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Energy Association of Pennsylvania

800 North Third Street, Suite 301, Harrisburg, Pennsylvania 17102
Telephone (717) 901-0600 • Fax (717) 901-0611 • www.energypa.org

November 6, 2006

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
P. O. Box 3265
Commonwealth Keystone Building
Harrisburg, Pennsylvania 17105-3265

COMMENTS of THE ENERGY ASSOCIATION of PENNSYLVANIA
RE: Proposed Rulemaking Inspection and Maintenance Standards – Docket No. L-00040167
and
Policies to Mitigate Potential Electricity Price Increases – Docket No. M-00061957

Dear Secretary McNulty:

Enclosed for filing at the above-referenced Dockets, please find an original and fifteen (15) copies of the Comments of the Energy Association of Pennsylvania. An electronic copy has also been filed.

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INDEPENDENT REGULATORY
REVIEW COMMISSION

Cordially,

Donna M. J. Clark

Donna M. J. Clark
Vice President and General Counsel

CC: Chairman Wendell F. Holland
Vice Chairman James H. Cawley
Commissioner Kim Pizzingrilli
Commissioner Terrance J. Fitzpatrick
Elizabeth Barnes (via electronic mail)

PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 Pertaining to Adding Inspection and Maintenance Standards for Electric Distribution Companies	: : :	**L-00040167**
***En Banc* Proceedings Re: Policies to Mitigate Potential Electricity Price Increases**	: :	**M-00061957**

COMMENTS of the ENERGY ASSOCIATION of PENNSYLVANIA
to PROPOSED RULEMAKING ORDER
RE: INSPECTION AND MAINTENANCE STANDARDS
and
COMMISSION'S *EN BANC* HEARING

I. BACKGROUND

On April 21, 2006, the Pennsylvania Public Utility Commission (Commission) entered a Proposed Rulemaking Order formally commencing its rulemaking process to establish regulations governing Inspection and Maintenance Standards for Electric Distribution Companies ("EDCs"). The Proposed Rulemaking Order was published in the ***Pennsylvania Bulletin*** on October 7, 2006, with comments due thirty (30) days following publication on November 6, 2006.

The Energy Association of Pennsylvania ("EAPA" or "Association") represents the interests of the Commonwealth's PUC-regulated electric distribution companies listed below. [1] EAPA actively participated in the final Rulemaking Order at L-00030161 which amended the EDCs' reliability reporting requirements referenced by the

[1] EDC members supporting these Comments include Allegheny Power, Citizens' Electric Co., Duquesne Light Co., Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania Power Co., PECO Energy Co., Pike County Light & Power Co., PPL Electric Utilities Corporation, UGI Utilities, Inc.-Electric Division, and Wellsboro Electric Co.

Commission in the instant Proposed Rulemaking Order. EAPA previously filed comments on behalf of its members on matters related to the Advance Notice of Proposed Rulemaking pertaining to Adding Inspection and Maintenance Standards, for the Electric Distribution Companies, Docket No. L-00040167. Comments were filed by EAPA to the Advanced Notice on February 9, 2005, and Reply Comments on March 11, 2005. EAPA incorporates by reference its previously filed comments.

EAPA and its members stated previously that "uniformity works against cost considerations and is contrary to the ultimate goal of reliability."

II. INTRODUCTION AND OVERVIEW OF COMMENTS

The fact that the Commission has mandated reliability performance benchmarks that an EDC must satisfy, ensures a reliable distribution system. The Commission has numerous opportunities to review system performance through quarterly and annual reliability reports, customer complaints, customer satisfaction surveys and individual company meetings. A still further opportunity available to the Commission is to review EDCs' Operation & Maintenance practices through the mandated management effectiveness and operating efficiency Audits that must be conducted not less than every eight years. [2]

The instant proposed Inspection and Maintenance Standards by the Commission has moved forward without the industry expertise or cost/benefit analysis to support such proscriptive requirements.[3] EAPA members estimate that, if the proposed

[2] Title 66, Pa. C. S. §516

[3] Based on the Commission intention to develop regulations, the EAPA members agree to make a bi-annual filing of the individual company's Inspection & Maintenance programs, subject to the removal of the mandatory specific Inspection and Maintenance time cycles.

regulations are implemented, the added expense to Pennsylvania ratepayers over and above current Inspection and Maintenance practices will exceed **$75 [4] million per year** with little or no assurance of improved electric service reliability. [5] EAPA provides this example of the magnitude of the impact these proposed regulations will have on Pennsylvania's EDCs and its ratepayers. The proposal would increase the overall EDCs' operations and maintenance expenses 6.3% without a cost effective result for improving reliability. If mandated in its present form, the EDCs will eventually have to recover their increased operating costs through increased rates. While the Commission appropriately sets the standards for electric service reliability, how an EDC achieves those standards and the resulting effect on their customers' electric service reliability is the responsibility and accountability of the EDC. Simply increasing every EDC's costs of operation through mandatory proscriptive Inspection and Maintenance Standards that provide no commensurate benefit to the customer is counterproductive.

This is a needless increase in cost to the consumer which could result in industrial job losses because of the increased electricity prices, the relocation of industry out-of-state, or not investing in present facilities. For example: Allegheny Technologies Inc. has pulled the plug on $400 million in investment at its Allegheny Ludlum subsidiary in Western Pennsylvania because of high electricity costs, according

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[4] Dollars are shown in present day dollars and present labor costs. If the regulations are implemented two years from now, the present day dollars would increase. Additionally, the number of EDC workers to perform the mandated Inspection and Maintenance Standards would have to increase because of the expected inflating costs associated with the depletion of skilled workforce resulting in demand outweighing supply. These increases means the estimate of $75 million would be understated.

[5] The Commission has a docket seeking to find ways to minimize electric price increases. The proposed rules in this docket are directly contrary to that effort. We are filing in both dockets so that the participants in both proceedings understand what is impacting rates.

to what was said at an energy symposium in Pittsburgh on October 20, 2006, by Douglass A. Kittenbrink, Allegheny Technologies executive vice president. [6]

Nowhere in this rulemaking has the Commission shown that the proposed Inspection and Maintenance Standards will improve distribution service reliability to Pennsylvania customers. When one compares the paucity of benefits attributable to these proscriptive regulations with the cost of complying with these standards, one cannot come to any other conclusion than these standards should not be implemented. The EAPA would like to reiterate the fact that the Commission recently implemented electric service reliability regulations effective September 18, 2004. These recently adopted regulations should be given a chance to work before adopting additional regulations. The EAPA and its member EDCs believe that the Commission addressed the need for electric service reliability standards through those regulations. The proposed additional reporting by the EDCs of their individual Inspection and Maintenance plans will provide the Commission with more than the necessary information for monitoring the performance of the EDCs toward meeting their customer electric service reliability goals.

Finally, EAPA has included a red-lined version of Annex A Subchapter N. – Electric Reliability Standards, indicating specifically where EAPA seeks language changes to the proposed regulations. EAPA and its members ask the Commission to carefully consider all of these suggestions.

Before addressing specific areas of concern, the EAPA would like to point out the following, which form the basis for its concerns:

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[6] Pittsburgh Tribune Review, Saturday, October 21, 2006.

- This initiative far exceeds those undertaken by neighboring states and other jurisdictions. This does provide a note of caution that the Commission should have a credible, factual basis to proceed. No such basis is yet evident.
- EAPA and its members do not support the establishment of strict and uniform, proscriptive Inspection & Maintenance Standards but support individual EDC flexibility for inspection & maintenance practices which have assured reliable electric service in the past. Mandated standards for the entire state would hinder the EDCs' ability to achieve efficiencies in work processes and would restrict the EDCs from employing new technologies which would accrue to their customers' benefit in the form of lower prices and better, more reliable service.
- If adopted as proposed, Pennsylvania citizens will eventually pay an additional minimum of $75 million annually, in current dollars, when EDCs eventually file for their next general rate case to recover these increased operating costs from their customers, or request a rider for current recovery. The EDCs' overall operations and maintenance expense would increase 6.3%, at present day value, over present practices without demonstrating a cost/benefit result for improving reliability. This occurs at a time when the Commission has an ongoing investigation to minimize electric rate increases for the companies coming out of rate caps. The EDCs would note that neither the $75 million or the 6.3% include dollars related to training the requisite workforce.

- For those EDCs currently under Transmission & Distribution rate caps, an Order requiring adoption of these rules must also address the means of recovery of these costs prior to the expiration of those caps.
- This rulemaking has no cost/benefit analysis to demonstrate that the proposed Inspection and Maintenance Standards will improve electric service reliability, yet the costs to consumers are significant at time when the Commission should do everything it can to minimize electric cost increases.
- The FERC has asserted jurisdiction over all EDC transmission plant. Promulgating regulations governing the Inspection and Maintenance of transmission plant is legally impermissible, as it is outside the jurisdiction of this Commission.
- Mandated additional inspection, maintenance and trimming time cycles will exacerbate an EDC's trained worker resources shortage and we believe will result in an increase in labor costs for EDCs because of the shortage of trained work force resources.
- Given the diversity of tree species, the diversity of topography, and the diversity of weather among utilities across the state, there is no basis to set a uniform vegetation maintenance cycle rate applicable to all utilities. Yet, according to a statement in the Inspection and Maintenance Standards rulemaking order, if the plan does not include four-year tree-trimming cycles for distribution lines, and five-year tree-trimming cycles for

transmission lines, it will be rejected. This proscriptive requirement makes absolutely no sense given the existing experience of the EDCs.

- Eighty-six point seven percent (86.7%) of tree-caused customer outages are caused by trees from outside the EDCs' right-of-way over which EDCs have limited control.
- Each EDC should be able to define the areas in their service territory. The forced distinction between rural and urban circuits adds no value, since circuits can cross many times between rural and urban areas. Further, this distinction based on population density between rural and urban has no value in terms of reliability.

The EAPA points out that rapid technology advancements, implemented by EDCs, work to accelerate the pace of cost-effective improvements to the operation and maintenance of transmission and distribution systems, which make mandated time cycles obsolete and outdated.

Although disagreeing with the need to submit proscriptive Inspection and Maintenance plans, the EDCs agree to submit their individual plans by October 1, 2007, for a Distribution Facility Inspection and Maintenance Plan that includes managing vegetation within the right-of-way of its distribution facilities, (meeting the October 1, 2007, filing date assumes the Rulemaking is completed six months in advance of the date the first report is due) and every two years thereafter.

Finally, the trained workforce to comply with the proposed expensive labor intensive rules simply does not exist now or in the likely future, as NERC recently observed:

"The loss of skilled and experienced technical talent is much more acute in the electric utility industry. According to a Hay Group study, 40 percent of senior electrical engineers and 43 percent of shift supervisors will be eligible for retirement by 2009. That study also found more than two-thirds of utility companies surveyed have no succession plan for supervisors and 44 percent have no plans for vice presidents. Not only does the industry not have enough professionals and managers, but the skilled labor force will be severely affected. Trying to get journeyman electricians and linemen will be more difficult than hiring the professional workforce.

"At the same time, the demand for engineers with power background and other utility professionals has increased due to the advent of independent transmission companies, regional transmission organizations, and various markets. This caused the transmission dependent users, independent power producers, and other wholesale entities to increase their professional staff, particularly those with transmission planning expertise.

"Aggravating the problem of sustaining the essential technical knowledge is the dwindling numbers of students in the power engineering programs of most universities. Currently, the electric power engineering programs within the United States graduate about 500 engineers per year; in the 1980s, this number approached 2,000." [7]

III. GENERAL COMMENTS

A. 57.192 Definitions

Urban area and Rural area

Individual EDCs may for their own vegetation management purposes designate distribution circuits, or portions thereof, as either "urban" or "rural". However there is no value in requiring all EDCs to distinguish between rural areas and urban areas, either by a population threshold of 5,000 or by any other means. Many distribution circuits cross between proposed urban and rural areas. One circuit may cross multiple times into rural and urban areas. Therefore, the request is

[7] NERC 2006 Long-Term Reliability Assessment, p. 26.

simply not practical. There is no benefit in designating an area as either rural or urban, which probably explains why no other state Commission makes such a distinction. Generally, a circuit would not be identified as being located within an area described as either having a population of greater than or less than 5,000 people.

Consequently, the EAPA asks that the designation of urban/rural areas be eliminated in the context of filing plans under any final rules.

Transmission FERC/NERC Jurisdiction

The EDCs oppose the Commission's proposed Inspection and Maintenance Standards for vegetation management on the transmission system because such standards will be duplicative and potentially in conflict with federal standards. Transmission facilities are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The National Electric Reliability Council ("NERC") has developed national reliability standards under the Energy Policy Act of 2005.

The newly adopted NERC Vegetation Standard, FAC-003-1[8] consist of eight major topics and 41 specific requirements, including a vegetation management plan, vegetation inspections, minimum clearances for vegetation and conductors, mitigation measures for inadequate vegetation clearances, and reporting of tree related outages. The NERC Vegetation Standard, becomes effective February 7, 2007, and addresses the concerns expressed by the Commission.

FERC designated NERC as the electric reliability organization ("ERO") charged with the responsibility to develop and enforce bulk power systems' reliability

[8] The NERC Board of Trustees approved Vegetation Standard FAC-003-1 on February 7, 2006

standards. EAPA respectfully requests that this Commission recognize that FERC and NERC have the oversight responsibility and will impose the reliability standards for transmission lines. Pennsylvania does not need to have duplicative and possibly conflicting costly standards. EAPA's comments will not further address the various transmission proposals except limited issues relating to cost and jurisdiction. EAPA will strike the proposals on the redline version of proposed regulations as they relate to transmission lines.

EAPA requests that the Commission eliminate all Standards in the proposed rulemaking related to transmission system since transmission is regulated by FERC and NERC.

B. <u>57.198 Inspection and Maintenance Standards</u>

Need for Vegetation Management Cycle Flexibility and Cost Estimates

The EDCs need flexibility in determining when vegetation management work must be conducted. Mandating a uniform four-year tree-trimming cycle for distribution lines in itself accomplishes very little toward improving service reliability.

Line clearance is a condition-based activity. Each EDC schedules tree-trimming on its circuits based upon its own individually established criteria. Typically considered are the proximity of tree branches to the wires, the number of customers fed by the circuit, the number of tree-caused outage events recently experienced on the circuit, and the elapsed time since last trimmed. The trim cycle time on any given circuit results from the application of these criteria. Basically, a circuit is trimmed when it needs to be trimmed; much like a homeowner cuts their grass when it needs cutting, rather than on a time based cycle. Trimming too soon results in wasting part of the value of the work done during the last trimming; trimming too late results in poor circuit performance. It should be noted that the tree/wire clearance attained at the time of pruning is not totally dependent on the cycle frequency. The clearance desired at the time of pruning is related to many factors: individual forest types and tree species, local environmental conditions (including temperature and rainfall), the trimming specification, the type of wire and its configuration, property owner concerns and the aesthetics of the tree. Cycle length and clearances, have significantly less influence on service reliability, especially in regards to on-right-of-way vegetation caused service outages compared to off-right-of-way trees falling into the lines. The proposed standards further specify a program that will provide for minimum clearances of vegetation from overhead distribution facilities is sufficient to avoid contact under design-based conditions. This is unreasonable.

California has a no contact requirement, but not for reliability reasons. The reason California has this standard is to avoid sparking from tree contact that could cause wildfires during their dry season. Pennsylvania does not need this requirement. The proposed "avoid contact" standard as written could require a trimming cycle more frequent than the proposed four years for distribution circuits. A more frequent clearing cycle to meet this standard would significantly impact the EDCs' vegetation management budget beyond the estimates to achieve the minimum time cycle standards stated below. Before the Commission invokes an "avoid contact" standard, it should have the data to support the perception implied with this requirement that trees in contact with conductors cause outages. The member companies' experience can prove this is incorrect. Without question, every EDC has trees on their system in contact with various distribution facilities that are not causing outages. Further data presented at the International Society of Arboriculture Annual Meeting in Minneapolis supports the visual evidence that trees branches growing into the conductors do not normally cause outages. This study is attached. Appendix "B" is a paper entitled "Research on How Trees Cause Interruption – Applications to Vegetation Management". Also attached, Appendix "C" is a study by Baltimore Gas and Electric Company entitled "Priority Trimming to Improve Reliability."

Forcing each EDC to move to proposed mandated distribution, proposed trimming and vegetation inspection cycles will result in an additional annual expense of **$38.7 million annually** over and above current practices. If the transmission trimming and inspection cycles were followed, another **$6 million** would be spent each year. A total additional amount of **$44.7 million** would be spent annually for trimming and inspection under the proposed regulations with little or no assurance of resulting benefit in increased reliability.

The Commission should permit each EDC the flexibility to determine the vegetation management program that best suits its territory, and flexibility to determine what should be done when the circuit is maintained, allows each EDC to manage its own right-of-way tree conditions most successfully.

Trees Off the Right-of-way

Typically, tree-related incidents are one of the larger causes of customer service interruptions for an EDC. In the majority of outage incidents involving trees, the trees are located outside the power line right-of-way where the EDC has not secured a right to prune or remove trees, which testifies to the efficacy of existing trim cycles. EDCs have no authority to cut down or trim trees outside the right-of-way. These off-right-of-way tree incidents account for **86.7 %** of all tree-caused customer outages. Notwithstanding this fact, in most cases, the EDCs could not identify which off-right-of-way tree may cause a problem because the problematic tree appeared to be perfectly healthy prior to its failure. Often, a diseased tree that is close to falling will appear healthy on visual inspection. The problem is off-right-of-way trees falling into the conductors or a domino effect of trees falling into other trees eventually hitting the line. Some trees may be eighty feet or more off of the easement width and outside the legal rights of the EDC to remove such trees. The costs to remove off right-of-way trees that may impact reliability is prohibitive and well beyond what property owners would allow to be removed.

The pictures in Appendix "A" provide a sampling of incidents caused by off-right-of-way trees.

EDCs' Arborist Experience in Vegetation Management Should Be Followed

The EAPA requests that the Commission allow the EDCs to continue to effectively utilize the vast experience and expertise of their line clearance staffs to manage the clearance programs. Proper consideration should be accorded to their combined 976 years of EDC arborist experience in managing vegetation around power lines. EDC's arborists know the growth patterns that dictate when tree-trimming needs to be done. Through an EAPA-sponsored survey, 60 professional arborists employed by Pennsylvania EDCs were identified as responsible for oversight of their respective

EDC vegetation management. Most of them have a four-year college degree in addition to certifications ranging from ISA Certified Arborist to ISA Utility Specialist.

The member companies utilize their employees' EDC arborist expertise to identify the types of hazardous trees, growing cycles, density of trees, topography of the terrain, length of regional growing season, weather patterns, and the specific attributes such as regional growing season and age of the vegetation, and then to devise a line clearance program to best meet its needs. Pennsylvania's EDCs currently perform vegetation management in a variety of ways and manage the vegetation growth by circuit. The EAPA requests that the Commission recognize the wealth of experience and expertise present within the Pennsylvania EDCs and permit the EDCs to establish trimming programs that are most appropriate to maintain reliable electric service to their customers.

The impact of a particular tree-trimming cycle, demonstrated in reliability statistics, is the most important measure of reliability. If a company has maintained adequate reliability statistics, there is no reason to burden the company and the ratepayers with unnecessary added expense for vegetation management or equipment-related time cycle inspection practices. Absent a cost/benefit analysis as required by Executive Order 1996-01, there is not a sufficient compelling reason to impose these inflexible restrictions and additional costs.

Mandatory Inspection and Trimming Cycles Will Increases Rate Differentials With Other States

The overly proscriptive rules offered by the Commission staff will widen the differential between the electric rates in Pennsylvania and the other states. None of the surrounding states have adopted such.

In New York, the standard employed by the Commission there is the National Electric Safety Code ("NESC"). The NYPSC establishes the NESC by the minimum standard and has done so formally.[9] The Ohio PUC has standards that involve utilities setting forth certain goals for annual right-of-way vegetation control and measuring their success versus their own goals. There are no mandated PUC vegetation cycles in Ohio.[10]

Other states do not have the proscriptive tree-trimming practices as proposed by the Commission. For example Texas, another state charged with a competitive mandate, has no specific requirements for tree-trimming, vegetation management or right-of-way clearance, but rather is guided by the provisions of the American National Standards Institute, Incorporated, the National Electrical Safety Code and other national standards.[11] Kansas follows the NESC as does Utah, Wisconsin and Oregon, since the NESC contains a Rule 218 that addresses tree-trimming requirements.[12] Most states don't have any standards, as evidenced by a review of the rules of in Alabama, Alaska, Colorado, Connecticut, Delaware, Georgia, Idaho, Illinois, Indiana, Kentucky, Maine, Maryland, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Mexico, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Tennessee, Washington and Virginia.

Those states that have implemented vegetation management standards have done so in a limited fashion. Ohio asks the utilities to set their vegetation goals, and

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[9] Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Case No. 04-M-0159, January 5, 2005.
[10] <u>Ohio Electric Service and Safety Standards</u> 4901: -10-27.
[11] <u>www.puc.state.tx.us/rules/electric/25.101.25.doc</u>
[12] Florida Rules 25-6.-345, and 25-6.0455(1)(a), Florida Administrative Code and Kansas ERR-Rule 4(h), WIS.Adm. Code S.PSC.114.

then measures how successful they have been in meeting those goals. New York asks for transmission-specific and EDC-specific clearance requirements, and reviews the plan. Massachusetts requires tree-trimming by utilities, and then has them report the results.

Absent a cost/benefit analysis as required by Executive Order 1996-01, there is no compelling reason to impose the inflexible restrictions and additional costs that would result from mandatory line clearance cycle times. If the practice of most other states is to either adopt national standards or have no standards at all in vegetation except for traditional regulatory monitoring, then this Commission should have some identified benefit that overrides the cost of these proposed Standards.

In addition, if the Commission adopts the proposed proscriptive standards in tree-trimming, there would have to be some demonstration that national standards for line clearance are inappropriate or do not provide reasonable reliability. This becomes especially necessary in light of the fact that 86.7% of all tree caused customer outages with power lines, come from trees not affected by the proposed vegetation standards.

Finally, the EAPA's position is supported by nearly 1,000 years of arbor experience and the expertise of 60 EDC arborists on the EDCs' staffs. No arborist expertise has been offered to support the proposed Commission regulations.

Increased Pole Inspections Do Not Increase Reliability

There is no causal relationship between increased frequency of pole inspections and reliability. Customer service outages due to pole failures are extremely rare. The proposed statewide ten-year cycle for pole inspection will increase the cost of electricity yet will have no impact on electric service reliability. The EDCs and their customers would experience **$ 4.4 million** of increased costs annually if the proposed ten-year inspection requirement is adopted.

EDC pole inspection and maintenance programs are largely geared toward extending pole life through mechanical means or application of chemical preservatives. When necessary, poles that are deteriorated beyond repair, or can no longer bear the weight of the wires and attachments, are replaced. This inspection process consists of inspecting the pole from top to below groundline, estimating the suitability of the pole to carry the applied load, and applying the appropriate treatment as, and if, required.

The inspection and maintenance cycle time is very EDC and region specific and can also vary by the type of pole and its initial preservation treatment. Inspections are made by the experts in this field after carefully considering all the factors mentioned above. The EDCs should be permitted to develop their own cycles for inspection of utility poles.

Pole Inspection*: *Another Widening of the Rate Differential Between Pennsylvania and West Virginia and Kentucky

West Virginia has rules governing pole inspection. However, inspections are to be done with reasonable frequency.[13] Kentucky requires that a utility shall construct and maintain its plants and facilities in accordance with good accepted engineering practices. The Kentucky Commission has adopted national standards including the National Electrical Safety Code ANSI-C-2, National Electric Code ANSI-NFPA-70, American National Standard Code for Electricity Metering ANSI-C-12-1, USA Standard Requirements for Instrument Transformers ANSI-Standard C.57.13 National Electrical

[13] West Virginia Legislative Rule, Public Service Commission Series 3, Rules and Regulations for the Government of Electric Utilities, 150-3-8.5 Pole Inspection.

Code.[14] If the Commission wants to mandate pole inspections, it should follow the lead of West Virginia and Kentucky.

Overhead Line Inspections Distribution- foot patrol annually and Transmission – aerially twice per year and foot patrol every two years

Under the proposed distribution line inspection regulation, inspection costs would increase an estimated **$12.0 million** annually, due to the necessity of more frequent inspections. The transmission line inspection under the proposed regulation would cost **$4.6 million** above present practices.

The current inspection and maintenance programs on overhead distribution lines utilized by Pennsylvania EDCs work well to both find and fix the problems. They focus on identifying deterioration of facilities, encroachment on the lines by property owners and vegetation, and finding damage to equipment that has not resulted in a service outage. Most equipment or material-related failures are caused by internal deterioration that is not readily determined by visual means. Many equipment and/or material failures are caused by lighting strikes, high winds or other severe weather events that cause flashovers or through-faults at the time of the event. These failures will not be deceased by increasing the frequency of visual inspection. Under current inspection schedules, a relatively small number of maintenance items are discovered. Increasing the frequency will yield little if any electric service reliability benefit, while significantly decreasing the EDC's resources available to investigate and improve worst performing areas. EAPA recommends that EDCs retain the ability to establish their individual inspection cycles for distribution lines.

[14] Kentucky 807 KAR:5:041, pursuant to KRS 278.280(2).

Repairing found problems within 30 days

Problems spotted during inspections vary in severity. Some problems identified may need to be fixed immediately or within a few days; others are emerging problems which do not present a current risk and may be scheduled for future repair without interfering with current construction schedules. On the transmission system, provisions exist today for emergency switching to resolve an urgent condition finding. However, scheduling of transmission line outages to repair less critical findings is subject to transmission line availability as directed by PJM. Factors such as electrical load and system contingencies often make a transmission line unavailable for removal from service. Transmission owners also shoulder the cost an outage creates which limits transmission system contingencies called "congestion". Today, EDCs gather non-urgent transmission findings and schedule an outage around line availability. Often this is limited to the spring and fall months. Placing a 30-day limit for repair will not improve reliability because it will not accelerate the repair of urgent problems; conversely, it will increase cost and decrease resource flexibility for work crews by placing artificially short time schedules on non-critical repairs. The EDCs should retain the ability to determine the urgency of repair and to schedule resources accordingly.

Inspection of overhead distribution transformers annually

EAPA opposes a uniform standard for the annual inspection of pole mounted distribution transformers. Increasing visual inspection of overhead distribution transformers will not increase customer service reliability. EDC's current inspection programs uncover very few transformer problems. Overhead transformer failures typically affect only a few customers. Increasing the frequency of inspection will not produce significant additional reliability benefits but will greatly increase costs and divert resources that could be used for EDC's maintenance programs that yield greater reliability benefits. Many transformer failures result from causes that occur right before the failure, such as lightning, or storm-related faults on secondary/service conductors. Annual visual inspections will not decrease the number of these events and will increase cost approximately **$2.9 million per year**. The EDCs should be allowed to continue to inspect overhead transformers using their current schedule.

Inspection of pad-mounted or below-grade transformers every two years

The EAPA opposes a standard for the inspection of pad-mounted and below-grade transformers every two years. Current inspection programs for this equipment are sufficient to maintain this equipment in a reliable fashion. Increasing the frequency of inspection of these devices will not significantly improve customer service reliability and increase cost of approximately **$4.0 million annually**. EDCs should retain the ability to establish inspection programs for pad-mounted and submersible equipment to optimize use of inspection resources and customer service reliability.

Inspection and testing of reclosers once per year

EAPA agrees with the need for individual programs for inspection and testing of reclosers, but it does not agree with the proposed regulation mandating this work be done on all reclosers on a one year cycle. Improvements in technologies and communications are resulting in the development of intelligent reclosers that specifically do not require time-based inspections. Some EDCs are also adopting Condition Based Maintenance practices for their equipment, that are based on operating cycles and other "wear and tear", independent of the time in-service. The amount of wear that a recloser experiences is related to the frequency of operation and ambient weather conditions rather than to the duration of installation. A newly installed recloser will have a trip frequency based on the number of faults on the line that it protects, rather than on the length of time that the recloser is installed. During the course of a year, due to changes in severe weather and other external causes, this recloser may not trip at all, or it may trip several times. Reclosers that meet their manufacturer's recommended fault duty in one year are extremely rare. Initiating a one-year testing standard would cause EDCs to routinely spend valuable resources inspecting and testing reclosers that are in new or nearly new condition. The additional cost of recloser inspection and testing to the EDC is estimated to be approximately **$14.0 million annually**.

A review of recloser inspection is included below for understanding how recloser inspections are handled by the EDCs. A "casual" visual inspection is done each time a recloser installation is visited, whether for recloser readings or operation. This inspection is a quick visual once over and is typically made from the ground.

EDCs will perform a more detailed visual inspection of the recloser and associated equipment on regular schedules. This inspection includes a thorough review of the recloser installation by trained or qualified individuals.

Further a complete shop inspection and testing, called for annually under the proposed regulations, is performed now by EDCs based on the number of operations and the duty cycle (amount of fault current interrupted) experienced in the field (i.e., every 200 operations). This inspection and testing includes changing the oil, internal visual inspection, and operations testing. The recloser unit must be removed from the field and returned to an appropriately equipped and staffed shop for this testing. When performed on a conditioned based maintenance basis, this typically involves the change-out of the existing reclosers in the field with reclosers from stock. After testing, the tested units would be returned to stock.

EDCs have ten of thousands of distribution line reclosers in service across the state. To support shop inspection and testing on an annual basis, considerable additional infrastructure and inventories would need to be developed. Some of those additional needs and considerations are listed below:

- Adequate stock for "rotating recloser inventories"
- Enhanced repair/test facilities to handle additional units being tested
- Enhanced transportation system to handle additional needs
- Staffing for:

    Field rotation of units

    Shop testing

    Program management

One EDC examined its outage history data for the three year period 2003 to 2005 and found that none of its customer outage events would have been prevented or shortened if the recloser inspection and maintenance program being prescribed was in place. While it is not being claimed that these results should be extrapolated over the rest of the Pennsylvania EDCs, it does suggest that the number of customer outages to be avoided by the prescribed recloser inspection and maintenance program are very few, if any. The EDCs assert that given this EDC experience, there is no credible evidence to support the imposition of $14 million in annual cost increases.

Recloser maintenance is a highly equipment specific and service conditions based issue. Manufacturers are continuously striving to improve their equipment to increase its performance and lengthen its service life.

EDCs should retain the ability to establish recloser testing programs based on manufacturer's recommendations and the in service conditions to which reclosers are subject.

Substation equipment, structures and hardware shall be inspected monthly

The EAPA disagrees with a requirement for monthly substation inspections and notes that this new requirement would add about **$3.3 million annually** in EDC operating cost. Current inspection programs are sufficient to provide reliable substation operation. EDCs have studied results of more frequent inspections and have found very little benefit in inspecting stations more frequently. All EDC's have routine cycles for inspecting substation equipment. These inspections are more rigorous than a mere visual inspection. Very few customer service outage incidents occur because of substation equipment failures that would have been detectable prior to their occurrence by a routine visual inspection. Most customer outages that occur due to the failure of substation equipment are the result of events such as animals or severe weather. These outages can not be prevented by increased visual inspection. Therefore, increasing the frequency of substation inspection will not significantly affect customer service reliability but will significantly decrease the ability of EDCs to devote resources to more pressing substation maintenance issues. The EDCs should retain the ability to establish substation inspection programs as needed to properly maintain substation equipment, structures and hardware.

Technology Re: Maintenance of Transmission and Distribution Systems

By the nature and necessity of their function, electric transmission and distribution systems have thousands of parts of varying degrees of complexity and importance dispersed over a large geographic area.

Maintaining systems in a cost effective manner, while maintaining or improving reliability requires the development of targeted, specific maintenance programs that among other things, take into account the characteristics of component parts, the environment in which they operate, and most importantly the electrical and mechanical stresses that they experience. Visual inspection programs, while being the simplest and most straightforward approach to facilities maintenance, do not provide the most critical information that EDCs need. EDCs invest in technologies in order to obtain and store this critical information, while decreasing the need for visual inspections with limited benefits, improving reliability, and controlling operating costs.

Mandating labor-intensive practices with their attendant high costs impairs the EDC's flexibility to invest in technological improvements that would produce greater benefits for the customer. Each EDC needs the flexibility to change its inspection and maintenance cycles and practices as it implements new diagnostic technologies. Technology and communications improvements impact transmission and distribution systems at an accelerating rate. Some of these advancements combine to bring cost-effective improvements to the operations and maintenance of transmission and distribution systems in the areas of sensors, communications and computers. By adopting these technologies, EDCs can become "smarter" in developing and implementing their inspection & maintenance programs, reducing outdated labor intensive practices, leading to better reliability and lower customer costs.

Sensors – Worldwide competition in sensor technology has brought about smaller, more powerful sensors available at increasingly lower prices. The combination of availability and price is making the use of high-tech sensors cost-effective more often throughout EDC transmission and distribution systems.

- Thermal sensor arrays are used via thermal imaging cameras to detect hot spots in electrical equipment.
- Acoustic sensors in the audible and ultrasonic ranges are used to find "noises" that might indicate problems with insulation, a connection, or the internal workings of a complex piece of equipment.
- Dissolved-gas detectors are used to test insulating oil for chemical indications of potential problems. Knowledge of the sources of the gases tells maintenance personnel when to open a piece of equipment on an as-needed basis, and when to leave it alone.
- Detectors of specific gases in air can be used to "see" the escape of insulating gases from live equipment. This is far more effective than the previous manual practice where maintenance personnel may have had to de-energize the equipment in the past to apply soapy water and look for bubbles.
- Corona detectors are being integrated into "corona cameras", helping to find electrical problems that were invisible in the past.

- Detectors of electromagnetic fields and waves can be placed in more and more places on transmission and distribution systems to indicate where currents and voltages are normal or abnormal.

Communications – The rapid pace of advancement in the high-quality, lower cost communications technology makes it now possible to monitor sensors remotely and accumulate technical information at central points or concentrators established at main office buildings, service centers, substations, and even on poles and towers. The ever-increasing options for combining and sharing this wealth of information about the condition of equipment on the electric delivery system keeps telecommunications and IT departments very busy. Engineers continue to devise ways to increase this flow of technical information back to decision makers in their organizations by linking sensors in the field to communication technologies like cell phones, fiber optics, pagers, radios in new bands, and the internet. Aided by superior technical information, decision makers are able to refine more cost effective inspection and maintenance practices.

Computer Applications - The amazing increase in computing power at reduced costs is of great benefit as EDCs endeavor to increase their ability to ascertain the health of their distribution systems. Increased storage capacity coupled with improvements in software for the extraction, analysis, correlation, and reporting of information allows analysts to undertake maintenance that was too labor-intensive in the past. Modern computer-based systems and data bases such as Outage Management System, Work Management System, Geographic Information System, Distribution Automation System, Maintenance Management System, and Customer Information

System allow EDCs to use this information to identify specific areas to address, and then sort out the possibilities to ultimately identify the best courses of action.

Technology advances continue to produce superior analysis as compared to human observation and thereby improve the effectiveness and efficiency of maintenance programs. The beneficiary of increased technology is the customer who receives lower prices and more reliable service.

Mandating inflexible, proscriptive time-based inspection and maintenance practices discourages the EDCs from integrating these technologies into their respective organizations because the mandates close the door on EDCs harvesting a payback in the form of reduced operating costs. EDCs should be permitted to develop targeted, specific, maintenance programs using the latest technologies that have cost-effective result for improving reliability.

IV. <u>Conclusion</u>

The proposed Regulations add significant annual costs, do not improve reliability, and cannot be implemented due to an absence of trained workers on a national level.

The EAPA strongly recommends the proposed regulations be modified so as to remove all of the mandated Inspection and Maintenance time cycles and eliminate automatic rejection of plans that do not have mandated time cycles. The key distinction is to permit each EDC to establish its own Inspection and Maintenance Programs that recognize the uniqueness of its electric delivery system. EAPA submits that before the adoption of mandated time cycles for electric facility Inspection and Maintenance practices, a cost/benefit analysis must be completed by the Commission, and such an analysis is legally required.

The workforces and resources required to accomplish the proposed mandatory line clearance time cycles and equipment program cycles are not available at the present time. The Commission has existing electric service reliability regulations in place, and with the additional reporting of each EDC Inspection and Maintenance Plans, has the tools to monitor each EDC's effort to meet its existing electric service reliability goal. The Commission also has the authority under these existing regulations to order any EDC under its jurisdiction to adopt more stringent Inspection and Maintenance practices should that EDC's reliability fall below established standards.

By allowing flexibility for each EDC to determine an appropriate trimming cycle and other maintenance programs, the Commission will help to mitigate the current expectation among the public that rates will increase as rate caps expired, as expressed by many in the Commission's *En Banc* proceeding to Mitigate the Increase in Electric Rates. This is a critical time -- with all of the major EDCs scheduled to emerge from 12 to 13 years of rate caps by 2010, and with the implementation of Renewable Energy Portfolio Standards, PJM's Reliability Pricing Model, and possible increase in rates because of mercury rules, stakeholders are bracing for significantly increased electric costs. The Commission should not add costly expenses, related to vegetation management and other mandatory time-based maintenance cycles, that have little or no benefit in reliability service the EDCs provide.

EAPA has provided recommendations and specific language changes to Annex "A", Subchapter N – Electric Reliability Standards, that provide for EDCs filing their specific Inspection and Maintenance Plans, and eliminates mandated inspection time cycles. The Commission always has the authority to investigate and implement discrete measures when, and if, reliability indices are not achieved by individual companies. EAPA looks forward to working with the Commission and other stakeholders to finalize and implement Inspection and Maintenance regulations that will further the objective of maintaining reliability under the Electricity Generation Customer Choice and Competition Act in a cost-effective manner.

The Commission has proposed rules that (1) harm Pennsylvania competitiveness versus other states; (2) will mandate standards for the entire state that would hinder the EDCs' ability to achieve efficiencies in work processes, and would restrict the EDCs from employing new technologies for improving reliability; (3) have no proven positive impact on reliability; (4) will create skilled work force shortages and increase skilled labor costs; and (5) add a $75 million annual increase, or 6.3% increase, to the EDCs' operations and maintenance expense, which is neither necessary or beneficial.

Respectfully submitted,

J. Michael Love, Esquire
President and CEO
Energy Association of Pennsylvania
800 North Third St., Suite 301
Harrisburg, PA. 17102

Donna M. J. Clark, Esquire
Vice President and General Counsel
Energy Association of Pennsylvania
800 North Third St., Suite 301
Harrisburg, PA 17102

Dated: November 6, 2006

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ANNEX A

TITLE 52. PUBLIC UTILITIES

Part 1. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 57. ELECTRIC SERVICE

Subchapter N. ELECTRIC RELIABILITY STANDARDS

* * * * *

§57.192. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

* * * * *

~~***Rural area*** **— A rural place designated by the United States Bureau of Census as having a population of less than 5,000 and whose boundaries have been approved by the Secretary of the United States, Department of Transportation.**~~

~~* * * * *~~

~~***Urban area*** **— An urbanized area or an urban place designated by the United States Bureau of Census as having a population of 5,000 or more and whose boundaries have been approved by the Secretary of the United States, Department of Transportation.**~~

* * * * *

§57.198. Inspection and maintenance standards.

(a) An EDC shall have a plan for the periodic inspection and maintenance of distribution system **poles, overhead conductors and cables, wires, transformers, switching devices, protective devices, regulators, capacitors, substations and other facilities critical to maintaining an acceptable level of reliability, in a format the Commission prescribes. The Commission will review each plan and may issue orders to ensure compliance with this section. The Commission may require an EDC to submit an updated plan at any time containing information the Commission may prescribe.**

(1) The plan shall be based on industry codes, national electric industry practices, manufacturers' recommendations, sound engineering judgment and past experience. ~~**The plan shall be divided into rural and urban areas.**~~

The plan shall take into account the broad ~~minimum~~ inspection and maintenance practices ~~intervals~~ provided for in subsection (e).

(2) An EDC shall reduce the risk of future service interruptions by accounting for the ~~age,~~ condition, design and performance of system components and by providing adequate resources to maintain, repair, replace and upgrade the system.

(3) The plan shall include a program for the maintenance of~~of~~ ~~minimum~~ clearances of vegetation from the EDC's overhead ~~transmission and~~ distribution facilities ~~sufficient to avoid contact under design-based conditions~~. The plan shall include a program for the trimming of tree branches and limbs located in close proximity to overhead electric wires when the branches and limbs may cause damage to the electric wires ~~regardless of whether the trees in question are on or off of a right-of-way~~.

(4) The plan, or updates to the plan, shall form the basis of, and be consistent with, the EDC's inspection and maintenance goals and objectives included in subsequent annual and quarterly reliability reports filed with the Commission.

(b) On or before October 1, 2007, and every 2 years thereafter, an EDC shall submit its whole plan for the following calendar year to the Commission for review.

(1) Within 90 days, the Commission ~~or its designee~~ will accept or reject the plan.

(2) Absent action by the Commission ~~or its designee~~ to reject the plan within 90 days of the plan's submission to the Commission, or by January 1, whichever is later, the plan shall be deemed accepted. ~~The acceptance shall be conditioned upon the EDC meeting Commission-established reliability performance standards.~~

(3) If the plan is rejected, in whole or in part, by the Commission ~~or its designee~~, the EDC shall be notified of the plan's deficiencies and directed to resubmit a revised plan, or pertinent parts of the plan, addressing the identified deficiencies, or submit an explanation why the EDC believes its plan is not deficient.

(c) An EDC may request approval from the Commission for revising an approved plan. An EDC shall submit to the Commission, as an addendum to its quarterly reliability report, prospective and past revisions to its plan and a discussion of the reasons for the revisions.

(1)**Within 90 days, the Commission** ~~or its designee~~ **will accept or reject the revisions to the plan.**

(2) Absent action by the Commission to reject the revisions to the plan within 90 days of their submission to the Commission, the revisions to the plan shall be deemed accepted.

(d) An EDC shall maintain records of its inspection and maintenance activities sufficient to demonstrate compliance with its ~~transmission and~~ **distribution facilities inspection, maintenance, repair and replacement programs as required by subsection (e)** for a period of two (2) years. **The records shall be made available to the Commission upon request within 30 days.**

(e) An EDC shall maintain the following types of ~~minimum~~ **inspection and maintenance** plans ~~intervals~~**:**

(1) Vegetation management. ~~The statewide minimum inspection and treatment cycles for vegetation management are 4 years for distribution facilities and 5 years for transmission facilities.~~

(2) Pole inspections. ~~Distribution poles shall be visually inspection practiceesed every 10 years.~~

(3) Overhead line inspections. ~~Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected on foot every 2 years~~. ~~Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Above-ground pad-mounted transformers and below-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested at least once per year.~~

(4) Substation inspections. ~~Substation equipment, structures and hardware shall be inspected monthly.~~

Appendix A

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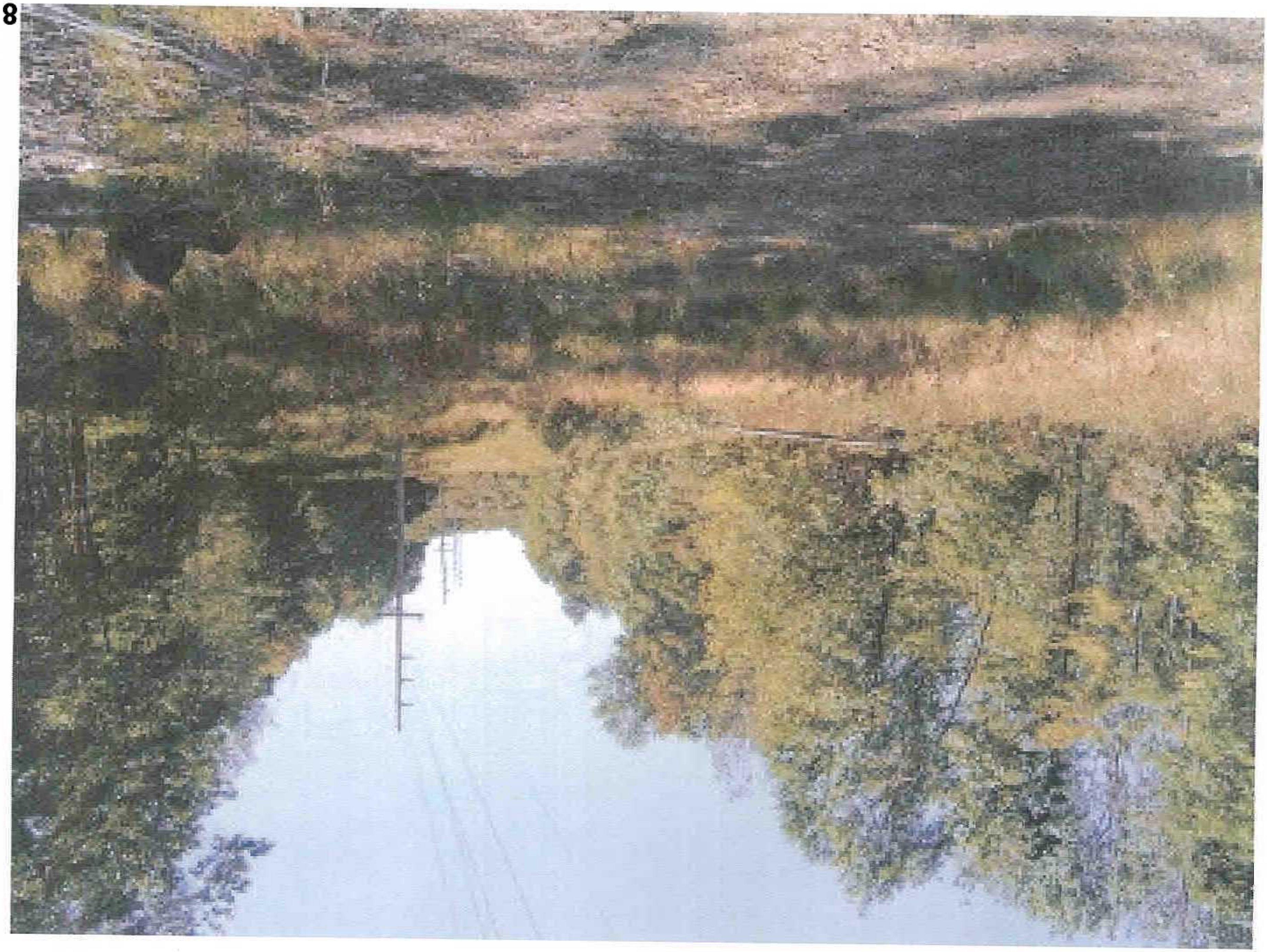

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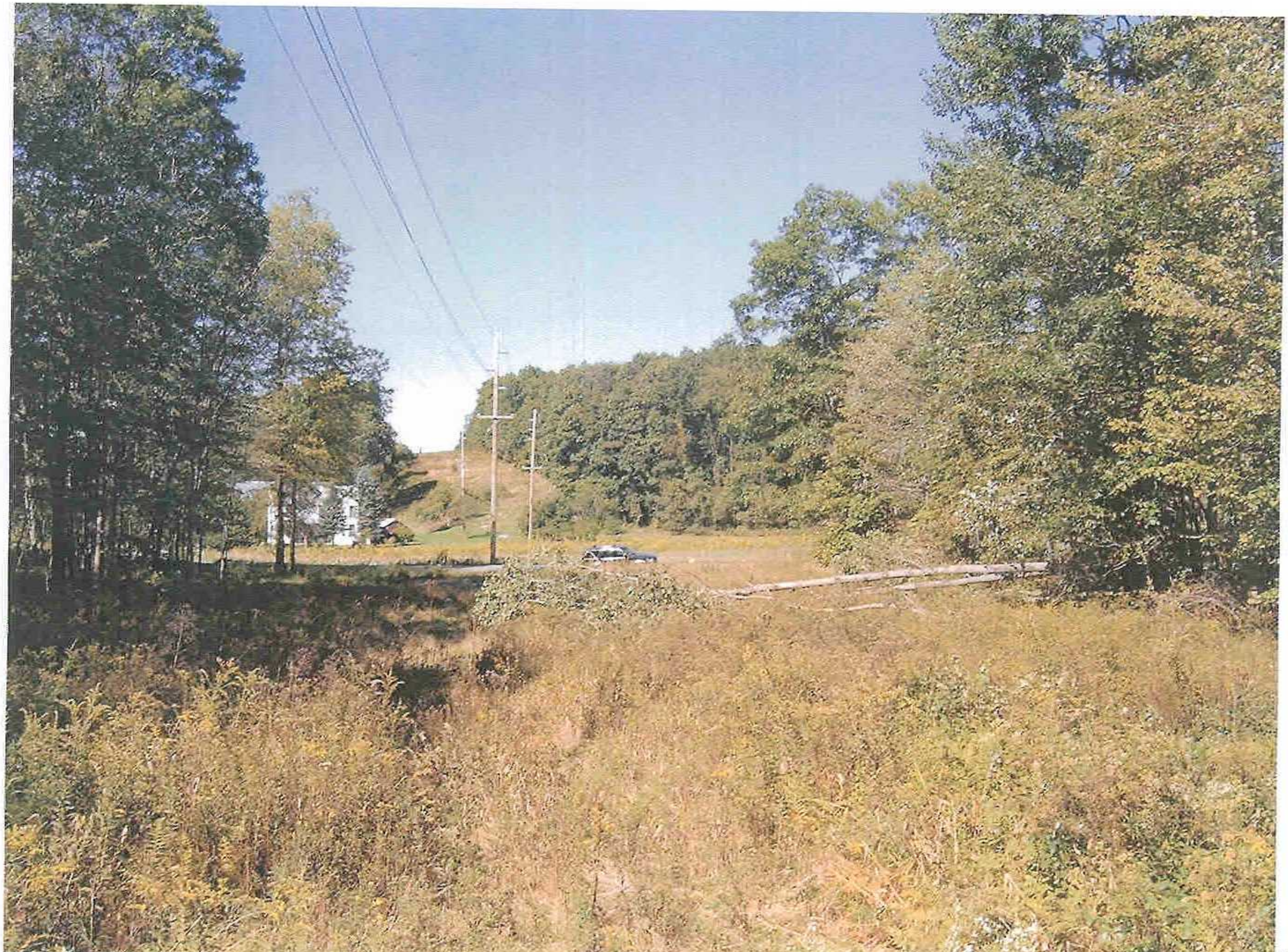

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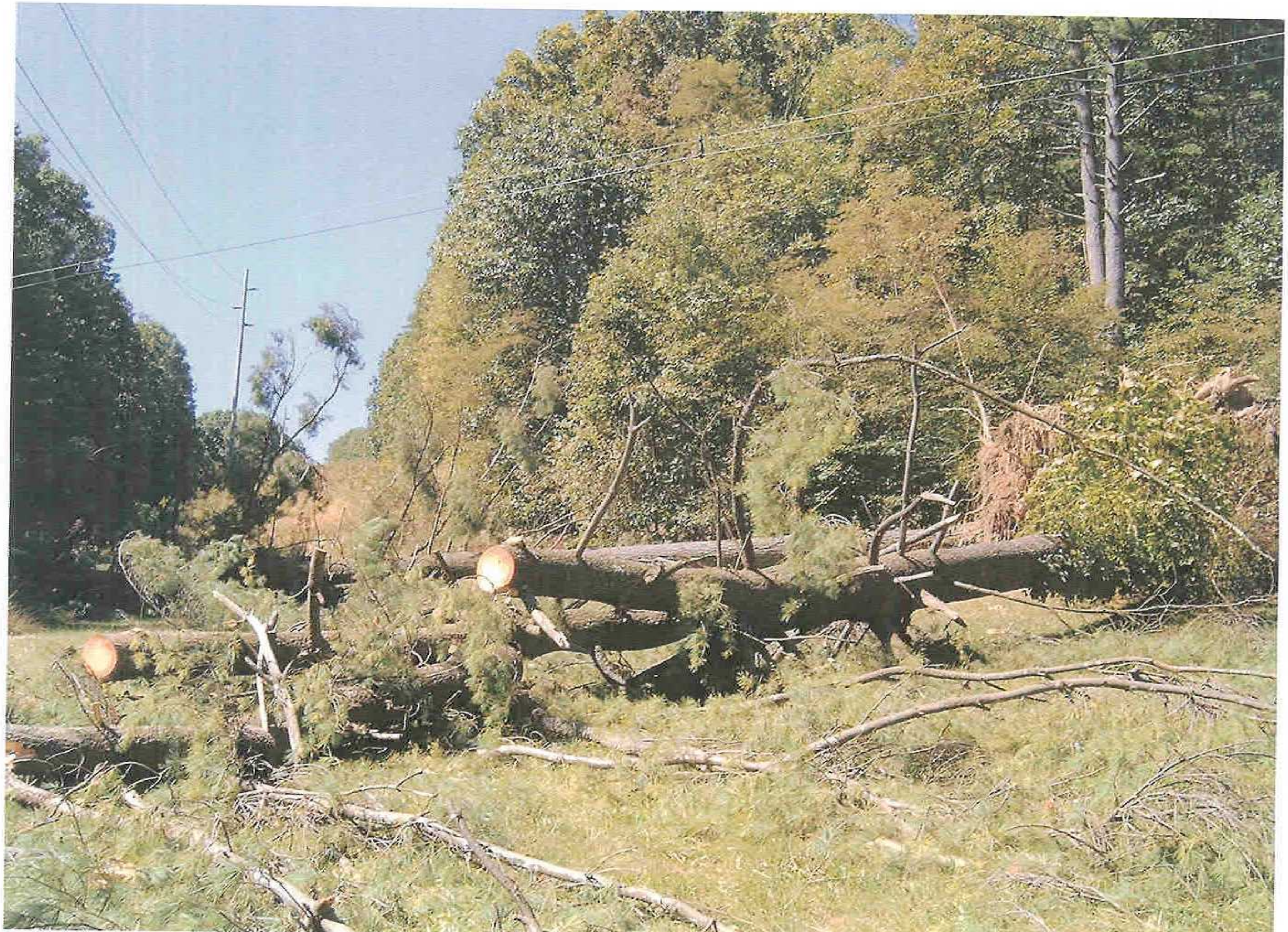

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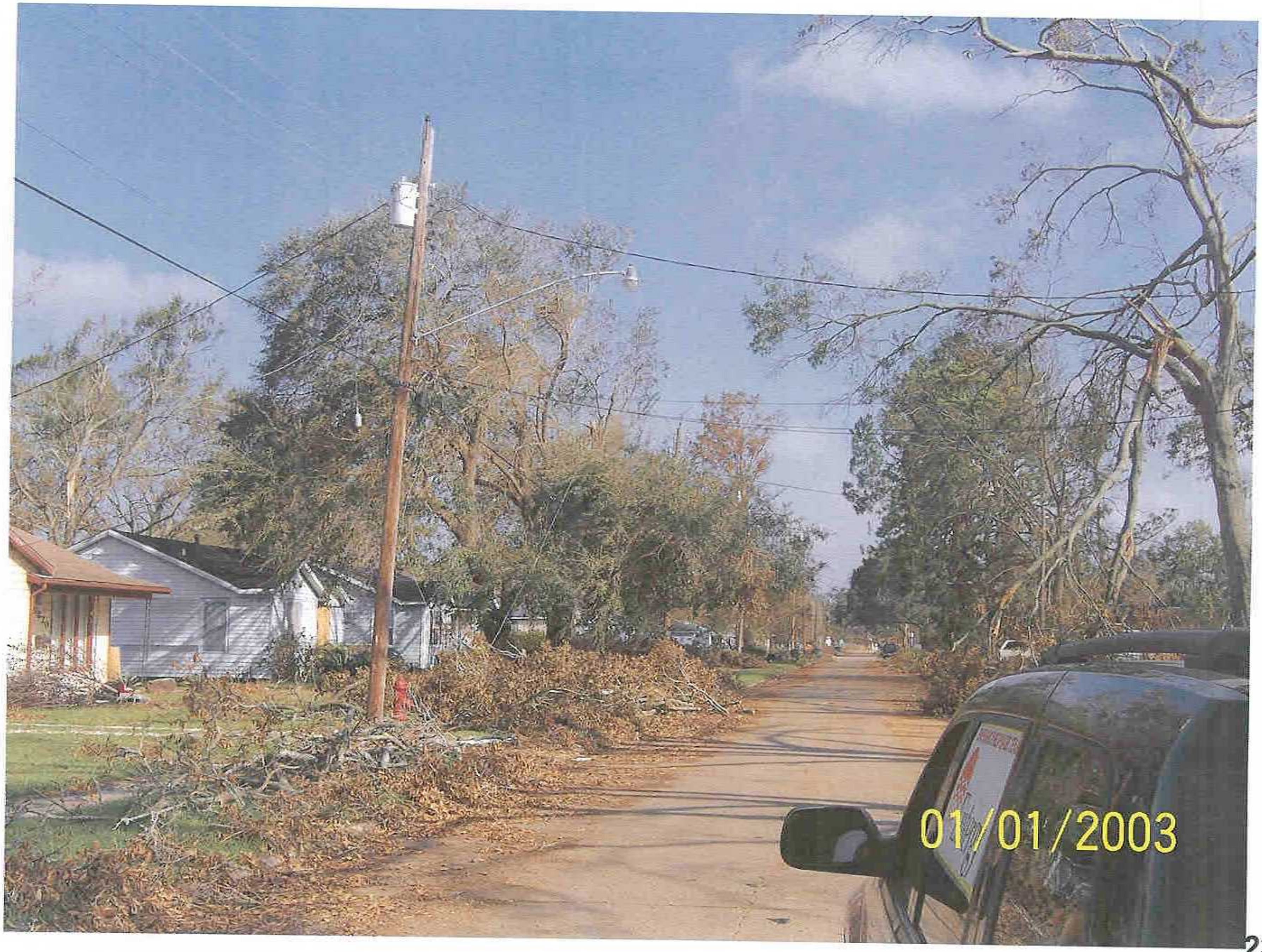
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Appendix B

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Conference Papers

Research on How Trees Cause Interruptions- Applications to Vegetation Management

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Paul J. Appelt,Consulting ServicesECI
John W. Goodfellow, Research Consultant

Paper No.
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0-7803-8298-6/04/$20.00 ©2004IEEE

Research on How Trees Cause Interruptions- Applications to Vegetation Management

2004 IEEE Rural Electric Power Conference in Scottsdale, Arizona.

by Paul J. Appelt[i] and John W. Goodfellow[ii]

Abstract. ECI and others have conducted applied practical research to the question of how trees cause sustained as well as momentary interruptions. This research has led to the development of a conceptual model of tree-initiated faults on overhead distribution systems. Information gained from this newfound understanding into distribution system construction, tree species, and voltage impacts on fault risk has implications for tree maintenance programs and construction standards. ECI has used this understanding to help utilities optimize maintenance cycles to reduce annual asset maintenance costs, while reducing interruptions associated with tree growth.

Understanding How Trees Cause Interruptions

Introduction

Trees are frequently among the top causes of electric distribution system service interruptions and tree maintenance expenditures typically account for one of the largest line items in an electric utility operating and maintenance budget. Gaining a better understanding of how trees cause interruptions is an important step towards identifying effective mitigation strategies that can provide the greatest improvements in reliability for the least cost. Trees cause distribution system interruptions through two fundamental mechanisms: (1) by failing structurally, causing physical damage to overhead utility infrastructure (mechanical failure mode), or (2) by providing a fault pathway between conductors and/or ground, resulting in a low impedance, high fault-current (electrical failure mode).

ECI has conducted research that explored how trees cause interruptions and some of the dynamics of electrical faults through trees. Through an understanding of the dynamics of tree-related interruptions it became evident that the relationships between system design, construction and protection were significant contributors to the overall risk of sustained tree-caused interruption on a distribution system. Findings from initial investigations into the electrical mode of sustained tree-caused interruptions have also led to challenging questions about the possible role of trees in momentary interruptions. ECI has also conducted investigations into the potential for trees to be causal agents for momentary service interruptions.

Through improved understandings of the mechanisms behind tree-caused electrical mode of system failure, innovative solutions to vegetation management problems have been developed which have, where implemented, resulted in reductions in annual asset maintenance expenditures related to vegetation control.

Research History

Why does a tree limb cause an electrical mode of system failure in some cases and not in others? Past research concerning this subject has been undertaken by various groups in an attempt to answer this question.

Baltimore Gas & Electric (BG&E) conducted some of the earliest publicized field demonstrations of electrical fault pathway development[1]. This work, begun in 1992, identified the formation of a carbon path across a tree limb as a condition for the operation of electrical protective devices, both in laboratory and field tests. Later, Florida Power Corporation performed some similar evaluations.

In 1997 under contract with Allegheny Power System (APS), ECI conducted some high voltage testing in a controlled laboratory experiment as part of a formal investigation into the factors influencing the creation of fault pathways through tree limbs. Subsequent high voltage research was completed in 1998 and 1999 for Niagara Mohawk Power Corporation (NiMo) and Portland General Electric. This research included investigations into the fault characteristics of tree limbs subject to voltage stress and influences of the following conditions:

- Voltage gradient
- Branch diameter
- Surface moisture
- Branch condition (living or dead)
- Branch origin (normal vs. "sucker" growth)
- Internal wood moisture content
- Seasonal variation and effect on impedance
- Species variation on impedance (eleven species)

This work resulted in development of a conceptual model for the mechanism of electrical modes of failure through trees. ECI conducted an engineering study and completed proof of concept field validations testing of the earlier laboratory studies on the APS and NiMo distribution systems in 2000[2]. In this phase, additional research data was acquired as trees and branches were introduced to energized primary voltage distribution lines under normal operations in the field. This work helped assess the relationship between incidental tree contact with a conductor and momentary interruptions.

Continued research into the variations in electrical fault characteristics among additional tree species subject to various voltage gradients continued in 2003, supported by the Tree Trust and individual utility cooperators including Illinois Power, Central Vermont Public Service, Black Hills Power and Keyspan.

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[1] Rees, Wm. T. Jr., T.C. Birx, D. L. Neal, C. J. Summerson, F.L Tiburzi Jr., and J.A. Thurber, PE. "Priority Trimming to Improve Reliability". Unpublished manuscript. BG&E. 1993.

[2] ECI. "Understanding the Way Trees Cause Power Interruptions". Private research report. 1998.

The Tree Fault Pathway Model

The body of research conducted by ECI and others has led to the creation of a tree fault pathway model for development of interruptions through the electrical mode of failure. The tree fault pathway model identifies four primary factors that influence whether or not a tree branch crossing two primary distribution phases (or phase and neutral) will result in an interruption. These factors include:

- Voltage gradient (voltage plus distance)
- Branch diameter
- Tree species
- Internal moisture content (living vs. dead limbs).

The multiple research efforts conducted by ECI confirmed that the formation of the carbon path is essential for the electrical fault to occur. Without a completed carbon path no fault occurs. However, once a carbon path is fully developed across a branch bridging two phases or a phase and a neutral, overcurrent protective devices will detect what has become a low-impedance fault, and operate as designed, creating an interruption.

Species Specific Variation in Impedance Testing

Background

The goal of ECI's 1998 study was to replicate some of the previous work in a controlled laboratory environment, where a large number of tree limb samples could be tested with multiple replications. Eleven species were tested within 4 different diameter classes. Subsequent testing in 2003 more than doubled the initial number of tree species tested. Time to fault and current measurements were recorded for each specimen as well as sample diameter and moisture content.

Experimental Design

The design allowed a predetermined test voltage level to be impressed uniformly across a fixed distance, achieving the desired voltage stress gradient. The voltage gradient impressed on each specimen was controlled, and varied for different sample lots by varying the voltage input.

The project involved two related but different experimental efforts. In the first phase of testing, branch specimens were subjected to fixed high-voltage gradients. The voltage stress gradients tested impressed relatively high voltage stress gradients of 2kV/ft, 3kv/ft and 5kV/ft. Tests were made on 48 specimens (4 replications x 4 diameter classes x 3 voltage gradients).

The second phase of the high-voltage laboratory work subjected individual specimens to decreasing fault gradients until a level was reached that did not result in a short circuit fault. The voltage gradient was stepped down 300 Volts between tests. The number of test specimens used in the second phase of the experiment varied, and was a function of the researcher's ability to estimate a starting voltage gradient close to the fault/no fault threshold.

Both phases of testing were conducted in a controlled high-voltage laboratory setting. Individual test specimens were placed between two conductor segments positioned a fixed distance apart. This configuration permitted the branch specimens to be consistently positioned for each testing sequence.

A variable output AC high potential test transformer provided a means of voltage control. A 60:1 power transformer with a maximum rated output of 15 kilovolts was used as a high voltage source. An instantaneous current sensing trip coil of a protective relay protected the test circuit. The relay was set to interrupt at a fault current level of 275 mA. Test set instrumentation provided for a continuous record of time and current, as well as real time observations of current, time, and voltage.

Results - Phase-to-Phase or Phase-to-Neutral Faults Through Tree Branches

Upon contact with two energized conductors (or between an energized conductor and grounded object or neutral), an electrical stress is imposed on the branch. While the gradient is relatively uniform, it is greatest at the point of contact due to the unequal potential of the bark and wood. Arcing at the points of contact oxidizes organic compounds in the branch into elemental carbon. The arcing fronts move in the direction of the gradient, increasing the stress as illustrated in Figure 1. If the voltage gradient between the two electrodes is high enough, the carbon path continues to form and grow together until the gap between the areas of unequal potential is bridged and the fault occurs.

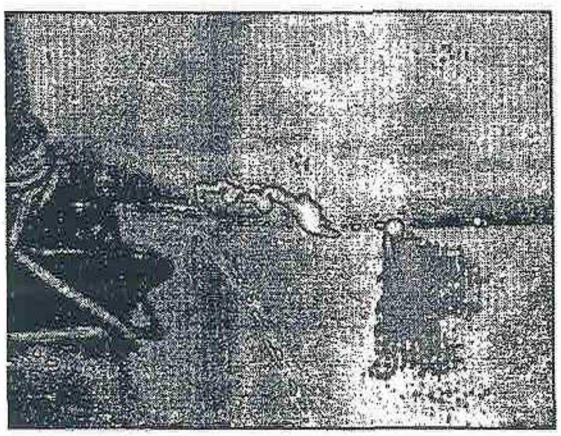

Figure 1. Creation of a Carbon Path

Of all the variables studied, voltage gradient, branch diameter and species have been found to have the greatest affect on fault current levels. Voltage gradient is a function of both the voltage differential between two points, and their distance apart.
All testing conducted to date indicates that formation of a complete carbon pathway is essential to transition from a high-impedance to a low-impedance condition and for a

fault to occur at distribution voltages. However, wood has certain insulating properties and the formation of the carbon path becomes a race between the push of the voltage gradient and the drying affect and increasing resistance of the wood itself. If the voltage gradient is high enough, the carbon path will form faster than the drying wood increases its resistance, and a fault will occur. But, if the voltage gradient is low enough, the drying effect increases the wood's resistance faster than the carbon path can form – and a fault will NOT occur. Effectively, the voltage gradient is not high enough to push the carbon path across the limb and completely bridge the gap. This helps explain why utility operations personnel often see limbs on the lines without adverse impact to system operation, especially at lower voltages.

A developing fault may also be interrupted when the limb that falls across phases, or across a phase and neutral, is actually so small that the branch burns through at one of the contact points before the carbon path fully develops. At high voltage gradients, however, the carbon path may develop before even a very small branch burns through.

Table 1. Common Line Types and Voltage Gradients

Line Type	Voltage Gradient
3 Ø 34kV on 10 foot arms	11.5 kV per foot
3 Ø 24.9kV on 8 foot arms (center φ on pole top insulator)	6.2 kV per foot
3 Ø 34kV on 10 foot arms	11.5 kV per foot
3 Ø 12.5kV on 8 foot arms	5.16 kV per foot
3 Ø 12.5kV on 10 foot arms	4.16 kV per foot
1 Ø 24.9 kV (14.4kV) on pole top insulator with neutral	2.4 kV per foot
1 Ø 12.5kV (7.2kV) on pole top insulator with neutral	1.2 kV per foot
3 Ø 4.2kV on 8 foot arms (center φ on pole top insulator)	1.0 kV per foot
1 Ø 4.2kV (2.4kV) on pole top insulator with neutral	0.4 kV per foot

Table 1 illustrates typical voltage gradients for the design and construction criteria common in the industry. As voltage increases and distance between potential points of contact decrease (arm length or distance to neutral), voltage gradient increases. While each utility has some differences in specific framing standards and slight operation voltage differences, Table 1 contains the general range of voltage gradients likely to be encountered. Figure 2 illustrates the relationship between voltage gradient and time to fault for trees based on all species in the initial studies. The "no fault" zone is different for individual tree species and the location of the curve will shift to the left or right as additional species are added through future research results.

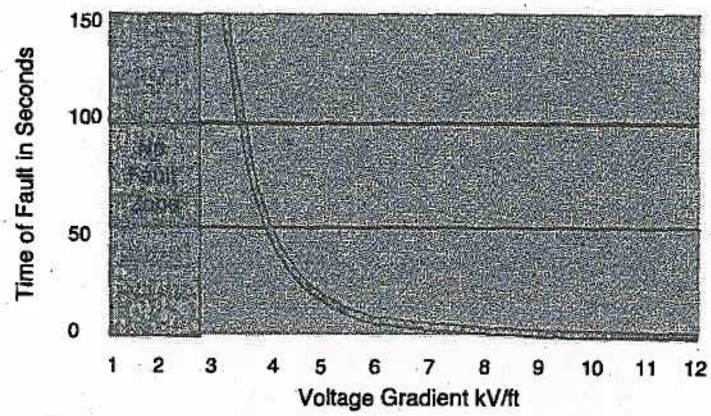

Figure 2 Influence of Voltage Gradient on Fault

Differences in Calculated Impedance: Rho

A final empirical approach to assessing differences in impedance made use of quantitative data collected in both experimental phases.

Current recordings were automatically recorded once every 0.88 seconds of each test. While fault impedance has been shown to evolve (change) throughout the course of each test, data immediately following energization of the specimen is believed to be an accurate indication of the initial impedance of the specimen.

After assembling a data set of initial impedance it was necessary to normalize each observation for the effect of the varying diameters of the test specimens. The calculated resistivity (Rho) of individual tree species does vary significantly between species as seen in Figure 3.

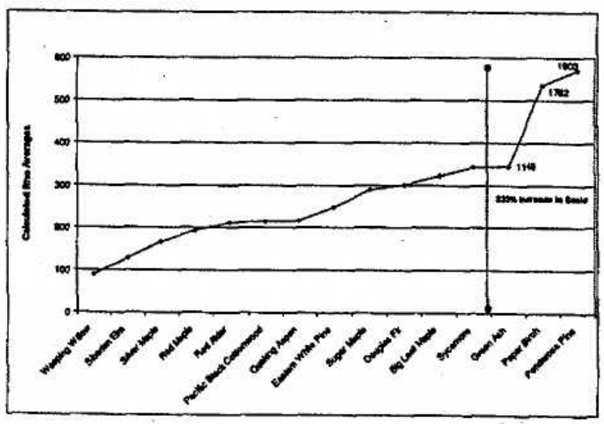

Figure 3 Calculated Rho Averages by Species

It should be noted that calculated Rho for green ash, paper birch and ponderosa pine were orders of magnitude greater than for the other species tested. For purposes of clarity, the Figure 3 scale was compressed artificially to accommodate these large values in order to also demonstrate the large differences in Rho among the other species.

Influence of Branch Diameter

Larger diameter branches are more conductive than small branches. Additional work is required to understand the exact electrical pathway through branches, although, there is speculation suggesting that xylem fibers play a major role as conductive pathways with layers of varying dielectric strengths.

Incidental Contact Between Trees and Conductors

In an effort to better understand the impact of incidental tree-to-conductor contact on momentary interruptions, ECI completed two separate field studies in 2000 designed to assess the relationships between tree-to-conductor contact and momentary interruptions[3]. These studies built on previous work and helped create additional understanding about what happens when a tree comes into contact with a single energized distribution conductor. These studies were conducted for and with the assistance of APS and NiMo.

Experimental Design

The NiMo project design included a single-phase, 7,620-volt tap off of a 13.2 kV line with maximum calculated fault current available to the site of 853 amperes. A 10K fuse was installed to isolate the tap and power quality monitoring equipment was installed on the customer side of the system.

The tap itself consisted of URD cable running down the pole, across the ground and up into the trees. A section of copper clad conductor was spliced onto the end of the URD cable and then placed in contact with test trees. The conductor made contact with multiple branches to simulate a line running out through the trees in an overgrown condition.

Data loggers and AC Current Probes were used to measure current flowing through the test trees. Digital Voltmeters (Figure 4) were placed at one-meter intervals down the tree and out in the soil away from the tree along major roots to measure voltage gradient down through the tree to the earth.

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[3] ECI. "Assessing the Relationship Between Tree-Conductor Contact and Momentary Outages at Niagara Mohawk Power Corporation". Private research report. 2000.

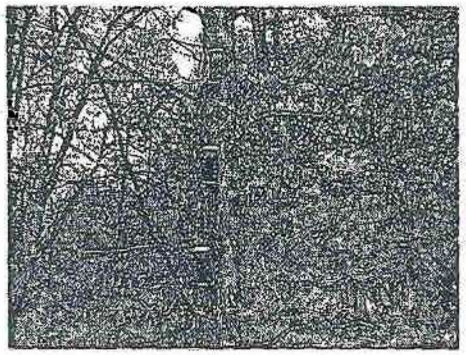

Figure 4 Voltmeters in Test Tree

Field Results

The levels of fault current observed in all tests were low. This result was consistent with both the engineering studies and experimental work. All of these field tests could be described as "high impedance faults". The fault current levels observed ranged in the order of 100mA, with the exception of a worst-case scenario test that resulted in fault current of nearly 500mA.

This worst-case test involved continuous contact with the main stem of an aspen tree 17 cm in diameter at the point of contact. Previous research efforts suggest that both the larger tree stem diameter in conductor contact and the shorter distance to ground (no lateral branches for current to flow through) contributed to the higher measured fault current. Even after over an hour of observation, fault current levels remained relatively stable and constant, did not exceed 0.5 Amperes and likely would have remained a high impedance fault if the test were not ended. It should be clear that the fault current levels at no time, in any of the tests, approached levels remotely high enough to have been detected by an overcurrent protection system.

Research Conclusions

Based on the laboratory testing and field demonstrations completed, it is evident that tree contact with single-phase conductors on 15kV class distribution circuits represents very low risk of causing a sustained or momentary interruption. Nor will incidental tree contact with a single-phase line cause a significant voltage sag or dip. Power quality measurements completed in the field demonstrations indicated no degradation in power quality.

It may be safe to conclude that there is minimal risk of an interruption when a tree on a typical distribution line contacts one phase of a multiphase distribution circuit. There is a risk of an interruption when a tree (or branch) provides a fault pathway between energized phases or between an energized phase and system neutral. It should be noted that this discussion applies only to the electrical failure mode through tree limbs and not mechanical failure.

These understandings of how trees cause outages create significant opportunities for both cost savings and reliability improvements through changes in scheduling and certain tree maintenance work selection criteria and guidelines.

Applying the Results

Based on the enhanced understandings of how trees cause interruptions as described in this paper, there is considerably different risk of interruption due to tree contact with conductors when construction types reflect high voltage gradients. In practical terms, single-phase lines or lines constructed with longer crossarms and lower-voltage lines represent lower interruption risk than multi-phase construction on short crossarms or higher voltage lines.

There is also different interruption risk associated with different tree species and with different size tree limbs in close proximity to conductors. ECI has utilized this understanding of risk variability to modify line clearance scheduling and maintenance practices to improve reliability and lower maintenance costs.

One case study includes program changes made at Kansas City Power and Light Company (KCP&L) that reduced overall distribution vegetation maintenance costs by over 13 percent while reducing tree-related interruption duration by over 50 percent.

The key to realization of these improvements was the reallocation of tree maintenance expenditures toward those locations on the system and those activities that represented a higher risk of tree-related interruptions. These resource reallocations included:

- Extending the single-phase maintenance cycle
- De-emphasizing trimming trees for service lines
- Shortening the three-phase backbone inspection and maintenance cycle, effectively placing greater emphasis on this critical element of the circuit.
- Emphasizing selective removal of hazardous trees and trees at higher risk of causing interruptions adjacent three-phase lines
- Implementing a highly prescriptive approach to work selection, prior to work assignment to line clearance crews, through tree assessments by individuals trained in an understanding of tree-related interruption risk

By extending the tree maintenance cycle for single-phase portions of circuits, a significant number of trees grow into the conductor by the time line clearance work is scheduled. As projected by the research, however, this intermittent contact has not had any detrimental impact on system reliability. Furthermore, KCP&L was able to reinvest some of the savings associated with cycle extension on single-phase lines to decrease the inspection cycle on 3-phase backbones and to selectively increase tree maintenance levels on these portions of the distribution system most at risk of interruption from trees.

Table 2 illustrates the theoretical potential savings associated just through cycle extension of single-phase construction on a 5,000-mile system with 50 percent single-phase construction.

Table 2. Potential Savings Example Associated with Cycle Extension

1φ Cycle Length	Est. 1φ Cycle Cost/ year	1φ System % Savings	3φ Cycle Length	Est. 3φ Cycle Cost/year	Total Annual Cost	Total System % Savings
4	$1,250,000	[illegible]	4	$1,250,000	$2,500,000	[illegible]
5	$1,000,000	20%	4	$1,250,000	$2,250,000	10%
6	$833,333	33%	4	$1,250,000	$2,083,333	17%
7	$714,286	43%	4	$1,250,000	$1,964,286	21%
8	$625,000	50%	4	$1,250,000	$1,875,000	25%

New information gathered on outage risk associated with the electrical impedance of different tree species is expected to result in further reliability improvements at KCP&L through modification of tree removal criteria based on those differences.

Additional interruption risk reduction can be realized through modification of construction standards, especially in areas of high tree density or where trees are highly subject to breakage. Changes to construction standards that result in reduced voltage gradients exposed to trees can help reduce interruption risk.

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[i] *Vice President, Consulting Services*
ECI
520 Business Park Circle
Madison, WI 53719

[ii] *Principal, Research Consultant*
7710 196th Ave NE
Redmond, WA 98053

Appendix C

PRIORITY TRIMMING TO IMPROVE RELIABILITY

by William T. Rees, Jr., Timothy C. Birx, Daniel L. Neal, Cory J. Summerson, Frank L. Tiburzi, Jr., and James A. Thurber, P.E.

Abstract

At BGE, changes in vegetation management practices were required to improve upon system reliability. Due to resource limitations, a systematic approach to vegetation management was implemented. Vegetation management activities were prioritized by voltage class and construction type. Concurrent with this process, actual impacts to service reliability from tree/wire contacts were investigated through controlled testing. With some modification, the testing validated the systematic management approach. As a result, a foundation has been formed for a flexible vegetation management program that factors in tree health, customer concerns and tree/outage relationships in its implementation.

Background

The Baltimore Gas and Electric Company (BGE) is an investor owned utility that serves over 1.1 million customers in the largely metropolitan Central Maryland Region. Over 9,000 miles of distribution lines are situated in a region where elevations range from sea level in the Atlantic Coastal Plain to almost 800 feet in the gently rolling hills of the Piedmont Plateau. The forest cover type is diverse, with many fast-growing species that, when combined with an average rainfall of 43 inches per year and up to 232 growing days , create challenging conditions for a vegetation manager.

At BGE, considerable amounts of operation and maintenance dollars are spent each year in managing vegetation as part of the process to provide reliable electric service to our customers. In the United States alone, almost 2 billion dollars are consumed each year by utilities on vegetation management activities. With this back-drop, there is one striking fact that is entirely incredible. Since the time that trees and wires have conflicted, no one to our knowledge has performed any significant research on the effects of trees on service reliability, or simply put--how trees cause outages.

In the early 1980's, we at BGE began to realize that many of the electric service interruptions attributed to trees were inconsistent with follow-up observations of the actual incidents. In many instances it did not appear that trees were responsible for outages attributed to them, or they were responsible in different ways than reported by field personnel. As a result of these observations, a seven year field study was conducted in one of our operating districts that investigated over 3,000 outages associated with trees.

During the course of this investigation, budgeting constraints required formulation of a different approach to our business. Rather than trying to trim the entire distribution system somewhat unsuccessfully, we decided to direct our limited resources where they could provide the greatest benefit to the greatest number of customers. This is not a new concept. Previously, we did not have a systematic vegetation management approach to the subtransmission system, and in the distribution program, single phase lines that only served a few customers were given equal priority to 3-phase mains that served as arteries to the feeder system.

A prioritization scheme was devised. First, a plan was developed to gain control of the 34.5 kV subtransmission system through a biannual inspection program. The purpose of this effort was to achieve reliability approaching that of our transmission system--0 outages due to trees. In conjunction with the subtransmission plan, a 3-phase-only plan was incorporated for the distribution system. The goal was to have all of the 3-phase system on a three year cycle within a 3 year period. The one and 2-phase systems were delegated to a "trim only as necessary" status. In theory, the improved condition of the subtransmission and 3-phase distribution systems would allow for more rapid maintainance in subsequent cycles. As a result, more time could eventually be devoted to the one and 2-phase systems.

Investigation

In the meantime, the on-going field investigations revealed some interesting observations that when analyzed, indicated that the prioritization plan was a good approach. A key concept was identified in the process that was consistent among the 3,000 tree-related outages. Formation of a carbon path in or on the wood seemed to be required before the wood could carry fault current. Other valuable information was compiled. Of all sustained outages attributed to trees, which comprise about 20% of our system outages, 75% were caused by dead shorts--where a good path to ground or a second phase, across a limited distance, existed over a sustained period of time. A limb across two or more conductors would be a good example. Further, 23% of the outages were caused by mechanical damage where actual physical damage was the cause, and 2% were labeled as incidental contact--a non-verifiable catch all category that assumed a problem such as temporary contacts by burning branch tips. Temporarily ignoring the 1 and 2-phase systems seemed to be a least-risk approach since natural growth beneath the lines did not appear to be a significant contributor to outages, especially where cross-arm construction was not a factor.

Based on these observations, and with apologies to Isaac Newton, we developed Birx's Law of Gravity. "What grows up must come down". In essence, 98% of sustained system tree outages appeared to be the result of trees or tree parts falling or leaning onto lines. These contacts could be quick and destructive, or they could be the result of more sublime associations such as a branch laying across multiple phases or a sapling leaning against a phase and neutral wire. Less than 2% of the outages may be attributed to natural growth or burning branch tips beneath the lines, vectors that have historically and conventionally been associated with a significant contribution to both sustained and momentary service interruptions

Testing

The results were intriguing although somewhat controversial. Naturally, we wanted to determine if the field observations would stand-up to testing under controlled conditions. This measure necessitated involvement of engineering personnel with technical capabilities associated with electric system operation. So a partnership with two engineering supervisors and their respective organizations was developed. An abandoned 13.2 kV distribution tap that was seven pole spans long was selected for the test. The vegetation had grown up through and around the three conductors along the entire length. The growth was so profuse that the conductors were actually pushed out of normal alignment--something that would not typically occur if the lines were energized and the branches were burnt clear. The ultimate goal of this test was to try to develop some correlation between the amount of tree contact and current and voltage readings. Meters were installed on the lines for this purpose. When the lines were energized, not only did the fuses not operate, but the instruments did not record any measurable variation in the voltage or current.

In the absence of metered data, it was decided to attach a rope to a tree and pull it into contact with a phase and neutral wire. Within minutes, burning started to occur at the two contact points. After a period of about 14 minutes a carbon path had developed along 75% of the length of the tree between the two points. No outage occurred and more importantly, again no significant readings were obtained from the instruments.

Finally, a piece of freshly cut aspen was placed across two phases. Within one minute and twenty seconds, a carbon path had developed almost the entire length of the limb and fault current was generated, operating the in-line fuse. Just prior to fault current, readings of up to 4 amps were recorded.

The most important information gained in this test validating the field observations, was that a carbon path did indeed need to be present in order for a tree or tree part to conduct fault current. The requirements are simple. A small amount of current passes through moisture in the wood. In the process, the moisture heats-up and is driven from the wood, usually in streams of water and as steam. As the moisture disappears, the wood begins to carbonize. As the carbon path develops to a point of near completion, along a limb for instance, an avenue for the fault current to travel is provided. We call this the "carbon path theory". This phenomena has not been observed for distances greater than 10 to 15 feet in our distribution testing or in the field. Trees appear to have too much inherent resistance to conduct electricity over distances that would be typical of phase to soil contacts.

The question that remained unanswered was how much current would a typical tree conduct. If this information could be obtained, perhaps the data could be extrapolated to determine the cumulative impacts from trees on system reliability for either sustained or momentary interruptions.

A second test was constructed on another abandoned distribution tap. In this instance, the line was cleared so that no trees or branches were in contact with the phase or neutral wires. The design called for a sequence of test iterations with test equipment that was significantly more sensitive than in the first series of tests. Each iteration was designed to measure or calculate the amount of current experienced at ground level for one tree under constant, tensioned contact with the 7.6 kV line. A variety of species were used over the seven iterations. Two of the iterations were performed under a constant spray of water that thoroughly saturated the trees and overhead facilities. As in the first set of tests, the time of year was mid-spring.

While it was difficult to obtain consistent and reliable measured ampere readings from the trees, calculated results were obtained by two different methods. The first was through measured touch potential and tree resistance readings. The second utilized measured line and transformer excitation currents. The calculated amperages ranged from .006 to .041 amps. Although no significant difference was detected between the same species when tested with and without the spray stream, current readings for wet or wetted wood trended lower than the dry control specimens, and seemed to favor conditions that would delay the onset of carbon path development.

This second series of tests seemed to validate what appeared obvious from the first test experience. It would probably require hundreds, perhaps even thousands of trees that are in the ground and in constant contact with the overhead wires to potentially cause sustained or momentary service interruptions. Due to branch tip burning, it is highly unlikely that this type of constant contact could occur. The carbon path theory seemed to hold-up as well. It is important to note that these tests were performed within proximity of substations and reclosers with high potential fault currents, and that no momentary outages were recorded at those locations. It should be further noted that the overhead aluminum wires used in these tests were not damaged by the tree contacts.

A third and final test was conducted in a controlled test facility. Phase to phase contacts were tested with different limb diameters, and with a variety of tree species, utilizing both live and dead specimens.

Distances between phases were varied during the test process. The test iterations were performed one branch at a time utilizing highly sensitive equipment.

Results

The results supported the conclusions derived from the earlier testing. Additional conclusions were drawn as well. Tree species with higher moisture contents seemed to require a longer period of time before carbon path creation. And, distance between phases and not the branch diameter seemed to affect the carbon formation.

The summation of all the testing has indicated that a carbon path must form before fault current can be conducted. And, moisture must be present initially in the carbon path development process, but must be eliminated before carbon formation can occur. Testing has also indicated that the distances typical of incidental branch or tree phase-to-soil contacts contain too much inherent resistance to allow carbon path formation. From this information and from field experience, the likelihood of carbon path formation decreases substantially as distance increases. This rate of decrease seems to increase rapidly beyond the 8 to 10 feet normally associated with phase to neutral separation. We can further surmise that outages due to trees are more likely to occur where multiple lines exist--most notably with cross-arm or armless constructed facilities. Pole-top-pin lines create significantly fewer opportunities for tree-related problems. It should be noted in the midst of these observations, that conclusions from our testing are only valid for lines that carry 13.2 kV or lower.

Discussion

A note on trees and momentary faults. This is more of an hypothesis based upon all of the data and not from direct observation. As mentioned previously, hundreds or even thousands of trees in the ground touching an energized wire do not appear to be associated with momentary faults. There are two likely causes where trees are concerned. The first, is from branches above multiple phases that when wet, lie across the phases and eventually form a carbon path that conducts fault current. The intense heat from the fault current will dry the branch or branches causing them to lift above the lines. If a recloser or station breaker is on-line, the fault should clear and become transient. As the branches get wet once again during the same storm or in subsequent storms, they will drop back down onto the wires with the previously formed carbon path and cause additional momentary faults. The second connection to a momentary fault is much simpler. Trees adjacent to multiple phases that knock the phases together during periods of high wind.

The significance of this information has impacted BGE in a number of ways. The test data have been utilized to tailor a program that is somewhat unique, and I might add, in a state of continual transition by design. Since the field observations and test results indicated that the single phase system is generally less vulnerable than the rest of the system, we elected to continue a form of the 3 phase versus 1 and two phase program. The new, modified version creates a dichotomy between cross-arm or armless construction and pole-top-pin constructed facilities. The change is not substantial. Now, all 2-phase lines and single phase lines with a neutral on a crossarm are given the same priority status as 3-phase lines.

As I mentioned earlier, BGE is largely a metropolitan utility. We do not typically have "right-of-way" on our distribution system to perform corridor clearing. Instead, we obtain the maximum clearances possible consistent with the intent to maximize service reliability, and balanced by adherence to regulatory requirements and the desire to enhance customer satisfaction.

We know that multiple phase lines and equipment are more prone to outages since they act as collectors of debris from above and have relatively short paths to ground, or close phase-to-phase associations. Wherever possible, we strive to remove as many overhangs above equipment and crossarm or armless constructed facilities. In most cases, this approach is species dependent and is phased-in over a number of trimming cycles to minimize adverse health effects to the trees. For pole-top-pin facilities, overhangs are targeted only where imminent hazards exist.

Hazard or danger trees adjacent to the facilities are candidates for removal if a risk to the facilities is presumed. This approach applies to all types of primary voltage construction. Trees in this category can be severely destructive to our facilities, are costly, and usually result in longer outages for our customers.

Natural growth beneath the lines is trimmed routinely for crossarm or armless facilities. If left untended, natural growth can escape through the phases, branch-out, and form potential cross-phase hazards. For pole-top-pin construction, the focus is on utilizing the tree's natural growth form to train the limbs past the wires. The ultimate goal is to form canopies over the facilities. This approach will eventually suppress sprout growth within the tree's interior, or inhibit regeneration from the forest floor. The interlocking canopy will also help protect the lines from catastrophic ice or wind storm damage.

Where off-cycle or hot spot trimming work is concerned, we focus on looking specifically for the tree or trees that may be causing service interruptions instead of trimming an entire tap. A car analogy is appropriate. If an engine is not working, why replace the entire engine when replacing the distributor cap will suffice. This approach is most appropriate when faced with limited budgets. With tight budget parameters, efficient, incisive trimming techniques will minimize valuable time away from routine maintenance trimming. It is important to note that we are not advocating that trees or branches should remain in constant contact with the overhead wires. That is not our intent. Sufficient clearances are helpful to buffer tree conditions that could become critical. A sapling leaning against phase and neutral wires is a good example. We also want to provide adequate clearances to minimize the likelihood of incidental contact by the public.

An important component of our vegetation management program is a thorough understanding of how trees cause outages and the utilization of this information through continual inspection of the overhead facilities. Not only do we prioritize the work based upon the tree conditions associated with various construction types and voltages, but we also look for other contributory causes to service interruptions. Faulty lightning arrestors, cracked insulators and deficient wildlife protection on equipment are but a few. Most importantly, we try to factor our customer's concerns into the program. We are improving in this area, but need to go further. We can never lose sight of why trees are trimmed--to maintain or improve upon service reliability. Although we are vegetation managers at one level, ultimately, we prefer to consider ourselves as outage reducers. The task is enormous, but the entire outage reduction equation is best solved by a partnership between forestry, system operation, construction and design personnel

Conclusion

At BGE we had a problem that needed to be solved. A vegetation management program that did not provide a consistent contribution toward service reliability. We needed to prioritize the work to obtain maximum value from our efforts. Concurrently, we noticed from field observations that trees did not appear to cause outages as traditionally perceived. Subsequent controlled electrical testing supported the field observations that trees do cause outages, but under very specific circumstances. Accordingly, we have utilized the test results to temper our prioritization approach to trimming which has created a technique-intensive, flexible vegetation management program. Our program is not fully implemented throughout the service territory at this time. We still need to make substantial inroads into the single phase system. Nonetheless, we are optimistic and even excited about the prospects.

What does all of this mean to other utility vegetation managers? Not much to some. Perhaps portions of our program may have relevance to other utilities with similar circumstances. In any event, and at the very least, I believe that further testing of how trees cause outages is in order. Is what we have found at BGE valid? Can even more useful information be found? I believe the industry would benefit from a collaborative effort to fund an expanded, more thorough analysis of the interaction between trees and wires.

In the customer and environmentally sensitive business in which we operate, knowing how trees cause outages is a very valuable asset, even beyond the practical field applications. Many times, we in the industry are seen as adversaries by our customers with disconnected interests. We are viewed as the people who want to clear as much as possible for as long as possible. This shouldn't be so. When we propose to a customer or regulator that we need to minimize the trimming around single phase facilities and tell them why, they may begin to realize that there is some rhyme to our reason. The program is not a one-size-fitsall solution. We stand to gain a measure of credibility as a result. If you can educate your customers proactively, not only about how you plan to manage the vegetation, but why you need to do so, you can allow them to intelligently participate in the management process. We will all win as a result.

Can what we learned at BGE benefit your company--you decide.

Baltimore Gas and Electric Company
P.O. Box 1475
Distribution Engineering Department
301 Front St.
Baltimore, MD. 21203