3

Overhead Line Performance

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Wind, fungi, ultraviolet light, tree branches, whole trees, and animals of various sizes—each of these can stress overhead distribution lines, electrically and/or mechanically. In this chapter, we explore several programs or options that utilities use to maintain and/or improve the performance of their distribution infrastructure. Poles, conductor, and line hardware all have long life, often exceeding 50 years, but many utilities have aging infrastructure. The deterioration and replacement of equipment must be monitored and managed to continue providing safe, reliable service.

Major storms increase stresses on overhead infrastructure, and damage to the overhead distribution system can overwhelm a utility’s normal response and repair, leading to customer interruptions lasting days. Hardening of overhead infrastructure or resiliency improvements to reduce damage and reduce times to repair can reduce customer impacts. Many of the programs discussed in this chapter also have applications for resiliency as well as for normal performance.

3.1 Vegetation Management

Trees are the source of many reliability issues on circuits, and vegetation management is expensive. 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. In addition to long-duration interruptions,
the faults from trees cause voltage sags and can cause momentary interruptions. During major storms, trees are particularly damaging to distribution infrastructure.

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

3.1.1 Outages and Damage from Trees

Understanding how trees cause outages and damage will help utilities design more tree-resistant lines and help utilities more efficiently manage vegetation maintenance. A great deal of work on tree faults has been done since the 1990s that should help utilities design more tree-resistant structures and optimize vegetation management. Faults caused by trees generally occur from a handful of conditions:

- Falling trees or major limbs knock down poles or break pole hardware (Figure 3.1 shows a common pole breakage just above the third-party telecom attachment point)
- Tree branches blown by the wind push conductors together
- A branch falls across the wires and forms a bridge from conductor to conductor
- Natural tree growth causes a bridge across conductors

Utility studies of tree outages have shown that most outages are caused from trees or branches bridging conductors or breaking equipment. Rees et al. (1994) examined

Figure 3.1  Video sequence of a falling tree causing a fault and breaking a pole. (Courtesy of Alexander Kirichenko. http://youtu.be/-gUD31Bqnuo.)
over 3000 tree-related outages over 7 years and 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
- 98% of tree-caused outages were from trees or tree parts falling on lines; less than 2% were due to natural growth or burning branch tips beneath the lines

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, and 2% from tree growth.

EPRI 1008480 (2004) documents surveys by BC Hydro of their tree-related interruptions were as follows: 70% from tree failure, 18% from branch failure, and 12% from growth.

Finch (2001) reported on a survey that Niagara Mohawk Power Corporation (now a part of National Grid) performed in 2000. 86% of permanent tree faults were from outside their maintenance zone covering out to 10 ft (3 m). Growth only accounted for 14% of outages (Figure 3.2), 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 maintenance zone, and 62% were caused by a broken trunk or branch.

Taylor (2003) reported on a 1995 sample survey of tree-caused outages where 73% of tree outages occurred when an entire tree fell on the line. 86% of these were from outside of a 30-ft (9-m) right-of-way. Dead limbs or trees caused 45% of tree outages. In addition, Duke Energy’s investigations of this 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.

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 3.3).

Detailed tree outage codes allow utilities to target causes more precisely. See Table 3.1 for a breakdown of tree faults and their impact on outages for one utility. Note that

![Figure 3.2](image-url)  
**Figure 3.2** Niagara Mohawk survey of tree outage causes. (Data from Finch, K., Understanding tree outages, EEI Vegetation Managers Meeting, Palm Springs, CA, May 1, 2001.)
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.

Duke Energy has done considerable work on using its 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 Energy’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 and also rain, snow, and ice.
- **Season and time of day**—The most tree faults occurred during summer and the least occurred during 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. 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).

| TABLE 3.1 Percentage of Tree Faults 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  |

Note: CI = customer interruptions; CMI = customer minutes of interruptions.*
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 mostly 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, 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. On the basis of these results, Niagara Mohawk modified its program to target the worst circuits, the 13.2-kV system, the circuit backbone, and hazard-tree removal.

Being highly correlated with weather, season has a large impact on tree fault rates. Duke Energy has the most tree-caused faults during summer and the least during fall (Chow and Taylor, 1993; Xu et al., 2003). Another southeastern U.S. utility also has the most outages during summer as shown in Figure 3.4.

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-caused 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 3.2 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;

![Figure 3.4](image_url)  
*Figure 3.4*  Tree-caused outage impacts by month.
the main difference is that faults impact less customers on the lower-voltage circuits. Table 3.3 shows data from a southeastern utility that shows similar tree-caused fault rates on 15- and 25-kV class systems. These findings strongly suggest that targeting of vegetation management should help improve performance and more efficiently manage tree maintenance budgets. Target tree maintenance and other tree-improvement strategies (such as 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

Trees are often associated with momentary interruptions, but trees are probably not a major contributor to momentary interruptions. As shown in Chapter 14, trees in contact with just one phase conductor do not cause high-current faults. There may be burning near the contact point, but the contact normally draws less than 1 A, and that is well below what is needed to trip reclosers or circuit breakers. So, if temporary faults regularly occur from trees, they must be across conductor-to-conductor contacts in close proximity, and not just conductor to tree. There are plausible mechanisms for this: 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.

### 3.1.2 Physics of Tree Faults

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

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**TABLE 3.2 Tree Faults by Voltage Class for a Northeastern U.S. Utility**

<table>
<thead>
<tr>
<th>Voltage (kV)</th>
<th>Tree SAIDI (min)</th>
<th>Tree Fault Rate per 100 miles per Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.4</td>
<td>4</td>
<td>11.6</td>
</tr>
<tr>
<td>4.16</td>
<td>22</td>
<td>9.6</td>
</tr>
<tr>
<td>13.8</td>
<td>34</td>
<td>10.8</td>
</tr>
</tbody>
</table>

*Note: Includes major storms.*

**TABLE 3.3 Tree Faults by Voltage Class for a Southeastern U.S. Utility**

<table>
<thead>
<tr>
<th>Voltage Class (kV)</th>
<th>Tree Fault Rate per 100 miles per Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>With Major Storms</td>
</tr>
<tr>
<td>15</td>
<td>68</td>
</tr>
<tr>
<td>25</td>
<td>51</td>
</tr>
</tbody>
</table>
phase or phase to neutral). A tree branch into one phase conductor normally draws less than 1 A of current under most conditions; this may burn some leaves, but it would not 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. Baltimore Gas and Electric (Rees et al., 1994) staged some revealing tests that showed how tree branches can cause faults. ECI (Appelt and Goodfellow, 2004; Finch, 2001, 2003a; Goodfellow, 2000, 2005) tested over 2000 tree branch samples covering over 20 species and a range of voltage gradients.

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. See Figure 3.5 for an example of a test on a 0.5-in. (1.3-cm) diameter red alder energized at 3 kV/ft (10 kV/m) that faulted in 80 sec.

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

![Figure 3.5](image-url)  
**Figure 3.5** Progression of arcing and carbonization of a branch. (From Goodfellow, J., BioCompliance Consulting, Inc. With permission.)
low-impedance carbon path will still be there unless the branch burns enough to fall off of the wires.

Some notable electrical effects include

- The likelihood of a fault depends on the voltage gradient along the branch (see Figure 3.6).
- The time it takes for a fault to occur depends on the voltage gradient (see Figure 3.7).
- 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.
- Thicker branches are more likely to cause faults because their impedance is lower. Thin branches can also burn through and fall off before the full carbon track develops. So, minor leaf and branch burning does not cause faults.
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- Lower-voltage circuits are more immune to flashovers from branches across conductors. A 4.8-kV circuit on a 10-ft (3-m) crossarm has about a phase-to-phase voltage gradient of 1 kV/ft (3 kV/m), very unlikely to fault from tree contact. A 12.47-kV circuit has a 2.7 kV/ft (9 kV/m) gradient, which is more likely to fault.

ECI found that branch characteristics affected the probability of failure (Goodfellow, 2000, 2005). Thicker branches were more likely to flashover, and live branches were also more likely to flashover 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 does not make the fault more likely. ECI did find some differences between species. Florida Power Corp. (Williams, 1999) also found variation: in their tests, palm limbs faulted the fastest (1 min in their setup), and pine limbs lasted the longest (15 min).

These effects reveal some key issues:

- Pruning 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 pruning strategy performs poorly since most tree 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 flashover because of tighter conductor-to-conductor spacings.
- Three-phase construction is more at risk than single-phase construction.

3.1.3 Utility Tree Maintenance Programs

Vegetation management is expensive—see Figure 3.8 for results of a survey showing annual costs vegetation management costs averaging $1039/mi ($646/km). Tree maintenance can also irritate communities. It is always a dilemma that people do not want their trees pruned, but they also do not want interruptions and other disturbances.

A similar survey data showed a median cost of $4754 per mile managed with upper and lower quartiles of $7981 and $2497 per mile managed based on average costs from 2005 to 2010 (CNUC, 2013). Costs vary significantly from utility to utility and reflect differences in tree coverage, load density (urban and suburban pruning is more difficult than rural tree maintenance), vegetation management cycle, and tree growth rates.

Figure 3.9 shows data on the costs of vegetation management programs and 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.
Most utilities use a fixed vegetation maintenance cycle time. Choosing a cycle time is tricky. Many utilities use a 3-year to 5-year cycle. One might expect that longer tree maintenance cycles should lead to higher fault rates. The optimal pruning cycle depends on

- Tree clearance specifications and historical clearing approaches
- Type of trees, growth rates, and growing conditions
- Community tolerance for pruning
- Economic assumptions

Correlating the effect of tree maintenance and performance can help utilities optimize vegetation maintenance, but this can be tricky. Some effects that can interfere with correlations between performance metrics and maintenance include

- **Targeting**—Targeting poorly performing circuits for maintenance can help improve customer satisfaction, 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 often vary and pruning specifications or contractors sometimes change. Both can impact different years differently.
- **Reconfigurations**—Circuit reconfigurations can make it difficult to reliably judge the history of tree fault impacts.

Figure 3.10 characterizes one utility’s impact of vegetation from 1999 to 2003, including major storms. These are primary events with a vegetation cause. Each
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Figure 3.11 shows the average annual tree-caused event rates for one of Duke Energy’s operating regions based on outages from 2009 to 2011. These are primary events, including major storms, but excluding days above a 3.5-beta threshold. These

Figure 3.9 Vegetation management costs versus performance. (Data from 2003 PA Consulting Benchmarking survey; BC Hydro, Revenue requirement application 2004/05 and 2005/06, Chapter 7. Electricity distribution and non-integrated areas, 2003; from EPRI 1008506, Power Quality Implications of Transmission and Distribution Construction: Tree Faults and Equipment Issues, Electric Power Research Institute, Palo Alto, CA, Copyright 2005. Reprinted with permission.)

diagram shows the effect of the time since the last tree pruning. So, the first datapoint in each graph is the given reliability metric based on all circuits that had tree maintenance during the previous year. One might naively expect that tree-caused outages would decrease steadily following tree maintenance, but the data does not show this. There is no strong trend over this short time period.

Figure 3.11 shows the average annual tree-caused event rates for one of Duke Energy’s operating regions based on outages from 2009 to 2011. These are primary events, including major storms, but excluding days above a 3.5-beta threshold. These
are normalized by overhead line miles. The fault event rate is relatively flat for most of the first 10 years after maintenance.

Overall, tree-caused outage events do not increase dramatically with longer times between tree maintenance when analyzed over reasonable time periods. Quoting Gugenmoos (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.”

Vegetation maintenance cycles are tied with maintenance specifications and historical clearance approaches. Table 3.4 shows results for several operating regions for Duke Energy. These regions have historically had different approaches to vegetation management. Areas X and Y have common vegetation approaches. Area Z

![Figure 3.10](image1)  
**Figure 3.10** Tree maintenance effect on performance.

![Figure 3.11](image2)  
**Figure 3.11** Vegetation fault rate versus time since maintenance for Duke Energy area Z. (Analysis courtesy of Lee Taylor, Duke Energy.)
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has longer-than-normal maintenance intervals but maintains larger-than-normal clearances. Area Z has lower vegetation fault rates at lower cost. Area Z’s performance challenges recent industry trends to shorter maintenance intervals. This area achieves performance partially by maintaining more clearance. With more clearance, fewer trees and branches are at risk of falling into the line. Costs are less because of longer cycle times, even though more vegetation is generally cut at a given location. Herbicides also help control undergrowth to allow this longer cycle. Larger clearances are easier to maintain if the clearance zone or right-of-way has been established and maintained consistently. The public will resist the major changes to clearance, but if clearance can be established, the public will accept the status quo, and it is easier for the utility to keep that clearance. Another factor contributing to area Z’s performance is a hazard-tree program for the three-phase mainline with annual inspections.

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

**Shock hazard**—See Chapter 14.

**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-in. (0.46-m) spacing between conductors and vegetation for all distribution and transmission circuits. In addition, California (Public Resource Code Section 4293) requires a clearance of 4 ft (1.2 m) for circuits in any mountainous land, or in forest-covered land, brush-covered land, or grass-covered land operating between 2.4 and 72 kV. Meeting 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, ECI found that extending tree maintenance cycles beyond the optimum can increase the 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 off. ECI estimated that for each $1 saved by extending maintenance

<table>
<thead>
<tr>
<th>Region</th>
<th>Cycle Time (Years)</th>
<th>Vegetation Specification</th>
<th>Maintenance Cost per Vegetation Mile per Year ($)</th>
<th>Customer Interruptions from Vegetation per Vegetative Mile</th>
<th>Average Vegetation Incidents/100 Vegetation Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>X</td>
<td>4</td>
<td>10 ft (3 m) to sides and down to neutral</td>
<td>1998</td>
<td>39.7</td>
<td>25.5</td>
</tr>
<tr>
<td>Y</td>
<td>6</td>
<td>10 ft (3 m) to sides and down to neutral</td>
<td>1154</td>
<td>26.8</td>
<td>29.5</td>
</tr>
<tr>
<td>Z</td>
<td>13</td>
<td>30 ft (9.1 m) ground to sky and herbicide</td>
<td>672</td>
<td>24.2</td>
<td>20.8</td>
</tr>
</tbody>
</table>

*Source: Courtesy of Lee Taylor, Duke Energy.*

TABLE 3.4 Duke Energy Cycle Times and Vegetation Specifications with Performance Metrics
cycles would require from $1.16 to $1.23 in spending if the cycle was extended 1 year past its optimum, and if the circuit is 4 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 Energy discovered that during the ice storm of 2002 that impacted their service territory, the circuits that had not been maintained in 13 years had 5 times the damage of circuits that had been maintained from 1 to 6 years prior (Taylor, 2004, personal communication). Because of this, Duke justified increasing the vegetation management budget based on reducing storm repair costs.

Regulations—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 if that coincides with decreased reliability or customer satisfaction, regulators may impose fines or mandate changes.

On many subtransmission lines, critical distribution lines, or circuit backbones, clearing a right-of-way is an effective way to reduce the chance of tree contacts from falling limbs or trees. Such right-of-ways are regularly maintained for high-voltage transmission lines. Even if a wide ground-to-sky clearance is not possible for complete circuits, where you can get clearance, it is advantageous to maintain what you can claim.

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.

### 3.1.4 Hazard-Tree Programs

Hazard-tree programs target those trees that are the largest threats to utility circuits. Tree pruning within a zone (e.g., ±10 ft) targets tree growth, but most tree outages are from trees or branches from outside of typical utility trim zones. Hazard-tree programs target dead trees or trees with significant defects, even if they are out of the normal maintenance zone or right-of-way. Consider hazard-tree inspections that are more frequent than the pruning cycle to catch death or deterioration in trees before they fall and cause damage.

Dead trees are the most obvious candidates for hazard-tree removals. In a sample of permanent tree faults, Niagara Mohawk Power Corporation (now National Grid) found 36% were from dead trees (Finch, 2001), and in another sample, Duke Energy found 45% were from dead trees (Taylor, 2003).
Targeting hazard trees is highly beneficial, but requires expertise to find many types of tree defects. Figure 3.12 shows some of the tree defects that led to tree faults in one study. In an examination of several cases where broken branches or trees damaged the system, Finch (2001) reported that 64% of the trees were living. 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 hazard trees. Dead trees or large splits are easy to spot. Cankers (a fungal disease) or codominant stems (two stems, neither of which dominates, where 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 3.5). Finch also reported that much of the extra impact of aspens on outages was due to

![Image of tree defects](image-url)

**Figure 3.12** Defects causing tree failure for the Niagara Mohawk Power Corporation. (Data from Finch, K., *Understanding Tree Outages, EEI Vegetation Managers Meeting*, Palm Springs, CA, May 1, 2001.)

<table>
<thead>
<tr>
<th>Species</th>
<th>Percent of Outages</th>
<th>Percent of New York State Population</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ash</td>
<td>8</td>
<td>7.9</td>
</tr>
<tr>
<td>Aspen</td>
<td>9</td>
<td>0.6</td>
</tr>
<tr>
<td>Black locust</td>
<td>11</td>
<td>0.3</td>
</tr>
<tr>
<td>Black walnut</td>
<td>5</td>
<td>N/A</td>
</tr>
<tr>
<td>Red maple</td>
<td>14</td>
<td>14.7</td>
</tr>
<tr>
<td>Silver maple</td>
<td>5</td>
<td>0.2</td>
</tr>
<tr>
<td>Sugar maple</td>
<td>20</td>
<td>12.0</td>
</tr>
<tr>
<td>White pine</td>
<td>6</td>
<td>3.3</td>
</tr>
</tbody>
</table>

*Source: Data from Finch, K., *Understanding Tree Outages, EEI Vegetation Managers Meeting*, Palm Springs, CA, May 1, 2001.*
hypoxilon canker, which their crews often overlooked as a defect. The sugar-maple faults were mainly from large, old roadside maples in serious decline.

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 hazard-tree programs can improve distribution performance, 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. Hazard-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 a striking distance of T&D circuits, a hazard-tree program cannot be a one-time expenditure.

While most hazard-tree programs are best directed by a professional forester, it is beneficial for anyone involved in distribution field investigations to have some background knowledge of the common tree defects. A number of resources are available for this, including USDA (1996, 2003), Fazio (1989), and EPRI 1012443 (2007).

### 3.1.5 Vegetation Program Performance

As with any program impacting reliability, efforts are best spent on the poorest-performing circuits that affect the most customers. To target, spend more on three-phase mains than on single-phase taps, as an example. Vegetation programs can be targeted by adjusting maintenance intervals, clearance requirements, use of herbicides or tree-growth retardants, and application of hazard-tree inspections and removals. These can be optimized based on the circuit or region or even system wide based on the needs and issues for the area. This type of reliability-centered maintenance can improve costs and performance (EPRI 1019417, 2009).

On the basis of outage reviews and testing on how trees were causing faults (Rees et al., 1994), Baltimore Gas and Electric switched to a more prioritized vegetation management program on its distribution system (mainly 13.2 kV). They focused less on pruning for natural growth and attempted to remove overhangs where possible. They implemented a 3-year maintenance cycle on the three-phase system, and delegated the one- and two-phase system to “trim only as necessary.” 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.

Eastern Utilities, a small utility in Massachusetts (now a part of National Grid) implemented a hazard-tree mitigation project (Simpson, 1997; Simpson and Van Bossuyt, 1996). Three-phase primary circuits were targeted, dead or structurally unsound trees were removed, and 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
Overhead Line Performance

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 hazard-tree mitigation project. Instead, they funded the program by changes to their normal vegetation management program. They did less pruning 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.

After a study of tree-caused outages on their system, Niagara Mohawk Power Corporation (now National Grid) implemented a program called TORO (tree outage reduction operation), which had the following characteristics (EPRI 1008480, 2004; Finch, 2001, 2003a,b):

- 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 also added inspections 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 (PSE) implemented a hazard-tree program (Puget Sound Energy, 2003). Started in 1998, the focus was 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 measurably. They reduced the cost of tree maintenance per circuit mile by about 15%.

Finch (2003b) provides details on several targeted programs. Two utilities adjusted maintenance cycles to reduce cost and focus work on the most critical portions. On urban circuits, one utility used a 4-year cycle on the backbone with a 2-year inspection to catch cycle busters and used a 5-year cycle on laterals. On rural circuits, they used a 5-year cycle for all circuits. They also developed a hazard-tree removal program based on results from their outage database. Another utility extended the maintenance cycle from 4 years to between 5 and 6 years on rural single-phase circuits.
As noted earlier, clearances and vegetation specifications are tied with reliability performance, maintenance intervals required, and cost. Especially for feeder backbones and important lines, more clearance above and to the sides can reduce the number of branches and trees that can hit lines. Herbicides and tree-growth regulators are also options to consider for managing clearances and reducing the amount of cutting needed. Consider pruning performance as improper pruning can trigger exaggerated regrowth and excess wounds.

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

- Talking to residents prior to/during tree pruning.
- Pruning trees during winter (or tree pruning done “under the radar”)—the community will not notice tree trimming as much when the leaves are not on the trees.
- Pruning trees during storm cleanups. Right after outages, residents are more willing to accept their beloved trees being hacked up (this is a form of the often practiced “storm-induced maintenance”; fix it when it falls down).
- Cleaning up after trees are cut/removed.
- Offering free firewood.

Audits can help utilities manage vegetation maintenance and improve performance. Many utilities do quality-assurance audits after tree maintenance. Especially with contract crews, postwork inspections 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.

There are limits to what vegetation management can realistically achieve for line performance. Just throwing money at vegetation management will not necessarily translate into improved reliability. A large portion of faults are caused by branches or trees from well outside normal maintenance zones. This effect is even more pronounced during major wind and ice storms, where much damage comes from trees falling from outside any realistic maintenance zone, many from healthy trees.

### 3.2 Covered Conductors

Utilities with heavy tree cover often use covered conductors, conductors with a thin insulation covering (Figure 3.13 shows an example). The covering is not rated for a full conductor line-to-ground voltage, but it is thick enough to reduce the chance of flashover when a tree branch falls between conductors. A 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 such as polyethylene, XLPE, and EPR are common. For modern-vintage material, insulation thicknesses typically range from 30 to 150 mils (1 mil = 0.001 in. = 0.00254 cm). From a design and operating viewpoint, covered conductors must be treated as bare
conductors according to the National Electrical Safety Code (NESC) (IEEE C2-2012), with the only difference that tighter conductor spacings are allowed. There are various grades of insulation used for the covering.

Spacer cable (Figure 3.14) and aerial cables are also alternatives that perform well in treed areas. Spacer cables are a bundled configuration using a messenger wire holding up three phase wires that use a covered wire. Aerial cables have fully rated insulation just like underground cables.

Other advantages of covered conductors include

- **Spacings**—The NESC 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 pointed out that it does not 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 that 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 the 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 deenergize 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 trade-offs to be aware of. They are more susceptible to damage from fault arcs, they may cause radio-frequency interference (RFI) if the correct insulator tie is not used, and conductor corrosion is more likely.

Good fault data is hard to find comparing fault rates of a bare wire with a 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 a bare wire and 1 per 100 km/year on a covered wire (Hart, 1994).

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 10:1 ratio (although the article did not specify if this included both temporary and permanent faults). The aerial cable faults were lower than a bare wire by a 20:1 ratio. The effect on interruption durations is shown in Table 3.6. Several spacer
Overhead Line Performance

cables or aerial cables can be constructed on a pole. Spacer cables and aerial cables have some of the same burn-down considerations as a covered wire. Spacer cable construction has a reputation for being hard to work with. Both spacer cable and aerial cable cost more than a bare wire. CEMIG estimated that the initial investment was returned by the reduction in tree maintenance. They did minimal pruning around an aerial cable (an estimated factor of 12 reduction in maintenance costs) and only minor pruning around the spacer cable (an estimated factor of 6 reduction in maintenance costs).

The utility data at the beginning of this chapter on the 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 Energy 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 77% (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 industrial data or testing to allow us to estimate the differences. Tighter spacings may have other adverse effects such as reduced insulation levels and more animal contacts.

Duke Energy has found that the best use of covered conductors is in areas with high overhang, where the trees are far above the three-phase lines (Short and Taylor, 2006). Often, tree branches fall from the high canopy and land between two conductors. Covered conductors really help in this situation. Short of ground-to-sky clearance, no amount of tree pruning can eliminate the problem.

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.

**TABLE 3.6** Comparison of the Reliability Index

<table>
<thead>
<tr>
<th>Construction</th>
<th>SAIDI (hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bare wire</td>
<td>9.9</td>
</tr>
<tr>
<td>Spacer cable</td>
<td>4.7</td>
</tr>
<tr>
<td>Aerial cable</td>
<td>3.0</td>
</tr>
</tbody>
</table>


*Note: SAIDI = average hours of interruption per customer per year.*
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 single conductors. While spacer cables should perform better for tree growth issues and for small-to-medium branches, if entire trees fall into them, poles are more likely to break because of the strength of the messenger and attachment to poles.

Pole structures with covered conductors can generate 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 is not stripped at the insulator
- Insulated conductor tie on a bare or covered line conductor (see Figure 3.15)

A conducting insulator tie in close proximity to the phase conductors creates a prime arcing scenario that can cause power-line noise. 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 et al., 2007). 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 et al. (2007) also document a second cause of RFI from incompatible insulator ties: if the insulation deteriorates enough so that the tie touches or nearly touches the line conductor, then an insulating oxide layer can build between the two, leading to microsparking noise from breakdowns across this small gap.

Figure 3.15  Example of a covered wire tie on a covered conductor. (From Vincent, W. R. et al., The Mitigation of Radio Noise and Interference from External Sources, 6th ed, United States Navy Naval Postgraduate School, 2007.)
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 1980s found that keeping the cover on raises the critical flashover voltage from about 115 kV with a 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 the weakest: at the insulator where the tie comes in contact with the covering (Figure 3.16). The covering will not add significant insulation to a structure with an insulator and a foot (0.3 m) or more of wood or fiberglass.

Covered conductors are heavier, have a larger diameter, and have a lower-strength rating. Relative to the same size of a 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

![Figure 3.16 Example of damage on a covered conductor from flashover at the insulator tie. (Courtesy of Duke Energy.)](image-url)
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 by 14%
- **Horizontal**—Loading due to wind increases by 8%
- **Resultant**—Loading due to the vertical and horizontal component increases by 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 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 cannot evaporate). On bare conductors, corrosion is rare—rain washes bare conductors periodically, and evaporation takes care 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 (see the previous chapter). 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 at high temperatures. 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 as high as 100°C.

### 3.3 Animal Protection

Animals cause many issues with distribution lines. For many utilities, they are the second or third cause of faults on overhead circuits. Many unknown faults are also likely to be animals. Fortunately, with proper construction practices that include animal protection, utilities can greatly reduce animal faults using relatively simple approaches.

3.3.1 Animal-Fault Basics

Faults caused by animals are often the number two cause of interruptions for utilities (after trees). An animal that bridges the gap between an energized conductor and ground or another energized phase will create a highly ionized, low-impedance fault-current path. The fault will cause a voltage sag to nearby customers and an interruption to the portion of the circuit covered by the upstream protective device. An animal can cause a temporary fault or a permanent fault. If the animal remains or a charred arc path leaves a conducting path, the circuit will not be able to hold voltage, and the fault will be permanent. If the animal gets blown off or falls away, the circuit can be reenergized (a temporary fault). Animal-caused faults are normally phase to ground. A phase-to-phase flashover path is uncommon but can happen; a three-phase flashover is rare.

Squirrels cause the most faults on overhead distribution circuits. Squirrels thrive in suburbs and love trees; utilities have noted increases in squirrel faults following the development of wooded areas. Squirrels are creatures of habit and tend to repeatedly follow the same paths. Squirrels have a need to gnaw, which can be destructive to utility equipment; they will chew secondary wire coverings and aluminum connectors.

Different species of squirrels are of different lengths. From the longest to the shortest, the main species are (lengths are nose to tip-of-tail measurements (Jackson, 1994))

- Fox squirrels: 18 to 27 in. (46 to 69 cm)
- Eastern and Western gray squirrels and tassel-eared squirrels: 16 to 20 in. (41 to 51 cm)
- Red and Douglass pine squirrels: 10 to 15 in. (25 to 38 cm)
- Northern flying squirrels: 10 to 12 in. (25 to 30 cm)
- Southern flying squirrels: 8 to 10 in. (20 to 25 cm)

While we can see that the longest fox squirrels can stretch more than 2 ft, separations between energized conductors of 18 to 24 in. are normally enough to prevent most squirrel-caused outages. Spacings less than 10 in. are extremely prone to squirrels—for example, across an unprotected bushing. While squirrels are the most common cause of faults, several other climbing animals can cause faults on overhead circuits, including raccoons, rats, cats, and snakes. While some of these animals are longer than squirrels, the protective measures for squirrels also protect against most faults from other climbing animals.

Common birds (including starlings and blackbirds) rank second behind squirrels as far as the number of animal-caused interruptions caused on overhead distribution circuits (EPRI TE-114915, 1999; Frazier and Bonham, 1996). Birds normally cause faults in much the same way as squirrels—by bridging the gap across locations with tight spacings: for example, unprotected bushings or surge arresters. Birds use utility equipment to perch on and for nests. Many of the same protective measures that protect against squirrel-caused faults will also protect against bird-caused faults. Other ways that birds can cause faults include bird-dropping contamination on insulators and woodpecker damage to poles. Large groups of flocking birds (such
as starlings or crows) can cause a conductor to swing into another conductor when the flock suddenly leaves the conductor. Many large birds, including eagles, hawks, owls, and herons are wide enough to span the normal phase-to-phase separations on overhead distribution circuits. Because of this, extra measures are needed to protect these birds from electrocution. As such, it is a matter of protecting endangered animals; in most cases, the frequency of large-raptor contacts is small relative to other animal contacts.

Most animal-caused faults occur in fair weather. Chow and Taylor (1995) found that over 85% of animal faults occurred during fair weather on the Duke Energy system. They also found that more than half of the animal faults occurred during the morning, and few occurred during the evening or late at night. Squirrels sleep at night and are most active in the morning as they are looking for food. Some utilities also experience seasonal variations in weather patterns, as animals are less active during winter.

Since animal-caused faults are normally during fair weather, the power-quality perception of these faults is heightened. Utility customers normally expect disturbances during poor weather—but not in good weather. When a customer loses a critical process due to a utility interruption or voltage sag, and it is not stormy, the customer is more likely to complain.

The types of animals causing faults vary considerably by region, and there is also a significant variation within a region. Animal faults also ebb and flow with animal populations. Animal population data can be used as one way to determine if “unknown” faults are really being caused by certain animals.

The patterns of animal-caused faults have been used to classify “unknown” faults. Chow et al. (1993) developed a classification routine to identify animal-caused faults based on the following outage inputs: circuit identity (ID), weather code, time of day, phases affected, and protective device that operated. Animal faults are more likely during fair weather, mornings, only one phase affected, and for a transformer or tap fuse. These same classification strategies can be used to estimate how many of the “unknown” faults are actually animals.

EPRI surveyed utilities on animal faults and animal protective measures (EPRI TE-114915, 1999). Out of 84 respondents, 77% had some sort of structured program to address animal-caused interruptions. 78% of animal-caused outages were attributed to overhead distribution with the remainder split almost evenly between underground distribution, substation, and transmission.

The EPRI survey also points out where most animal-caused outages occur—at equipment poles, where phase-to-ground spacings are tight. Figure 3.17 shows that most problem areas are at equipment poles. Transformers are by far the most widely found pole-mounted equipment on a distribution system. Unprotected transformer poles normally have many locations susceptible to animal faults: across the transformer bushing, across a surge arrester, and from a jumper to the transformer tank. Riser pole installations, regulators, reclosers, and capacitor banks all have susceptible flashover paths unless utilities employ protective measures. Poles without equipment are much less susceptible to animal faults (exceptions are poles with grounded guys or ground wires near phase conductors).
### 3.3.2 Animal Guards, Wire Coverings, and Other Protective Equipment

Of the major causes of faults—animals, trees, lightning, and equipment failures—animal faults are the most easily prevented. The two main ways to protect equipment against animals (particularly squirrels and birds) are

- Bushing protectors
- Covered lead wires

Bushing protectors and covered lead wires are inexpensive if installed with equipment (but relatively expensive to retrofit). A variety of bushing guards are available. These can be used for bushings and surge arresters found on transformers, capacitors, regulators, reclosers, and sectionalizers. Of these locations, transformers are the most common. Properly applied bushing guards in conjunction with covered jumper wires can effectively prevent most animal-caused faults. For example, in one Duke Energy circuit, animal guard application on all distribution transformers on the circuit reduced animal faults from 12 per year to an average of 1.5 per year (Chow and Taylor, 1995). In Lincoln, Nebraska, the application of animal guards on all 13,000 transformers reduced the cost of animal-caused faults by 78% (Hamilton et al., 1989).

#### Figure 3.17
Overhead distribution points most susceptible to animal-caused faults. (From EPRI TE-114915, Mitigation of Animal-Caused Outages for Distribution Lines and Substations, Electric Power Research Institute, Palo Alto, CA, 1999; EPRI 1002188, Power Quality Implications of Distribution Construction. Copyright 2004. Reprinted with permission.)
Animal guards and covered jumper wires prevent most animal flashovers at equipment poles by physically covering energized conductors. See Figure 3.18 for examples of installations. The insulation is not fully rated and provides no degree of safety for line workers (animal guards have no voltage rating, and covered jumper wire is normally 600-V class insulation). The insulation is normally enough to prevent a full flashover across an animal for a momentary contact. For retrofit situations, split-seam insulation covers for jumper wires are available.

Proper installation is important for bushing guards. The guard should be placed securely around the bushing and locked into place according to the manufacturer’s directions. Height placement is also important (see Figure 3.19). For bushing protectors, have crews leave some room between the bottom of the bushing protector and the tank. Animal guards are not fully rated insulators—they can track and flashover, so we do not want the animal guard to fully bypass the insulator. Many manufacturers direct you to install the guard under the second shed from the top of the bushing. If you are more than half-way down the bushing, you are certainly incorrect.

The most common mistake is leaving some energized pathways exposed. Crews should cover every bushing and arrester and use insulated leads on all jumpers. In a survey of 253 poles that should have had animal protection, Pacific Gas & Electric (PG&E) found that 165 poles (65%) were found with incomplete or improperly installed devices (California Energy Commission, 1999). The most common problems were missing bushing covers or missing covers on jumpers (see Figure 3.20).

**Figure 3.18** Examples of wildlife protection with animal guards and covered jumpers. (From EPRI 1001883, *Distribution Wildlife and Pest Control*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)
Animal guards are relatively flimsy compared to most other distribution line hardware. When selecting animal guards, choose models that are large enough to sufficiently cover bushings and arresters. The small protectors that just cover the bushing cap can pop off, and determined animals can wedge between the caps and the bushing. Also, choose animal guards tested to withstand degradation from ultraviolet radiation. Crews should not use tape or nylon ties to secure guards. If the guard does not properly fit, then they should apply the one that does fit. Also, crews should be careful not to block the gap on air-gapped arresters. Some bushing guards come with knockouts that can be removed to maintain the gap.

In a survey (EPRI TE-114915, 1999), utilities reported some animal-mitigating measures caused new outage or maintenance problems. Several utilities reported bushing covers deteriorating and tracking. Figure 3.21 shows an example of a deteriorated animal guard. Exposure to ultraviolet radiation causes depolymerization in polymer

![Animal guard installation](image)

**Figure 3.19** Animal guard installation. (From EPRI 1001883, *Distribution Wildlife and Pest Control*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)

**Figure 3.20** Problems with animal protective devices. (Data from California Energy Commission, *Reducing Wildlife Interactions with Electrical Distribution Facilities*, 1999.)
materials (the polymer bonds break down). The effect of the material depolymerization is a roughening of the material surface, which is often accompanied by cracking and pitting of the surface. The roughened surface may now be more susceptible to pollutant collection and thus more susceptible to dry-band arcing and further deterioration. Exposure to ultraviolet radiation is primarily achieved through exposure to sunlight (of which ultraviolet radiation is a component) although ultraviolet radiation is also present in corona discharge, which can create a localized rapid aging effect.

Of the 253 poles examined by PG&E, 80 poles (32%) were found with degraded devices (California Energy Commission, 1999). The type of degradation observed, ranked from least to most, was discoloration (e.g., ultraviolet light damage), black traces, tracking and/or erosion, tearing (caused by wear), and deformation. PG&E anticipated that those devices showing discoloration or black traces would have a greater likelihood of performing as they were designed, while those devices showing obvious tracking/erosion, tearing, or deformation would have lost some of their designed functionality. They grouped the results into classes A and B to represent these less severe (discoloration or black traces) and more severe (tracking/erosion, torn, or deformation) forms of degradation, respectively:

- **Class A**—Degradation that is of a lesser degree such as discoloration or black traces that will not likely affect performance.
- **Class B**—Degradation of a greater degree that will likely result in reduced performance such as tears, signs of tracking/erosion, or deformation.

This ranking of degradation severity is only based on what could be observed of the device’s condition from the ground. A closer examination could reveal other clues.
that would indicate greater or lesser degradation. For example, tracking could occur on the inside surface of a device that only appeared discolored on the outside surface.

Table 3.7 summarizes the extent of deterioration on the poles surveyed by PG&E. Of the 80 poles with degraded devices, 43% were exposed to heavy automobile exhaust, and all but one was fully exposed to sunlight (no environmental shielding). Also, 62% were in residential areas, and 14% were in agricultural areas.

PG&E reported that their tests in 1997 found that PVC products perform poorly compared to similar products made from other base materials, such as polypropylene copolymers, ethylene propylene diene methylene (EPDM), and silicone rubber (California Energy Commission, 1999).

Newer products are expected to resist degradation better than older units. The materials are more resistant to degradation from ultraviolet radiation.

When selecting animal guards, also consider their flammability. There have been incidents of reclosers and other significant equipment completely burning down because animal guards ignited and turned a temporary, low-damage event into major damage. Burning material can also drip from the guard and start secondary fires. From flammability tests of animal guards, some ignite faster than others, and some continue to burn while others self-extinguish when the heat source is removed (EPRI 1016043, 2008). Consider including a flammability test as part of purchasing specifications.

This section has concentrated on bushing guards and wire coverings—the most common and effective animal-control technologies. Some additional items that also help include

- Clear trees—Squirrels get to utility equipment via trees (pole climbing is less common). If trees are kept away from lines, utility equipment is less attractive.
- Good outage tracking—Many outages are repeated, so a good outage tracking system can pinpoint hot spots to identify where to target maintenance.
- Identify animal—If outages are tracked by an animal, it is easier to identify proper solutions.

Animal guards and wire coverings help with birds as well as with squirrels and other climbing animals. Additionally, some bird-specific practices include

- Getting rid of nests
- Installing perch guards (mainly in raptor areas)
- Tracking as a separate category
- Removing nearby roosting areas

### Table 3.7 Deterioration of Animal-Protective Devices

<table>
<thead>
<tr>
<th>Degradation</th>
<th>Number of Poles</th>
<th>Number of Degraded Devices</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class A</td>
<td>69 (27%)</td>
<td>91</td>
</tr>
<tr>
<td>Class B</td>
<td>28 (11%)</td>
<td>37</td>
</tr>
</tbody>
</table>

*Source: Data from California Energy Commission, Reducing Wildlife Interactions with Electrical Distribution Facilities, 1999.*

*Note: Survey of 253 pole locations.*
Unprotected transformer bushings and arresters are the main sources of animal problems. Other problems can occur where there are low clearances at cutouts or grounds and guys. Ground wires near phase conductors can create short phase-to-ground separations. Figure 3.22 shows an example that illustrates the problem. On this pole, a ground wire runs from the neutral to the top of the pole, leaving less than 6 in. (15 cm) between the phase and the neutral. This is the type of installation that could have repeated animal faults because of the short phase-to-ground separation. The best solution is to remove the ground wire. This type of ground wire is unnecessary in most cases. Insulated supports and standoffs can also help reduce animal issues.

Fusing can also change the impact of animal-caused faults for faults across a distribution transformer bushing or an arrester. Having an external fuse reduces the impacts of animal-caused faults. If the transformer is a completely self-protected transformer (CSP) with an internal fuse, then the tap fuse or upstream circuit breaker or recloser operates, leaving many more customers interrupted, with much more area for crews to patrol. CSPs on the mainline are especially problematic for reliability.

Line surge arresters are another common overhead line application that normally does not have a local fuse. Line arresters are arresters applied not to protect any particular piece of equipment, but to improve the performance of the line itself. On such installations, it is important to provide adequate animal protections.

Figure 3.22   Electrocuted cat and the ground wire that made the pole susceptible to animal faults. (Courtesy of Duke Energy.)
3.4 Inspections and Maintenance

Historically, most distribution hardware was considered as “run to failure,” and maintenance was minimal. Now, many utilities have programs for inspection and maintenance that covers much equipment.

Visual inspections can find many issues, including NESC violations, cracked or broken crossarms, cutout issues, severely deteriorated poles, and so on. Many regulatory bodies now require periodic inspections.

Voltage regulators and reclosers require inspection and maintenance. Inspection and maintenance of these are normally based either on a time interval or on operation counts. Manufacturers will normally provide operating duties for equipment that can form the basis for maintenance based on operation counts. Reclosers may be rated for 50 to several hundred operations. The actual duty is based on fault currents seen by the recloser. Modern recloser controls can provide a “wear monitor” that accounts for operations and fault currents.

Thermal or infrared imaging can help identify distribution problems, especially with connectors. Thermal inspections can be done in a drive-by inspection. Since hot-spot temperatures vary with current loading, inspections are most effective when performed with the circuit under heavier load. Some hot spots are not load dependent, such as arresters, tracking problems, and capacitor connections. The CEA reported that 27% of utilities did annual thermal inspections of overhead lines, 18% had inspection intervals between 2 and 5 years, 28% did not perform thermal inspections, and 20% had ad hoc or other inspection cycles (CEA 290 D 975, 1995).

Experience with finding problems with thermal imaging can vary based on utility equipment and design issues. Sullivan (2001) reported that 50% of problems identified on Mississippi Power feeders were hot arresters, 40% were connections and compression crimps, and 10% were fuse cutouts. Kregg (2001) found just over one anomaly for each 12-kV feeder for Commonwealth Edison. Connections were the largest portion of anomalies followed by transformers (see Figure 3.23). See Figure 3.24 for examples of issues.

![Figure 3.23](image-url) Portion of anomalies found from thermal inspections on 12-kV circuits. (Data from Kregg, M. A., Development of a utility feeder infrared thermography preventive maintenance program—With lessons learned, InfraMation, The Thermographer’s Conference, 2001.)
The criteria for identifying issues and assigning priorities are sometimes based on absolute temperature, but it is best to use a temperature rise relative to a comparable reference point. Table 3.8 shows one priority grading system. Table 3.9 shows prioritizations by Commonwealth Edison. These vary by equipment type; “nonline of sight items” have a tighter temperature criteria because in equipment such as transformers and pot heads, the heat source is internal and not directly observable.

Connector issues are commonly identified by thermal imaging. Sullivan (2001) reported that most of their connection issues were due to human error. For compression crimps, Sullivan found issues with using the wrong size crimp, the wrong die, an out-of-adjustment crimping tool, and improper crimping. Sullivan reported that bringing attention to issues and training has helped reduce this problem.
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Sullivan (2002) identified several issues with fuse cutouts at Mississippi Power. The most common issue they found was loose caps, but they also had issues with proper tightening of clamp nuts, and hinge problems. Bad connections were also a big portion of their problems. They also had issues with one cutout design where the mechanical stop was aligned wrong, so the fuse tube would not latch properly.

3.5 Pole Inspections and Maintenance

Most utilities use a pole inspection and maintenance program to manage their pole plant. Many utilities have relatively old pole populations, and an inspection and maintenance program can optimize replacements.

Pole decay is most common near the ground line. This decay is normally internal and cannot be seen externally. Fungi that feed on wood are the leading cause of pole decay. The initial chemical preservatives such as creosote, chromated copper arsenate (CCA), or pentachlorophenol (penta) delay decay. For ground-level decay, moisture and temperature are the primary variables affecting decay. Fungi grow with moisture content above 20%. Growth increases with temperature, peaking between 60°F and

### TABLE 3.8 Anomaly Priority Grading System

<table>
<thead>
<tr>
<th>Priority</th>
<th>Temperature Rise</th>
<th>Repair Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>50°C or more</td>
<td>Repair immediately</td>
</tr>
<tr>
<td>2</td>
<td>21 to 49°C</td>
<td>Repair in 7 days</td>
</tr>
<tr>
<td>3</td>
<td>11 to 20°C</td>
<td>Repair in 3 months</td>
</tr>
<tr>
<td>4</td>
<td>10°C or less</td>
<td>Monitor regularly</td>
</tr>
</tbody>
</table>

*Note: Used by Asplundh Infrared Services for thermal inspections of Orange and Rockland Utilities' infrastructure (EPRI 1000194, 2000).*

### TABLE 3.9 Thermal Inspection Priority System Used by Commonwealth Edison

<table>
<thead>
<tr>
<th>Temperature Criteria</th>
<th>Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>For Line of Sight Items Such as Bolted Connections, Splices, Disconnect Jaws, and So On</td>
<td></td>
</tr>
<tr>
<td>&gt;135°F</td>
<td>Critical—corrective action immediately</td>
</tr>
<tr>
<td>64 to 135°F</td>
<td>Serious—correction action as soon as possible</td>
</tr>
<tr>
<td>18 to 63°F</td>
<td>Intermediate—corrective action as scheduling permits</td>
</tr>
<tr>
<td>&lt;18°F</td>
<td>Attention—no corrective action but monitor equipment</td>
</tr>
<tr>
<td>For Non-Line of Sight Items Such as Transformer and Capacitor Cans, Cable Up-Feed and Down-Feed Pot Heads, Arrester Bodies, and So On</td>
<td></td>
</tr>
<tr>
<td>&gt;36°F</td>
<td>Critical—corrective action immediately</td>
</tr>
<tr>
<td>18 to 36°F</td>
<td>Serious—correction action as soon as possible</td>
</tr>
<tr>
<td>1 to 17°F</td>
<td>Intermediate—corrective action as scheduling permits</td>
</tr>
</tbody>
</table>


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

Sullivan (2002) identified several issues with fuse cutouts at Mississippi Power. The most common issue they found was loose caps, but they also had issues with proper tightening of clamp nuts, and hinge problems. Bad connections were also a big portion of their problems. They also had issues with one cutout design where the mechanical stop was aligned wrong, so the fuse tube would not latch properly.
80°F (16 to 27°C). These factors are typically the worst near the ground line. Because of the dependency of decay on moisture and temperature, decay rates are different in different regions. See Figure 3.25 for a map with zones based on decay severity from the America Wood Protection Association (AWPA); a higher number of zones have more risk of pole decay.

Most decay occurs internally. Poles can look weathered but can still be good because the external damage is not deep. For mechanical strength, the outer shell is critical. Figure 3.26 shows theoretical bending strength as a function of the thickness

![Deterioration zones](image)

**Figure 3.25** Wood pole deterioration zones from AWPA Standard U1 (2013). (Courtesy of the American Wood Protection Association.)

![Theoretical strength remaining as a function of shell thickness](image)

**Figure 3.26** Theoretical strength remaining as a function of shell thickness. (Courtesy of Oregon State University; from Morrell, J. J., *Wood Pole Maintenance Manual: 2012 Edition*, Forest Research Laboratory of Oregon State University, 2012. With permission.)
of the sound outer shell. According to Morrell (2012), most utilities require a sound outer shell of 2 in. (5 cm).

Decay can also occur where the equipment is attached or near the top of the pole where the pole is more exposed and where preservatives may be lost due to gravity.

For more detailed information on pole decay and treatments, see Morrell (2012) and EPRI 1017703 (2009).

Pole inspections normally involve a visual inspection followed by a sounding test and boring:

- **Sounding or hammer test**—A hammer is used to test for dull-sounding points that might indicate decayed wood and indicate where boring might be needed.
- **Boring**—Poles are drilled at an angle to identify soft spots. Then shell thickness (the width of the sound wood) can be measured with a long steel bar with a hook on it.
- **Excavation and boring**—Since many instances of decay occur just below the ground line, boring tests can be made after excavating around the pole, typically 18 to 24 in. (0.4 to 0.6 m) deep.

Most inspections are combined with ground-line fumigant treatment to slow down further decay.

A number of pole-testing technologies have been tried, using different approaches, including ultrasound, resistivity measurements, mechanical movement, and backscatter technology (EPRI 1010654, 2005; EPRI 1021996, 2011). Renforth and Taras (2002) reported on a technology that measures ground-line density and moisture content and found that the predictions from this technology correlated well with strengths measured in full-scale destructive tests.

Over 85% of utilities have a regular pole inspection program according to surveys (EPRI 1002093, 2004). In a 1997 survey with 261 responses, the average duration between pole inspections was 8.1 years (EPRI 1002093, 2004). The same report also reported an average duration between pole inspections of 11.4 years (though there were only eight responses to this survey). The U.S. Rural Utilities Service (RUS 1730B-121, 1996) recommends an initial inspection between 12 and 15 years for decay zone 1, 10 and 12 years for decay zones 2 and 3, and 8 and 10 years for decay zones 4 and 5. After the first inspection, the RUS recommends inspections every 12 years for zone 1, 10 years for zones 2 and 3, and 8 years for zones 4 and 5.

Pole inspection results can be used to generate information to understand the benefits of pole maintenance and possibly to tailor how often inspections and maintenance should be done. Translating pole inspection data into survivor curves or failure-rate curves is tricky. **Figure 3.27** shows industry data from pole inspection programs. It includes two types of data: initial inspections and second inspections. Each provides different information.

- **Initial inspection**—These are the initial inspections. We know the age of the pole and whether or not it passed an inspection.
- **Second inspection**—These are the points labeled “recycle” in Figure 3.27. These are interval samples. We know the age of the pole, the age at which it was previously inspected, and whether or not it passed an inspection.
From the inspection data, it is possible to estimate failure rates as a function of pole age and region. These failure rates or “hazard curves” are developed differently for different inspection types.

We also need to be careful about what type of failure rates we are looking for. Some possibilities are

![Figure 3.27 Pole inspection rejection rates as a function of pole age. (From EPRI 1012500, Guidelines for Intelligent Asset Replacement: Volume 4: Wood Poles (Expanded Edition), Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)](image-url)
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- **Decayed**—The rate at which poles turn from the state of “good” to the state of “decayed.” The states of “good” and “decayed” are determined by inspections.
- **Rejected**—The rate at which poles turn to the state of “rejected.” Once rejected, the pole will normally be replaced or reinforced. One can actually have two hazard rates here: (1) the rate at which poles become rejected when either good or decayed or (2) the rate at which poles become rejected when decayed.
- **Failed**—The rate at which poles actually break or are otherwise removed from the system.

The normal progression is \textit{decayed} \rightarrow \textit{rejected} \rightarrow \textit{failed}.

Figure 3.28 shows estimates of failure rates with age using the data in Figure 3.27. These are estimates with treatment and without treatment.

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

\[ S_i = 1 - \frac{r_i}{n_i} \]

where

- \( r_i \) = number of rejections of poles within a given age range
- \( n_i \) = number of poles within a given age range

This should be an ever-decreasing function. Hazard functions can be found from survival curves using

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

Nelson (1982) provides a more refined estimate of the cumulative hazard function by using maximum likelihoods.

The pole data in Figure 3.28 does not quite follow this. We should not expect the hazard function to decrease over time. What is missing is that rejection rates in the inspections are missing some data. Consider the set of poles inspected at age 50. The estimate of the survival rate is the number of poles that passed the inspection divided by all poles within that age group. This would be an appropriate estimate if the set of poles inspected included all poles of age 50. What is missing from the set is poles that were installed 50 years previously, became decayed, and failed or were otherwise removed because of decay. These are missing from the inspections because they are no longer in the field. The portion of poles removed would tend to become bigger with age, so this explains why the hazard rates level off or start to reduce with age. To account for this factor, use only the hazard curve up to the point...
where it starts to level off or reduce. It is unknown what it really does beyond the point where failures become significant, but you could linearly extrapolate beyond that kneepoint.

The data also includes rejection rates on the second inspection. This is interval-censored inspection data. If we take poles that passed inspection at age 30 and were inspected again at age 40, those that passed at age 40 are right censored, and those that failed the inspection at age 40 are interval censored (they became “rejected” sometime between age 30 and age 40). With interval-censored data, we can directly

Figure 3.28  Estimates of pole failure rates. (From EPRI 1012500, Guidelines for Intelligent Asset Replacement: Volume 4: Wood Poles (Expanded Edition), Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)
estimate the hazard function by breaking the data into groups by age and time between the first and second inspection:

\[ \lambda = \frac{r}{n_i} / t \]

where
- \( r_i \) = number of rejections of poles within a given age range and time between inspections
- \( n_i \) = number of poles within a given age range
- \( t \) = time between the first and second inspections

With the data in Figure 3.27, we do not know the time between inspections. The results in Figure 3.28 are based on a 10-year interval (it is probably between 10 and 15 years).

Having a better knowledge of pole performance can be used to try to optimize pole inspection and maintenance programs (EPRI 1012500, 2006).

### 3.6 Hardening and Resiliency

The impact of major storm events has increased focus on hardening distribution infrastructure and make it more “resilient” to major events. The options for utilities to improve resiliency include overhead improvements, undergrounding, more automation, and expanded vegetation management. For overhead improvements, options include stronger-class poles, concrete or steel poles, enhanced guying, more aggressive pole inspection and treatment, breakaway connectors on service drops, pole-top refurbishments, reconductoring with covered conductors, and design for NESC extreme wind conditions. Most programs implement changes based on new construction or are targeted at certain parts of the system, such as mainlines.

Hardening and resiliency sometimes require different focus than normal utility reliability programs. During major storm events, damage is more severe and repair costs increase. See Table 3.10 for storm damage from several different types of storm events in Connecticut (CT PURA, 2013). In larger storm events, both costs and damage increase. For example, in hurricane Sandy, one pole was replaced for every six outage events, but for typical thunderstorms, this ratio was one pole replaced for every 25 to 45 outage events. Overhead structure resiliency programs focus on reducing major damage such as pole breakage that is more common in larger events.

The industry has only a few examples of correlations between damage and overhead construction characteristics. For hurricane events, Brown (2008) found that the rates of pole failures increased exponentially with storm category for Florida Power and Light. Brown found little solid evidence for performance difference based on pole treatment type (creosote or CCA) during Wilma, an event that caused mainly wind-only damage. Mainline pole failure rates were more than twice that of poles on lateral taps, suggesting that mainlines are more vulnerable to wind events, possibly due to higher loading from conductors, pole-top equipment, and/or third-party
He also noted a surprisingly high failure rate for concrete poles, being only 30% lower than that for wood poles.

Trees causing mechanical damage make up a large portion of tree-caused outages, especially during major storms, and these are the faults that require the most time and expense be repaired. One approach to reducing the impact of damage from trees is to coordinate the mechanical design such that when tree and large limb failures occur, the 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 off of insulators 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 3.29 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.

The role of telecom attachments is also important to consider as these add extra wind loading and weight to the existing structures. They also provide an anchoring point at which poles tend to break as in the example in Figure 3.29.

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 poles, leading to a much longer repair time.

Kaempffer and Wong (1996) describe 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

| Table 3.10 Damage and Costs for Connecticut Light and Power for Several Storms |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
|                 | June-2011 Storm | Storm Irene     | October Nor'easter | September-2012 Storm | Storm Sandy     |
| Storm type      | Thunderstorm    | Tropical storm  | Nor'easter        | Thunderstorm     | Hurricane       |
| Customer outages| 209,045         | 1,024,032       | 1,438,797         | 80,575           | 856,184         |
| Outage events   | 2603            | 16,101          | 25,475            | 1483             | 16,460          |
| Transformers replaced | 332          | 1748            | 1964             | 111              | 2198            |
| Poles replaced  | 95              | 1297            | 1655             | 33               | 2763            |
| Crossarms replaced | 438          | 3204            | 5590             | 126              | 4745            |
| Cost per customer outage | $52       | $109            | $122             | $114             | $182            |
| Cost per outage event | $4187  | $6906           | $6873            | $6204            | $9478           |

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. Kaempffer and Wong used this analytical approach to analyze several of BC Hydro’s standard designs and 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 distribution structures to make them easier to repair during storms. The choice of conductor (AAC versus ACSR) also plays a role. In some applications, ACSR may be strong enough to move the weakest link to a harder-to-repair supporting structure.

References


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Finch, K., *Understanding line clearance and tree caused outages*, *EEI Natural Resources Workshop*, April 1, 2003a.


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