Reliability Based Vegetation Management Through Intelligent System Monitoring

Final Project Report

Power Systems Engineering Research Center

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since 1996

Power Systems Engineering Research Center

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September 2007

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Power Systems Engineering Research Center

This is a project report from the Power Systems Engineering Research Center (PSERC). PSERC is a multi-university Center conducting research on challenges facing the electric power industry and educating the next generation of power engineers. More information about PSERC can be found at the Center's website: http://www.pserc.org.

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Acknowledgements

Executive Summary

Trees and other vegetation have adversely affected the operation of electric power transmission and distribution systems since the construction of the first electric lines. Vegetation intrusion causes loss of reliability and creates safety hazards. Current vegetation management practices have received renewed scrutiny in recent years. Failure to perform vegetation management has been identified as a contributing factor in wide-spread local outages, and, particularly during extreme weather conditions, to system-wide outages. Vegetation management programs for transmission lines operated at 200 kV and above are now subject to a reliability standard approved by the Federal Energy Regulatory Commission and transmission owners must report certain vegetation-caused outages. Programs for lower voltage lines are subject to state regulatory policies that often focus on reporting of reliability indices at the system or feeder level. In general, the policies focus on attaining a reliable system rather than on how to do so efficiently. Vegetation management is expensive, with tree-trimming alone on the order of seven to ten billion per year in the U.S.

Most vegetation management programs for distribution systems are calendar-based. Unfortunately, each distribution circuit has its own unique level of exposure and outage risk associated with vegetation. As a result, a calendar-based trimming program cannot provide an optimal reliability solution, especially for a large distribution system. Calendar-based tree trimming cycles result in some circuits being trimmed more frequently than needed, thereby consuming resources with little or no benefit to customer reliability. Other circuits are not trimmed often enough and experience reliability problems because proper clearances are not maintained.

The level and efficiency of distribution system reliability could be enhanced if feeders were trimmed only when necessary. A possible approach is to detect incipient reliability problems through remote monitoring of electrical activity on a feeder to provide advanced warning when vegetation contact starts to become a problem on that feeder. Thus, sensitive field measurements would be used as a proxy to determine each feeder's level of vegetation intrusion. For instance, in research work at Texas A&M, long-term instrumentation of 60 operating feeders at 11 electric utility companies recorded numerous instances of precursors to failures. Utility companies later determined that some of these measured anomalies were caused by casual vegetation contacts that had not yet caused outages or other problems.

This project was a first attempt to monitor and record power system data in the hope of developing tools to assist utilities in developing customized tree-trimming schedules to achieve desired levels of reliability, based on the level of vegetation contact activity and weather parameters. Conceptually, by monitoring system parameters and vegetation-related outage occurrences, utilities could tailor their tree trimming cycles for each feeder, resulting in a predictable level of reliability for a given circuit.

Data limitations did not allow the project team to develop the relationship between measurements and reliability impact as fully as hoped. Researchers correlated utility outage logs to recorded power system events, but had difficulty identifying a significant number of recorded events which could be reliably tied to known outages. The project involved two years of monitoring, compared to common utility trim intervals of three to five years, making it impossible to monitor a complete trim/growth cycle. The project period also fell in the early part of the cycle (i.e., soon after trimming was completed), reducing the likelihood of significant vegetation intrusion during the subject period.

Despite these limitations the project provided important, useful information regarding the behavior of vegetation-related outages and interruptions:

- Regular, well-designed trim cycles appear effective in minimizing vegetation-related events on distribution feeders.

- Vegetation intrusion produces electrical signals on distribution feeders that are measurable from a remote substation.

- Field experiments conducted during this project provided valuable insights on the progression of vegetation-related fault conditions.

Despite difficulties of obtaining sufficient vegetation event recordings, the project substantially added to the body of knowledge regarding the progression of vegetation-related incidents on power systems, the types and frequencies of such occurrences, and the electrical signals produced when vegetation contacts distribution lines.

The detection of incipient vegetation-related conditions remains a central component of enhancing overall system reliability, but more experimentation and field work is needed to get the necessary data to design an effective remote detection program.

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1. **Introduction**

1.1 **Vegetation and Power Lines**

Trees and other vegetation cause power system faults, outages, interruptions and other power quality problems. There are a variety of mechanisms through which this happens. Tree contacts can be abrupt and result in conductors contacting each other, either directly or indirectly, or even in line sections being torn down. Tree limbs "can fall over onto conductors, can drop branches onto conductors, can push conductors together, and can serve as [a] gateway for animals" (1).

Vegetation can also cause slowly developing problems due to continuous growth. This phenomenon is not well documented but is believed to occur as follows:

> "When a tree branch bridges two conductors, a fault does not occur immediately. This is because a moist tree branch has a substantial resistance. A small current begins to flow and starts to dry out the wood fibers. After several minutes, the cellulose will carbonize, resistance will be greatly reduced, and a short circuit will occur." (1).

Experience suggests that operation of automatic circuit reclosers may temporarily relieve the faulted condition, but leave the offending branch in place, precipitating future problems. An example provided later in this report illustrates a real-world case in which vegetation caused numerous momentary interruptions before ultimately resulting in a burned down line and sustained outage.

In addition to compromising service quality and reliability, safety is a major concern. Tree contacts are a major cause of downed conductors. Research has shown that as many as one in three downed conductors will remain energized upon contact with the ground, presenting a highly dangerous public safety hazard (2)(3)(4)(5)(6)(7)(8)(9). Additionally, vegetation in contact with lines can create dangerous touch potentials which present shock and electrocution hazards (10).

1.2 **Power System Reliability**

The *Electrical Engineering Handbook* defines the reliability of a power system as "the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service" (11).

With the proliferation of consumer electronic devices in businesses and homes, even momentary interruptions have become costly, and prolonged outages can have crippling effects. According

to some estimates, the U.S. economy suffered billions of dollars of productivity loss during the 2003 Northeast Blackout. Following the blackout, the North American Electric Reliability Council (NERC) performed an in-depth study of the root causes of the blackout and determined that vegetation was a primary factor. They proposed a national mandatory standard for vegetation management which applies to transmission systems (12). There is no specific national standard for vegetation management of distribution systems.

With the increased focus on reliability, many utilities are required to report calculated reliability indices to regulatory bodies, and some utilities are required to report their worst performing feeders (13). As a result, electric utilities are more interested in improving their overall reliability, and improved vegetation management is seen as a key way to accomplish that objective.

Utility companies measure reliability using several standardized indices (14). Four indices primarily used by utilities are:

SAIFI – System Average Interruption Frequency Index is intended to give information about the average <u>frequency</u> of sustained interruptions per customer and is calculated as

$$SAIFI = \frac{Total\ Customer\ Interruptions}{Total\ Customers\ Served} \qquad 1.1$$

SAIDI – System Average Interruption Duration Index is commonly referred to as customer minutes of interruption and represents the average number of minutes each customer is without service per unit time (e.g., per year). It is calculated as

$$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Customers\ Served} \qquad 1.2$$

CAIDI – Customer Average Interruption Duration Index represents the average duration per interruption and is calculated as

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Customer\ Interruptions} \qquad 1.3$$

ASAI – Average Service Availability Index is the fraction of time (often in percentage) that a customer has power provided during one year or the defined reporting period. It is a different way of stating SAIDI, and is calculated as

$$ASAI = \frac{Total\ Customers \times \frac{No.Hrs}{yr} - \sum Customer\ Interruption\ Durations}{Total\ Customers \times \frac{No.Hrs}{yr}} = 1 - \frac{SAIDI}{\frac{No.Hrs}{yr}} \qquad 1.4$$

Although each of these indices is affected by many types of outages, tree contacts are known to be a major contributing factor affecting each index. Reduction in vegetation-related outages will improve these indices and will improve customer service continuity in general.

1.3   Vegetation Management: State of the Art

Current methods to combat vegetation intrusion consist primarily of tree trimming and application of growth retardants. While it is clear that trees will need to be trimmed, money is wasted either because feeders are trimmed before there is enough growth to make it necessary, or because feeders are not trimmed soon enough to prevent adverse impacts to reliability, safety and potential damage to the system. The March 2002 issue of *Transmission and Distribution World* magazine, a widely read trade publication, devoted an entire section to the subject of vegetation management, and noted that "vegetation management activities … usually are the largest cost element in an electric utility's operating budget (tree trimming alone is a US$7 - $10 billion business)" (15).

Many utilities use fixed time-based cycles when scheduling tree trimming. Tree trimming specifications generally aim to remove contact for a certain number of years. Methods are proposed in the literature to optimize tree trimming cycles, but there is no universally accepted or proven method of doing so (16). At best, the cycles are estimates derived from incomplete knowledge.
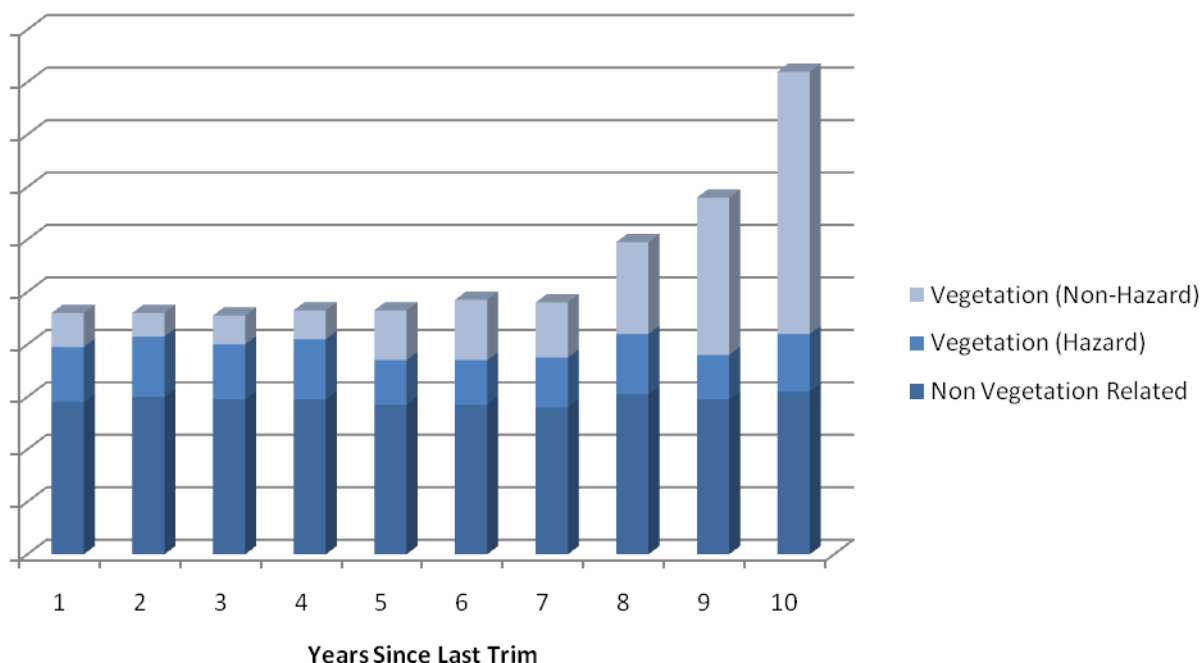
Figure 1.1: Hypothetical Representation of Outages by Cause as a Function of Time

Figure 1.1 is a hypothetical example of how vegetation-related outages may grow over time. In this example, non-vegetation-related outages and outages caused by "hazard trees" which exist outside the utility's right of way remain relatively constant from year to year. Vegetation-related outages not caused by hazard trees also remain relatively constant for the first few years, but begin to increase as time goes on. This is more clear in Figure 1.2 where the non-vegetation and hazard-related vegetation components have been removed. In this example, the non-hazard component of vegetation-related outages remains low and relatively constant for five years after the circuit is trimmed. After five years, however, vegetation has encroached heavily on the system, and reliability will fall to unacceptable levels unless corrective action is taken.
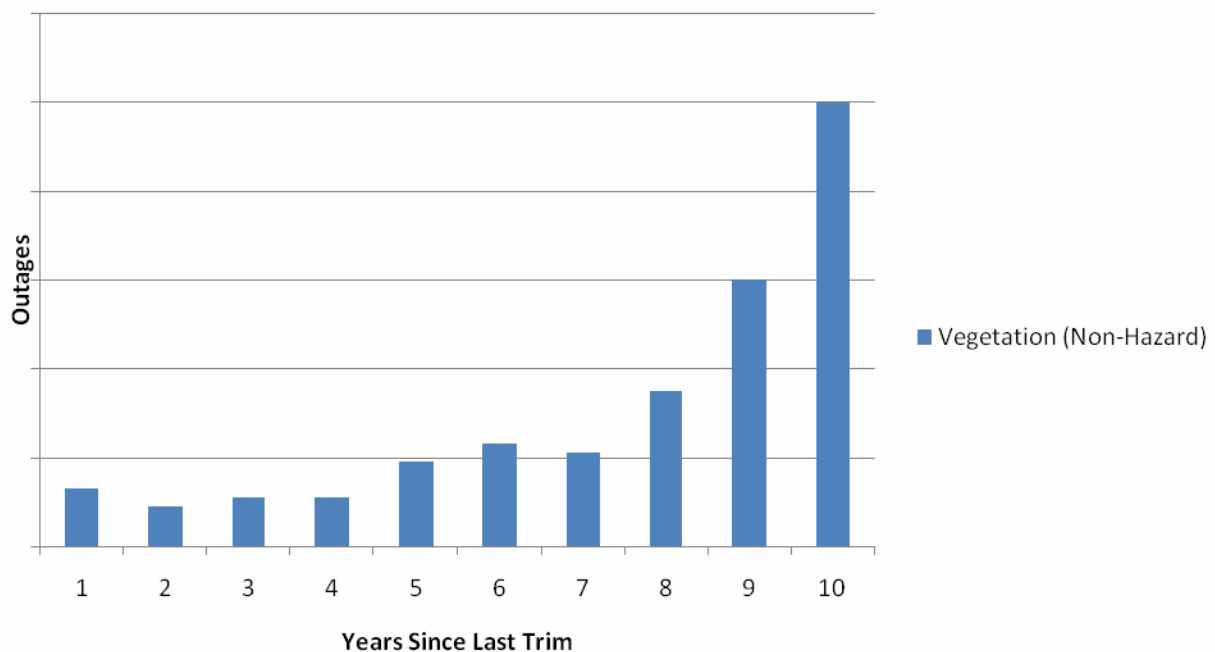
Figure 1.2: Hypothetical Representation of Vegetation-related Outages as a Function of Time

Current optimization techniques for tree trimming generally center around a formulaic, statistical expression which takes as input various factors including local vegetation types, tree density, tree growth rate, trim frequency and environmental factors (17),(18). These techniques are often ineffective because they do not reflect the actual condition of the system, but rather a statistical estimation as to when the optimal trim time will be. While these can be supplemented with historical trim data, they nonetheless fail to take into account actual system conditions and variations between circuits. Visual inspections are sometimes employed, but are expensive and time consuming, and in many cases difficult to accomplish (19).
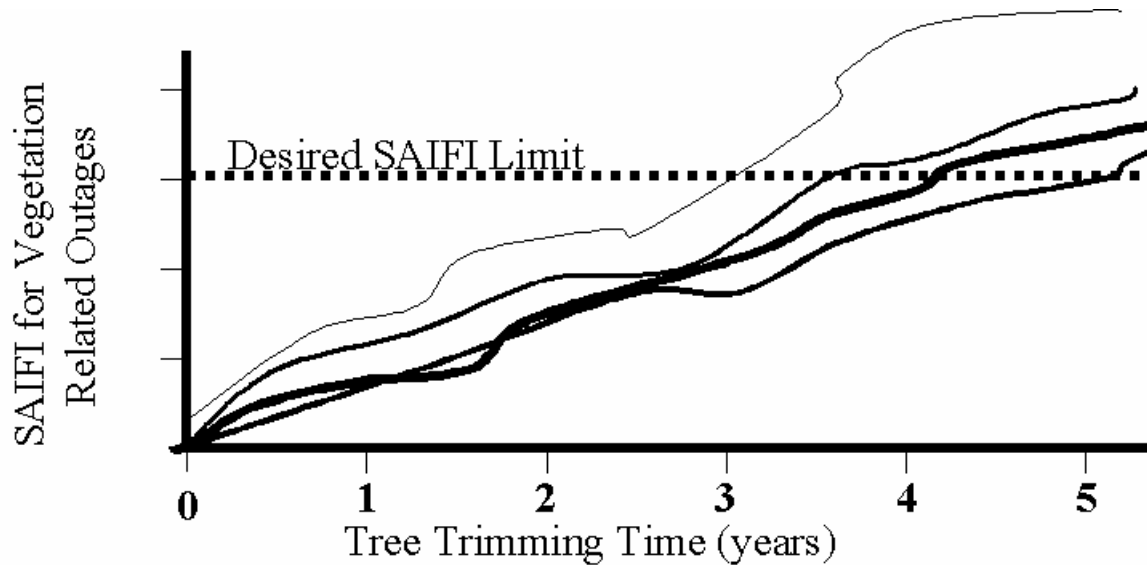
Figure 1.3: Vegetation-related Reliability Over Time

Figure 1.3 is a hypothetical illustration of how the vegetation-related component of SAIFI for individual distribution circuits can vary widely. In this example, reliability levels for four feeders are shown as a function of time. To achieve the same level of vegetation-related SAIFI, one feeder should be trimmed after only three years, whereas another feeder could be trimmed every five years with the same level of reliability. Suppose the feeders in the above example were trimmed every four years. Some feeders (the highest two lines) needed to be trimmed after three and three and a half years respectively. In this example, these feeders would have an unacceptably high SAIFI, as they were not trimmed soon enough. One feeder, on the other hand, should be trimmed after five years, and thus would be trimmed one year early. While this feeder would not suffer adversely in terms of reliability the additional cost of more frequent trimming would be a waste of resources, with little or no benefit to customer reliability.

The potential economic benefits of intelligently reducing tree trimming are enormous. For example, assume that 20% of a utility's circuits could have their trim cycles extended from four years to five years without significant impact on vegetation-related reliability. Trimming these circuits every five years instead of every four years would result in a 20% reduction in cost for those circuits. If one further assumes that this company spends $40M per year to trim trees, the company would save 20% x 20% x $40M, or $1.6M every year without affecting reliability. Put another way, the company's current trimming practice wastes $1.6M per year, or 4% of the total vegetation management budget, money that clearly could be better spent elsewhere. If one generalizes these numbers to the industry at large, even a 4% savings of the previously cited $10B spent nationally each year would result in $400M available for other projects.

Very little fundamental work exists in characterization of the signals that are produced when vegetation contacts electric power lines. The studies that do exist have been very small in nature and limited in scope. Through computer modeling, W.K. Daily attempts to develop a

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justification for tree trimming by creating a computer-based model of a tree in contact with a medium-voltage power line to determine whether a touch potential exists along the tree such that a person contacting the tree would be in danger of shock or electrocution (10). He proposes a model, but no hard data is presented, and the model has not been verified for accuracy. Additionally, all results from this study are based on simplified assumptions, most of which are necessary because no solid research exists documenting what actual measured data.

Preliminary experiments by Texas A&M researchers recorded data from trees in contact with distribution level voltages (20). The authors measured the voltage gradient along a tree in contact with a 7,200 V conductor. The contact resulted in low-level small currents only a few amperes which are not detectable at a substation with any system used by utilities today. The data presented was encouraging, but not comprehensive due to the limited scope of the experimentation. The experimentation presented was preliminary, and further characterization was needed to obtain significant data and draw meaningful conclusions from this research.

This PSERC project was a first attempt to monitor and record power system data in the hope of assisting utilities in developing customized tree-trimming schedules to achieve desired levels of SAIFI based on the level of vegetation contact activity and weather parameters. In theory, by monitoring system parameters and vegetation-related outage occurrences, utilities could tailor trim cycles by feeder, resulting in a predictable level of reliability for a given circuit.

To accomplish this, researchers proposed to monitor distribution circuits fed from substations monitored by Distribution Fault Anticipator (DFA) prototypes installed as a part of Texas A&M's ongoing DFA project with the Electric Power Research Institute (EPRI). By analyzing the level of tree-contact activity on each monitored circuit and comparing these levels to vegetation management schedules, vegetation-related interruptions, and statistical data such as wind and storms, researchers hoped to develop algorithms for determining optimal tree trimming schedules to achieve specific levels of SAIFI for vegetation-related outages. Such models would allow for more equitable reliability of service across the entire utility customer base, allow utilities to more effectively use their limited resources, and allow for trim cycles that result in a predictable level of reliability. Specific aspects of the implementation of these activities are explained in further detail in subsequent sections of this report.

2. **Failure Methods**

The causes of vegetation-related outages can be described in three general categories: outages caused by "hazard trees," outages caused when trees bridge primary conductors, and hazards caused by trees contacting secondary conductors.

2.1 **Hazard Trees**

"Hazard tree" is a term used by utilities to describe trees which are outside of their trimming right-of-way, yet still pose a danger to the system if they fall. These trees present a particular difficulty, as they are too far from the power lines to be detected using any electrical means. Furthermore, since these trees exist outside the trimming path of the utility, no action can be taken to prevent them from presenting a danger to the system.

Hazard trees often cause outages because of an external force or event which causes the tree or part of the tree to break and fall across energized lines. Causes of hazard tree outages are wide and varied, but can include storms, lightning strikes, automobile accidents, customer tree-trimming accidents, and high wind.

Hazard trees often present the greatest danger to the power system in terms of customer outages, as they tend to break lines as opposed to simply causing faults. Additionally, they often fall across the main three-phase section of a feeder, disrupting far more customers than tree faults which occur in a customer's secondary. From an electrical standpoint, the failure mechanism of hazard trees is generally no different from any other event which breaks lines, causing them to either trip or remain energized as high-impedance faults. These faults have, by definition, no electrical precursors, and are thus not detectable by electrical means.

2.2 **Branches Intruding Into Primary**

Distribution vegetation management is intended primarily to prevent trees and other vegetation from encroaching into the primary feeder lines. In general, vegetation management programs do a good job of preventing these occurrences. There are, however, cases where vegetation does contact primary feeder lines.

If branches simply contact one phase of an energized primary line, previous research indicates that at normal distribution voltage levels, only a marginal amount of current is conducted through the tree and root system to ground due to the relatively high impedance of the tree and the comparatively low voltage gradient generated (20)(21). Several tests have been conducted where energized lines remained in contact with the main trunk of various species of trees where only a few amperes were drawn. Each of these studies concluded that branches contacting only a phase line present little danger of progressing electrically into high-current events.

The situation is different, however, when a branch bridges either two phase wires or a phase wire and the neutral conductor. In these situations, the available voltage is distributed across a much shorter physical distance. This increased voltage gradient opens up the possibility for the occurrence of a high-current fault. This phenomenon has been observed on branches laid across a phase conductor and neutral, and by extension should occur between multiple phase conductors as well.

When a branch spans a phase conductor and a neutral conductor a few feet apart, scintillation begins near each contact point. The localized heat begins to char and carbonize the organic wood products, making these carbonized points more conductive. The non-carbonized area immediately adjacent to this then begins to scintillate and burn, further extending the portion of the path that is charred. This process continues to feed on itself, lengthening the charred, carbonized portion of the path from each contact point, preferentially in the direction of the other contact point. The charring continues to lengthen from each end until the paths meet and form a continuous charred path, at which time the low-impedance path enables a much higher current to flow.

This is illustrated in Figure 2.1 where the carbonized path can be seen starting from the line and proceeding to the right in the direction of the other conductor. It is important to recognize this process occurs at each end of the conductor, with each path proceeding toward the center of the branch.

These paths proceed only when enough moisture content is present within the branch. Field tests indicated that a dry, dead branch does not readily form carbonized paths even after tens of minutes of solid contact between the phase conductor and neutral. Figure 2.2 shows the carbonized path progressing along a branch between phase and neutral conductors.

As the carbonized path progresses, it may progress on the surface as shown in Figure 2.2, or under the bark, as shown in Figure 2.3. The photo shows steam and smoke escaping through holes in the bark as the carbonized path burns and dehydrates the wood underneath.

While the paths burn toward the center, the tree branch serves essentially as a high-impedance conductor for low-level fault current. Significant heat, burning, and steam may be produced while the fault is drawing only an ampere or less of current. When the two paths meet in the middle, the high-impedance path gives way to a low-impedance path, and a high-current event occurs, as shown in Figure 2.4.

Figure 2.1: Tree Branch Following Flashover, Carbonized Path Visible on Right
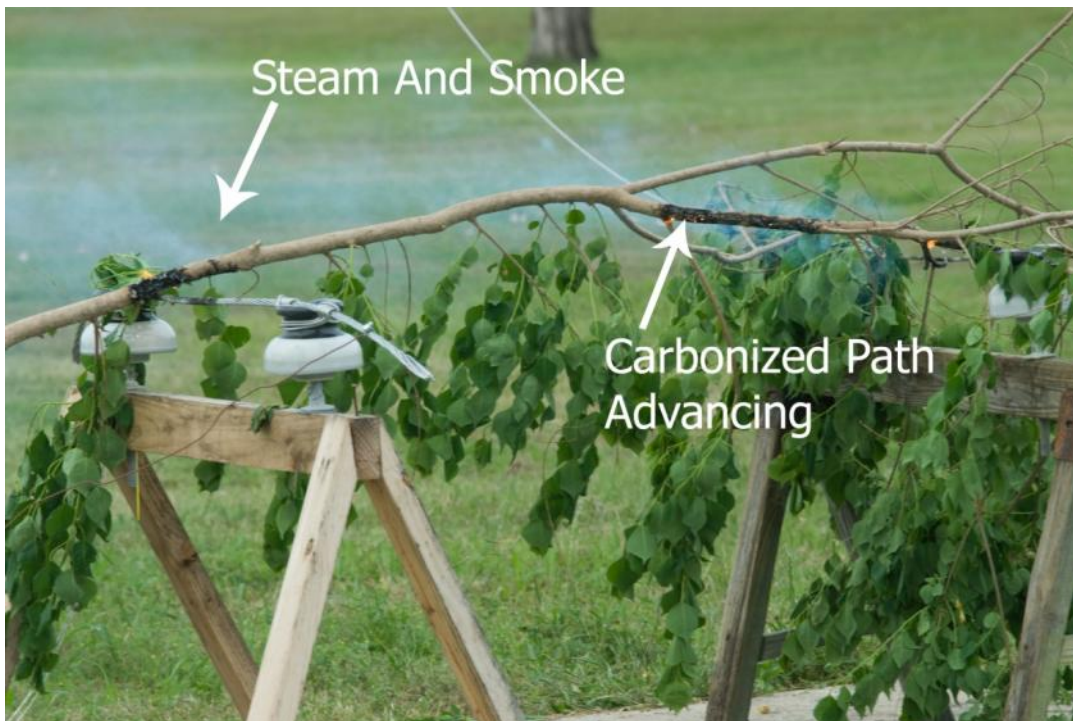

Figure 2.2: Carbonized Path Progressing from Both Contact Points

Figure 2.3: Carbonized Path Under Bark Producing Steam and Smoke

Figure 2.4: Formation of Arc Between Lines

Figure 2.4 clearly shows the electric arc struck between the two power lines. The arc forms initially along the carbonized path, but quickly transfers into the plasma immediately surrounding the branch. One can note how the arc wraps around the center of the branch in Figure 2.4. As is common with arcing faults of this nature, the heat of the plasma causes it to rise into the air which increases the arc length, also increasing its impedance. At some point, the voltage between the lines will no longer be able to sustain the arc through the plasma, and it will extinguish. The carbonized path remains along the branch, however, and another arc is reenergized along the path again, repeating the process. Alternatively, the branch may separate from one or both of the contact points, temporarily removing the fault from the system. This process may repeat until a protection device is operated or until a line burns down. Electrical effects from this interaction may be measurable at a distant substation, as will be discussed later in the text.

2.3   Trees Contacting Secondary

While hazard trees and vegetation contacting primary conductors cause significant outages affecting sometimes hundreds or thousands of customers, many other vegetation-related events occur when trees contact secondary lines between service transformers and customer service entrances. Data obtained from a major utility regarding all vegetation-related outages at a 32-feeder substation between 2000-2006 indicates that 108 of 171 vegetation-related outages affected less than 20 customers, and 76 outages affected only one customer (see Figure 5.1 later in this report). The majority of these events involved tree contacts on the secondary service side of the transformer.

Often vegetation-related outages in the secondary occur because of mechanical contact with trees in much the same way hazard trees bring down lines. These outages are far less significant than typical hazard tree outages, as they only disrupt service to a small number of customers.

Because of the low voltage levels present on the secondary, high current faults are extremely unlikely, even if branches span the phase and neutral conductor. It is possible, however, for tree branches to push the phase and neutral conductors together to the point where they contact each other, producing essentially a bolted fault of high current on the secondary side of the transformer. These events may continue until the conductors break apart, or until the transformer fuse operates.

3. DFA Project and Case Studies

The work done in this PSERC project was motivated, in part, by research in the Distribution Fault Anticipation (DFA) project, a research project at Texas A&M. This chapter describes that project.

3.1 Project Background

Texas A&M researchers are conducting a major research project in the area of power system reliability improvement. The goal is to identify and take advantage of measurable precursor signals that failing line apparatus produce during early stages of failure. The original focus of that project was not specifically on vegetation management, but long-term field data collection efforts suggest the possibility of detecting signals indicative of vegetation intruding into overhead lines. The nature of the ongoing efforts is such that it is appropriate to provide the reader with a brief overview of the data collection system that is in place.

Master Master Station   11 Utility   14 Monitoring Units   60 Monitored
(TAMU HQ)   Master   In 14 Substations   Feeders
Stations
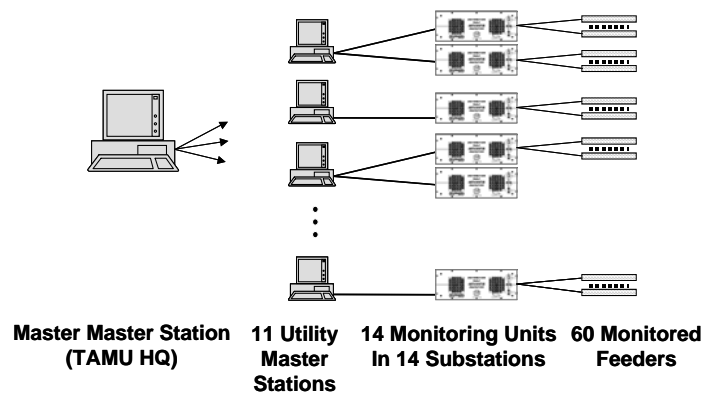
Figure 3.1: Current DFA System Architecture

Illustrated at right, the system consists of a network of custom, high-quality instrumentation that monitors and records current and voltage signals from current and potential transformers at electric utility substations. Each monitoring unit can monitor up to eight feeders in a substation, and each unit is accessible via the Internet. Eleven utilities participate by having monitoring units installed in their substations. In total, these units monitor 60 feeders across North America. Each utility has a Master Station computer that allows the utility to view data recorded by its monitoring unit(s), and Texas A&M has a "Master Master" Station that interfaces with all of the utilities' monitoring units. These Master Stations use automated processes to collect data from the monitoring units multiple times each day, bringing the collected data back to the utilities and to Texas A&M headquarters for subsequent review, analysis, and archiving.

This distributed data collection system has recorded current and voltage signals caused by vegetation contacts with overhead conductors on multiple occasions. Some of these have resulted

in interruptions and outages, while others have exhibited precursors to incipient failures. The following examples document specific recorded cases.

3.2   Example: Incipient Vegetation-Related Failure

The waveforms shown below illustrate one measured episode of an incipient vegetation-related failure. In Figure 3.2, a "spike" in RMS current is visible around 2.45 seconds. This and all other DFA-measured events record current and voltage signals at the substation. Therefore the measured waveforms include the normal load on the feeder, in addition to any current drawn by vegetation contactor other anomalies. This spike momentarily adds about ten amps to the 335 amps of current drawn by normal loads on the monitored feeder. The utility company on whose system this occurred later determined that the cause of this spike was a tree limb contacting overhead, open-wire service conductors. The instantaneous phase current in Figure 3.3 provides more detail about the shape of the waveforms involved. The third positive current peak in the waveform is slightly larger than the other current peaks. This slight increase is the only sign that the tree contact occurred, and it is barely recognizable over the normal load current present during the rest of the illustrated time period.
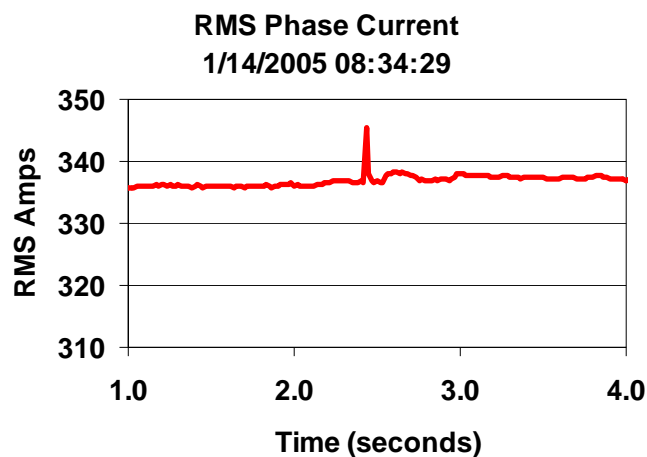

Figure 3.2: RMS Phase Current for Incipient Failure

Instantaneous Phase Current
1/14/2005 08:34:29
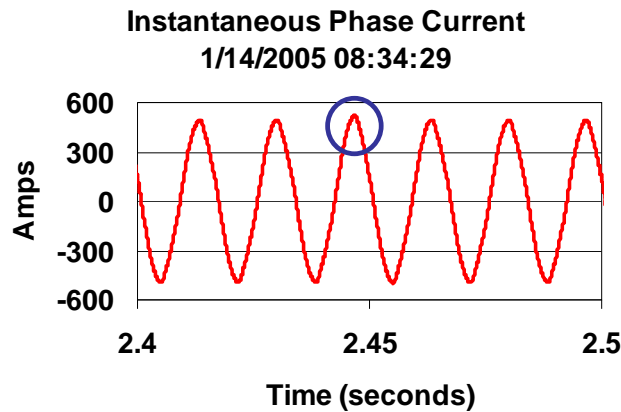
Figure 3.3: Instantaneous Phase Current for Incipient Failure

Instrumentation at this location recorded several dozen instances of nearly identical waveforms over an eight-day period. Coincident with episodes on the eighth day was a customer service call that reported visible arcing in the customer's overhead service. The utility company removed the intrusion and the measured instances ceased. Interestingly, the utility looked at weather patterns during this eight-day period and determined that the times at which the measured episodes occurred correlated with periods of rainfall.

3.3 Example: Vegetation-Related Outage

The distributed data collection system also has measured several examples of tree contacts that have become severe enough to cause voltage sags, momentary interruptions, and sustained outages. The figures shown below illustrate the first in a series of faults, voltage dips, and interruptions that eventually caused a burned-down line and a sustained outage. The Figure 3.4 illustrates the RMS currents measured at the substation. There were slightly less than 200 amps of load current on each phase prior to the fault. The fault, which occurred at about 2.4 seconds in the figure, drew additional current of about 700 amps, resulting in an instantaneous value of around 900 amps on the affected phase. This was sufficient to operate an overcurrent protective device, a three-phase poletop recloser located between the substation and the fault point. This temporarily cleared the fault by opening the circuit for approximately two seconds, long enough for the branch to lose intimate contact with the overhead line. After closing back in, service was restored to downstream customers, at least temporarily. The Figure 3.5 illustrates the voltage dip that all customers fed by this substation experienced as a result of the momentary fault. Those customers downstream of the recloser experienced a total interruption for the recloser's two-second open interval, a clear power quality concern in the modern age of electronics in every home and business.

Figure 3.4: RMS Phase Current for Vegetation Outage

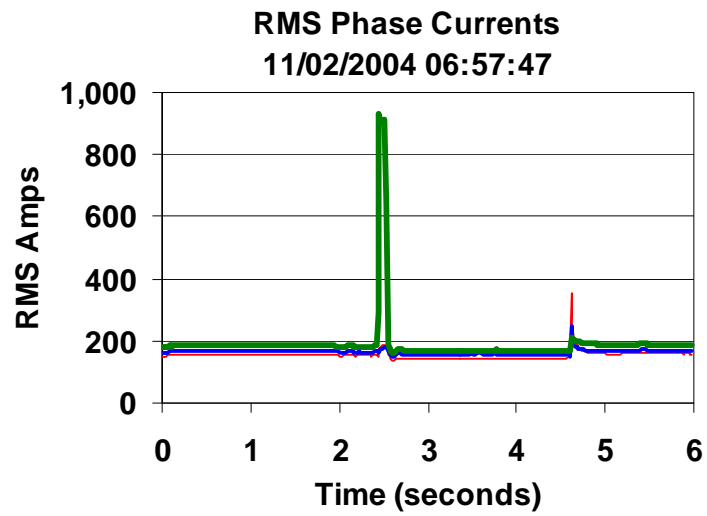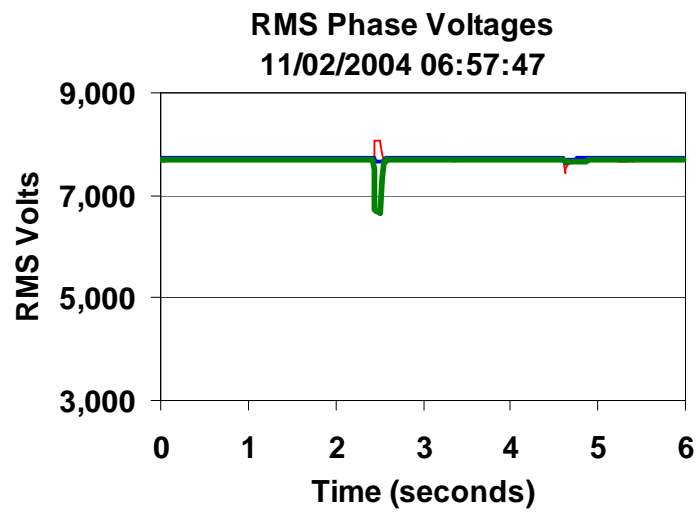Figure 3.5: RMS Phase Voltages for Vegetation Outage

Table 3.1: Recloser Activity prior to Vegetation Outage

Date	Time	Trips
11/2/2004	6:57:47	1
	7:58:33	2
11/3/2004	0:09:06	1
	0:16:48	1
	0:40:38	1
	0:40:53	1
	1:10:51	1
	1:12:37	1
	1:15:30	1
	3:24:47	1
	4:19:39	1
	4:30:36	1
	5:51:01	1
	6:19:45	3
Total		17

Over the next 24 hours, this fault recurred multiple times. The tabulation at right shows 14 distinct times at which the fault manifested itself in an overcurrent. Each instance tripped the recloser at least one time, and two instances tripped it multiple times. Each time the fault occurred, all customers experienced a voltage dip, and those customers downstream of the recloser experienced a momentary interruption.

Each instance of this fault also caused arc damage to the conductors at the point of the fault. Figure 3.6 and Figure 3.7 illustrates the RMS currents and voltages recorded during the final instance of the fault. In this instance, the limb made more persistent contact with the line conductors, causing repetitive overcurrents. This resulted in the line burning down at the point of contact, which left 140 customers without power for 62 minutes.

When the utility responded to the resulting customer lights-out calls, they found that a tree limb had fallen on the line without immediately breaking the line. The line was constructed with a phase conductor on top of the poles and a neutral conductor several feet below it on the same poles. A fork in the tree limb caused the limb to hang on the phase conductor. The weight of the limb pulled the phase conductor down closer than normal to the neutral conductor. The tree limb contacted the phase conductor continuously and the neutral conductor intermittently. This casual contact caused the periodic flashovers that resulted in the overcurrents and interruptions and in the cumulative damage that eventually brought the line down.

**RMS Phase Currents
11/03/2004 06:19:45**
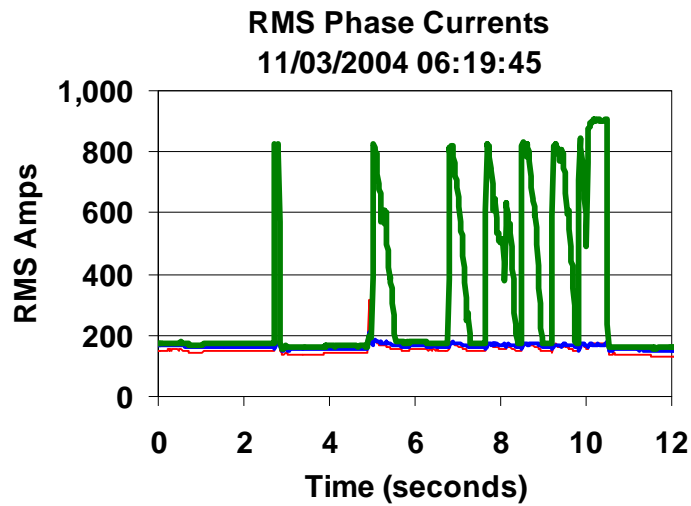
Figure 3.6: RMS Phase Currents for Final Failure in Vegetation Outage

**RMS Phase Voltages
11/03/2004 06:19:45**
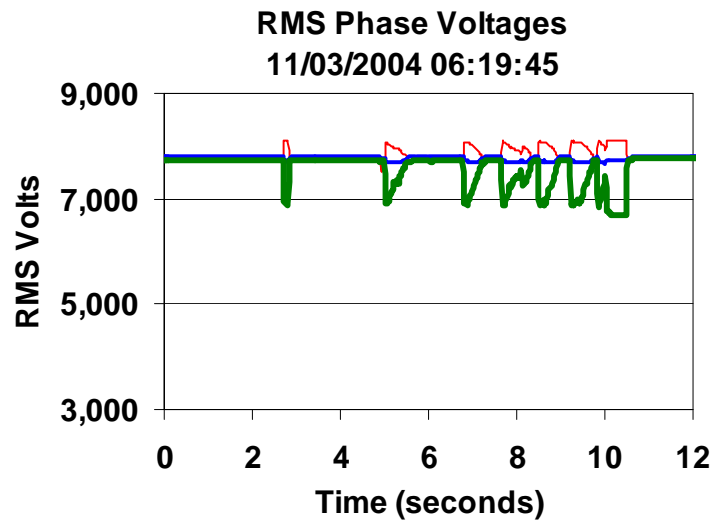
Figure 3.7: RMS Phase Voltages for Final Failure in Vegetation Outage

In each of these cases, it is important to note that DFA technology recorded and measured indications of an incipient condition, sometimes days in advance of a critical vegetation-related condition. Had operations personnel been made aware of these occurrences, it is possible they could have prevented the outages from ever occurring. More importantly, however, indications of non-hazard vegetation-related contacts on primary distribution feeders might indicate more general encroachment of vegetation into lines, especially if multiple instances of vegetation-related contacts were recorded in the same area.

4. **Ideal Experimental Plan**

To address the many issues related to electrical detection of vegetation management through remote monitoring, an ideal experiment would involve a significant amount of resources and data.

Due to the relatively low frequency of major vegetation-related events, any comprehensive study would require the observation of a large number of distribution feeders. For example, as described later in Section 5, after events affecting less than ten customers were removed from the data, a 32-feeder substation recorded an average of only 0.34 events per feeder per year over a seven-year period. These events varied widely in their cause and the number of customers they affected. To obtain a reasonable sample size of a wide range of events, it would be preferable to monitor a significantly larger number (e.g., 100) of feeders. This would give the possibility of capturing potentially hundreds of vegetation-related events which could be studied, analyzed, and eventually correlated to utility outage logs. It would be beneficial if these feeders were geographically dispersed resulting in a wide range of locations and weather conditions.

Because vegetation management trim cycles are designed to prevent encroachment of vegetation on power lines, another essential requirement of an ideal experimental protocol would involve allowing the monitored feeders to progress past their scheduled trim dates without taking corrective vegetation management action. This would be essential to determine at what point vegetation-related outages began to significantly increase. If feeders are trimmed on a reasonable cycle, "time-since-trim" should not be a primary factor in determining the frequency of vegetation-related events.

Finally, any experiment seeking to comprehensively study this problem will require a long observation window. Many utilities operate their vegetation management programs on cycles of several years. To properly study the phenomena involved, an observation period of at least one year before and after the extended trim cycle would be required to observe a baseline on either side of the trim window. Preferably the observation period would be even longer to allow continuous observation through two or more complete trim cycles.

Achieving this ideal experiment is problematic, as utilities would need to allow vegetation encroachment beyond what traditional practices would otherwise dictate on a significant number of feeders, ultimately sacrificing some degree of reliability for research purposes.

5. **Statistical Utility Outage Data**

As part of this PSERC project, statistical outage data were collected from one of the substations monitored by DFA equipment. Monitoring equipment was installed in 2002 at the substation monitoring eight of its 32 feeders. Originally the substation was chosen because its trimming cycle was scheduled for the summer of 2003. This window of time was chosen so that researchers would be able to have a significant window of time to observe both a baseline condition before the trim cycle began, during the transition through the trim cycle, and afterward. Unfortunately, equipment problems during the summer of 2003 prevented the field hardware from retrieving any data, and data before the summer of 2003 suffered from problems related to settings internal to the device. The combination of these events resulted in an absence of data during the pre-trim window of interest.

After the substation's DFA unit was repaired, monitoring began in the hope of detecting events which appeared to be related to vegetation contact. Due to the previously stated delays in beginning the monitoring activity, however, researchers were monitoring feeders which had recently been trimmed, resulting in few vegetation-related incidents which could be reliably tied to outage logs. Over the past three years, researchers have continued to monitor captured events and waveforms recorded from the DFA unit installed at the substation, hoping to correlate them to outage records. Thus far, there have been few confirmed events which can conclusively be tied to vegetation contact.

There are several factors which make this process difficult. While detection algorithms developed in the DFA project can reliably identify generic arcing events, they are only able to distinguish between various types of arcing in select cases. While it is understood that branches in contact with power lines will produce arcing, it is often difficult to differentiate arcing generated by vegetation intrusion from other generic forms of arcing. As many events on the power system also generate similar arcing characteristics, additional information is needed to confirm the cause of a specific recorded event and trace it to a particular source. Each of the DFA cases mentioned in the previous section was confirmed to be vegetation-related after customers reported outages. It is unlikely, however, that minor arcing signatures generated by preliminary vegetation contacts which do not cause outages would ever prompt customer calls or utility attention. Consequently, while DFA technology has recorded numerous instances of arcing on the eight monitored feeders, no vegetation-related outages have occurred close enough in time to these recorded events to suspect correlation.

To attempt to correlate outage records to DFA records, the full list of outage reports were obtained from the monitored substation covering the period from 2000-2006. Analysis of these records yielded interesting results.

Table 5.1: Vegetation-Related Outage Summary at Monitored Substation, 2000-2006

Year	Number of Outages	Storm Condition	(Total – Storm) Outages
2000	30	6	24
2001	17	7	10
2002	13	2	11
2003	16	8	8
2004	24	11	13
2005	32	29	3
2006	39	19	20

Table 5.1 shows a summary of the number of vegetation-related outages recorded in the utility's logs from 2000-2006 at the 32-feeder substation. The first observation from Table 5.1 is that from 2001-2004, the number of outages, once storm activity was removed, remained relatively constant. In fact, the only significant increase occurred in the year immediately following the trim cycle. If storm conditions are disregarded, the total number of vegetation-related incidents actually increased each year after trees were trimmed. In fact, the year with the lowest number of total outages was 2002, the year immediately before trees were trimmed. This seems to suggest that the 48-month trim cycle, with the latest trim occurring in 2003, might be able to be extended without adverse affects to reliability. It is critical to remember, however, that data from one trim cycle at one substation from one utility represents an extremely small sample size. Additionally, with so many factors involved over such an extended period of time, it is difficult to tie increases or decreases in the number of occurrences of vegetation-related outages to any single factor. Various other factors including weather, customer activity, and institutional reporting practices may have influenced the outage numbers in ways that are neither known nor predictable.

A more detailed breakdown of the number of affected customers yields additional relevant data. Figure 5.1 shows a histogram of the numbers of customers affected per outage on the substation from 2000-2006. It is clear from the histogram that the vast majority of vegetation-related outages affect relatively few customers, with approximately 55% of outages affecting ten customers or less. Second, it is equally clear that while the majority of vegetation-related outages affect relatively few people, there are outages which affect significantly more people. During the observed time period, a vegetation-related outage disrupted service to over 1000 customers at least once per year on average.
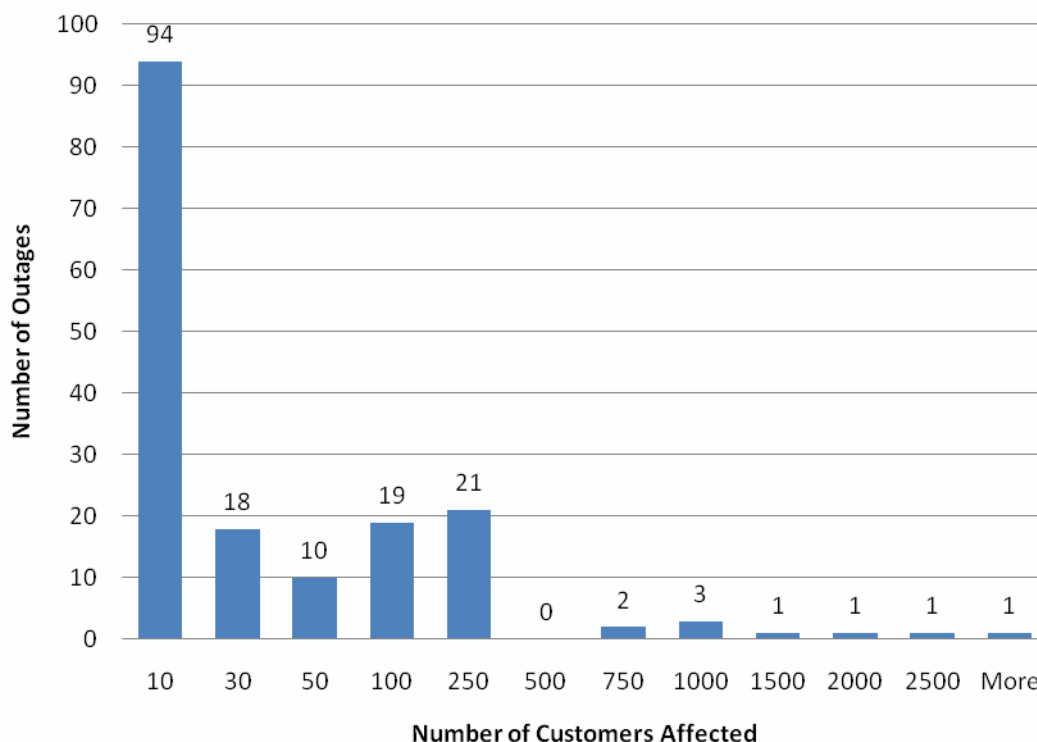
Figure 5.1: Number of Affected Customers Per Outage at Monitored Substation, 2000-2006

This trend becomes more apparent when viewing a histogram of customer minutes, as shown in Figure 5.2. Again, a significant number of vegetation-related outages are relatively minor, but incidents do have the potential to have a major impact on reliability metrics. In fact, of the top ten disruptions (in terms of customer minutes) at the substation between 2000-2006, three were vegetation-related. While vegetation-related outages accounted for 10.5% of outages by number during the observed period, they accounted for 13.9% of customer outage minutes during the same period. If these outage statistics are broken down by year, again the years with the best reliability statistics are 2001 and 2002, the two years immediately before the scheduled trim.

As with Table 5.1, these data seem to indicate that it may be possible to extend the 48-month trim cycle without adversely impacting reliability. It should be cautioned, however, that these data represent one substation from one utility, and may not even be representative of most substations within the same utility. Nevertheless, there does not seem to be a strong correlation between trim-cycle period and numbers of outages on the substation, suggesting that the trim cycle occurs often enough to prevent a significant increase in vegetation-related outages.
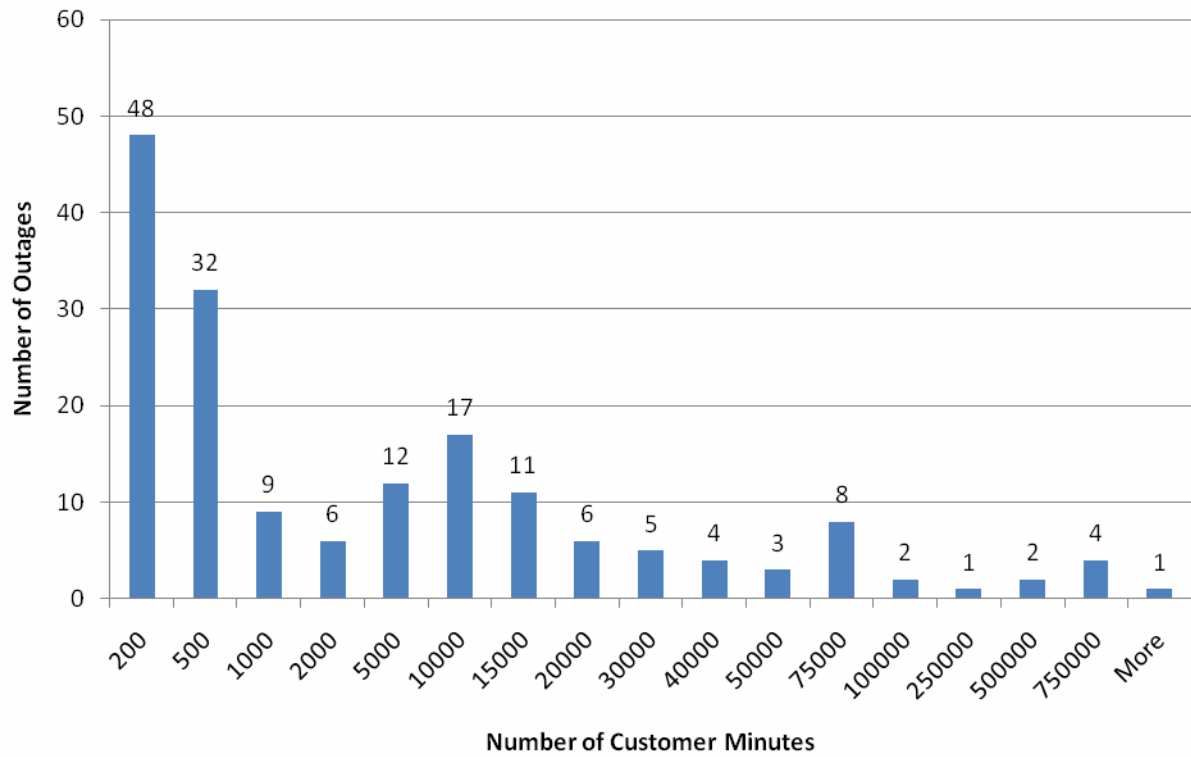
Figure 5.2: Customer Minutes Per Outage at Monitored Substation, 2000-2006

6. **Experiments**

6.1 **Experimental Setup**

In April 2006, researchers conducted staged experiments at Texas A&M's Downed Conductor Test Facility. These experiments were designed to revisit and expand on previous research on vegetation contacts with power lines.

The downed conductor test facility is served by a 7,200 V primary feeder, and is located approximately two electrical miles from the substation. Researchers have previously used this facility for a variety of high-impedance fault testing, including research on vegetation contacts with lines (20). At the facility, researchers are able to conduct experiments on an operational power system, as opposed to simulating similar conditions in the laboratory.

In these experiments, researchers wanted to explore and record the progression of vegetation-related faults as they occur when vegetation spans a primary phase conductor and neutral. To simulate prolonged contact with trees, researchers selected branches from trees in the surrounding area to trim and use for experiments. Local vegetation consisted primarily of hackberry, crape myrtle and chinaberry trees. Branches of varying diameters and lengths were selected.

To support the branches and lines, two sawhorses were positioned approximately four feet apart. Each sawhorse had two insulators, one mounted at each end, to which conductors were secured. The primary conductor was directly connected to the distribution feeder at 7,200 V. The neutral conductor was connected to ground through a bank of resistors with equivalent resistance of 500 ohms for current limiting purposes. The entire setup was fused with a 2A, type T fuse.

The general experimental setup, excluding the resistor bank, is show in Figure 6.1. Branches were laid across the lines, but not attached physically in any way.

To determine the feasibility of detection of vegetation events from a remote substation, researchers recorded feeder phase currents and voltages at the substation. Measurements were acquired on a National Instruments DAQ system sampling at 15,360Hz, or 256 points per cycle.

After a branch was laid from phase conductor to neutral, linemen would energize the line. Video and still pictures were taken to document the progression of each experimental run.

Figure 6.1: Experimental Setup

6.2 Experiment 1

The branch used for experiment one was cut from a crape myrtle tree, approximately 0.75" in diameter. The tree was in solid contact with the line on both ends of the branch. Immediately after the line was energized, scintillation carbonized paths began appearing on the exterior of the branch. This process continued with obvious smoke and burning of the branch appearing along the exterior from both ends, tracing a path toward each other in the center. It was observed that the path proceeded most quickly from the end of the branch with the smaller diameter. This finding was confirmed in subsequent experiment runs.

The process of carbonization continued in a high impedance state for 4 minutes, 38 seconds before the first full arc occurred. During this time, researchers measured an extremely low current (less than 1A) at the fuse. At this point, the tree began arcing violently for 27 seconds, finally blowing the fuse. During this time, the arc formed and extinguished 19 times, with the final burst lasting approximately 172 cycles, or 2.86s. This final arc was of unusual duration, with most of the other arcs approximately 15 cycles long. It is believed this burst was of extended length primarily due to a large gust of wind which occurred at precisely that moment. The extended burst caused the fuse to blow, deenergizing the line.

At this point, the fuse was replaced and the line reenergized, which resulted in the immediate ignition of the arc, which, owing to another gust of wind, continued for approximately 5 seconds until the fuse was blown again. Researchers re-fused the circuit one additional time and

reenergized the line, resulting in a sustained 4 second arc burst causing the fuse to blow a third time. Researchers observed that the crape myrtle, a hardwood tree, seemed likely to continue in this configuration for an indefinite amount of time until the tree burned in half. Furthermore, each time the line was reenergized, the already-formed carbonized path caused the fault to progress immediately to its maximum fault current. It is hypothesized that long term intermittent contact between branches and lines would, over an extended period of time, eventually create a carbonized path which would then allow subsequent contacts to proceed immediately to a bolted fault state, unless mechanical vagaries of lines, links, wind, etc. caused physical separation.

Figure 6.2 shows recorded data from a 27-second period during the fault recorded in Experiment 1. The figure shows RMS neutral current (I_N) calculated at two points per cycle. Each peak seen on the graph corresponds to one instance of a high current event. Each peak is approximately the same height and several have approximately the same profile and duration. The final extended burst can also be seen.

Figure 6.3 shows a detailed view of the final burst in Experiment 1. As previously noted, the extended length of this burst was caused by a gust of wind which prevented the arcs from lengthening in their characteristic nature.
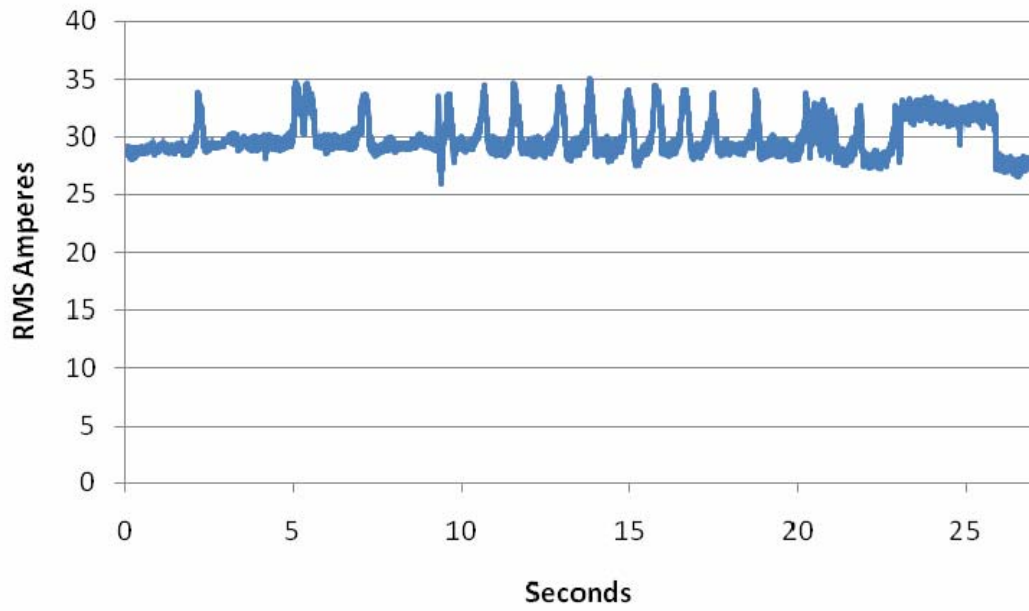
Figure 6.2: Experiment 1 - Neutral Currents
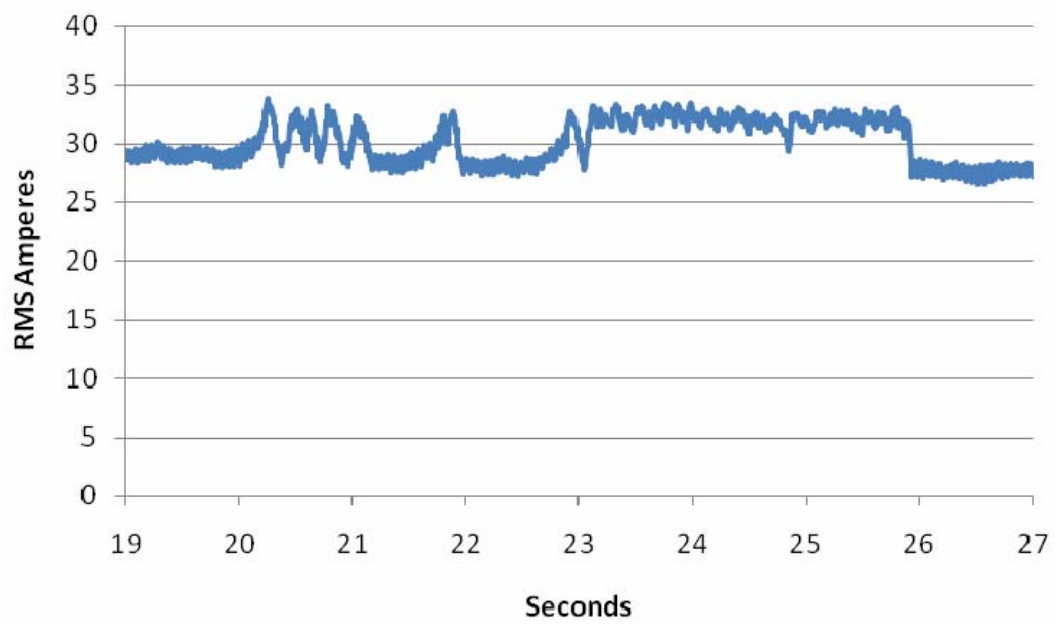
Figure 6.3: Experiment 1 - Detailed View - Final Arc Bursts

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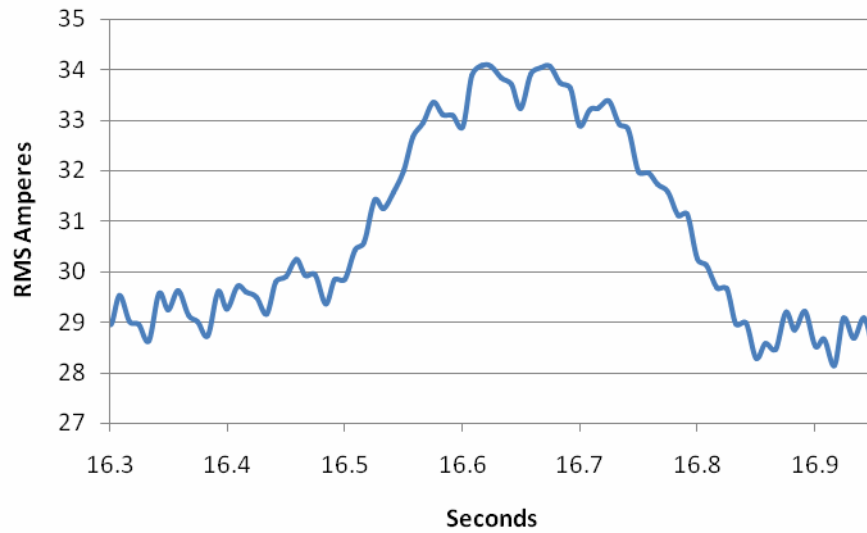
Figure 6.4: Experiment 1 - In RMS, Peak, zoomed in

Figure 6.4 is a detailed view of the RMS of one of the peaks recorded in Figure 6.2. It is important to note that this waveform capture is very similar to waveforms captured in the DFA project.

Figure 6.5: Experiment 1 - Crape Myrtle Tree Releasing Smoke and Steam

Figure 6.6: Experiment 1 - Crape Myrtle Tree With Arc

Figure 6.7: Experiment 1 - Extended Final Arc on Crape Myrtle Tree

Figure 6.5, Figure 6.6, and Figure 6.7 show a photographic progression of Experiment 1. In Figure 6.5, the crape myrtle tree producing smoke and steam. One feature of interest in this

photograph is that the branch is contacting ground not only through the neutral conductor, but also through some of the leaves which are touching the ground, as seen on the right side of the photo. This incidental contact quickly burned away after the line was energized. Figure 6.6 shows the typical high current arc formed when the formation of a carbonized path has completed. This particular arc has just formed, and is not particularly long at this point. Figure 6.7 shows the final extended arc burst, and the gusting wind can be observed affecting the arc. The phase and neutral conductors were placed four feet apart, so the initial arc was approximately that length. As the arc plasma rose away from the branch, the arc typically lengthened by several feet before ultimately extinguishing.

After the extended arc burst operated the 2A fuse, the branch remained intact between the two lines. Researchers decided to reenergize the line without removing the branch to determine whether or not the fault would immediately recur. Figure 6.8 and Figure 6.9 show currents generated after the line was reenergized. The first time the line was reenergized, the faulted condition immediately returned and persisted for approximately five seconds before again operating the 2A fuse. Figure 6.8 shows the RMS for I_N.

Researchers again re-fused and reenergized the line without moving the branch. The currents for the second reenergization are shown in Figure 6.9. In this experiment, the faulted condition again returned immediately and persisted for approximately 230 cycles, or just under four seconds before again operating the 2A fuse. It seems likely that the line would have continued to remain in place until it burned free or operated system protective devices.
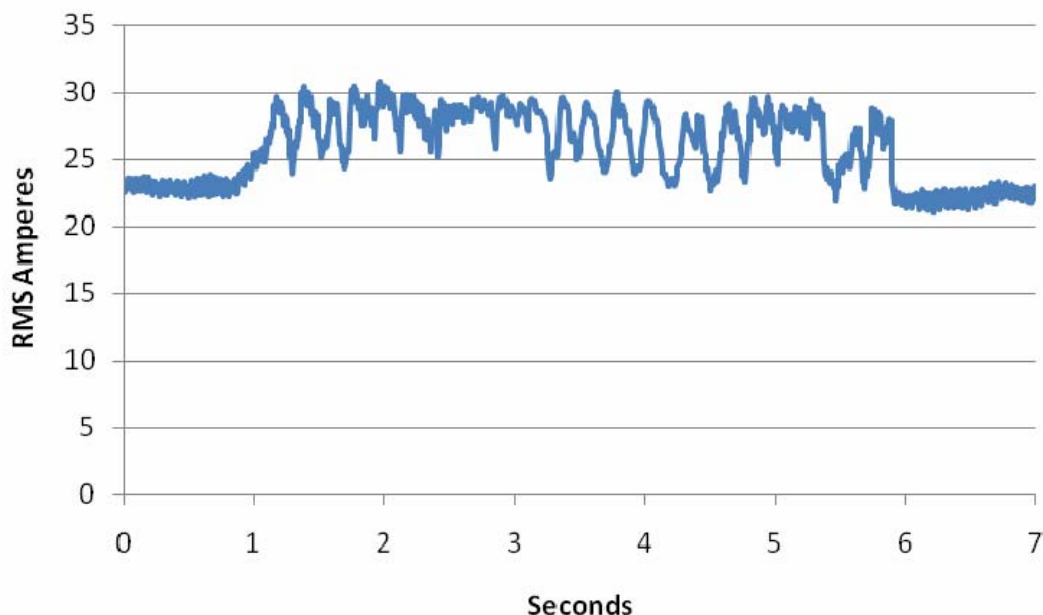

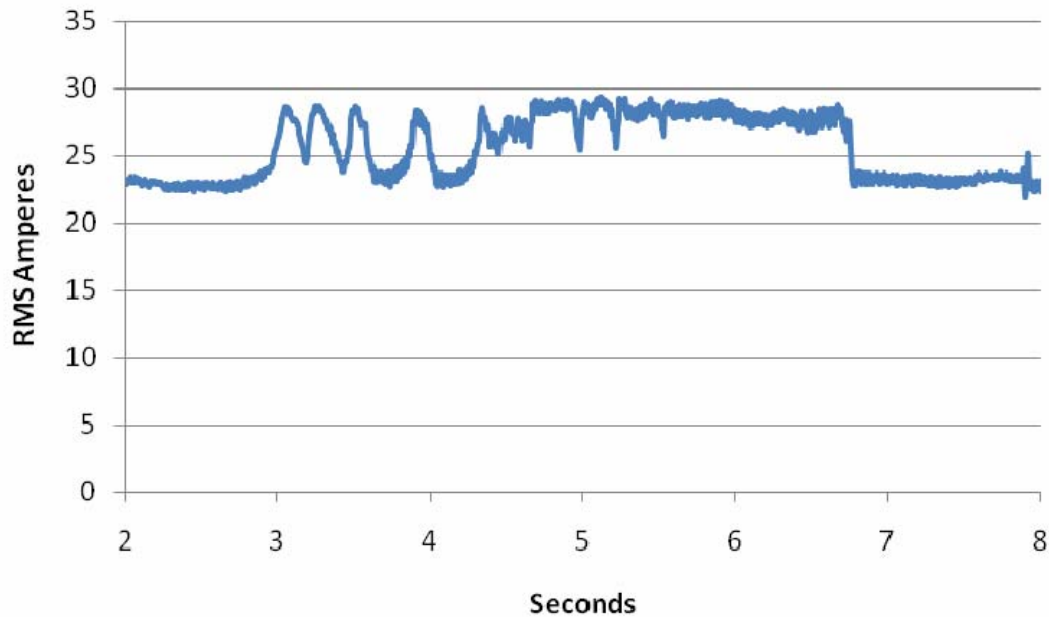Figure 6.8: Experiment 1 - Currents During First Reenergization

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Figure 6.9: Experiment 1 - Currents During Second Reenergization

After the trials, researchers inspected damage on both the lines and the trees. Not surprisingly, the tree suffered significant damage. Figure 6.10, Figure 6.11, and Figure 6.12 show the contact points between branch and line after Experiment 1 was complete. Figure 6.10 shows both the branch and line damage on the phase conductor. Not only is the branch heavily damaged, there is significant damage to the line as well. While it is likely this small branch will fail much sooner than the line, the high current arcs have clearly damaged the line, likely impacting its mechanical integrity. Figure 6.11 and Figure 6.12 show the branch contact with the neutral conductor. Again, significant damage was observed both on the branch and line. Figure 6.13 shows damage along the branch, specifically at the point where the carbonized paths met. The photo clearly shows the bark peeled back from the wood.

Finally, Figure 6.14 shows damage to the insulator on the primary line. At the beginning of the test, a small stem from the branch was in incidental contact with this insulator. The insulator was not new, but had incidental damage resulting from general power system use and testing. Arcing through this branch cracked the porcelain and ultimately further damaged the insulator, ultimately causing a large chip of porcelain to separate from the insulator.

Figure 6.10: Experiment 1 - Branch Contact on Phase Conductor

Figure 6.11: Experiment 1 - Branch Contact on Neutral Conductor

Figure 6.12: Experiment 1 - Damage to Line and Branch, Neutral Conductor

Figure 6.13: Experiment 1 - Damage Mid Branch, Where Carbonized Paths Met.

Figure 6.14: Experiment 1 - Damage to Insulator

6.3   Experiment 2

Experiment 2 used a chinaberry branch of approximately 1.5" at its thickest point. For Experiment 2 the branch was turned in the opposite direction with the largest part of the branch resting on the phase conductor and two 0.375" contacts resting on the neutral conductor. As with Experiment 1, the carbonized path began forming immediately after the line was energized. This process continued for 5 minutes and 8 seconds when one of the two neutral contact points burned through and caused a slight reconfiguration of the branch. The carbonized path continued to form for an additional one minute and 12 seconds when the second neutral contact point burned through and the branch fell free of the neutral conductor.

This experiment was of interest in that the carbonized paths did not meet, and while the paths were close, the branch never fully reached a low impedance fault state before the branch was removed from contact with the line. This is of particular interest in vegetation management as most small branches with intermittent contact with lines will likely burn away in a matter of minutes. This does not, however, remove the danger of a larger line being forced into mechanical and electrical contact with conductors. While conductors can essentially "protect themselves" from encroachment of the smallest branches, the presence of such branches may indicate the proximity of larger branches which pose a mechanical threat to the lines which will remain even after the smaller ends of the branches have burned away.

6.4   Experiment 3

Experiment 3 used a hackberry branch of approximately one inch at its thickest point. As with Experiment 2, this side of the conductor rested on the primary conductor and two smaller contact points of approximately 0.375" and 0.5" rested on the neutral conductor.

Again, as with previous tests, a carbonized path began to form on the branch immediately after the line was energized and continued for 4 minutes and 55 seconds before the paths met and created a low impedance arc. The tree began a series of arcing which lasted for approximately 18 seconds. During this period of time there were 13 short bursts followed by one extended burst. As with Experiment 1, the short bursts persisted for approximately 15 cycles. The final burst again was extended by a gust of wind, and persisted for approximately 6.5 seconds. Waveforms for the 18 second period are shown in Figure 6.15. As with Experiment 1, the RMS for both the neutral and waveforms with ambient removed are presented. Figure 6.16 presents the final arc burst in greater detail. It is important to note that Figure 6.15 and Figure 6.16 are strikingly similar to Figure 6.2 and Figure 6.3 observed in Experiment 1.

After 6.5 seconds, the contact point with the neutral conductor burned through, but the branch did not fall clear of the line. Instead, it remained on the line an additional one minutes and 45 seconds, and another carbonized path began to form along the branch. Then, the new contact point burned through, and the branch fell clear of the neutral conductor and contacted the concrete slab on which the tests were performed. Researchers allowed the tree to remain in contact with the ground for approximately one minute, but no additional activity resulted.

Figure 6.17 - Figure 6.22 are photographs taken during and after Experiment 3. Figure 6.17 shows the initial setup just after the line was energized. Figure 6.18 shows the branch during the 18 second arcing interval. Evident in the photograph is the large amount of foliage that has burned away, visible on the ground in the lower left half of the frame. Additionally, it is of interest to note that the shape of the tree has changed, and is more bowed than in Figure 6.17. In each experiment, the trees physical profile was altered. Figure 6.19 shows the branch immediately after the end of the extended arc burst during the 18 second period. It can be seen from the photograph that the tree has dropped from its original contact point and is no longer arcing. Figure 6.20 shows some of the damage to the branch. Specifically, Figure 6.20 shows the branches which rested on the neutral conductor. Figure 6.21 shows the end of the branch connected to the phase conductor, which remained attached to the conductor by means of the small offshoot branch, visible in the photograph. Figure 6.22 is a close-up picture of the same section of line with the branch removed to show the damage. Again, as in Experiment 1, the line still functions as a conductor, but has sustained damage which could potentially alter its mechanical and structural properties.

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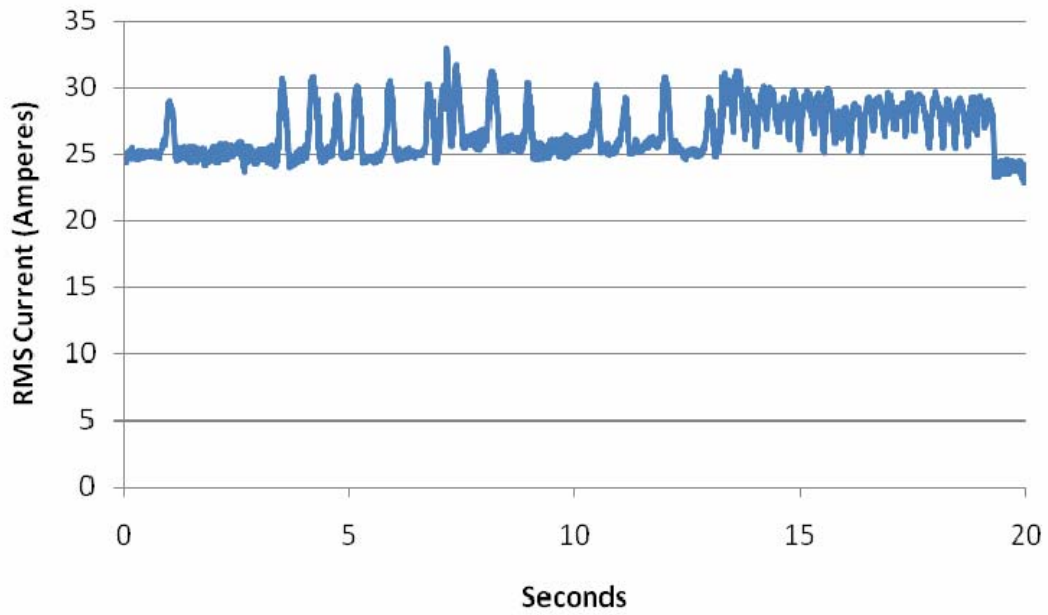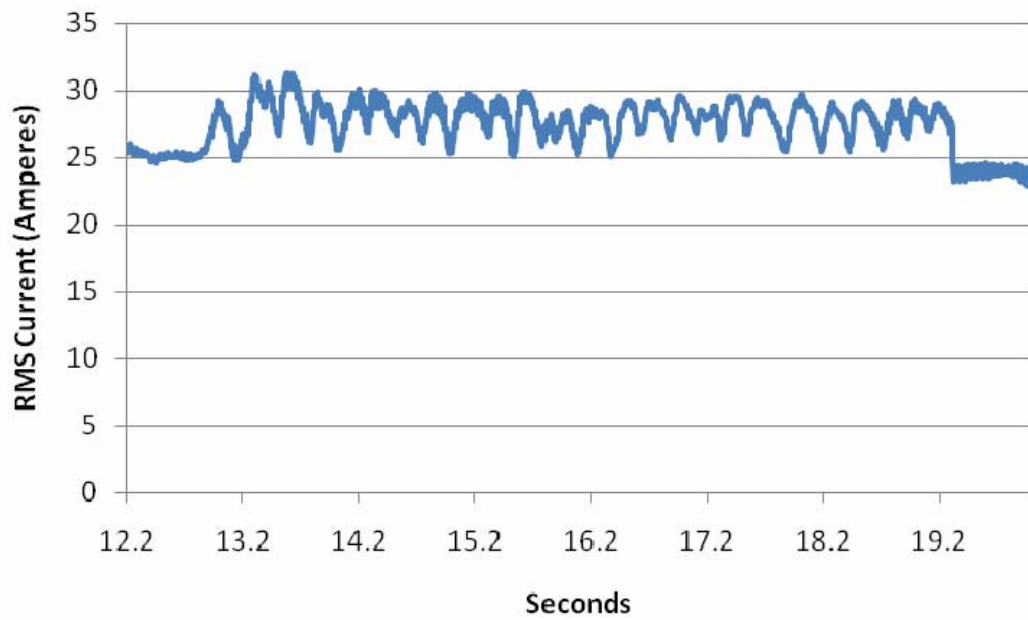Figure 6.15: Experiment 3 - Arc Burst Waveforms

Figure 6.16: Experiment 3 - Final Arc Burst, Detailed Waveform

Figure 6.17: Experiment 3 - Initial Setup

Figure 6.18: Experiment 3 - Branch Arcing

Figure 6.19: Experiment 3 - Branch Burns After Arc Burst

Figure 6.20: Experiment 3 - Branches Burned Through

Figure 6.21: Experiment 3 - Main Branch Remains on Line

Figure 6.22: Experiment 3 - Damage to Line

6.5   Experiment 4

Experiment 4 used a chinaberry branch with multiple contacts. The thickest contact point was approximately 1.25" which rested on the neutral conductor, while two 0.5" and one 0.375" points contacted the phase conductor. One of the 0.5" contact points is shown in Figure 6.23. As with previous tests, a carbonized path began to form immediately after the line was energized. This proceeded for approximately four minutes, with the branch expelling significant amounts of steam and smoke as the path continued to form. After four minutes, the branch arced once, then remained relatively calm for approximately 4.5 seconds, then began a sustained series of arcing which lasted approximately 4 seconds. A ten second waveform capture from this period is shown in Figure 6.24. This graph is expanded to cover more detail in the area of interest in Figure 6.25. Figure 6.26 shows the chinaberry tree during the arcing stage, while Figure 6.27 shows typical damage to a branch after a series of arcing events.

Figure 6.23: Experiment 4 - Branch Contact
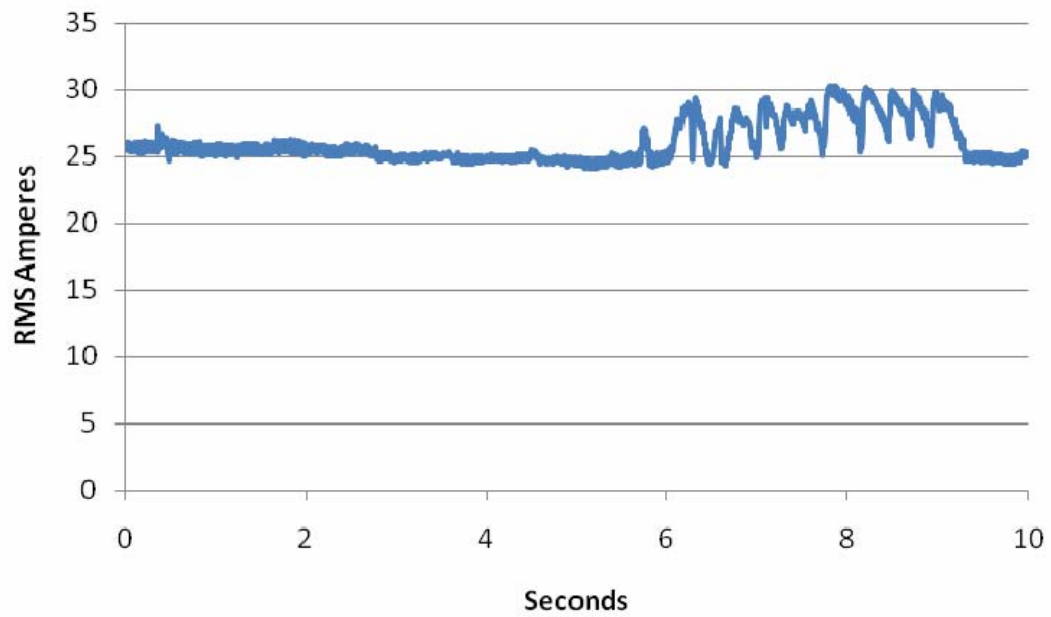
Figure 6.24: Experiment 4 - Arc Waveforms
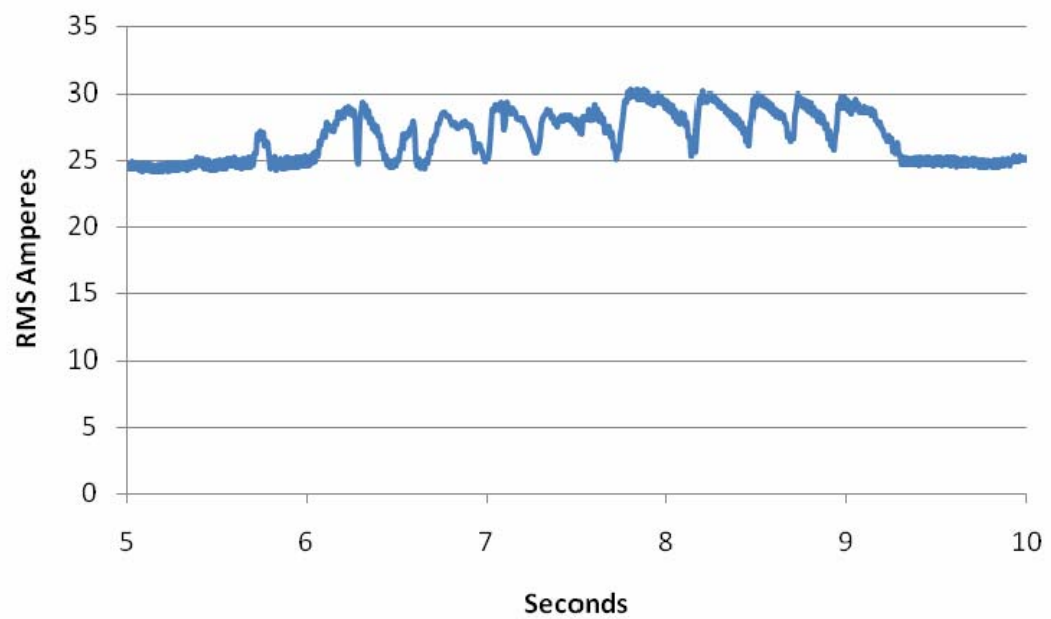
Figure 6.25: Experiment 4 - Arc Waveforms Detail

Figure 6.26: Experiment 4 - Arcing

Figure 6.27: Experiment 4 - Burned Branch

6.6 Conclusions

These staged tests provided additional insight with regard to the behavior of trees when they make contact between phase conductors or phase and neutral conductors. The recorded data suggests that it is possible to detect the electrical signals generated by such contacts at a remote substation. Additionally, photographic and video recordings made of multiple trials adds to the body of knowledge with regard to the physical behavior of these phenomena.

7. **Recommendation for Future Work**

Measuring and recording incipient vegetation-related outages has proved more difficult than anticipated for a variety of reasons. Utility trimming practices are effective in preventing many vegetation-related outages, reducing the number of events available for analysis. At the one monitored substation, for instance, vegetation-specific reliability actually decreased in the year of and the year following the trim. This project assumed that enough time would pass in one trim cycle to see significant vegetation contact on feeders such that trimming would significantly improve reliability, which was not the case, at least on the feeders for which reliability information was available. During the seven year period of outages analyzed by researchers, there were 171 outages at the 32-feeder substation mentioned in Section 5, an average of only 0.76 outages per feeder per year, a problem intensified by the fact researchers were monitoring only eight of the 32 feeders. It is suggested that future research examine feeders that have extended trim times to determine at what point vegetation-related outages significantly increase and impact reliability.

In addition to extended trim times, an increase in the overall number of monitored feeders is crucial to obtaining a significant number of representative events. Once events affecting ten or fewer customers are removed, the average number of events per feeder per year on the 32-feeder substation in Section 5 drops from 0.76 to 0.34, many of which were caused by hazard trees and not detectable electrically. Again, this problem was amplified by the fact researchers monitored only eight of the 32 feeders at the substation. As a result, there were many difficulties in tracking actual events to recorded waveform data. In addition, the one substation monitored represents effectively one data point, making generalizations to distribution systems in general potentially problematic.

When incipient events are detected, it is impossible to reliably correlate such events without an eventual failure and outage report. Almost all incipient events generate arcing characteristics. DFA equipment has monitored multiple related arcing events over extended time periods on many of the feeders on which it is installed. This activity may be very active for a day or two, then disappear for weeks or months before reappearing. While several of these series of captures ended ultimately in outages which allowed researchers to track their cause back from the result, many never progressed to an ultimate outage, and their cause remains unknown. Because of this, reliable utility outage records with accurate vegetation-related cause codes are an essential piece in developing a system to detect such events electrically. Continued support , both monetarily and with support personnel, is necessary to ultimately address this problem.

8. Conclusions

It is well accepted and logical that vegetation intrusion causes momentary interruptions and sustained outages. As vegetation intrusion increases, reliability falls and eventually can become unacceptable. Multiple factors influence the rate at which vegetation becomes problematic. Vegetation types, rainfall, and other factors vary from feeder to feeder. Therefore, using standardized, calendar-based trim cycles to maintain acceptable reliability on all feeders necessarily means some feeders have their trees trimmed more often than truly necessary.

The intent of this project was to study vegetation-related reliability and determine means for utilities to adjust their practices to get the most "bang for the buck." A central component was use of sensitive measurements as a proxy to determine each feeder's level of vegetation intrusion, thereby enabling utilities to trim based on a feeder's true need instead of on standardized cycles.

Data limitations did not allow the project team to develop the relationship between measurements and reliability impact as fully as hoped. This project involved two years of monitoring, compared to common utility trim intervals of three to five years, making it impossible to monitor a complete trim/growth cycle. The project period also fell in the early part of the cycle (i.e., soon after trimming was completed), reducing the likelihood of significant vegetation intrusion during the subject period.

Despite these limitations the project provided important, useful information regarding the behavior of vegetation-related outages and interruptions:

- o **Regular, well-designed trim cycles appear effective in minimizing vegetation-related events on distribution feeders.**

  Over a seven-year study period, a 32-feeder substation experienced 0.74 outages per feeder per year. Many of these affected small numbers of customers and therefore had little impact on reliability. The number of outages affecting ten or more customers during the same study period was only 0.34 per feeder per year – or only one such outage per feeder every three years. This indicates the four-year trim cycle used by this utility keeps vegetation-related outages at a relatively low level. What remains unknown is whether the four-year interval is too conservative. Would there be significant impact on reliability if the trim interval were increased to five or six years instead of four? This certainly would conserve valuable utility resources, but available data does not allow observation of the effect on reliability because trees are trimmed every fourth year and therefore never reach the period of most interest.

- o **Vegetation intrusion produces electrical signals on distribution feeders that are measurable from a remote substation.**

  Vegetation contacts can produce measurable electrical signals that may or may not cause momentary interruption(s) or sustained outage(s). Individual contacts may be self-clearing due to multiple factors including vegetation size and type, line movement, tree movement, wind, moisture, etc. Electrical behavior has been recorded during incidents in which vegetation contacts were repeatedly established and lost over substantial periods of time, and then eventually sustain themselves or damage the line sufficiently to cause an outage and a possible downed line or other damage to system apparatus. The period of time over which casual, intermittent contacts occur in the field may be hours, days, or even weeks.

- o **Field experiments conducted during this project provided valuable insight on the progression of vegetation-related fault conditions.**

  Vegetation-induced electrical signals were captured at the remote substation serving the feeder with staged vegetation experiments. Researchers also obtained valuable video and photographic measurements regarding the physical development of vegetation-related faults. These data have contributed substantially to the understanding of how vegetation-related events evolve electrically and physically, and continue to suggest the use of measured electrical signals to detect the development of vegetation-related problems.

Significant work remains in the enhancement of system reliability through sensitive, intelligent monitoring. Evidence to date and vegetation-management economics continue to suggest the need for particular focus on vegetation-related reliability. Researchers view vegetation management as critical to overall reliability and wish to continue this investigation through additional utility cooperation.

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