPE, and EPR are common. Insulation thicknesses typically range from 30 to 150 mils (1 mil = 0.001 in = 0.00254 cm); see Table 3-1 for typical thicknesses. From a design and operating viewpoint, covered conductors must be treated as bare conductors according to the National Electrical Safety Code (NESC) [IEEE C2-2000], with the only difference that tighter conductor spacings are allowed. There are various grades of insulation used for the covering.

Table 3-1
Typical Covering Thicknesses of Covered All-Aluminum Conductor

			Diameter, inches	
Size AWG or kcmil	Strands	Cover Thickness in mils	Bare	Covered
6	7	30	0.178	0.238
4	7	30	0.225	0.285
2	7	45	0.283	0.373
1	7	45	0.318	0.408
1/0	7	60	0.357	0.477
2/0	7	60	0.401	0.521
3/0	7	60	0.451	0.571
4/0	7	60	0.506	0.626
4/0	19	60	0.512	0.632
266.8	19	60	0.575	0.695
336.4	19	60	0.646	0.766
336.4	19	80	0.646	0.806
397.5	19	80	0.702	0.862
477	37	80	0.771	0.931
556.5	37	80	0.833	0.993
636	61	95	0.891	1.081
795	61	95	0.997	1.187

Spacer cable and aerial cables are also alternatives that perform well in treed areas (Figure 3-2). Spacer cables are a bundled configuration using a messenger wire holding up three phase wires that use covered wire. Aerial cables have fully-rated insulation just like underground cables.

Courtesy of Duke Power

Figure 3-1
Example of a Compact Armless Design Using Covered Conductors

Figure 3-2
Example of a Spacer Cable Run Through Trees

Other advantages of covered conductors include:

- *Spacings*—The NESC [IEEE C2-2002] allows tighter conductor spacings on structures with covered conductors. Tighter spacings have aesthetic advantages. Also, more conductors can be placed in proximity, making it easier to build multiple-circuit lines, including underbuilt distribution. Spacer cables and aerial cables allow even more flexibility in squeezing more circuits on a pole structure.
- *Animal-caused faults*—Covered conductors add another line of defense against squirrels and other animals. Covering jumpers and other conductors that are near grounded equipment is the application that is most effective at reducing animal-caused faults.
- *Fire reduction*—Covered conductors reduce the chances of fires starting from arcing between conductors and trees and other debris on the power line. Wildfire prevention is the main justification for using covered conductors in Australia [Barber, 1999].

Safety is sometimes cited as a reason for using tree wire, but covered conductor systems do not necessarily offer safety advantages, and in some ways the covering is a disadvantage. Even though Landinger et al. [1997] found small leakage currents through covered wires, they correctly point out that it doesn't cover all scenarios: covered conductors *may* reduce the chance of death from contact in some cases, but they are in no way a reliable barrier for protection to line workers or the public. Covered conductor circuits are more likely than bare-wire circuits to lead to downed-wire scenarios with a live distribution conductor on the ground. And if a covered wire does contact the ground, it is less likely to show visible signs that it is energized such as arcing or jumping which would help keep bystanders away.

Additionally, with the use of covered conductors and spacer cables for preventing tree faults, preventing a fault is not always a good thing! If the weight of a tree deeply sags a covered conductor down to within reach of pedestrians, but because of its covering a fault does not occur, then the covered conductor may remain energized posing a public safety issue. On the other hand, with bare conductors if it is pulled down to this degree then a fault is more likely and an upstream protective device is likely to interrupt the circuit and de-energize the conductor posing less hazard to the public. The covering may also make a high-impedance fault less likely to transition to a low-impedance fault. If a downed phase conductor comes in contact (either intermittent or sustained) with a metallic object, the covering may prevent flashover for some time.

Covered conductor systems have additional tradeoffs to be aware of. They are more susceptible to damage from fault arcs, they may cause radio frequency interference if the correct insulator tie is not used, and conductor corrosion is more likely. These topics will be discussed in more detail in a subsequent section.

Industry Performance Data

Good fault data is hard to find comparing fault rates of bare wire with covered wire. European experience with covered conductors suggests that covered-wire fault rates are about 75% less than bare-wire fault rates. In Finland, fault rates on bare lines are about 3 per 100 km/year on bare and 1 per 100 km/year on covered wire [Hart, 1994].

Table 3-2 shows data for Connecticut Light and Power comparing the performance of bare-wire construction to other constructions (this is also likely to be the source of the data cited by Hendrix [1998]). The bare-wire construction had much higher interruption rates than did the covered conductor, both tree-caused interruptions and other interruptions. Note that this data likely overstates the performance difference between bare and covered conductors. At CL&P, tree wire is used on new construction; the bare wire population is significantly older than the covered wire population. Most is 40+ year-old copper. Many of the additional failures on the bare wire system may have been age-related rather than being a function of the covering. CL&P documented several deficiencies on the older structures, including: excessive sag, rotted crossarms, and multiple splices. Also, most of their bare wire is on laterals rather than mainlines. This may influence the interruption rate comparisons, because fused laterals may have more interruptions from lightning and other temporary faults that could blow the tap fuse whereas a recloser or circuit breaker may successfully clear the same fault on the mainline.

Table 3-2
Interruption Rates for Various Constructions for CL&P

	Outages Per 100 Miles Per Year				
	Bare Wire	Tree Wire	Spacer Cable	Aerial Cable	Underground
Trees	24.9	3.6	1.1	6.0	0.3
Animals/Birds	20.9	3.0	2.4	2.4	0.9
Lightning	5.2	1.0	1.6	3.7	1.2
Equipment failure	5.7	0.7	1.8	10.6	13.1
Unknown	1.2	0.8	0.8	2.4	0.9
Others	19.8	2.6	2.7	8.2	5.5
TOTALS	77.7	11.6	10.5	33.3	21.8

Source: Connecticut Light and Power Company (CL&P) Transmission and Distribution Reliability Performance (TDRP) reports, submitted to the Connecticut Department of Public Utility Control Department, 2000 – 2004.

In South America, both covered wire and a form of aerial cable have been successfully used in treed areas [Bernis and de Minas Gerais, 2001]. The Brazilian company CEMIG found that spacer cable faults were lower than bare-wire circuits by a 10 to 1 ratio (although the article didn't specify if this included both temporary and permanent faults). The aerial cable faults were lower than bare wire by a 20 to 1 ratio. The effect on interruption durations is shown in Table 3-3. Several spacer cables or aerial cables can be constructed on a pole. Spacer cables and aerial cables have some of the same burndown considerations as covered wire. Spacer cable construction does have a reputation for being hard to work with. Both spacer cable and aerial cable costs more than bare wire. CEMIG estimated that the initial investment was returned by the reduction in tree trimming. They did minimal trimming around aerial cable (an estimated factor of 12 reduction in maintenance costs) and only minor trimming around spacer cable (an estimated factor of 6 reduction in maintenance costs).

Table 3-3
Comparison of the Reliability Index SAIDI

Construction	SAIDI, hours
Bare wire	9.9
Spacer cable	4.7
Aerial cable	3.0

SAIDI = average hours of interruption per customer per year
Source: [Bernis and de Minas Gerais, 2001]

The utility data from Chapter 2 on types of tree faults can give us some idea of the maximum benefit from covered conductors. Depending on the utility, from a low of about 23% (Baltimore Gas and Electric) to a high of over 70% (Duke Power and BC Hydro) of tree faults were due to mechanical damage from large branches or entire trees falling on circuits. If we assume that the conductor covering will not affect mechanical damage from faults, then the best that a covered conductor will do is to reduce tree-caused faults by 30% (for utilities with a high percentage of mechanical damage) to 75% (for utilities with mainly growth or small limb contacts). This assumes application of covered conductors at the same spacings as bare conductors. If tighter spacings are used for covered conductors (often done), then the reduction in tree-caused faults may not be as great, but this is speculative as there is no industry data or testing to allow us to estimate the differences.

A conductor covering may slightly increase the likelihood of mechanical damage—the covering increases the wire's weight and mechanical load on the conductor, so it takes less force from a branch or tree to cause mechanical damage. Using the same reasoning, the extra ice loading on a covered conductor (due to increased surface area) could also increase the likelihood of damage from trees during ice storms.

On the other hand, spacer cable systems can be more immune to mechanical damage from tree limbs. The combination of the high-strength messenger cable along with the tightly-bundled phase conductors is much stronger than a single conductor. With spacer cable, the force (weight) of the tree on the wires is more likely to be distributed amongst several wires (the neutral messenger and the three phases) than with crossarm, armless, or candlestick feeder designs. Furthermore, the numerous spacer insulator brackets may have more strength where they attach to the pole than standard pole top pin insulators.

Covered Wire Issues

Arc Damage and Burndowns

Fault-current arcs can damage overhead conductors, especially covered conductors. The arc itself generates tremendous heat, and where an arc attaches to a conductor, it can weaken or burn conductor strands. On distribution circuits, two problem areas stand out:

1. *Covered conductor*—Covered conductor (also called tree wire or weatherproof wire) holds an arc stationary. Because the arc cannot move, burndowns happen faster than with bare conductors.
2. *Small bare wire on the mains*—Small bare wire (less than 2/0) is also susceptible to wire burndowns, especially if laterals are not fused.

Several utilities have had burndowns of covered conductor circuits when the instantaneous trip was not used or was improperly applied [Barker and Short, 1996; Short and Ammon, 1997]. If a burndown on the main line occurs, all customers on the circuit will have a long interruption. In addition, it is a safety hazard. After the conductor breaks and falls to the ground, the substation breaker may reclose. After the reclosure, the conductor on the ground will probably not draw enough fault current to trip the station breaker again. This is a high-impedance fault that is difficult to detect.

Covered conductor is susceptible to burndowns because when a fault current arc develops, the covering prevents the arc from moving. The heat from the arc is what causes the damage. Although ionized air is a fairly good conductor, it is not as good as the conductor itself, so the arc gets very hot. On bare conductors, the arc is free to move, and the magnetic forces from the fault cause the arc to move (in the direction away from the substation—this is called *motoring*). The covering constricts the arc to one location, so the heating and melting is concentrated on one part of the conductor. If the covering is stripped at the insulators and a fault arcs across an insulator, the arc motors until it reaches the covering, stops, and burns the conductor apart at the junction (see Figure 3-3 for an example of such damage). A party balloon, lightning, a tree branch, a squirrel—any of these can initiate the arc that burns the conductor down.

Courtesy of Duke Power

Figure 3-3
Conductor Damage From Arcing Where the Conductor Cover Begins

Burndowns are most associated with lightning-caused faults, but it's the fault current arc, not the lightning, that burns most of the conductor. Lightning triggers the arc; see Figure 3-4 for an example where a conductor was damaged by a puncture as the conductor flashed to the insulator tie. Lee et al. [1980] reported on a survey of 390 fallen covered conductor cases by the

Pennsylvania Power and Light Company (PP&L). They found that over half of these cases were caused by lightning with trees as the second leading cause. Lightning and trees together accounted for 75% of burndown causes, and no other single cause exceeded 5%.

Courtesy of Duke Power

Figure 3-4
Conductor Damage From Arcing

The conductor damage is a function of the duration of the fault and the current magnitude. Burndown damage from a fault arc occurs much more quickly than conductor annealing.

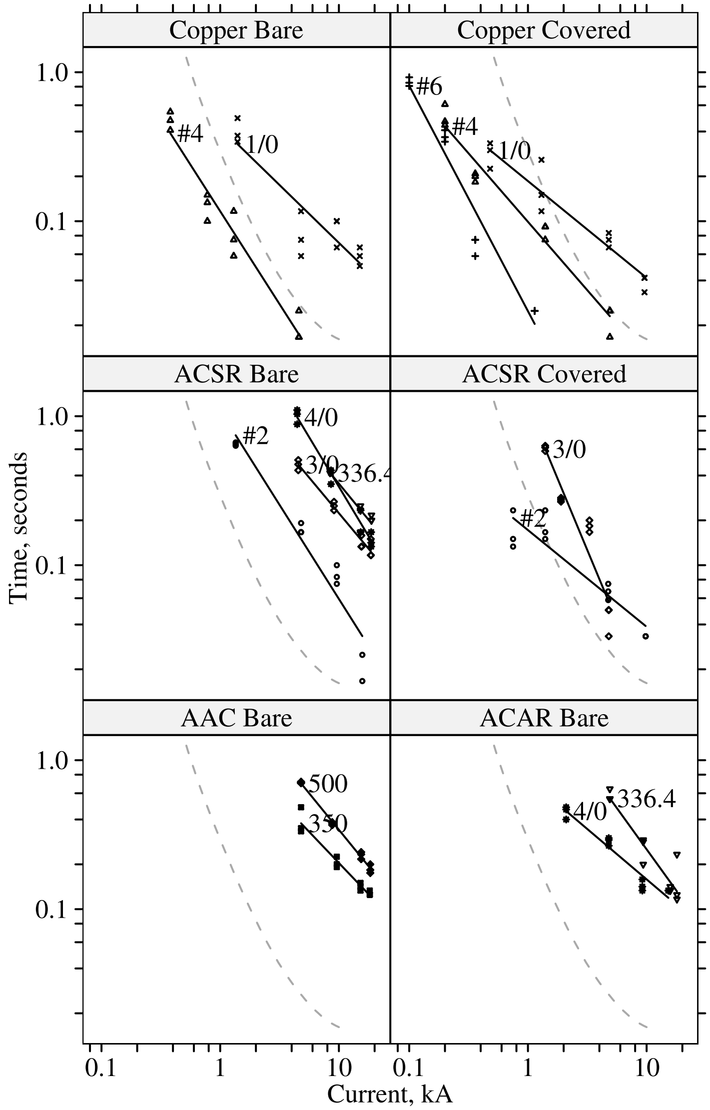
What we would like to do is plot the arc damage characteristic as a function of time and current along with the time-current characteristics of the protective device (whether it be a fuse or a recloser or a breaker). Doing this, we can check that the protective device will clear the fault before the conductor is damaged.

Unfortunately, such arc damage data for different conductor sizes as a function of time and current is limited. Table 3-4 summarizes burndown characteristics of some bare and covered conductors based on tests by Baltimore Gas & Electric [Goode and Gaertner, 1965]. Figure 3-5 shows this same data on time-current plots along with a 100 K fuse total clearing characteristic. For conductor sizes not given, take the closest size given in Table 3-4, and scale the burndown time by the ratio of the given conductor area to the area of the desired conductor.

Table 3-4
Burndown Characteristics of Various Conductors

		Duration, 60-Hz cycles			
	Current, A	Min	Max	Other	Curvefit
#6 Cu covered	100	48.5	55.5	51	t=858/$I^{1.51}$
	200	20.5	24.5	22	
	360	3.5	4.5	4.5	
	1140	1.5	1.5	1.5	
#4 Cu covered	200	26.5	36.5	28	t=56.4/$I^{0.92}$
	360	11	12.5	12	
	1400	4.5	5.5	5.5	
	4900	1	1.5	1.5	
#4 Cu bare	380	24.5	32.5	28.5	t=641/$I^{1.25}$
	780	6	9	8	
	1300	3.5	7	4.5	
	4600	1	1.5	1	
#2 ACSR covered	750	8	9	14	t=15.3/$I^{0.65}$
	1400	10	9	14	
	4750	3.5	4.5	4	
	9800	2	2	NA	
#2 ACSR bare	1350	38	39	40	t=6718/$I^{1.26}$
	4800	10	11.5	10	
	9600	4.5	5	6	
	15750	1	1.5	NA	
1/0 Cu covered	480	13.5	20	18	t=16.6/$I^{0.65}$
	1300	7	15.5	9	
	4800	4	5	4.5	
	9600	2	2.5	2.5	
1/0 Cu bare	1400	20.5	29.5	22.5	t=91/$I^{0.78}$
	4800	3.5	7	4.5	
	9600	4	6	6	
	15000	3	4	3.5	
3/0 ACSR covered	1400	35	38	37	t=642600/$I^{1.92}$
	1900	16	17	16.5	
	3300	10	12	11	
	4800	2	3	3	

Data source: [Goode and Gaertner, 1965].



The dashed line is the total clearing time for a 100 K fuse.
Data source: [Goode and Gaertner, 1965]

Figure 3-5
Burndown Characteristics of Various Conductors

Controlling Arc Damage

The main ways to control arc damage on covered conductors and spacer cable is to limit the duration and magnitude of fault current. Options to manage fault currents include:

- *Transformer impedance*—Specifying a higher-impedance substation transformer limits the fault current. Normal transformer impedances are around 8%, but utilities can specify impedances as high as 20% to reduce fault currents.
- *Split substation bus*—Most distribution substations have an open tie between substation buses, mainly to reduce fault currents (by a factor of two).

- *Neutral reactor*—A reactor in the substation transformer neutral limits ground fault currents. Even though the neutral reactor provides no help for phase-to-phase or three-phase faults, it provides much of the benefits of other methods of fault reduction. Neutral reactors cost much less than line reactors (another option). Ground faults are the most common fault; and for many types of single-phase equipment, the phase-to-ground fault is the only possible failure mode. On the downside, a neutral reactor has a cost and uses substation space, and a neutral reactor reduces the effectiveness of the grounding system.
- *Fault-current limiters*—Several advanced fault-current limiting devices have been designed [EPRI EL-6903, 1990]. Most use some sort of nonlinear elements—arresters, saturating reactors, superconducting elements, or power electronics such as a gate-turn-off thyristor—to limit the fault current either through the physics of the device or through computer control. Since most distribution systems have managed fault currents sufficiently well, these devices have not found a market.

Overcurrent protective device selection, placements, and settings can impact the likelihood of damage on covered conductors and spacer cables. Consider the following options to more effectively use overcurrent devices to minimize arc damage:

- *Fuse saving*—Using a fuse blowing scheme can increase burndowns because the fault duration is much longer on the time-delay relay elements than on the instantaneous element. With fuse saving, the instantaneous relay element trips the circuit faster and reduces conductor damage. For more information on fuse saving versus fuse blowing schemes, see EPRI 1001665 [2003].
- *Fuse ALL taps*—Leaving smaller covered conductors unprotected is a sure way of burning down conductors.
- *Tighter fusing*—Not all fuses protect some of the conductor sizes used on taps. Faster fuses reduce the chance of burndowns.

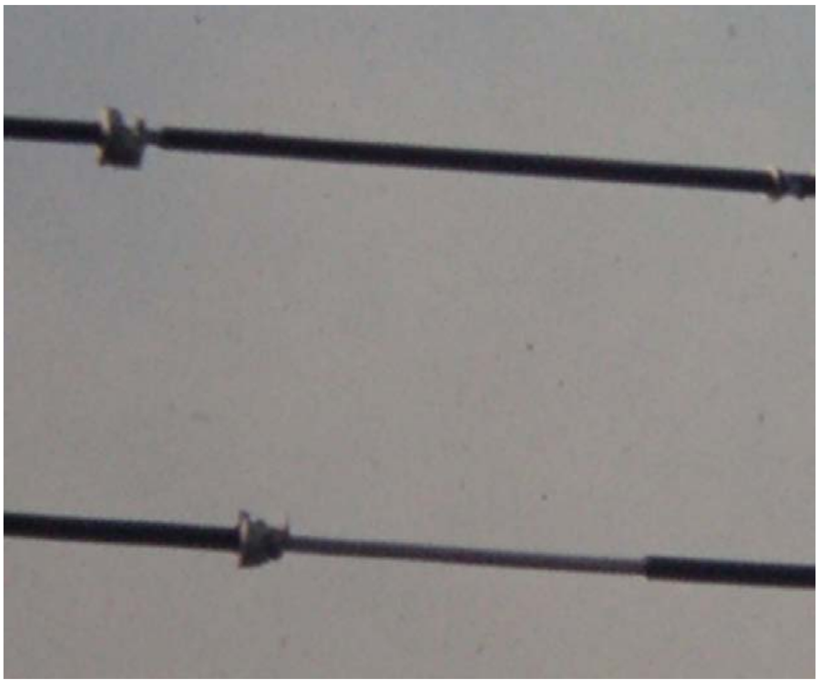
Finally, consider using bigger and/or stronger conductors to better withstand arcing. Bigger conductors take longer to burn down. Doubling the conductor cross-sectional area approximately doubles the time it takes to burn the conductor down. Using a stronger conductor such as ACSR may also help reduce the chance of downed conductors in that the steel messenger may still hold up the conductor even if a good portion of the aluminum is burned away.

Arc Protective Devices

Arc protective devices (APD's) are sacrificial masses of metal attached to the ends of where the covering is stripped (see Figure 3-6 for an example). The arc end attaches to the mass of metal, which has a large enough volume to withstand much more arcing than the conductor itself. Figure 3-7 shows an example of an APD that has absorbed the energy from a fault-current arc; based on the loss of mass, this device could absorb several more such fault arcs before the conductor was endangered. Lee et al. [1980] reported work by PP&L to study burndowns and test arc protective devices as a solution. Based on this work, their standard practice is to strip the covering at each insulator and install APD's [Lee et al., 1981].

APD's only need to be installed on the load-side of the covering. The motoring action of the arc will push the arc away from the source, and it will attach to the bare conductor where the covering starts on the load side. Utilities can also specify installation of APD's on both sides of the stripped section. This is appropriate on circuits that can be operated as a loop, and it also eliminates the possibility of crew mistakes on which side is the load side.

Due to low material cost, APD's are inexpensive when installed with the line, but they can be expensive to retrofit because of manpower issues. If a line crew is already set up on a structure, that is another cost-effective time to add APD's.



Courtesy of Duke Power

Figure 3-6
Arc Protective Devices

Courtesy of Duke Power

Figure 3-7
An Arc Protective Device That Has "Operated"

Lightning Protection and Covered Conductors

A number of publications have advocated auxiliary lightning protection as a means of reducing the chance of covered conductor damage [Tapio, 2003]. Even though most covered-conductor burndown scenarios may be initiated by lightning, it is difficult to stop a flashover from direct strikes. The most common approaches are with:

- *Surge arresters*—Surge arresters can be used to protect overhead T&D circuits from flashover. For significant improvement from direct strikes, the arresters must be used at tight spacings, either at every pole or every other pole. Arresters at wider spacings may not limit direct-strike flashovers, but they will help reduce induced-voltage flashovers for lines with low insulation levels.
- *Current-limiting arcing horns*—Developed in Japan, these are small-block metal-oxide arresters with an air gap made of an arcing horn [Washino et al., 1988]. The arcing horns are mainly for protection against induced voltages on lines with low insulation levels that are common in Europe and Japan (less than 100-kV critical flashover voltage). The arcing horn flashes over, and the metal-oxide element stops the power follow current. Since the metal-oxide blocks are so small, they cannot withstand direct strikes. They have not found use in North America.

Consider the tradeoffs carefully before considering additional lightning protection as a means of reducing covered conductor damage. First, if the lightning protection is done correctly, it may not offer much additional protection. Also, additional lightning protection is a significant expense and also introduces additional failure modes at each arrester location (from animals across the arrester bushing or from failure of the arrester itself). For more information on lightning protection, see IEEE Std. 1410-1997 and EPRI 1002188 [2004].

Wire Tie and Insulator Compatibility

Pole structures with covered conductors can generate radio-frequency interference (RFI) if the insulator wire tie is not compatible with the covering. Power-line noise can be generated by conducting insulator ties separated by insulation from the line conductor. These scenarios include the following combinations:

- Bare conductor tie on a covered line conductor that's not stripped at the insulator
- Insulated conductor tie on a bare or covered line conductor (see Figure 3-8)

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 arc 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.

A conducting insulator tie in close proximity to the phase conductors creates a prime arcing scenario. A voltage can develop between the conducting insulator tie and the line conductor. The capacitance between the two is on the order of 30 to 50 pF, which is enough to charge the conducting tie relative to the line conductor [Vincent and Munsch, 2002]. The line covering may hold this voltage, but the covering may deteriorate or lightning may puncture it. Once the insulation has been bridged, repetitive arcing can occur across the air gap as the tie wire charges and then discharges into the line conductor. Arcing will further deteriorate the conductor insulation, possibly causing more arcing. Vincent and Munsch [2002] also document a second cause of RFI from incompatible insulator ties: if the insulation deteriorates enough so that the conducting insulating tie touches the line conductor, then an insulating oxide layer can build between the two, leading to microsparking noise from breakdowns across this small gap.

For more detail on power-line RFI including finding sources and solutions, see Loftness [1996], NRECA 90-30 [1992], and the US Navy/ARRL Power-Line Noise Mitigation Handbook [Vincent and Munsch, 2002].

Source: Vincent and Munsch [2002]

Figure 3-8
Example of a Covered Wire Tie on a Covered Conductor

The main problem with these partial discharges is that they cause radio interference. There has been speculation that these discharges could damage the conductor, but in tests by the Pennsylvania Power and Light Company (PP&L), Lee et al. [1980] reported that in tests of different wire tie and insulator combinations, no evidence of conductor damage was found.

To reduce radio interference with covered-conductor systems, use insulator ties that are compatible with the insulator:

- Either strip the conductor at each insulator and use bare metallic insulator ties; or
- Leave the conductor covering on, and use nonconducting insulator ties.

For covered-conductors with conducting insulator ties, a retrofit is possible by stripping the insulation on one side and bonding the insulator tie to the conductor.

Some utilities argue that lines have better lightning protection if the covering is left on the conductor. While the improvement is marginal, there is some difference between different covering and insulator tie combinations. Tests at Clarkson University [Baker, 1984] of 15-kV class pin insulators in the 1980's found that keeping the cover on raises the critical flashover voltage from about 115 kV with bare wire to about 145 kV with the cover on using a preformed plastic tie (with a semiconductive tie or a polyethylene covered aluminum tie, the values were slightly less than this). For a direct strike, these differences should not matter, but for a weakly insulated line (with little wood or fiberglass), the extra insulation could help reduce induced-voltage flashovers, but for most North American designs, the difference in overall insulation is small. Direct strikes will still cause flashovers and possible damage; the most likely flashover point is where the insulation is weakest: at the insulator where the tie comes in contact with the covering (Figure 3-9). The covering will not add significant insulation to a structure with an insulator and a foot or more of wood or fiberglass.

Courtesy of Duke Power

Figure 3-9
Example of Damage on a Covered Conductor From Flashover at the Insulator Tie

Other Covered-Conductor Issues

Covered conductors are heavier, have a larger diameter, and have a lower strength rating. Relative to the same size bare conductor, a 477-kcmil all-aluminum conductor with an 80-mil XLPE conductor covering weighs 20% more, has a 17% larger outside diameter, and has a 10% lower strength rating.

The ice and wind loading of a covered conductor is also higher than a comparable bare conductor. Both increase with increasing diameter. In the example comparing a 477-kcmil all-aluminum conductor with an 80-mil XLPE covering, the loadings for the covered conductor versus a bare conductor increase as follows:

- *Vertical*—Loading due to ice and conductor weight increases 14%.
- *Horizontal*—Loading due to wind increases 8%.
- *Resultant*—Loading due the vertical and horizontal component increases 11%.

Another issue with covered conductors is the integrity of the covering. The covering may be susceptible to degradation due to ultraviolet radiation, tracking and erosion, and abrasion from rubbing against trees or other objects. Early covering materials, including the widely used PVC, were especially susceptible to degradation from ultraviolet light, from tracking, and from abrasion. Modern EPR or XLPE coverings are much less susceptible to degradation and should be much more reliable.

Covered conductors are more susceptible to corrosion, primarily from water. If water penetrates the covering, it settles at the low points and causes corrosion (the water can't evaporate). On bare conductors, corrosion is rare—rain washes bare conductors periodically, and evaporation takes take of moisture. Australian experience has found that complete corrosion can occur with covered wires in 15 to 20 years of operation [Barber, 1999]. Water enters the conductor at pinholes caused by lightning strikes, cover damage caused by abrasion or erosion, and at holes pierced by connectors. Temperature changes then cause water to be pumped into the conductor. Because of corrosion concerns, water-blocked conductors are better.

Covered conductors have ampacities that are close to bare-conductor ampacities for the same operating temperature. Covered conductors are darker, so they absorb more heat from the sun but radiate heat better. The most significant difference is that covered conductors have less ability to withstand higher temperatures—the insulation degrades. Polyethylene is especially prone to damage, so it should not be operated above 75°C. EPR and XLPE may be operated up to 90°C. A bare conductor may have a rating of as high as 100°C.

Mechanical Coordination of Construction

Trees causing mechanical damage make up a large portion of tree-caused faults, and these are the faults that require the most time and expense to repair. One approach to reducing these faults is to target and remove hazard trees—those most likely to fall on T&D infrastructure; this is considered in the next chapter. Another approach to reducing the impact of the damage is to coordinate the mechanical design such that when tree and large limb failures occur, equipment fails in a manner that is easier for crews to repair. When a tree falls on a line, crews will have an easier repair if it just breaks the conductors rather than breaking poles and other supports. The fault still occurs, but crews are able to more quickly repair the damage and restore service. Figure 3-10 shows an example of a hard-to-repair failure; if the conductors or insulator ties had broken first, the poles may have been left standing, and crews would have been able to repair it more quickly.

Figure 3-10
A Pole Broken in Half by a Tree Falling Onto the Line Structure During a Windstorm

Spacer cable systems are an example that can cause a mechanical “miscoordination.” Spacer cable systems are quite strong, so they withstand some tree branch contact that an open-wire system would not. But, the spacer cable is strong enough that the conductors are less likely to be the weakest link. When a heavy tree does fall on the line, the spacer cable can break several poles, leading to a much longer repair time.

BC Hydro [Kaempffer and Wong, 1996] has developed an approach to overhead structure design that considers the order of failure of equipment. Yu et al. [1995] developed methodologies for calculating conductor tensions under the stress of a large concentrated load (the falling tree or branch). With the tension information, they use a probabilistic approach to determining failures of components. Each component’s probability of failure is used to rank the likelihood of failure of each component. Then, once the weakest member is determined to fail, the stresses and probabilities are recalculated for the remaining components to determine what might fail next. This provides a sequence of failures for a given design. BC Hydro used this analytical approach to analyze several of their standard designs. They found the following general results:

- Neither pole species, pole length, or pole classes affected results.
- Trees falling near midspan and those falling near a pole were similar.
- For tangent structures, with #2 ACSR, the phase and neutral failed first when a tree fell on either conductor. For 336.4-kcmil ACSR, the pole tended to fail first.
- For angle structures, the guy grip for the phase and the tie wire for the neutral usually failed first.
- For deadend structures, the guy grip tended to fail first.

Although this method of distribution design is not widely used, mechanical coordination should be given consideration in designing T&D structures to make them easier to repair during storms. Choice of conductor (AAC versus ACSR) also plays a roll. In some applications, ACSR may be strong enough to move the weakest link to a harder-to-repair supporting structure.

4
PROGRAMS TO REDUCE TREE POWER QUALITY PROBLEMS

General Guidelines and Strategies

Vegetation management programs can be implemented more efficiently by more focused programs:

- *Removal*—This is the most effective fault-prevention strategy, and many homeowners are willing to have trees removed, especially dead or decaying trees.
- *Danger trees*—Trimming/removal is most effective if trees and branches that are likely to fail are removed or trimmed to safe distances. This does take some expertise by tree trimming crews.
- *Target circuits*—As with any fault-reduction program, efforts are best spent on the poorest performing circuits that affect the most customers.
- *Target mainlines*—The most significant power quality impacts on customers are for tree faults on the three-phase mains, so prioritize tree maintenance to target those faults.

Consider the type of tree exposure affecting a line. Compare the circuits in Figure 4-1 that have significant tree overhangs to the circuits in Figure 4-2 that have exposure to growth. Which are worse? As shown by the data from several utilities, branch failure and tree failure are much more of a problem than tree growth. So, tree maintenance strategies should concentrate on removing overhangs and removing trees in danger of falling on circuits.

In general, more aggressive cutting strategies will have the most significant power quality and reliability impact. Tree removal can also be less costly than selective pruning, especially when the costs are evaluated over the life of the tree.

Figure 4-1
Circuits With Significant Tree Overhang

Figure 4-2
Circuits With Impending Tree Growth Contact

Vines are a special situation that requires special attention (Figure 4-3). Vines can grow very quickly, and they cause some of the most repeatable faults. Because of the repeatability, when responding to a vine-caused interruption, crews should exterminate the offending vines as best as possible (or flag the pole for later attention by vegetation crews). Repeatability is also a reason to have a separate outage cause code for vines—this makes it easier to follow vine-caused faults for vegetation crews. Especially on circuit mainlines, vines should be targeted for removal because they are so fast growing and will cause repeated outages if not kept under control.

Figure 4-3
Circuits With Vines

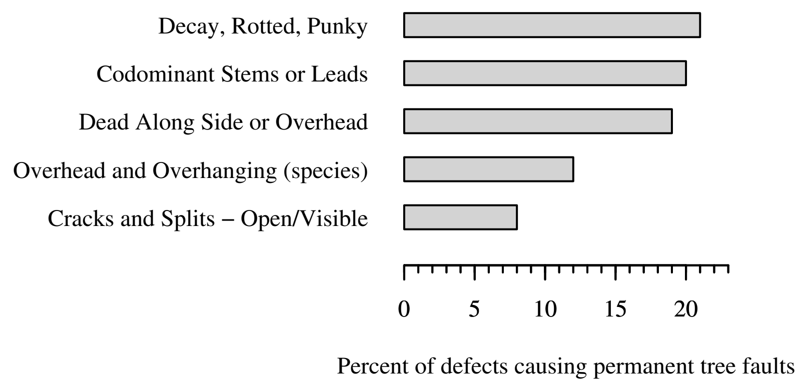
Acceptable tree trimming (that is also still effective) is a public relations effort. Some strategies that help along these lines include:

- Talk to residents prior to/during tree trimming. Get permission for removal of hazard trees outside of the normal trim zone.
- Trim trees during the winter. The community will not notice tree trimming as much when the leaves are not on the trees.
- Trim trees during storm cleanups. Right after outages, residents are more willing to accept tree maintenance.
- Clean up after trees are trimmed/removed.
- Offer free firewood.

Hazard-Tree Programs

Danger-tree or hazard-tree programs target those trees that are the largest threats to utility circuits. Tree trimming within a zone (+/- 10 feet for example) targets tree growth, but most tree outages are from trees or branches from outside of typical utility trim zones. Danger-tree programs target dead trees or trees with significant defects, even if they are out of the normal trim zone or right-of-way. Figure 4-4 shows some of the tree defects that led to tree faults in a study by the Niagara Mohawk Power Corporation.

Dead trees are the most obvious candidates for hazard-tree removals. In a sample of permanent tree faults, Niagara Mohawk found 36% were from dead trees; and in another sample, Duke Power found 45% were from dead trees [Taylor, 2003].



Data source: Finch [2001]

Figure 4-4
Defects Causing Tree Failure for the Niagara Mohawk Power Corporation

Targeting danger trees is highly beneficial, but requires expertise. In a careful examination of several cases where broken branches or trees damaged the system, 64% of the trees were living [Finch, 2001]. Finch also advises examining trees from the backside, inside the tree line (defects on that side are more likely to fail the tree into the line). Finch describes several defects that help signal danger trees (see Figure 4-4). Dead trees or large splits are easy to spot. Cankers (a fungal disease) or codominant stems (two stems, neither of which dominates, each stem at a branching point is approximately the same size) require more training and experience to detect.

For identifying hazard trees, it also helps to know the types of trees that are prone to interruptions—this varies by area and types of trees. Finch [2001] showed how Niagara Mohawk evaluated a sample set of tree outages in a study in 2000. Niagara Mohawk compared the tree species that caused faults to the tree species in New York state. They found that Black Locusts and Aspens are particularly troublesome; large, old roadside maples also caused more than their share of damage (see Table 4-1). Finch also reported 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 4-1
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]

In an informal survey of seven utilities, Guggenmoos [2003a] found that most utility hazard-tree programs removed about five trees per mile of circuit, with the most intense programs removing 10 to 15 trees per mile.

Note that while danger-tree programs can improve power quality, they are not a panacea. Tree outages will still occur regularly. Many tree faults are from weather that causes tree failures of otherwise healthy trees. Danger-tree programs must be ongoing programs. As Guggenmoos [2003a] 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 T&D circuits, a danger-tree program cannot be a one-time expenditure.

Identifying Tree Defects

While most hazard-tree programs are best directed by a professional forester, it is beneficial for anyone involved in distribution power quality field investigations to have some background knowledge of common tree defects. Fortunately, many common tree defects are relatively easy to identify. Although making predictions of future tree behavior for targeting hazard tree removal may require a trained forester, some basic background on common tree failures is often sufficient for the engineer investigating a power quality problem.

Defects can often be linked to previous wounding, infestation, or undesirable growing conditions and are a visible sign that a tree has a disposition to fail. Just like any other structure, trees fail whenever the loading on them exceeds their mechanical strength. Defective trees will fail before healthy trees because the defect lowers the mechanical strength of the surrounding wood thus weakening the tree. The most common tree defects are as follows:

- *Deadwood* – as the name implies, this is wood that has died. Deadwood is dry and brittle and cannot bend under load (wind, ice, etc.) and is therefore prone to breakage. This defect can range from individual branches to whole trees. Deadwood is often indicated by limbs or trees that do not have green, new growth leaves during the summer season such as that shown in Figure 4-5. Dangling dead braches are particularly dangerous.

Figure 4-5
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 has already started to fail. There are four types of cracks (Figure 4-6):
  - Shear Crack - A shear crack, as shown in Figure 4-6, separates the stem into two halves and carries a high risk of failure.
  - Inrolled Crack – The edges of this vertical crack are inrolled encompassing the bark and wood. Trees with inrolled cracks almost always suffer serious 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.
  - Horizontal Crack – These cracks run across the wood grain and are rare to find since they develop just before the tree fails.

Shear cracks

Inrolled crack　　Ribbed crack　　Horizontal crack

Figure 4-6
Examples of Cracks

- *Weak Branch Unions* – A weak branch union is a defect or weakness at the point at which two branches separate. A strong branch union is characterized by a small bark ridge line in the center of the union as shown in Figure 4-7. This indicates that the annual rings of the branch and stem are growing together creating a strong union. Weak unions lack this ridge line indicating that bark may be growing into the union (Figure 4-8) or that the union is an offshoot from a previously damaged spot.

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

Figure 4-7
Example of a Strong Branch Union

Notice the absence of a bark ridge line in the center of the union and the ingrown bark

Figure 4-8
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 that offers few outward indications and it can occur in the roots, stem, or branches. Decayed wood is always weaker than healthy wood and is therefore prone to failure. When present, outward signs of decay include discoloration, holes, and fungal fruiting bodies as shown in Figure 4-9.

Figure 4-9
Examples of Outward Signs of Tree Decay – Discoloration, Holes, and Fungal Activity

- *Cankers* – A canker is a dead area of bark and/or cambium which stops a new annual ring from being added each year at that location. Since cankers do not allow tree growth they reduce the trees strength by limiting the amount of wood at that location. Several examples of cankers are shown in Figure 4-10.

Figure 4-10
Examples of Cankers

- *Root Problems* – Root damage or inadequate root anchoring results in the tree tipping over because it cannot anchor itself into the ground. Root problems can be caused by tree growth in a confined earth area (such as a city sidewalk), excavation or paving near the tree, fungal infection, drought, or flood. Some indications of root problems include leaning trees, reduced tree crown, exposed roots, and recent construction work near the tree(s) as shown in Figure 4-11, Figure 4-12, and Figure 4-13.

Figure 4-11
Example of Root Damage due to Excavation

Figure 4-12
Example of Crown Decline due to Root Damage

Figure 4-13
Examples of Leaning Trees due to Root Damage

- *Poor Tree Architecture* – Poor architecture is a growth pattern, such as that shown in Figure 4-14, that indicates structural imbalance or weakness in the tree. Poor tree architecture develops over many years due to damage and poor environmental conditions. Trees that are leaning or have large branches that are out of proportion to the rest of the crown are particularly prone to failure.

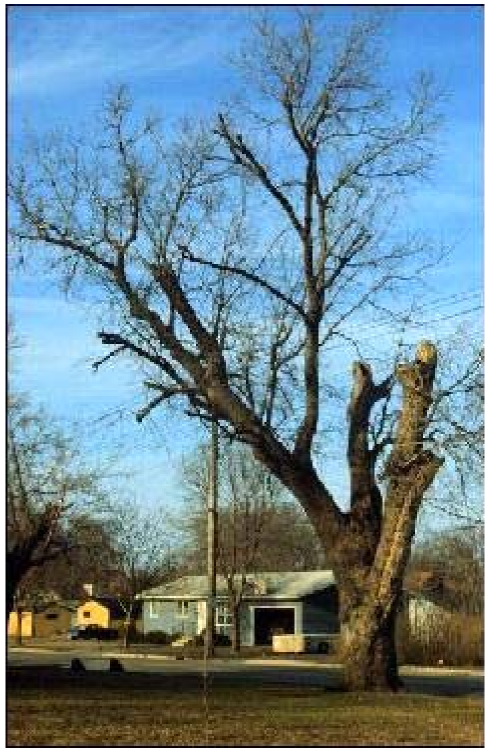


Figure 4-14
Example of Poor Tree Architecture

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

- *How to Recognize Hazardous Trees*, USDA Forrest Service Northeastern Area, Report NA-FR-01-96. At the time of publishing, this report is 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

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/

Right-of-Way Widening

On many subtransmission lines, critical distribution lines, or circuit backbones, clearing a right-of-way is the most effective way to reduce the chance of tree contacts. Such right-of-ways are regularly maintained for high-voltage transmission lines.

With normal distribution/subtransmission tree maintenance programs, many tree faults still occur. Even with hazard-tree programs, 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. The only way to drastically reduce tree faults is to clear a right-of-way. Then, 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 [2003a] 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.

Audits

Many utilities do audits after tree maintenance. Especially with contract crews, audits ensure that the work is being done to specifications. Even more so with hazard-tree programs and other targeted programs, audits can help educate tree crews at the same time that they ensure that the work is being done. Education comes from pointing out tree defects that were missed or tree cuts that should be made to reduce tree hazards or meet specified clearances.

Utility Results With Targeted Programs

Eastern Utilities

Eastern Utilities, a small utility in Massachusetts (now a part of National Grid) implemented a danger-tree mitigation project with the following characteristics [Simpson, 1997; Simpson and Van Bossuyt, 1996]:

- Three-phase primary circuits were targeted.
- Dead or structurally unsound trees were removed.
- Overhanging limbs were cut back.
- Trees were "storm-proof" pruned, meaning that trees were pruned to remove less severe structural defects. This was mostly crown thinning or reducing the height of a tree to reduce the sail effect.

On circuits where this was implemented, customer outage hours (SAIDI) due to tree faults were reduced by 20 to 30%. In addition, the program reduced tree-caused SAIDI by 62% per storm.

Eastern Utilities did not increase funding for their vegetation management program to fund their danger-tree mitigation project. Instead, they funded the program by changes to their normal vegetation management program. They did less trimming of growth beneath the lines. They also embarked on a community communications effort to educate utility customers and win support for tree removal and more aggressive pruning. Also, they did not remove viable trees without the landowner's consent. In addition, they found significant overall savings from reduced hot spotting and an even more significant savings from reduced outage restoration costs.

Prior to implementing their program, Eastern Utilities surveyed random line sections to determine how extensive their program would need to be. They found that of the trees along those spans, 7% had excessive overhang, and another 6% were weak species or had a visible structural weakness.

Niagara Mohawk

After considerable study of tree-caused outages on their system, Niagara Mohawk Power Corporation implemented a program called TORO (Tree Outage Reduction Operation), which had the following characteristics [EPRI 1008480, 2004; Finch, 2001; Finch, 2003a; Finch, 2003b]:

- Targeted work to the worst-performing circuits based on specific tree-caused indicators.
- Removed hazard trees located on targeted circuit segments.
- Specified greater clearances and removed overhanging limbs where possible on the backbone.
- Lengthened tree-maintenance cycles on rural 5-kV systems from 6 years to 7 or 8 years. Urban and suburban systems kept to a 5-year cycle.
- Looked for opportunities to improve system protection. They recently added inspection for the presence of single-phase tap fuses.

As of 2002, based on 250 feeders completed, on 92% of the feeders, tree SAIFI improved an average of 67%. More recent results show even more improvement.

Puget Sound Energy

Puget Sound Energy (PSE) implemented a hazard tree program they called TreeWatch [Puget Sound Energy, 2003]. Started in 1998, the focus of TreeWatch is on removing dead, dying, and diseased trees from private property along PSE's distribution system.

On the circuits where they implemented their program, the average number of tree-caused outages and average outage duration dropped as shown in Table 4-2. They also found that they did not need to classify as many storms as major storms. Even in years with higher-than normal average windspeeds, PSE declared fewer storms as major storm events (where 5% of PSE's electric customers are without power due to weather-related causes).

Table 4-2

Results of the PSE TreeWatch Program

	Tree-Caused Outages			Average SAIDI, min/yr		
TreeWatch Year	Pre-TW	Post-TW	**Change**	Pre-TW	Post-TW	**Change**
2001 (82 Circuits)	272	170	**-37.4%**	53.4	47.8	**-10.4%**
2000 (62 Circuits)	208	209	**0.4%**	100.0	86.7	**-13.3%**
1999 (26 Circuits)	241	172	**-28.6%**	121.0	102.6	**-15.2%**

Source: [Puget Sound Energy, 2003]

PSE started the TreeWatch program as a one-time program but hopes to continue the program at a reduced level of funding. Puget Sound Energy also estimates that they reduced the cost of tree-maintenance on a per circuit mile basis by about 15%. They also estimated major reductions in storm restoration costs.

Other Utility Programs

Finch [2003b] provides details on programs that ECI helped implement, including those by Niagara Mohawk (discussed previously), Kansas City Power & Light, and Flint EMC. KCPL and Flint EMC adjusted maintenance cycles to reduce cost and focus work on the most critical portions. On urban circuits, KCPL used a four-year cycle on the backbone with a two-year inspection to catch cycle busters and used a five-year cycle on laterals. On rural circuits, KCPL used a five-year cycle for all circuits. KCPL also developed a hazard-tree removal program based on results from their outage database. Flint EMC extended the maintenance cycle from four years to between five and six years on rural single-phase circuits.

Another good resource is EPRI 1008480 [2004], *Electric Distribution Hazard Tree Risk Reduction Strategies*. This documents hazard-tree program results by Niagara Mohawk, Central Hudson, and BC Hydro. They also provide a process tree map to help guide utilities through the process of developing a hazard-tree program.

5
CONDUCTOR SPACING AND SPAN LENGTHS

Background

Conductor spacing and span lengths play a critical role in determining how sensitive the system is to faults induced by wind, trees and the magnetic forces associated with short circuit currents. This section focuses on three main areas:

1. National Electrical Safety Code Clearance Requirements and Span Lengths
2. Faults Induced by Short Circuit Forces
3. Wind and Tree Related Faults

Overhead distribution system designs must address all of these areas affectively to provide reliable and safe operation.

NESC Clearance Requirements

A basic requirement of an overhead distribution system design is to provide a suitably robust system construction design and sufficient clearances of conductors to avoid faults and safety problems. This includes the spacing between phases, phase and neutral, neutral and ground, and any phase and ground. It also includes spacing between adjacent power supply circuits, communication circuits, and circuits on other supporting structures, as well as objects around and underneath the lines.

The National Electrical Safety Code (NESC, [IEEE C2-2002]) has specific requirements for the minimum spacing and clearances of aerial conductors. The requirements of the NESC are intended to offer basic provisions for safeguarding of persons from hazards arising from the installation, operation, and maintenance of overhead electric supply and communication lines. While not directly focused on achieving a specific level of reliability and power quality, NESC requirements achieve this indirectly by establishing a certain level of resistance against some of the most common causes of line faults. However, it is important to recognize that the clearances and practices in the NESC are minimum requirements, and while they provide suitable levels of safety, they may not provide the desired level of reliability and power quality. The NESC was never intended for that purpose and its requirements may need to be substantially exceeded to achieve suitable results in many cases.

The key areas of the NESC requirements that relate to conductor spacing and clearances for overhead distribution lines are detailed in Part II, Section 23, pages 69 through 152 of

IEEE/ANSI Standard C2-2002. In this section, the following topics (or “rules” as they refer to them) are covered:

a. Rule 230 – General clearance issues
b. Rule 231 – Clearances of supporting structures
c. Rule 232 – Vertical clearances of conductors above ground, roadway, rail or water surfaces
d. Rule 233 – Clearances between wires, conductors and cables carried on different supporting structures
e. Rule 234 – Clearances of wires, conductors and cables from buildings, bridges, rail cars, swimming pools and other installations
f. Rule 235 – Clearance of wires, cables and conductors carried on the same supporting structures
g. Rule 236 – Climbing Space
h. Rule 237 – Working Space
i. Rule 238- Vertical clearance between communications and supply facilities located on the same structure

The most relevant spacing and clearance requirements as they relate to power quality and reliability impacts of trees, wind and fault current forces are in *Rule 235 –Clearances of wires, cables, and conductors carried on the same supporting structures*. These clearances, to a great extent, determine the susceptibility of the circuit to the most common types of conductor faults relating to wind, trees and short circuit forces. In Rule 235, there is a certain minimum clearance required between each conductor based on operating voltage. In addition, there are increased clearance requirements based on the sag of the conductors. In the NESC method, the greater the line sag, the more the presumed amount of movement due to wind and other factors that may cause the conductors to establish momentary contact. In other words, the larger the sag, the greater the needed clearances. Also, NESC recognizes that smaller conductors tend to move more easily and need greater spacing for a given amount of sag so they have developed two tiers of clearance requirements – one set for conductors less than AWG No. 2 and the other for conductors AWG No. 2 and larger. The NESC utilizes the following equation to determine the horizontal clearance requirements for conductors smaller than AWG No.2:

$$Clearance = 0.3 \times kV + 4.04\sqrt{S - 24} \qquad \textbf{Eq. 5-1}$$

Where:

Clearance is in inches

kV is the RMS voltage between conductors

S is the sag in inches

Horizontal clearance requirements based on the above equation are shown in Table 5-1 for various amounts of conductor sag. These are the same clearances as specified in Table 235-2 of the NESC C2-2002, but they have been extended here to show 69 and 115 kV values (the NESC Table only goes to 46 kV).

Table 5-1
Horizontal Clearances Between Line Conductors Smaller Than AWG No. 2 at Supports, Based on Sags (Adopted From NESC C2-2002 Table 235-2)

Nominal Voltage Between Conductors (kV RMS)	Sag in Inches							
	36	48	72	96	120	180	240	But Not Less than
	Horizontal Clearance (inches)							
2.4	14.7	20.5	28.7	35.0	40.3	51.2	60.1	12.0
4.16	15.3	21.1	29.3	35.6	40.9	51.8	60.7	12.0
12.47	17.7	23.5	31.7	38.0	43.3	54.2	63.1	13.5
13.2	18.0	23.8	32.0	38.3	43.6	54.5	63.4	13.8
13.8	18.1	23.9	32.1	38.4	43.7	54.6	63.5	14.0
14.4	18.3	24.1	32.3	38.6	43.9	54.8	63.7	14.3
24.94	21.5	27.3	35.5	41.8	47.1	58.0	66.9	18.5
34.5	24.4	30.2	38.4	44.7	50.0	60.9	69.8	22.4
46	27.8	33.6	41.8	48.1	53.4	64.3	73.2	26.9
69*	34.7	40.5	48.7	55.0	60.3	71.2	80.1	NA
115*	48.5	54.3	62.5	68.8	74.1	85.0	93.9	NA

**Note: for voltages above 50 KV NESC requires use of the maximum voltage rather than nominal voltage in calculating the spacing requirements. Maximum voltage is typically 5% higher than nominal per ANSI C84.1-1995. In this chart the clearance based on the nominal voltage is shown for illustration purposes.*

For conductors equal in size or larger than AWG No. 2, the following equation is utilized:

$$Clearance = 0.3 \times kV + 8\sqrt{\frac{S}{12}}$$ **Eq. 5-2**

Where:

Clearance is in inches

kV is the RMS voltage between conductors

S is the sag in inches

Horizontal clearance requirements based on Eq. 5-2 are shown in Table 5-2 below. These are the same clearances as specified in Table 235-3 of the NESC C2-2002. The clearance requirements for these larger conductors are somewhat less than the smaller ones.

Table 5-2
Horizontal Clearances Between Line Conductors AWG No. 2 or Larger at Supports, Based on Sags (Adopted From NESC C2-2002 Table 235-3)

Nominal Voltage Between Conductors (kV RMS)	Sag in Inches							
	36	48	72	96	120	180	240	But Not Less than
	Horizontal Clearance (inches)							
2.4	14.6	16.7	20.2	23.3	26.0	31.7	35.6	12.0
4.16	15.1	17.3	20.8	23.8	26.5	32.2	37.0	12.0
12.47	17.6	19.7	23.3	26.3	29.0	34.7	39.5	13.5
13.2	17.8	20.0	23.5	26.5	29.2	34.9	39.7	13.8
13.8	18.0	20.1	23.7	26.7	29.4	35.1	39.9	14.0
14.4	18.2	20.3	23.8	26.9	29.6	35.3	40.1	14.3
24.94	21.3	23.5	27.0	30.0	32.8	38.4	43.2	18.5
34.5	24.2	26.4	29.9	32.9	35.6	41.3	46.1	22.4
46	27.7	29.8	33.3	36.4	39.1	44.8	49.6	26.9
69*	34.6	36.7	40.3	43.3	46.0	51.7	56.5	NA
115*	48.4	50.5	54.1	57.1	59.8	65.5	70.3	NA

**Note: for voltages above 50 KV NESC requires use of the maximum voltage rather than nominal voltage in calculating the spacing requirements. Maximum voltage is typically 5% higher than nominal per ANSI C84.1-1995. In this chart the clearance based on the nominal voltage is shown for illustration purposes.*

In cases where sag is so minimal as to result in a very small clearance value, then the clearances can't be less than the minimum indicated amount in the preceding tables (see Table 5-1 and Table 5-2– rightmost column). For voltages above 50 kV, the NESC does not specify a minimum no sag horizontal clearance requirement so the rightmost column is not applicable for voltages above 50 kV. Another clarification is that the clearances should be based on the maximum rather than nominal voltage level for voltage levels above 50 kV. Voltages below 50 kV use the nominal voltage. In Table 5-1 and Table 5-2 above, the nominal voltages are used at 69 and 115 kV for illustration purposes only and for a real world application the maximum voltages would need to be used resulting in slightly larger clearance requirements than shown for those two rows. Normally, the maximum voltage would be about 5% higher than the nominal voltage per the ranges specified in ANSI C84.1-1995. For voltages exceeding 470 kV, the NESC requires that the horizontal clearances be determined by an alternative equation (see NESC C2-2002 for details).

There are also vertical clearance requirements. Vertical clearance requirements for vertically arranged conductors are a bit less than those for horizontally arranged conductors. A reason for this is that wind and fault induced motion on sagging vertically arranged conductors will not cause them to contact each other the way horizontally sagging conductors can be affected. On the other hand, such vertically arranged conductors can sag into each other if thermal or mechanical loading is considerably unbalanced (between phases) or if one conductor breaks or due to unbalanced conductor tensions (due to conductor breakage, mechanical issues, etc.).

Table 5-3
Vertical Clearances Between Conductors at Supports

Conductor Type (usually at lower level)	Open Supply Conductors		
	0 to 8.7 kV	Over 8.7 kV to 50 kV	
	(inches of spacing)	Same Circuit (utility) (inches of spacing)	Different Circuit (Utility) (inches of spacing)
Open conductors less than 750 V *(such as secondary) or effectively grounded neutrals*	16	16 plus 0.4 per kV over 8.7 kV	40 plus 0.4 per kV over 8.7 kV
Open conductors 750 V to 8.7 kV	16	16 plus 0.4 per kV over 8.7 kV	40 plus 0.4 per kV over 8.7 kV
Open Conductors 8.7 to 22 kV:			
1. Worked on energized, but with adjacent circuits energized		16 plus 0.4 per kV over 8.7 kV	40 plus 0.4 per kV over 8.7 kV
2. Worked on energized, but with adjacent circuits deenergized		16 plus 0.4 per kV over 8.7 kV	16 plus 0.4 per kV over 8.7 kV
Open Conductors 22 kV to 50 kV		16 plus 0.4 per kV over 8.7 kV	16 plus 0.4 per kV over 8.7 kV

The clearance requirements shown above for vertically arranged conductors are at the supports. NESC recognizes that the clearance might be less at midspan and requires that the sag on all conductors shall be such that clearances at any point on the span shall be no less than 75% of the clearances specified at the supports. Note that there are special clearance requirements in Table 5-3 associated with the ability to allow live line work without de-energizing an adjacent circuit.

The NESC Section 23 also specifies the clearances of conductors above roadways, railroads, buildings, pools, waterways, walkways, etc. There are several tables and rules applying to different types of structures and objects. Table 5-4 shows some selected excerpts under Rule 232 of the clearance requirements in the NESC for vertical clearances above the ground, roadways, rail tracks, and water. The clearance used in these tables is the worst of the following: the clearance that occurs at a conductor temperature of 50 degrees C (120 ºF) with no wind, or at the maximum conductor operating temperature (if a higher temperature) with no wind, or at 0 degrees C (32 ºF) with the maximum design ice loading condition and no wind.

Table 5-4
Vertical Clearance Requirements Above Ground, Roadways, Rail Track and Water

Nature of Surface Beneath Wires, Conductors or Cables	Supply Conductors Under 750 volts (Feet)	Open Supply Conductors 750 volts to 22 kV Line-to-Ground (Feet)
1. Track rails of railways (except overhead electrified railways)	24.5	26.5
2. Roads, streets and other areas subject to truck traffic	16.5	18.5
3. Driveways, parking lots, and alleys	16.5	18.5
4. Other land traversed by vehicles (cultivated grazing forests, etc.)	16.5	18.5
5. Spaces and ways subject to pedestrians	12.4	14.5
6. Water areas not suitable for sailboats	15.0	17.0
7. Water areas suitable for Sailboats:		
Less than 20 acres	18.5	20.5
Over 20 to 200 acres	26.5	28.5
Over 200 to 2000 acres	32.5	34.5
Over 2000 acres	38.5	40.5
8. Established boat ramps and associated rigging areas	Clearance above ground shall be 5 ft greater than in 7 above for the type of water areas served by the launching site	
Where wires conductors or cables run along and within limits of highways or other road rights-of-way but do not overhang the roadway		
9. Roads, streets, or alleys	16.5	18.5
10. Roads in rural districts where it is unlikely that vehicles will be crossing under the line	16.5	18.5

Covered Conductors and Neutrals

The required clearances for covered conductors (such as tree wire) are considered to be the same as bare (open) conductors for all clearance requirements except that spacing may be reduced below requirements for open conductors when the conductors are owned, operated or maintained by the same party and when the conductor covering provides sufficient dielectric strength to limit the likelihood of a short circuit in case of momentary contact with other covered conductors or the grounded conductor.

Neutral conductors of circuits with 0 to 22 kV line-to-ground voltage that are effectively grounded are treated with the same clearances as guy wires and messenger wires. All other neutrals of supply circuits shall have the same clearances as phase conductors.

Illustration of Clearances

The application of the clearances in Table 5-1 through Table 5-4 is illustrated graphically in the following diagrams. Figure 5-1 shows the application of horizontal clearances at the supporting crossarm as well as the vertical clearance above a roadway. The vertical clearances are measured at the point of minimum clearance under the worst-case sag conditions discussed earlier. Figure 5-2 shows the application of vertical clearances between open conductors of the same circuit.

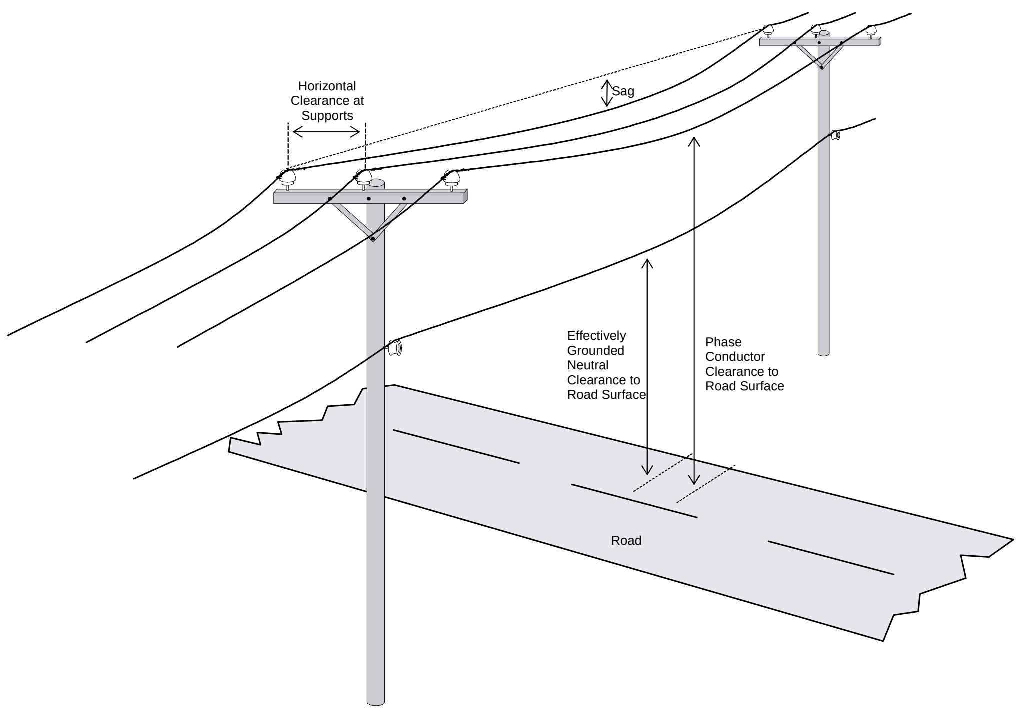


Figure 5-1
Application of Horizontal Clearances at Supports Between Conductors and Vertical Clearance Between a Road and Conductors

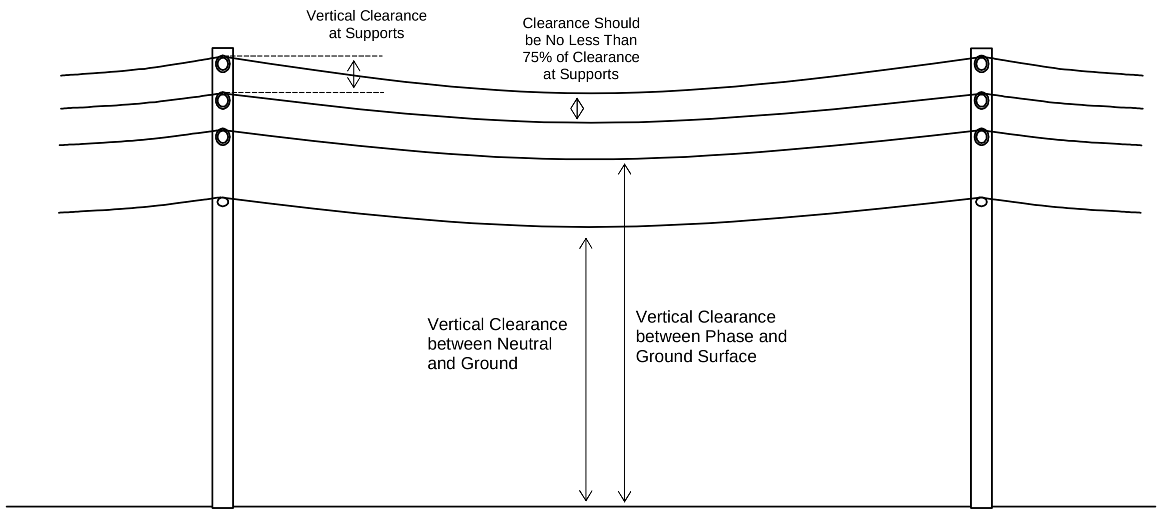


Figure 5-2
Vertical Clearances Between Conductors

A complication in determining the required clearances is that not all conductors are displaced just horizontally or just vertically. For example, "candle stick" or armless arrangements like that shown in Figure 5-3 have both a horizontal and vertical component of spacing. In such cases, the required spacing is determined by applying both the vertical and horizontal clearance requirements of the NESC to each axis respectively.

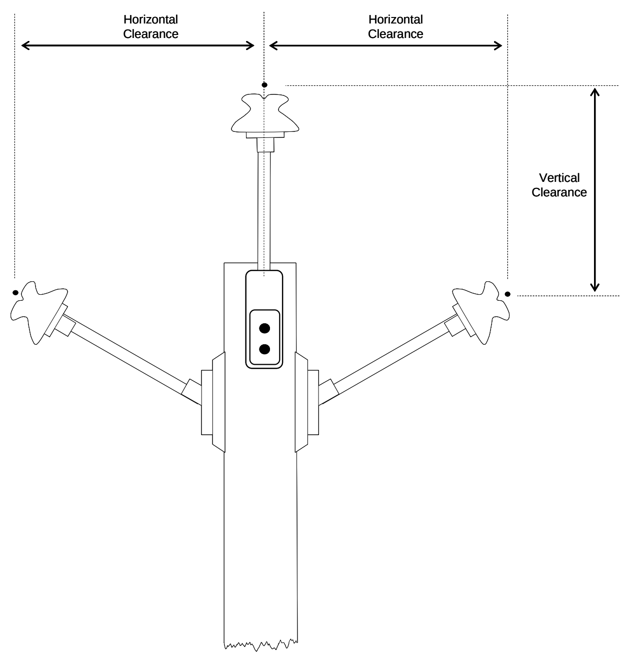


Figure 5-3
Geometries Involving Both Horizontal and Vertical Clearances

Climbing Spaces and Work Areas

The NESC addresses climbing spaces and working areas on poles and between wires. These clearances are intended to provide sufficient space between conductors, equipment, and/or circuits such that a line crew can safely perform maintenance or restoration work and can safely access the needed work areas without causing a fault or exposing themselves to undo danger. For example, the horizontal clearance between conductors bounding a climbing space on a 13.2-kV circuit between phases should be no less than 30 inches according to Rule 236. On a 25-kV class circuit this becomes 36 inches and on a 34.5-kV circuit it is 40 inches. Full details on climbing spaces and work areas can be found in Rules 236 and 237 in Part 2, Section 23 of the NESC. Figure 5-4 shows an example of a climbing space between several feeder circuits on a common pole. If the climbing and working spaces are sufficient, it is possible for the crew to work on one circuit, while the other two remain energized. This not only facilitates faster restoration for the failed circuit, but also avoids an interruption on the other circuits that would otherwise be needed to allow crews to restore service on the failed circuit. Furthermore, proper working spaces reduce the chance crews will accidentally cause a fault on an energized circuit during restoration –improving safety for crews as well as power quality and reliability for customers.

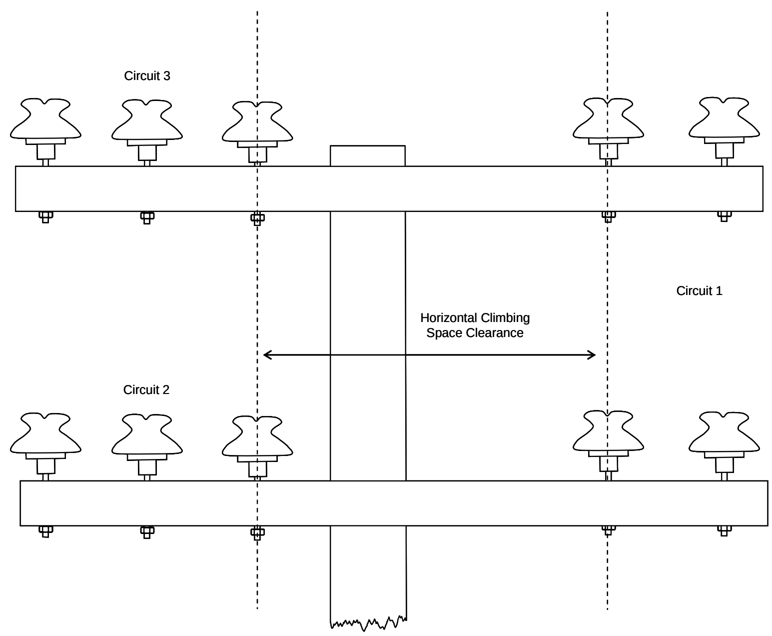


Figure 5-4
Example of a Climbing Space That Has Been Provided in the Layout of the Pole to Allow Safe Crew Access

Span Lengths

Span lengths for medium and high voltage supply conductors of distribution lines are not directly addressed in the NESC using a specific table of span length requirements. Instead, they are addressed indirectly through requirements for the maximum allowable conductor tension as a percentage of its rated breaking strength. This approach works fine because the physics of supporting a wire on poles automatically establishes a needed span length if a target tension level must not be exceeded for a given wire size. The support poles will need to be spaced at specific intervals for each type of wire and external load conditions – so for structures carrying multiple utilities and circuits, the weakest type of conductor will establish the span length requirement. The amount of tension for a given span is a function of the wire size and type, ancillary wire hardware weight (such as spacers, clamps, etc), and external loading due to wind and ice conditions. These factors, along with the grades of line construction, mechanical strength requirements and wind/ice loading requirements determined the appropriate span length and are discussed in detail in Sections 24, 25 and 26 of the NESC.

The allowed tensions include factors for ice, snow, and wind loading. The NESC has specific maps and several tables of loading factors for wind and ice in various regions of the country. For example, in heavy ice loading areas, the design is based upon ½ inch of radial ice collection on the conductors. In medium and light icing areas 0.25 and 0 inches of ice collection is the minimum design requirement respectively (see Rule 250). The wind speed design criteria ranges from 85 mph in some western areas to 150 mph in certain coastal regions of the southeast. There are several different grades of construction depending on the type of circuit to be carried (communications, supply conductors, etc.).

The basic design load requirement (which includes the internal load which is the weight of the conductor and parts plus external loads such as ice and wind) should not exceed 60% of the rated mechanically loaded breaking strength per NESC Rule 250B. Furthermore the tension, without external load should not initially exceed 35% of rated breaking strength, and after settling in the unloaded tension should not exceed 25%. There are special cases where overload factors are applied to the design loading requirements. These factors range from under 1.0 to 4.0 depending on the application and are meant for certain part of the line and at certain locations with higher stress or criticality.

The specific span lengths used by utilities are as much a function of economics as they are NESC requirements and other technical factors. The locations of customers also play a key role in dictating pole placement and hence span length. Generally in rural areas spans for distribution primary construction may be anywhere from 40-200+ meters, whereas in urban/suburban areas spans are typically only 30-60 meters. The numerous equipment and customer locations in urban areas dictate shorter spans. Also, those areas are likely to have more CATV and telephone services that may require tighter spans (note: the NESC also has requirements that address CATV and telephone cable spans).

If economic consideration was the only factor of interest and customers were far apart, then very large span lengths pushing the conductor tensions, sags and clearances to the NESC limits would be the most desirable approach for distribution circuits. However, since power quality and reliability are also a concern, the most economic design may not be the best from an overall performance perspective. Smaller spans allow for a stronger distribution line that is less likely to be damaged by wind and ice (because each pole takes a smaller portion of the conductor wind/ice load and conductor tensions can be less). Furthermore, tighter spacing can reduce conductor galloping due to wind and ice and also conductor slapping due to forces associated with fault currents. If the span length is reduced from the maximum possible, faults can likely be reduced to a certain extent. However, this only occurs to a certain lower limit of span length. As span length is further reduced, there are a significantly increased number of poles that result in more opportunities for automobile accidents into poles or pole damage. There are also be more opportunities for animal or bird faults at pole tops and insulator flashovers as pole-tops. Obviously, there is an optimum span length from a power quality and reliability perspective. For rural systems, this length is likely to be shorter than the optimum economic length, but for suburban systems with short spans it might actually be longer. There would be an interesting area of focus for a future study – to address the optimum span length for reliability based upon all the causes of faults.

In considering the NESC clearance requirements and span distances that can be achieved, there are creative solutions that can help reduce faults while still maintaining long spans for economic purposes. For example, use of a longer crossarm to increase phase conductor clearances can decrease conductor slapping or wind related contact faults. Use of an increased spacing between phase and neutral can reduce contact between phase and neutral lines while allowing span distances to be maintained. For vertically oriented lines, increased vertical separation beyond the NESC minimum requirements can reduce the susceptibility to icing faults. Neutrals built under lines can be offset using a small crossarm or bracket so the horizontally oriented phase conductors above don't sag into them if burdened with ice. Certain types of unconventional conductor spacing patterns such as wide triangles (similar to candlestick layouts only larger) may help reduce faults (see the section on tree faults).

It is important to recognize that the NESC limits are the minimum that have been established mainly for safety purposes and not for economic or reliability reasons. The line designer has the flexibility to exceed the NESC clearance and design requirements and use innovative layouts when these can lead to better economics or reliability in the line construction.

Conductor Slapping Due to Short Circuits

Conductor slapping due to short circuits is a phenomenon caused by the magnetic forces associated with short circuit currents flowing in the line. Depending on where a fault is located on the system, short circuit currents can be 10-100 times larger than typical load currents and the onset of a fault will result in a significant magnetic force between the phase conductors. This force can cause substantial conductor movement. If the conductors are spaced too closely (poor clearances) and/or if there is too much play (easily achieved due to high sag) a short circuit at one location may trigger enough motion in a conductor upstream to cause a subsequent momentary fault at another location. The lines that are most easily affected are those with a combination of lighter weight conductors, tight conductor spacing, above average sag, long spans and relatively high fault levels. Any span where these characteristics occur together could be particularly susceptible to short circuit induced conductor slapping.

Conductor slapping due to short-circuit current forces is not just an obscure problem, but instead one that is widely encountered at most utilities. Because of its transient nature and occurrence at typically unknown locations as well as lack of visual evidence following the event, many incidents simply go undetected and it is not really known in the industry what percent of faults also lead to conductor slapping faults. It can be difficult to identify that slapping has occurred even when it is known. For example, Allegheny Power investigated slapping on a 46-kV line using fault recorders to determine the location of the conductor slapping faults. Even with this information, visual inspection at the possible fault locations revealed only minor pitting/melting of the aluminum, and it was very difficult to recognize that slapping had occurred [Frank and

Reese, 2001]. Had the slapping not been detected with fault recorders, these marks probably would have been discounted as being from earlier flashovers unrelated to conductor slapping.

Conductor slapping is more than an inconvenience for the utility company. It can cause unnecessary operation of protection devices, unneeded lockout of circuit breakers or reclosers, wasted resources in tracking down perceived equipment coordination problems, and additional equipment deterioration (substation transformer subjected to more fault events, circuit breaker operations increased, conductors are unnecessarily pitted/partially melted). Overall, it degrades reliability and power quality and results in increased maintenance cost for the distribution system.

The conductor-slapping phenomenon is illustrated in Figure 5-5. In this example a phase-to-phase flashover between phases B and C at a pole top results in a strong magnetic force (initially repelling the two conductors). During the initial fault, the forces can be thought of as an impulsive force on the conductors swinging them outwards from each other. The magnetic force will usually be terminated well before the conductors reach the outward limit of their swing because the fault may last only 4-6 cycles with an instantaneous circuit breaker operation, and the crest of the swing outwards occurs much later. Once the crest of the outward swing is reached, then the conductors, each like a pendulum, will swing back in approaching each other and potentially faulting if there is insufficient clearance. Analysis shows that the line-to-line type of fault is normally the mode of fault that causes the worst forces and highest likelihood of a conductor-slapping event.

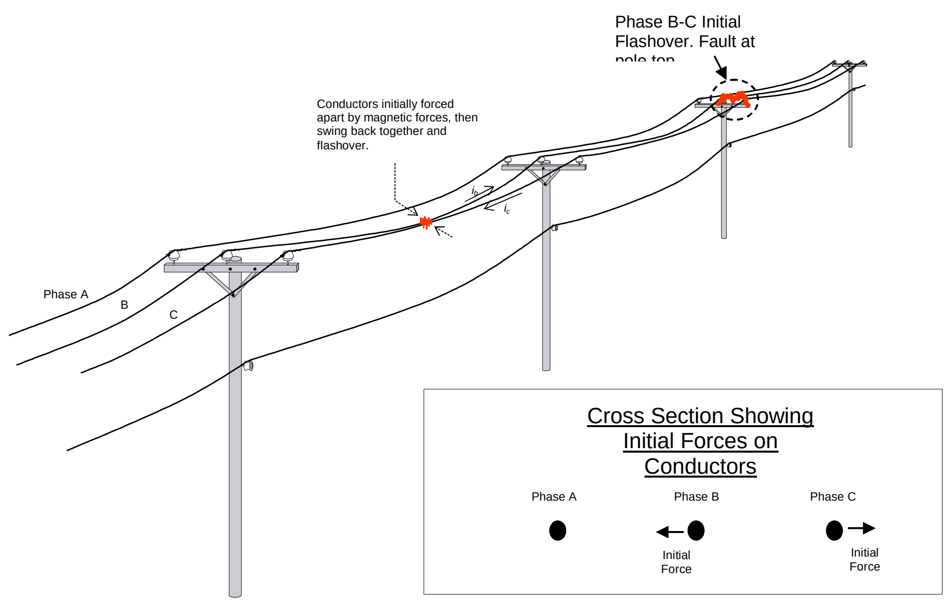


Figure 5-5
Illustration of Conductor Slapping Fault Due to Magnetic Forces of an Earlier Flashover

Magnetic Forces

We can calculate the short circuit forces on conductors from basic physics. The magnetic force between two parallel conductors is determined by the following equation adapted from the Aluminum Conductor Electrical Handbook [Aluminum Association, 1986]:

$$F = M\,\frac{5.4I^2}{d10^7} \qquad \textbf{Eq. 5-3}$$

Where:

M = Short circuit force multiplier (based on dc offset of fault current. Use 2 for a symmetrical fault and 8 for a fully offset fault)

F = Pounds per linear foot of conductor

I = Line-to-line short-circuit current in each conductor in amps

d = Spacing between centerlines of conductors in inches

A line-to-line fault with tightly spaced crossarm or candlestick construction is considered the worst type of fault from the point of view of magnetic forces on conductors. This is because a three phase fault results in a less intense magnetic field between any two conductors (due to field cancellation effects) and a single phase to ground fault results in interactions between the neutral and phase, which are spaced farther apart and usually vertically oriented resulting in much less force and conductor displacement. The one exception where the line-to-ground fault can be worse than a line-to-line fault is the case where the neutral is also on the crossarm in close proximity to the faulted phase, and the fault is at a location where the zero-sequence impedance is low (such as near the substation and with a delta to grounded/wye substation transformer).

Plugging values of line-to-line fault currents ranging from 500 to 20,000 amperes into Eq. 5-3 above and assuming a typical M value of 4 (this is an average offset for illustration purposes), we can generate a table of results (see Table 5-5). We can see that the forces range from less than a tenth of a pound per foot at wide spacing and low currents to over 50 pounds per foot at close spacing and very high fault currents. As an example, a conductor with a spacing of 24 inches, and 5000 amperes of symmetrical fault level, would experience about 1.69 pounds of force per foot of conductor. On a 200-foot span, this is 338 pounds of force pushing the two conductors apart.

Table 5-5
Force Per Linear Foot of Conductor for a Line-to-Line Fault on a Feeder

Line to Line Fault Level (Amperes)	Phase to Phase Horizontal Conductor Spacing (inches)					
	12	24	36	48	60	72
	Pounds of Force Per Linear Foot of Conductor					
500	0.034	0.017	0.011	0.008	0.007	0.006
1000	0.14	0.07	0.05	0.03	0.03	0.02
1500	0.30	0.15	0.10	0.08	0.06	0.05
2000	0.54	0.27	0.18	0.14	0.11	0.09
3000	1.22	0.61	0.41	0.30	0.24	0.20
4000	2.16	1.08	0.72	0.54	0.43	0.36
5000	3.38	1.69	1.13	0.84	0.68	0.56
7500	7.59	3.80	2.53	1.90	1.52	1.27
10000	13.50	6.75	4.50	3.38	2.70	2.25
15000	30.38	15.19	10.13	7.59	6.08	5.06
20000	54.00	27.00	18.00	13.50	10.80	9.00

The characteristics that contribute to the likelihood of conductor slapping include:

- High fault currents (faults closer to the substation)
- Maximum dc offset (faults at locations with high X/R ratio and at the point of wave causing highest offset)
- Long spans and close conductor spacing
- High levels of sag
- Smaller, lighter conductors
- Conductors in the same horizontal plane
- Increased duration of fault current

Dominion Resources recently published an analysis of the dynamics behind conductor slapping behavior and the susceptibility of various construction types to the slapping phenomenon [Ward, 2003]. They concluded that armless construction (such as candlestick arrangements) with their relatively tight spacing would be one of the more vulnerable types of construction. Table 5-6 shows the results of three different construction types that they analyzed for fault forces.

Table 5-6
Short Circuit Forces for Typical Constructions

Distribution Construction Type	Closest Phase Spacing	Per Unit Magnetic Force Compared to Standard 44 Inch Spacing
Armless	0.8m (32 inches)	1.375
2.4 m (8ft) crossarm	1.1m (44 inches)	1.00
3.0 m (10 ft) crossarm	1.4 m (56 inches)	0.786

Source: Ward [2003]

To determine how much the conductors move and whether or not a fault will result is much more complicated than simply calculating the steady state magnetic forces on the conductor. The fault event is a transient event, imparting what amounts to an impulse force to the conductor causing it to swing outwards to a crest point and then return in a harmonically damped motion. This motion is best compared to the swinging oscillations of a pendulum, and we can use the same dynamic equations that describe pendulum motion to evaluate the total swing of the conductors and whether or not a fault will occur. The first step in doing this is to simplify the conductor into a single lumped mass with the appropriate pendulum length. A pendulum with mass equal to 1 span of conductor and with an arm length equal to 2/3 of the conductor sag is a good representation of a swaying conductor for dynamic modeling purposes (see Figure 5-6) [Ward, 2003].

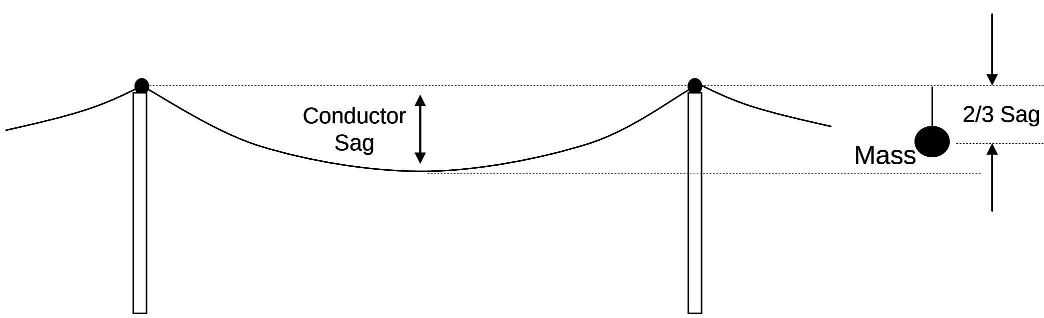


Figure 5-6
A Sagging Conductor Can Be Represented by a Mass Equal to the Weight of One Span With an Arm Length Equal to 2/3 of the Total Sag of the Conductor

Based on harmonic oscillation concepts that we can apply to our “representative pendulum” we can calculate the range of motion (the amount of swing) of each conductor and the separation between them. The swing of both conductors plotted as a function of time is qualitatively illustrated in Figure 5-7. Here we can see that at fault initiation, the conductors begin moving apart – accelerating as the fault continues. Upon fault clearing, the conductor’s inertia allows the separation to increase until a crest value of separation is reached. At this stage the conductors start “falling” back towards each other eventually reaching a point of minimum separation (or contact). If the minimum separation is small enough, then a flashover could occur. There will be some damping as shown in the illustration with each subsequent oscillation. The damping shown has been exaggerated for clarity.

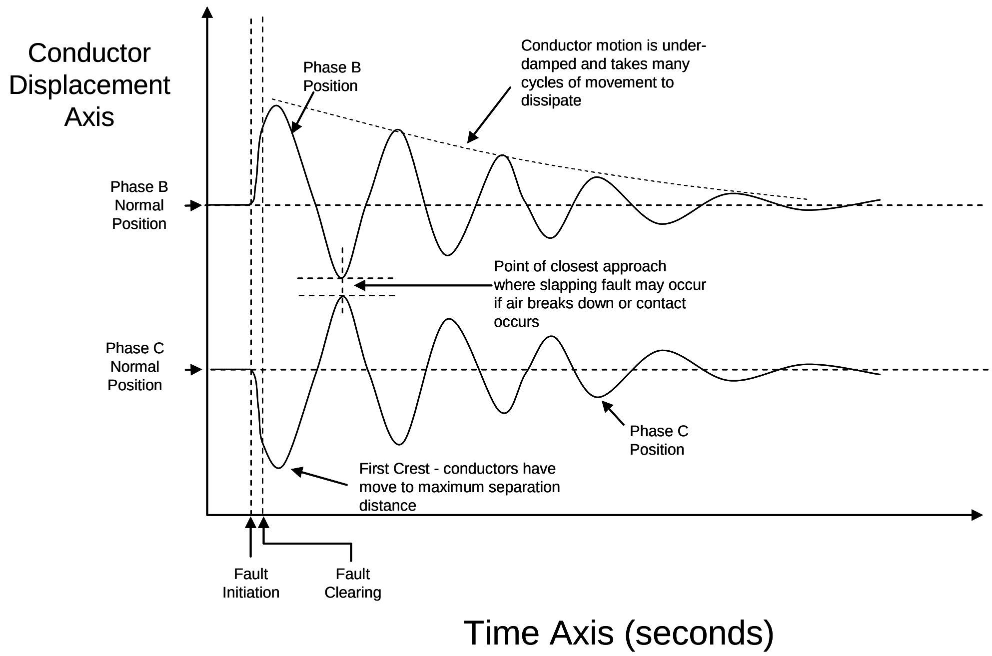


Figure 5-7
Theoretical Illustration of the Conductor Displacement Versus Time

From basic harmonic motion theory, we can calculate the period of a pendulum if we know the distance (l) of the arm and the force of gravity:

$$\tau = 2\pi\sqrt{\frac{l}{g}} \qquad \textbf{Eq. 5-4}$$

Where:

τ = the period of the oscillation in seconds

l=the length of pendulum in meters (that is 2/3 of the total sag of the conductor in meters or feet)

g = gravitational constant (which is 9.8 m/s^2if meters are used for sag or 32.2 ft/s^2if feet are used for sag)

From this formula we calculate the conductor oscillation period for various amounts of sag (see Table 5-7). Notice that the conductor weight and span length do not directly factor into the period of oscillation. Rather it is dependent entirely on the acceleration due to gravity (a constant) and the pendulum length.

Table 5-7
Period of Conductor Oscillation for Various Sags (Assuming no Damping)

Total Conductor Sag (feet)	Period of Oscillation (seconds)
2	1.28
3	1.57
4	1.81
5	2.02
7	2.39
9	2.71

The periods of oscillation are long compared to the typical high current fault duration on a feeder. Most faults we are concerned about will result in instantaneous breaker operations (well under 10 cycles duration), and only some may be time delayed lasting up to 60 cycles perhaps. Few of concern would ever be more than 60 cycles. Given the period of oscillation, if there is an instantaneous trip, the fault will be cleared well before the conductor reaches its first crest (maximum separation). In fact there is more than enough time in these slow period oscillations for the high speed reclosing without intentional dead time delay to clear the fault and re-energize the line in time to allow a conductor slapping fault.

It is a simple matter to determine the first swing conductor displacement in the X and Y coordinates by using basic physics and straightforward trigonometry. We can use the basic laws of conservation of energy and Newton's laws of motion (F=MA and $X=1/2AT^2$) to figure this out as an approximation. If we know the force input to the conductor, we can then calculate its acceleration. The force input is:

$$J = \int F \, dt \qquad \textbf{Eq. 5-5}$$

Where:

J= impulse in pound-seconds

F = force in pounds

t = time in seconds

From the force input, we can now calculate the acceleration of the conductor using F=MA (we know the mass of the conductor and the force applied). From F=MA, acceleration and speed are determined, and we can now calculate the kinetic energy of the conductor at the bottom of the swing angle, which is equal to ½ MV^2. Due to conservation of energy, the conductor's kinetic energy must be transformed completely into potential energy (MGH) at the first crest of the swing. If we set MGH = ½ MV^2, we can find the height of the initial swing (H) as shown in Figure 5-8. Once we know the height (H), we can assume the conductor, acting a pendulum, will swing the same amount to the other side based on conservation of energy. (In fact, it won't swing quite as far due to losses but these can be ignored.) From this point, it is a simple matter of trigonometry to calculate the X and Y axis displacements and clearance between the conductors during the second crest.

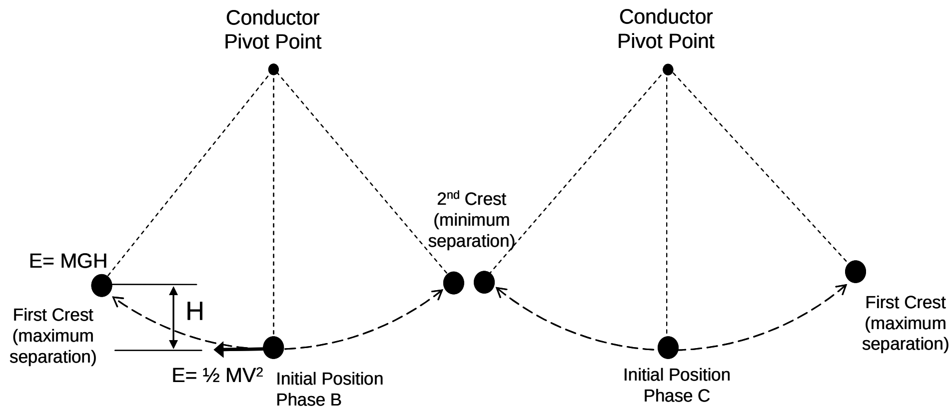


Figure 5-8
Shows the Method of Conservation of Energy to Calculate the Height H of the Initial Swing

A number of researchers have performed analysis of the conductor slapping phenomenon and several technical resources are now available. One resource is the EPRI Transmission Line Reference Guide: 115 – 138 kV Compact Line Design [EPRI, 1978]. It has extensive discussion on conductor movements due to wind and magnetic forces for compact transmission line designs—and even though it is transmission focused, much of the theory can also be applied at subtransmission and distribution levels of the system. Another possible source of information is Duke Power. Duke Power has developed an in-house software package called "MISFAULT" designed to calculate fault forces and predict conductor swings [Craven and Xu, 2004]. It has been used successfully for several studies. A recent IEEE paper written by Dan Ward of Dominion Resources is one of the best detailed papers on this topic available and is focused entirely on distribution applications [Ward, 2003]. Dominion Resources studied this problem extensively on many of their circuit designs and developed an in-house software package for studying fault forces and conductor movements. They performed several parametric studies of the effects of fault currents on various distribution configurations to identify optimum circuit breaker/recloser settings and line design practices to minimize conductor slapping problems.

Possible Conductor Slapping Solutions

The work that has been done in the industry by EPRI and several utilities is providing a better understanding of this issue. Calculation methodologies based on computer software now exist to analyze this problem and determine the appropriate line design criteria to minimize slapping faults. It is recommended that utilities always include in any new distribution line designs the proper provisions in the design to limit conductor slapping. This could mean screening the basic design characteristics to look for span situations that are susceptible to conductor slapping. Use of technologies such as covered conductor can also solve the problem. By staying away from long spans, tight conductor spacing, and excessive sag, utilities can reduce this problem.

Duke Power found that an easy but effective way of reducing the chance of conductor slapping faults is to always mount the middle-phase pin insulator on the pole rather than on the crossarm. In addition to gaining more horizontal separation, the additional vertical separation helps separate the conductor swinging motions. By changing the force vectors to include a vertical as well as a horizontal component, the force pushing the conductors apart is reduced.

Ward [2003] provides some excellent graphs for common distribution feeder designs which were analyzed for slapping faults. While these results apply mainly to one company's designs, they are generic enough to be useful to many others. These results show the critical fault levels and clearing times where conductor slapping could become an issue for various conductor spacings and span lengths. The results suggest that most problems occur with time-delayed faults and that instantaneous trips would mitigate many problems.

In cases where conductor slapping is an identified problem on already existing circuits, there are solutions available that utilities can consider. These include the installation of spacers at midspan to reduce conductor excursions on the impacted spans. In addition, shortening the duration of faults by using faster tripping times for circuit breakers and reclosers is another technique to reduce the total displacement of the conductors during the fault. Identifying that there is a problem is a key part of the process, and utilities can use monitoring resources (like digital relays) to look for signs of this problem. A telltale sign is when line-to-line faults occur that are followed within 1-2 seconds by a fault of larger magnitude. This would be an indication that a downstream fault has triggered a new fault closer to the substation probably as a result of slapping conductors.

Wind and Trees

Tree Faults

With a tree branch across conductors, the amount of time it takes to go from a high-impedance fault to low impedance can range from a few seconds up to many days or even never in some cases. In some cases the limb will eventually fall away or move away from the line never causing a low-impedance fault. Usually a limb must bridge two conductors across a short distance (less than 4-6 feet) for a fault to be established. A growing limb touching a single conductor usually has too much impedance in the current path back through the tree trunk and won't establish a sufficient voltage gradient to develop a low-impedance fault.

Tests by ECI have shown that as long as the voltage gradient along the wood is less than about 2 kV/ft that it is unlikely that a low-impedance fault will develop when a branch bridges across two conductors (see Chapter 2 and Goodfellow [2000]). With the spacing found on typical 12.47- and 13.2-kV lines, such as candlestick construction or 8- to 10-foot crossarm construction, the voltage gradient would be large enough for a fault to develop. At 15 kV or less, bridging distance longer than about 6 feet should bring the gradient down to a level where a fault won't occur. This has some ramifications for line designs. It suggests that the use of a wider than normal crossarm configuration such as 12 feet could allow conductors to be spaced in a manner that would greatly reduce tree faults at the 15-kV class level. It would not be practical at the 25- and 35-kV class level because huge crossarms of 25 feet and over would be required. It is noteworthy that 4.16- and 4.8-kV distribution designs see fewer tree faults of this nature. It is clear that the already existing spacing levels used in typical 5-kV class construction are effective at limiting bridging faults since the voltage gradient is typically well under 2 kV/ft in those situations. Covered conductor also solves these faults and is discussed later.

There is also the question of how vertically oriented bare conductors perform in the tree branch bridging situation compared to horizontally oriented bare conductors. With vertical distribution designs, as long as the weight of the tree branch is not sufficient to force the upper conductor to sag into the lower conductor, it seems very plausible that this type of construction might perform better than horizontal construction for most types of bridging branch conditions. On the other hand, other types of tree faults such as heavy limbs that force conductors together (discussed later) may actually be worse with typical vertical conductor spacing. Since those types of faults appear to be more prevalent, vertical construction may be worse than horizontal from an overall tree fault perspective. Other than comparisons of tree wire and spacer cable to bare designs, no data was found in the literature on the relative tree fault susceptibility for various conductor orientations. As future research work, it would be worthwhile to compile data on tree fault rates for different design configurations (crossarm, armless vertical, and armless candlestick approaches) to see if one is better than the others. It is possible that a widely spaced triangular conductor orientation, such as candlestick, but with much more spacing, could offer improved resistance to certain types of tree faults when using bare conductor. Figure 5-9 compares conventional designs to the proposed widely spaced triangular orientation.

Another option is to use covered conductors on just the center phase on three-phase construction, since a phase-to-phase tree contact will normally involve the center phase. That would help with both tree faults and with conductor slapping faults. And by using only one covered phase, the extra cost of covered conductors is reduced, the structure ice and wind loading is reduced, and the probability of a burndown is diminished. The middle phase conductor could also be made larger to reduce the chance of burndowns.

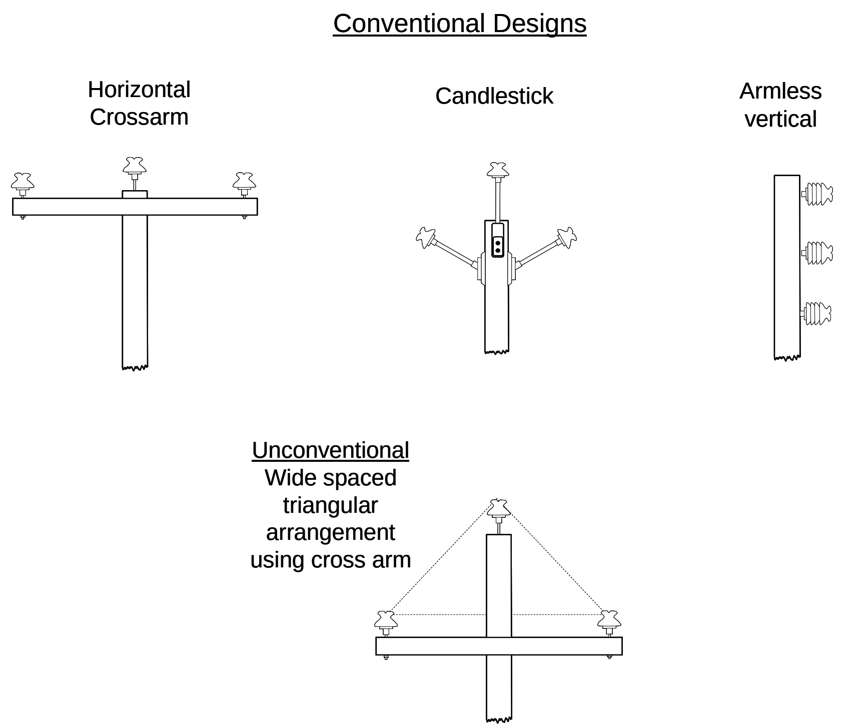


Figure 5-9
Example of a Non-Conventional Design That Might be More Resistant to Certain Tree Faults

Another type of tree problem involves a limb or tree that has fallen or blown onto the line in such a manner that it pushes two or more conductors together. This results in a direct contact fault between the wires if they are bare conductors. There is little that can be done to solve this type of fault if a big tree or limb hits a bare conductor line. The weight of a large tree limb and the forces involved are simply too great for the tensions in typical conductors to prevent such contact. For smaller trees and medium size limbs, there is a chance that use of stronger support arrangements, more spacing, and more conductor tension can help reduce some of those faults. Covered conductors or spacer cables could help reduce such scenarios.

Faults Due to Wind-Induced Conductor Motion

A strong wind alone, without any tree debris, can cause faults by forcing conductors into momentary contact. Aeolian vibrations and galloping effects are types of conductor movement and oscillations that can lead to faults. While these effects may be less critical on distribution systems than on transmission systems, they still play a role in many faults. The best approaches for mitigating these problems are very similar to those discussed earlier for short circuit current conductor slapping faults. That is, make sure the spans are not too long, that the conductor clearances are very large (not just NESC minimums), and that sag is limited. Use of spacers and vibration dampers can help in cases where these conditions can't easily be satisfied. The EPRI Transmission Line Reference Book [EPRI, 1978] has a complete chapter on wind-induced motions in conductors. The physic and equations discussed there, while focused on compact transmission line designs, can be applied to distribution scale lines since compact transmission is in some ways not that much different.

Mitigating Wind and Tree Faults

Overall, there is no easy solution to the problem of trees when it comes to overhead lines. Covered conductors and spacer cable can solve some but not all of the problems related to trees. These technologies can be used in heavily treed areas and provide other benefits besides mitigating tree faults. However the user should be aware that covered conductors, whether they are tree wire or spacer cable, have an increased possibility of burndown and so must be more carefully coordinated with overcurrent protection schemes and properly installed. In addition, spacer cable may have a lower critical flashover voltage (which can increase certain types of lightning faults). Covered conductors and spacer cable still won’t stop the heavy tree damage that pulls down the line and pole hardware, but they are good solutions for the smaller limbs and branches.

6
EQUIPMENT ISSUES

This chapter covers several miscellaneous issues that can impact power quality. The equipment issues discussed in this chapter stem from both design and material concerns.

Fiberglass Standoffs

Polymer standoffs are a commonly used alternative to the standard wooden cross arm in modern distribution system construction. As the number of units, and the amount of time in the field has increased, several utilities have documented cases in which a fiberglass standoff has unexpectedly flashed over. The phenomenon was initially witnessed by line crews after making repairs subsequent to a storm. When the distribution circuit was re-energized, a standoff assembly flashover was observed. The equipment where the flashover occurred was replaced, and the failed standoff sent for evaluation. Other than severe weathering, and arc damage, the standoff was intact. Since occurrences seem to be rare, there has been very little research into this issue, and the body of knowledge regarding it is therefore rather small. The following discussion presents the most plausible *theory* to explain the standoff failures based on currently available information [Crudele, 2004], but other factors that are yet unknown may also play a role in the failures.

Figure 6-1
Wooden Cross Arm Construction

Historically, distribution line construction utilized ceramic insulators mounted on metal pins and wooden cross arms to support the phase conductors as shown in Figure 6-1. Although wooden cross arms have performed very well, being both strong and durable, they are also heavy and labor intensive to assemble. As an alternative, the insulator industry began producing polymer based replacements for the wooden cross arms in the form of fiberglass reinforced polymer (FRP) standoff brackets. A typical polymer cross arm installation is shown in Figure 6-2. The main advantage of the fiberglass standoff over traditional wooden cross arms lies in the speed and ease of installation resulting in lower labor costs. Therefore, even with a slightly higher materials cost, the fiberglass standoff can still show an economic advantage.

Figure 6-2
Fiberglass Standoff Construction

A polymer standoff consists of a fiberglass reinforced polymer (FRP) core with metal end-fittings bonded or clamped to each end. One end-fitting provides a flat base where the standoff can be mounted to the utility pole while the other end-fitting provides a threaded connection point for a pin-type insulator (Figure 6-3). FRP is used for the core because it is relatively inexpensive, easy to fabricate, and mechanically strong. Under dry conditions FRP is non-conductive. The FRP core is coated with a UV resistant paint to give the standoff a weather resistant finish.

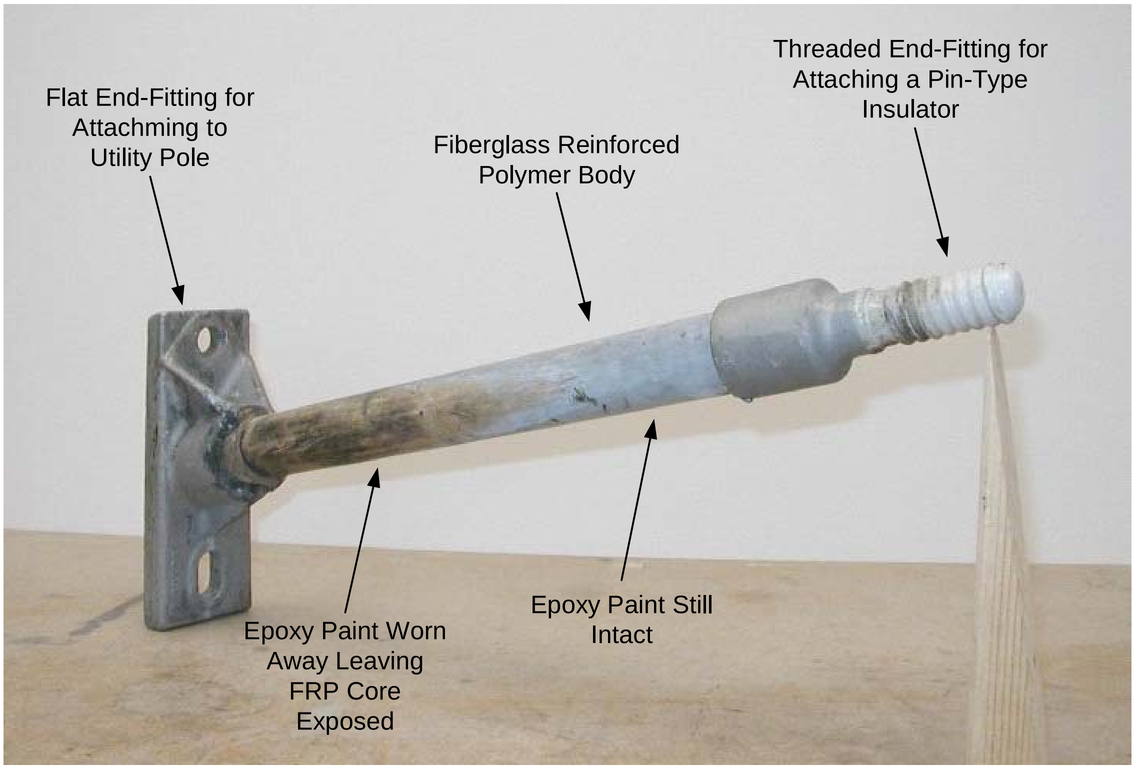


Figure 6-3
A Weathered and Damaged Fiberglass Standoff Showing the Various Components

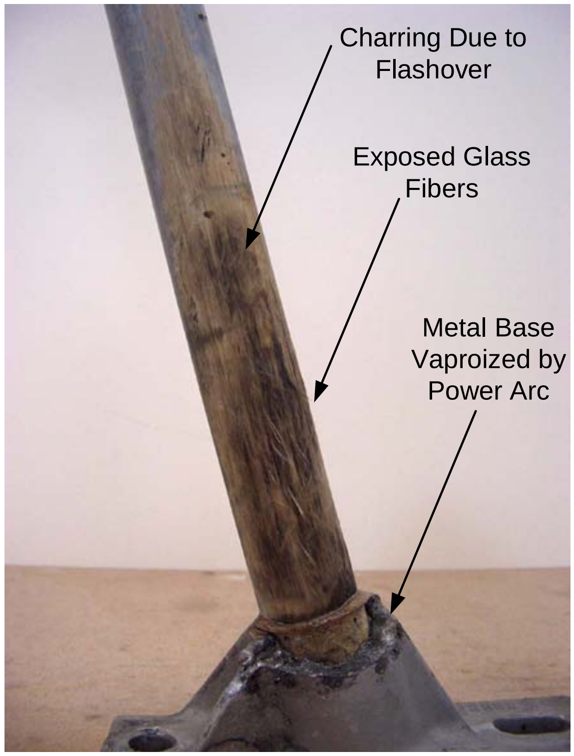


Figure 6-4
Damaged Fiberglass Standoff

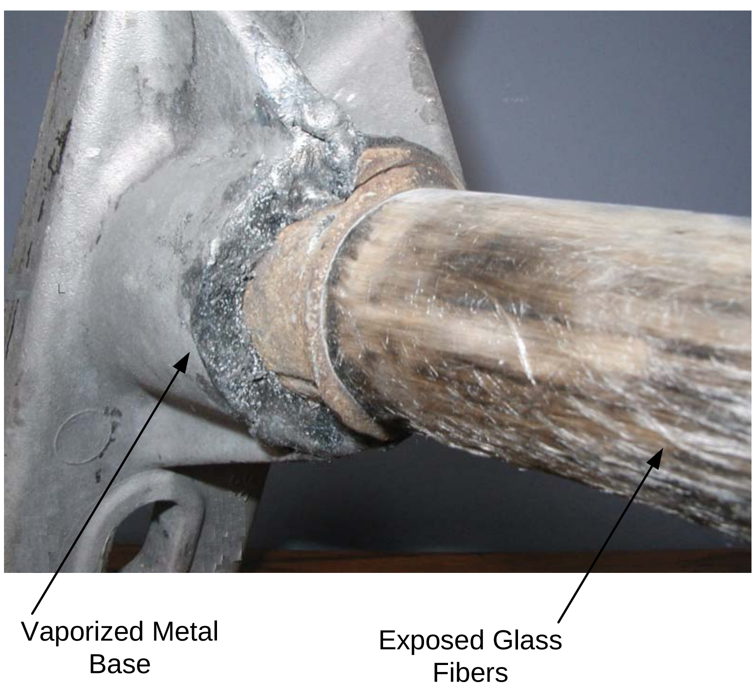


Figure 6-5
Close-up View of Damaged Fiberglass Standoff

Mechanics of the Flash Over

The failure of the fiberglass standoff is the result of a combination of factors, each of which by itself would probably not lead to a flashover. The first cause to be considered is the poor weathering characteristics of the epoxy coating on the standoff. The epoxy coating is seen to degrade rapidly when exposed to the UV present in natural sunlight. Figure 6-6 through Figure 6-8 show weathered standoff brackets. These pictures were taken as part of an informal field survey. The location was selected at random and did not have any remarkable features that would accelerate ageing (such as chemical or food processing plants or other unique contaminant sources).

Figure 6-6
Vertically Mounted Fiberglass Standoff Bracket Showing Surface Degradation

Note that the pole top is split, and the opposite standoff is pulling away from the pole

Figure 6-7
Horizontally Mounted Fiberglass Standoff Bracket Showing Surface Degradation

Figure 6-8
Fiberglass Standoff Bracket Showing Surface Degradation

As the exterior coating degrades it exposes the underlying fiberglass reinforced polymer core as shown in Figure 6-4 and Figure 6-5. In fact, it is not uncommon for half the length of the core to be exposed after just a few years in the field. When the core is exposed, precipitation falling on the standoff is wicked into the core by the glass fibers thus making sections of the core conductive and reducing the overall creepage distance of the standoff/insulator assembly. This alone should not pose a great threat because the pin-type insulator, which separates the standoff from the conductor, should provide an adequate level of insulation. However, the dielectric relationship between the ceramic pin-type insulator and the fiberglass standoff is such that they form a capacitive voltage divider as shown in Figure 6-9. The divider is characterized by the following equation:

$$V_{\text{standoff}} = V_{\text{line-to-ground}} \bullet \frac{C_{\text{bell}}}{C_{\text{bell}} + C_{\text{standoff}}} \qquad \textbf{Eq. 6-1}$$

The capacitance of the ceramic insulator is much larger than the capacitance of the fiberglass standoff, thus V_{standoff} is nearly equal to $V_{\text{line-to-ground}}$. This means that most of the line voltage is held-off by the fiberglass standoff and not the ceramic insulator. This does not normally pose a threat under dry conditions. However, as mentioned above, when precipitation is wicked into the fiberglass core it becomes conductive thereby reducing the creepage distance. If the reduced creepage distance is not sufficient to hold off the voltage, and the line potential does not properly shift to the insulator when the standoff becomes conductive, then the standoff flashes over.

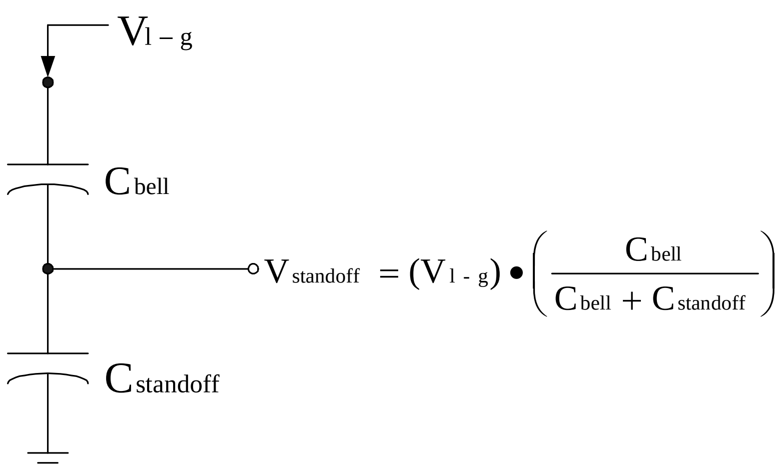


Figure 6-9
Capacitive Voltage Divider Created Between a Ceramic Pin-Type Insulator and the Fiberglass Standoff

Are Flashovers More Likely After Thunderstorms?

The common impression within the utility industry is that the fiberglass standoffs are more likely to flashover shortly after thunderstorms. However, there is no specific evidence to either prove or disprove this. It is possible that the standoff failures *appear* to be more frequent following thunderstorms because line crews are more frequently in position to observe the failures during this time period since they are out repairing storm damage. Nevertheless, there are some interesting characteristics of the post-storm time period that lend credibility to the idea that the standoff flashovers are more common in the post storm timeframe.

There are two factors that may cause increased flashover activity after thunderstorms. The first deals with the wetting and drying characteristics of the standoff and the impact on its conduction properties. The second deals with high-frequency transients which may occur when re-energizing a line after a storm related outage or line repair. During the storm, precipitation is wicked into the core through areas of exposed fiberglass. The wetted core provides a conductive path causing the line potential to shift from the standoff to the insulator. Once the storm passes and the standoff begins to dry, dry bands begin to form, which disrupt the conductive path and cause the potential to shift back to the standoff. If the potential across the standoff is great enough an arc will form over the surface to bridge these high resistance dry bands. This dry band arcing process leads to carbonization of the polymer creating permanently damaged conducting sites that can grow over the surface of the rod. This process can then lengthen to eventually short the entire standoff resulting in a flashover. Coincidentally, the time frame in which the candlestick becomes partially dry is also when line crews are likely to be re-energizing circuits that had tripped due to storm activity. When a circuit is re-energized a transient is created and the line can experience an increased voltage and a high frequency ringing on top of the 60-Hz power frequency. As if the overvoltage wasn't bad enough, the voltage divider between the ceramic insulator and the fiberglass standoff is also more likely to be dominated by their relative capacitances, as opposed to resistances, under the higher frequency conditions thus furthering the extent to which the line voltage must be held off by the fiberglass standoff.

Laboratory Demonstration

A laboratory experiment was set up to investigate the discharge behavior of a fiberglass standoff upon energization after the passage of a storm. In this test an I6, complete with a tied conductor, was placed on top of a standoff. The standoff used had previously been in service for sufficient time for most of the painted surface to have been lost due to weathering, revealing much of the underlying resin and reinforcing glass fibers. A small amount of distilled water was sprayed over the entire assembly to simulate wetting due to passage of the storm. The output of a voltage source was connected to the conductor on top of the I6, while the bottom of the standoff was grounded. The applied voltage was chosen to be at a high frequency to correspond to the oscillations present in a typical energizing switching operation. Numerous discharges were found to appear along the length of the standoff, occasionally accompanied by discharges on the I6 and conductor assembly. Figure 6-10 shows an example of the discharge behavior.

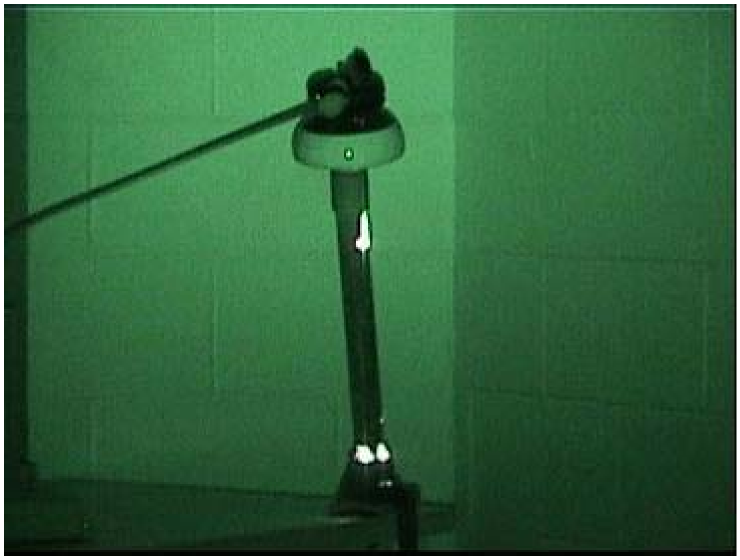


Figure 6-10
Discharges Over the Surface of an Energized Fiberglass Standoff

The voltage applied in this test was 35 kV, at a frequency of 1 kHz. In Figure 6-10 it can be seen that there are several coincident arcs along the length of the fiberglass rod, indicating that most of the applied voltage lies across its surface rather than on the insulator that it is supporting.

Degradation of Other Fiberglass Apparatus

Other fiberglass reinforced polymer (FRP) products often experience the same type of field degradation whether or not they are under electrical stress. For example, fiberglass guy strain insulators which are used to replace ceramic guy insulators (commonly referred to as “johnny balls”) often exhibit similar surface degradation due to UV exposure and environmental contaminants. They are afforded somewhat better UV resistance compared to the insulator standoffs because they are veiled rather than painted but they still show similar degradation over time. The veiling technique is used to provide the guy strain insulators with better abrasion resistance. Although they are not normally under electrical stress, it is unclear how the surface degradation affects the mechanical strength of the insulators.

Possible Solutions

There are several possible solutions that can be applied to avoid the standoff flashovers:

- *Different insulators* – It may be possible to use insulators with a lower capacitance thus altering the capacitive divide ratio and placing more of the working voltage across the insulator instead of the standoff. Some polymer insulators may offer a lower capacitance than the ceramic insulators. However, capacitance is highly dependent on the insulator shape, so long, skinny insulators, much like the candlestick, would most likely offer the best chance for a more favorable divider ratio.

- *Different or additional sheath material* – The problem may be remedied by keeping the fiberglass core from being exposed. One possibility would be to jacket the core in several millimeters of silicone rubber. While it would add to the cost of the unit, it would also provide far superior weatherability and keep the inner core from being exposed. Other materials such as EPDM or an improved paint formulation could also be employed.
- *Conductive standoffs* – By incorporating conductive materials in the core of the standoff, or even by using a metallic standoff, the voltage distribution would favor a condition where the line voltage would be across the insulator only, at all times. This approach achieves the goals of fast and inexpensive construction while reducing the flashover potential of the standoff / bracket.
- *Wood construction* – While the fiberglass standoffs are lighter and less costly to install than the traditional wood cross arms, which is why they are used, the wood cross arm does not pose the same flashover threat as the fiberglass standoff. While reverting back to wood construction is a possibility, it is also the least attractive solution because it represents a step backwards in terms of cost and ease of installation.

The Need for Further Study

Little information is known within the utility industry regarding the standoff failures. One reason for this is that the failures are seldom observed and hard to diagnose. The failures do not always cause a protective device to operate and when they do the standoff may function normally once the line protection clears the fault and the circuit is re-energized. One consideration that remains relatively obscure is what exactly the electrical path is when the standoff flashes over. It is not known whether it presents a line-to-ground fault, line-to-line fault, or both. The main source of information on the occurrence of these failures has come from line crews who witnessed the failures in the field. There has been very little laboratory research done to investigate the cause of these failures and possible remedies. It would be beneficial to the industry for more formal research to be untaken to study the processes that lead to such failures.

Polymer Insulators

While they have not yet gained widespread acceptance in the utility industry, polymer based insulators are being used to a greater extent than ever before in the construction and repair of electrical distribution lines. The first of the modern polymer insulators emerged in the 1960's [Hall, 1993]. From that point onward, manufacturers have constantly strived to increase their product's performance while decreasing costs. Over time, the forward progress in technology has resulted in many changes to the physical design of the insulators as well as changes in the base materials and fillers they are made from. Unfortunately, the constantly evolving nature of the polymer or non-ceramic insulator (NCI), coupled with its relatively recent development, has made it difficult to obtain long-term field performance data. For this reason the long-term reliability of polymer-based insulators is still somewhat unknown. In order to help fill in this gray area, a great deal of work has been done in *accelerated* ageing and laboratory testing of polymer insulators. There are however many ageing and stress variables to consider including environmental considerations, variations in materials, and physical differences in the designs from different manufacturers. For these reasons it is still not possible to definitively determine whether polymer based insulators will exhibit an operational life comparable to the ceramic insulators they are intended to replace. However, there is a strong case that polymer insulation can outperform ceramic over relatively short service intervals, especially under heavily polluted conditions. For more background on polymer insulators, see Hackam [1999], Mackevich and Shah [1997], Mackevich and Simmons [1997], and Simmons et al. [1997].

Composition of Polymer Insulators

Modern polymer insulators are molded from one of four main compounds: ethylene-propylene-diene-monomer (EPDM), silicone rubber, high-density polyethylene (HDPE), or another thermoplastic material. In addition to these base polymers, the insulators contain a variety of fillers as well as other agents to enhance their performance. In fact, the compounds for modern non-ceramic insulators are rather complicated and usually consist of 10 or more different "ingredients". Most of the materials in the formulation fall into the following categories:

- *Elastomers* – This is the base polymer, usually EPDM, HDPE, silicone rubber, or thermoplastic material.
- *Vulcanizing agents* – These agents cause a chemical reaction that results in cross-linking of the elastomer material. Cross-linking makes the material stiffer and more temperature stable.
- *Coagents* – The coagents protect the already formed cross-link bonds and help to promote new bonds.
- *Antidegradants* – These retard the deterioration of the rubber compounds. Rubber compounds are degraded by oxygen, ozone, heat, and UV light and therefore the antidegradants are also called antioxidants, antiozanants and inhibitors.
- *Processing aids* – The processing aids help in the flow, mold, and release stages of the manufacturing process.
- *Fillers* – Fillers are used to reinforce physical properties, impart processing characteristics, and reduce costs. Two common fillers are alumina trihydrate (ATH) and silica. It is typical to include 10-20% silica for rheological control and ~50% ATH to act as a flame retardant. Adding ATH also provides a cost savings, since ATH is generally less expensive than the polymer base material.
- *Coupling agents* – The coupling agents aid in bonding the filler and elastomer materials.
- *Plasticizers and softeners* – These are used to adjust the flow and flexibility of the material during the molding process and in the final product.
- *Special purpose materials* – These are typically the manufacturer's "secret ingredients" that are used to impart certain characteristics to the material that help set it apart from the competition.

The exact formulation of the polymer compounds are proprietary to each manufacturer and are closely guarded trade secrets. It is also common for manufacturers to alter their formulation every few years as they work to improve their products and reduce costs.

Depending on the particular application, a polymer insulator may be molded as one piece which is composed entirely of the polymer material or it may be made from several pieces, not all of which are polymer based. For example, pin-type polymer units that are intended to replace ceramic bell insulators are injection molded as a one piece unit composed entirely of polymer material and resemble the traditional ceramic bell in shape (Figure 6-11). One the other hand, strain-type polymer insulators utilize a polymer jacket and weather sheds molded to a fiberglass reinforced polymer core with metal end-fittings clamped to each end as shown in Figure 6-11.

Available Designs

Polymer insulators are available for just about any distribution application that was traditionally performed by a ceramic insulator including:

- Pin-Type Insulators
- Strain-Type Insulators (dead-ends)
- Post Insulators
- Standoffs (cross arm replacements)
- Guy Strain Insulators

Figure 6-11 shows some of the different types of polymer insulators available. Polymer insulation was initially adopted on a wider scale by the transmission industry because of the tremendous weight savings offered by polymers. This was particularly beneficial when upgrading transmission voltages on towers that could not handle the weight increase that additional ceramic insulation would have caused.

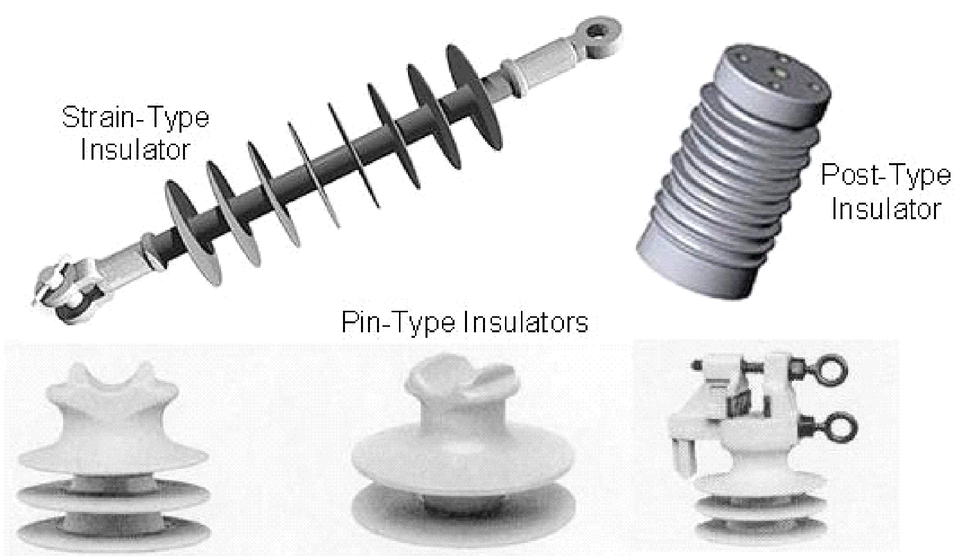


Figure 6-11
Different Polymer Insulator Designs

Advantages of Polymer Insulation

Polymer insulation has several benefits when compared to traditional ceramic insulation, namely:

- *Weight reduction* – Polymer based insulators are much lighter than their ceramic counterparts. The average 15-kV class strain-type polymer insulator weighs approximately 2.5 pounds while a 7.5-kV class strain-type ceramic insulator averages 5.5 pounds. Furthermore, a single 15-kV polymer insulator can be used where two 7.5-kV ceramic insulators were needed previously. This corresponds to an approximate 75% reduction in weight!
- *Flexibility and impact resistance* – Polymer based insulators offer a much higher level of impact resistance compared to ceramic insulators. Since the polymer material is less brittle than the ceramic material, the polymers are less likely to be broken during transportation and installation. Polymer insulators are fairly tolerant to being dropped and offer great advantages in resistance to vandalism. While a gunshot will normally shatter a ceramic insulator, polymer insulators have a tendency to allow the bullet to pass through the insulator sheds leaving behind a hole but remaining for the most part in tact.

Drawbacks of Polymer Insulation

Utilities, which are historically conservative in nature, have been slow to adopt polymer insulators into their construction practices. Switching over to polymer insulators presents some new ground for many utilities who are primarily concerned with the following drawbacks:

- *Lack of long-term field performance data* – Since the modern polymer insulator industry is relatively new, especially given the expected length of service of distribution insulators, there is little long-term field performance data available. Another factor complicating the collection of long-term data arises from the continually evolving nature of polymer insulators. Since manufacturers alter the composition of their products every few years many products that have undergone field and laboratory testing are no longer available.
- *Susceptibility to tracking and erosion* – Polymer insulators can be more susceptible to tracking and erosion than ceramic insulators. The polymer material is particularly vulnerable to corona cutting in which corona discharges on the surface of the insulator cut channels into the polymer material. Corona cutting leaves behind carbon tracks which can act to short the insulator or the corona cutting can degrade the insulator to a point at which is fails mechanically.

Degradation of Polymer Insulators

Like ceramic insulators, the performance of polymer or non-ceramic insulators is degraded by exposure to the natural environment in the field [Crudele, 2002; McGrath et al., 2001]. Insulator degradation usually begins as surface erosion, which results in reduced surface hydrophobicity and may eventually culminate with dry-band arcing and insulator failure. Exposure to ultraviolet light and ozone, both of which are naturally occurring *and* created by corona discharges, degrades polymer materials. Outdoor insulation is also constantly exposed to airborne pollutants from a variety of sources. A few of the major contaminants are road salt that is levitated up from the roadway, sea salt, cement dust from cement plants, and bird droppings. Additionally, hematite (Fe_2O_3) is found on insulators in strong concentrations near steel plants; and anhydrous gypsum, silica, and bassanite are found on insulators in both agricultural and industrial areas. These pollutants settle out of the air onto the surface of the insulator coating it in a layer of "pollution dust". Furthermore, the acids found in acid rain also attack the insulator surface causing erosion of the polymer material.

Surface degradation results in reduced surface hydrophobicity. The roughened surface with reduced hydrophobicity is more likely to hold contaminants and water thus forming a conductive film on the insulator's surface. The actual conductivity of the film depends on the surface contamination as well as the conductivity or the precipitation. Once contaminated, leakage current will flow through the film layer creating heat from the process of Joule Heating. The heat created causes non-uniform evaporation of the water on the insulator surface leading to "dry-bands" which are surrounded by wet areas. The dry-bands present an area of high resistance in the conductive path on the surface of the partially wetted insulator. This process effectively shortens the creepage distance of the insulator and allows for a high voltage drop over the small distance of the dry-band. The increase in electric field across the dry-band is enough to cause small discharges or scintillations. The discharges will carry more current as they grow in size and intensity. The arcing discharges produce a large amount of localized heat, which decomposes the polymer and allows the free carbon to rise to the surface. This process forms a conductive, carbonized path, or track, that will eventually short the electrodes of the insulator.

Polymer insulators may also suffer from corona discharges. The UV generated by the corona discharge promotes surface erosion and the heat generated by severe corona discharges can cut into the polymer surface resulting in what is known as corona cutting. Corona cutting is rare at the distribution level so loss of hydrophobicity from surface erosion tends to be the greater concern.

Issues Not Related to Electrical Performance

Other issues that are not based on insulator performance can influence utilities to apply polymer based insulation. One major factor is that polymer insulators have reached a cost at or below that of ceramic insulators. In fact in many utilities, the purchasing department is driving the switch to polymer insulators. A second driver in the switch to polymer insulation is a continually diminishing supply of ceramic insulators. Several ceramic insulator manufacturers have stopped production or gone out of business in the past several years creating some concern about their future availability.

Current Usage Trends

Non-ceramic insulators currently represent the majority of newly installed high voltage insulators in North America. Furthermore, some estimates indicated that as much as 70% of new insulator installations are non-ceramic [Hackam, 1999]. Early insulator formulations left much to be desired and attached a stigma that polymer insulators are just beginning to overcome within many utilities. In general, utilities appear to look favorably upon the performance of their existing NCI installations, especially those utilizing the latest product offerings. The main source of concern regarding polymer insulation continues to stem from their uncertain service life. Modern polymer insulators have not exhibited reduced service life, they just haven't been in the field long enough to prove that they are capable of 30 years or more of reliable service. Overall, it seems that the migration to non-ceramic insulators is in full swing and may almost be a necessity as the supply of ceramic insulators continues to dwindle.

Stress Cracking of Fuse Cutouts

Some utilities have reported that a portion of their porcelain fuse cutouts are experiencing stress cracking of the insulator that can lead to it breaking apart. During fuse insertion/removal, the crack can lead to a break that results in faults or swinging energized parts hanging from or near the cutout. A weakened cutout can also break on its own (unattended) due to external loads or during the forces associated with a fault clearing operation of the fuse. Cracks in porcelain can allow water ingress over time into the material itself, which may eventually lead to flashovers within and around the porcelain. These failures can pose a risk to crews working on circuits as well as the public, and they can degrade power quality and reliability. The nature and extent of this problem is currently under study within the industry. For the most part, the problem appears to be limited to one type of porcelain fuse cutout (manufactured mainly 10+ years ago). However, the industry needs to collect more data on this to determine if the issue is more widespread and is significant enough to warrant industry wide attention.

Porcelain insulated fuse cutouts use three metal pins cemented with a grouting compound into holes in the porcelain insulator (these are often called potted pin cutout designs). These metal pins are located at the top and bottom of the insulator to hold the source and load conductor connecting hardware, and a third pin is at the center body of the insulator to attach the cutout mounting bracket (see Figure 6-12). The stress cracking that has been observed in some cutout units is believed to originate from within the porcelain at the locations where these pins are cemented into the insulator. At these locations, the porcelain is subjected to stresses due to the electrical, mechanical and environmental operating conditions to which the cutout is exposed. Over time, water entry into cement material can occur. Freeze/thaw cycles of this water result in stress cracking of the porcelain at the cement/porcelain interface. Besides water entry, other processes, such as the differential expansion between the porcelain and metal, may also create some of the stress cracks.

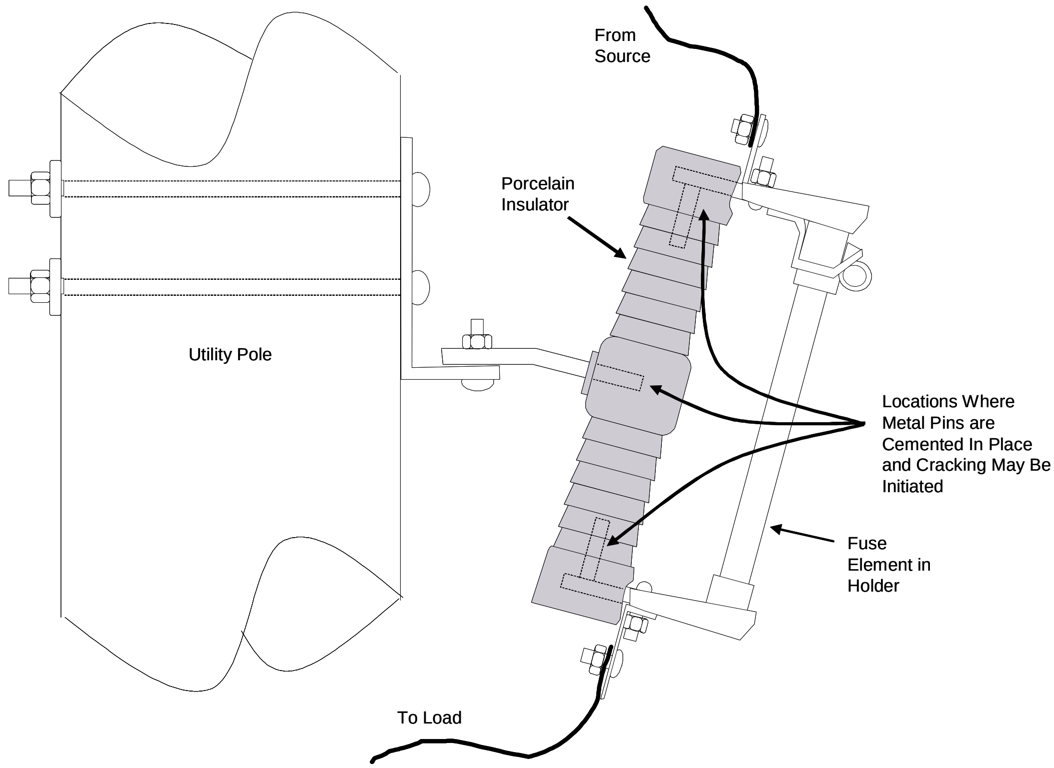


Figure 6-12
Typical Porcelain Fuse Cutout Configuration Showing Cemented Metal Pins in Porcelain

Once a crack is initiated, it can grow through repeated stress cycles until mechanical cutout failure occurs. A cutout can remain partially cracked for some time without apparent malfunction and would even require very close physical inspection to see the cracks in some cases. The force of a lineman inserting or removing a fuse can easily be more than enough to completely break a weakened (cracked) unit. A breakage at the moment of fuse insertion/removal could easily result in the lineman accidentally causing a fault so this becomes a safety concern for the utility.

British Columbia Hydro (BC Hydro) is one utility that has studied the porcelain cracking issue and developed a strategy for managing the risk. They published their results in a recent technical paper [Li et al., 2004]. The BC Hydro experience shows that they have approximately 308,000 porcelain-insulated fuse cutouts on their distribution system and most of these are in good condition—however, a small portion have begun to crack. To mitigate the risk of defective cutouts and to maintain reasonable reliability of their distribution system, BC Hydro adopted a "Risk-Based Least Cost Strategy" for managing risk associated with their porcelain fuse cutouts. The strategy was developed by Powertech Labs and included the following steps:

- A random sampling process of the existing cutout population was performed to determine the portion of the fuse cutout population likely to be subject to a cracking condition.
- The reliability of cracked cutouts under the range of typical operating conditions was assessed.
- The risk that cutout failure poses to line maintenance personnel and the public was assessed and remedial actions evaluated to reduce risk.

- Cost-benefit analysis of the most appropriate remedial actions was assessed.

The random sampling program evaluated 13,529 fuse cutouts across 52 districts in the BC Hydro service territory. Based on the sampling results, the percent of the installed population with cracking ranged from 0.27% in the district with the lowest number of defective units to 8.0% in the district with the highest number of defective units. For the entire population (all districts), the percent of the population with cracking was calculated to be about 0.84% based on the random sampling. No cracking was observed in units purchased after 1997. BC Hydro indicated that this was due to more stringent quality control included in the purchase specification.

A fault tree was developed for BC Hydro that considered the possible risk outcomes associated with cracked cutouts. The analysis considered the probability of failure when crews were attempting to operate the cracked cutout as well as the probability of failure when crews are simply working nearby (climbing the pole and causing vibrations). Based on historical injury data, laboratory tests of the forces needed to fail a weakened cutout, and engineering judgment, the probability of injury associated with a lineman attempting to work with or near a partially cracked (weakened) cutout was conservatively estimated to be 1 in 1000 per work operation (0.1%). The probability of loss of life was estimated to be 1 in 5000 per work operation (0.02%).

To address the fuse cutout problems, BC Hydro considered a remedial action plan that offers the lowest net present value (NPV) cost over a 10-year period. The cost model included factors such as liability, outages, materials and labor. Three remedial approaches were considered at the district level:

1. *No action*—Simply replace cracked cutouts as they are found in the field – this was the existing standard practice.
2. *Selective replacement*—Replace fuse cutouts, regardless of their being cracked or un-cracked, when crews are working at cutout pole. Also, replace in high-risk areas.
3. *Blanket replacement*—Initiate program to rapidly replace all pre-1997 porcelain cutouts throughout the system.

Based on the NPV analysis, option 3 was determined to be best (lowest NPV cost) for two of 52 districts, option 2 was best for 18 districts, and option 1 was best for the remaining districts. It should be recognized that while the BC Hydro work focused heavily on the safety of crews and the public, that there also is a reliability benefit of applying the proposed remedial plans since this would reduce faults and accelerate the speed of power restoration efforts by crews.

Several other Canadian utilities besides BC Hydro have had an interest in this issue. As a result, CEA Technologies, Incorporated (CEATI), a Canadian research organization, has prepared a report titled *Condition Assessment of Porcelain Cutouts (#T044700-5031)* that evaluated methods for detecting cracked cutouts in the field. The report also contains some data on cutout failures. In the US, some utilities have also expressed interest in the issue and Georgia Tech's National Electric Energy Testing Research and Applications Center (NEETRAC) has recently initiated research to assess the scope of the problem. The project involves laboratory tests and analysis on failed units and was just beginning as of early 2005. Results of the NEETRAC investigation may be available later this year (2005) or next year.

To obtain a better understanding of the scope of the cutout cracking issue, many North American utilities, a manufacturer, and industry experts were informally surveyed about their experiences with cracking fuse cutouts. The consensus of the discussions was that most utilities are not having a problem at this time but that roughly 1/5th (20 percent) of those responding reported a problem. Those that have a problem reported it was primarily with one particular brand made nearly a decade ago. 15- and 25-kV fuse cutouts were the most commonly cited voltage ratings where the problem occurred. There is more concern about this issue in colder climates (such as at Canadian Utilities and northern US utilities) which makes sense given how the freeze/thaw cycles likely impact the formation of cracks.

Based on the discussions with industry experts, manufacturers and utility engineers, the susceptibility of the cutout to this kind of cracking is greatly a function of the manufacturing quality control and design, and it can be virtually eliminated with proper manufacturing processes, materials, and sealing methods. This statement tends to be confirmed by the fact that BC Hydro was able to essentially eliminate cracking in units purchased after 1997 by specifying specific manufacturing characteristics and quality. As a result, it is felt that the cracking problem has nothing to do with the general viability of porcelain as an insulation medium; in fact, porcelain has shown excellent long-term aging characteristics in its history of use. Instead, the problem is with the manufacturing process and materials used in the design of the particular cutouts in question.

Some engineers feel that the industry movement from the old “banded” fuse cutout design of several decades ago, to the more modern potted pin based designs, while lower in cost, not only results in a potential water ingress point if the potting material cracks, but also results in increased stress on the porcelain. The potted pin approach subjects the insulator to the weaker tension mode of strength rather than in its stronger compression mode as the banded designs did. These may be reasons for the increased cracking happening in some potted pin porcelain cutouts. These characteristics for potted pin designs put increased importance on having a good manufacturing design and process control compared to the earlier banded designs.

An area that needs to be looked at is the reporting of cutout failures. It is hypothesized that some cracking problems may be underreported because they are reported simply as cutout flashovers or faults in the utility outage reporting database and this does not stand out as a “cracking issue” in the minds of utility engineers that see this data. These may be instead listed as a lightning flashover, contamination flashover, or some other type of non-cracking related failure. However, some of these faults may have originated from water ingress into stress cracks which led to reduced voltage withstand strength, tracking and eventual failure (flashover). If this is the case, then a larger portion of utilities could be experiencing the cracking issue than is accounted for in the informal survey discussed above. The data that has been published in the industry technical literature so far is insufficient to determine if the cracking problem is widespread or simply inconsequential and not worthy of much attention. The pending results of the NEETRAC investigation, possible future EPRI studies, and other studies at utilities should eventually provide the data needed to address this issue.

For now the main advice to utilities when considering this issue is to make sure that the cutout manufacturer from whom they purchase equipment recognizes the potential problem and has implemented suitable safeguards in the design and manufacture to limit moisture ingress into the pin locations and limit stresses that could cause cracking. Some utilities have decided to change over to polymer insulated fuse cutouts as a solution to cracking, but this approach, in the long run, may not lead to any higher reliability since overall porcelain units have generally performed well in the field and the porcelain insulator surface has well established and excellent aging characteristics. Polymer insulators, being newer, do not yet have as much long-term aging experience.

Remedial actions to detect cracking in the field and change out any existing units that are cracking must be done on a cost effective basis similar to that described in the BC Hydro paper. However, the CEATI work indicated that it can often be difficult to detect the small cracks visually in the field so how this process is implemented practically without removal of the cutout is not clear. Some cracks can be easily detected, but others may go unnoticed.

7
SUMMARY AND FUTURE WORK

Tree Faults and Power Quality

The main power quality impact of trees is that they cause interruptions, and some of the damage from these faults can take considerable time to repair. Trees can cause faults in several ways: growth into conductors, failing trees or branches bridging gaps or pushing conductors together, and failing trees or branches causing mechanical damage. Results of utility surveys show that growth is normally less than 15% of permanent interruptions. Dead trees or branches account for about 30 to 40% of tree faults, and trees with significant defects account for another significant portion.

Reviews of utility outage databases show the following:

- *Major storms*—For many utilities, most faults and most damage during major storms are from trees. Tree faults are strongly a function of the weather, with wind and ice being major sources of tree failure.
- *Protective device*—Tree faults on the circuit mainline cause the most impact to customers. Trees also tend to be a higher percentage of fault causes on three-phase circuits than on single-phase circuits.
- *Feeders*—Tree interruption effects on customers can cluster significantly by circuit: some circuits have much more impact on overall customer interruptions. These are circuits with high numbers of customers and high exposure to tree faults.
- *Voltage*—Higher voltage circuits tend to be impacted by tree faults more, mainly because of more circuit exposure.

Tree faults also can cause momentary interruptions and voltage sags. Although trees have been reported to cause flicker, analysis in this report shows that tree contacts that cause flicker are unlikely: the impedance of the tree is too high to draw sufficient current to cause noticeable flicker. Once a tree limb arcs and breaks down, it will become a short circuit.

Strategies to Reduce Tree Faults

Utilities should attempt to gain more information about tree faults to help target these faults more efficiently:

- *Outage cause codes*—Use more specific outage cause codes to help develop strategies to reduce tree faults. Rather than just having a code for “trees,” use more specific codes or sub-codes like: vines, tree from out of right-of-way, tree in the right-of-way, limb from in the right-of-way, and limb from out of the right-of-way. Use a separate code to track weather at the time of the fault. Consider using a separate code to indicate the damage done: none, pole down, wire broken, and so on. Also, consider doing a follow-up audit on a certain portion of outages to ensure that outage cause codes are not being misused.

- *Sample surveys*—Use sample follow-up surveys of tree outages to identify more specifics for the particular region. Use follow-up visits to the outage site with a forester to identify the tree species that caused the fault, the type of fault (trunk failure, small branch, growth, and so on), and any identifiable tree defects. This information will help when targeting hazard trees.

To most efficiently apply tree maintenance for the best power quality, consider vegetation management programs to target those circuits where tree faults would impact power quality the most and where tree faults are more likely, including:

- Mainline portions of circuits
- Circuits with more customers or critical circuits feeding industrial parks or other important customers
- Circuits with a history of tree faults
- Circuits with higher voltage

With a targeted program, don't just use a uniform maintenance cycle and pruning specification, but use a targeted approach to more effectively reduce the fault rate from trees on the targeted sections:

- *Maintenance cycle*—Vary the maintenance and/or inspection cycle. For example, a utility may be able to improve power quality and reduce costs by tightening the mainline cycle and lengthening the single-phase cycle.
- *Clearances*—On targeted sections (such as mainlines), use wider clearances, do more tree removal, and clear more overhangs.
- *Hazard-trees*—On targeted sections, clear trees that are the most likely to fail and fall on conductors. These are trees that are dead or have another significant defect and are likely to fall on the line because of the defect.

Each of these factors could be handled differently. For example, a utility could choose to have a fixed maintenance cycle of four years on all circuits, remove overhangs on all circuit mainlines, and remove hazard trees on the mainlines of the worst 25% of circuits (where worst could be some tree-related benchmark like five-year customer interruptions from trees). A comprehensive tree-maintenance strategy should include economics as well as impacts on power quality and reliability.

Several construction options are available to make overhead circuits more resistant to tree faults:

- *Wider spacings*—At spacings with voltage gradients less than 1 to 2 kV/ft, tree branches across conductors are unlikely to fault. A 12.5-kV structure with a 10-ft crossarm and with the center phase pin on the pole has about five feet between phases; this is about 2.5 kV/ft, a spacing that can still have tree faults. Wider spacings may be possible by raising the middle phase or using a vertical structure.

- *Covered conductors*—Covered conductors can help reduce faults from tree limbs bridging conductors or trees pushing conductors together. If using covered conductors, take extra measures to protect covered conductors from arcing damage from faults—try to make sure that relaying and fusing adequately protects the conductors, and/or consider using arc protective devices. Also, account for the other drawbacks of covered conductors, including increased weight, increased wind and ice loading, and increased possibility of conductor corrosion.
- *Spacer cables*—Spacer cables offer the advantages of covered conductors and offer some extra mechanical protection as well. The spacer cables also have most of the disadvantages of covered conductors to consider. In addition because of reduced spacings, the insulation to lightning may be lower, so lightning-caused faults may increase.
- *Mechanical coordination*—Consider equipment component failures in structure designs, and try to coordinate the mechanical design such that when tree and large limb failures occur, equipment fails in a manner that is easier for crews to repair. When a tree falls on a line, crews will have an easier repair if it just breaks the conductors rather than breaking poles and other supports. The fault still occurs, but crews are able to more quickly repair the damage and restore service.

Conductor Slapping Faults and Conductor Spacings

When a fault occurs on a circuit, the magnetic forces from the flow of fault current can cause conductors to swing together. This causes another fault upstream of the original. The result is a deeper voltage sag and a possibility that more customers are interrupted as an upstream protective device may operate. Conductor slapping due to short-circuit current forces is not just an obscure problem, but instead one that is widely encountered at most utilities. Long spans, tight conductor spacings, and excessive sags are especially susceptible. Avoiding these can reduce the probability of conductor slapping. On horizontal crossarm designs, an easy but effective way of reducing the chance of conductor slapping faults is to always mount the middle-phase pin insulator on the pole rather than on the crossarm. In addition to gaining more horizontal separation, the additional vertical separation helps separate the conductor swinging motions. In addition, shortening the duration of faults by using faster tripping times for circuit breakers and reclosers is another technique to reduce the problem. Also, covered conductors can be used.

Equipment Issues

In this project, several miscellaneous equipment issues that might impact power quality were reviewed. These include:

- *Fiberglass standoffs*—Fiberglass distribution apparatus does not possess a long service history and thus questions remain about its degradation characteristics and service expectancy. Anecdotal evidence as well as samples removed from service indicates that fiberglass standoff brackets in particular may be prone to flashover. This phenomenon can contribute to degraded power quality and poses a possible safety risk.

- *Polymer insulation*—While they have not yet gained wide-spread acceptance in the utility industry, polymer based insulators are being used to a greater extent than ever before in the construction and repair of electrical distribution lines. Unfortunately, the constantly evolving nature of the polymer or non-ceramic insulator (NCI), coupled with its relatively recent development, has made it difficult to obtain long-term field performance data. However, there is a strong case that polymer insulation can outperform ceramic over relatively short service intervals, especially under heavily polluted conditions, and there is growing evidence that non-ceramic insulators also perform satisfactorily in the long term.
- *Fuse cutouts*—Some utilities have reported that a portion of their porcelain fuse cutouts are experiencing stress cracking of the insulator that can lead to it breaking apart. These failures can pose a risk to crews working on circuits as well as the public, and they can degrade power quality and reliability. The nature and extent of this problem is currently under study within the industry. For the most part, the problem appears to be limited to one type of porcelain fuse cutout (manufactured mainly 10+ years ago). However, there is a distinct possibility that the problem is more widespread, and the industry needs to collect more data on this issue to determine the scope of the problem.

Future Work Plan

This project is part of a multi-year effort to concentrate on ways to improve power quality using practical methods on transmission and distribution systems. More work is planned on developing a base of knowledge from utilities, particularly in developing a set of case studies and sharing cost and performance data for construction-improvement projects. In 2005, work will focus on consolidating work done in 2002 through 2004 and providing tools that utilities can use to help design and operate their T&D systems with better power quality. Specifically, online resources will be created with the following information and features:

- Reports
- Online calculators
- Case studies
- Interactive forums

A focus for the 2005 work will be gathering case studies from utilities, and as this project continues, the online resources will continue to grow in content and capabilities.

The information and capabilities of most interest to utility sponsors will be added first. Topics available for the online resource include:

- Line lightning protection
- Distribution transformer configuration
- Line clearance
- Protective device coordination
- Recloser and fuse operation
- Capacitor placement and control
- Single-phase tripping
- Overhead versus underground designs
- Technologies for controlling faults caused by animals
- Controlling faults caused by trees
- Grounding practices
- Conductor size and characteristics
- Voltage regulation technologies

Other Future Work

During this project, several other areas were found that warrant further research. These are not yet part of a specific research plan, but they should be considered for future work:

- *Tree Fault Tests with Covered Conductors and Spacer Cables* – Several utilities have done tests of trees and tree branches in contact with distribution circuits with bare conductors. Tests of field-aged covered conductors and spacer cables could answer several questions, including: what voltage gradients are needed for flashover, how does new covered wire compare to aged, what types of coverings perform better (XLPE, EPR, PVC, etc.), and what types of degradation (abrasion, UV, pinholes) make flashovers more likely?
- *Burndown Tests of Covered Conductors* – Burndown of covered conductors is still the main problem with applying covered conductors. More data on the characteristics of a wider range of conductors under arcing conditions would help utilities choose conductor sizes more effectively and apply fusing and overcurrent protection sufficient to protect the conductors from burndown.
- *Tree Fault Rates of Different Line Configurations* – There already exists a fair amount of data regarding the mechanisms of tree faults. However, little information exists comparing the tree-fault susceptibility of various conductor orientations. It would be worthwhile to compile data on tree fault rates for different design configurations (crossarm, armless vertical, armless candlestick, etc.) to determine which designs offer the best tree fault performance with different conductor types. More non-conventional designs, such as a widely spaced triangle, should also be investigates since they could also offer improved resistance to tree faults – especially when using bare conductor. It would also be worthwhile to gather more data on tree wire vs. spacer cable vs. bare wire construction.
- *Optimum Distribution Span Length* – The longest possible span length is desirable from a purely economic standpoint. However, power quality and reliability both suffer at very long span lengths thus the most economic design may not be the best from an overall performance standpoint. Smaller span lengths allow for stronger, more reliable line up to a certain lower

limit. Power quality and reliability are reduced beyond the lower span length limit because significantly increasing the number of poles results in more opportunities for animal-induced faults, automobile accidents, and other types of pole damage. Therefore, the optimal span length is somewhere in the middle when economics, power quality, and reliability are considered together. For rural systems, this length is likely to be shorter than the optimal economic length. For suburban systems that already utilize short spans, the optimal span length may be longer than that dictated by economics only. Further study needs to be performed to address these issues and determine a method for assessing optimum span length based upon economics, power quality, and reliability considerations.

- *Fiberglass Standoff Degradation and Flashover* – There has been very little research within the industry regarding the degradation and flashover over fiberglass reinforced polymer standoff brackets. Anecdotal evidence and informal field surveys have indicated that the standoffs can be compromised by environmental ageing, possibly culminating in a flashover of the standoff. This phenomenon poses both a potential safety risk as well as a risk to power quality and reliability and thus warrants further investigation. Further research should involve quantifying the manner and timeframe in which the standoffs degrade (ultraviolet exposure is suspected to be the major degrading factor) as well as probing further into the dielectric relationship between the standoff and insulator.
- *Mechanical Degradation of Fiberglass Apparatus* – All fiberglass line apparatus will suffer some amount of degradation due to environmental exposure, regardless of whether or not it is exposed to electrical stress. Many fiberglass components, like guy insulators and insulator standoffs are also under large mechanical loads. This leads to the question of how the mechanical strength of these components is affected by environmental degradation. Both fiberglass insulator standoffs and fiberglass guy insulators have exhibited severely degraded surfaces including the exposure and detachment of glass fibers after several years of environmental exposure in the field. It would therefore be beneficial to investigate the affect that environmental exposure has on the mechanical strength of fiberglass components.
- *Stress Cracking in Fuse Cutouts* – Some utilities have reported that a portion of their porcelain fuse cutouts are experiencing stress cracking of the insulator that can lead to it breaking apart. This can result in faults or swinging energized parts hanging from or near the cutout during fuse insertion or removal. A weakened cutout can also break on its own (unattended) due to external loads or during the forces associated with a fault clearing operation of the fuse. Although it appears to be isolated to specific manufacturers and specific vintages, it would be beneficial to the industry to undertake more research into quantifying the scope of the problem – are certain designs, vintages, or installations more prone to fail and what is the likelihood of failure? This information will help utilities determine if replacement is warranted, and if so, how to optimally replace the affected cutouts. Although some of this work has been done by individual utilities, there needs to be a large-scale examination of the porcelain cutout population.

8
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